Exhibit 2

RATE BASE

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Exhibit 2: Rate Base

2.1 Rate Base Overview

This Exhibit provides KWHI's distribution rate base forecast for the 2020 Test Year. It also provides an explanation of variances for 2014 through 2018 Actual, 2019 Bridge Year and the 2020 Test Year.

The rate base used for the purpose of calculating the revenue requirement in this Application follows *Chapter 2 of the Filing Requirements for Electricity Distribution Applications* issued by the Ontario Energy Board (Board or OEB) on July 12, 2018 (the Filing Requirements). In accordance with the Filing Requirements, KWHI has calculated the rate base as an average of the net capital balances at the beginning and the end of the 2020 Test Year, plus a working capital allowance, which is 7.5% of the sum of the cost of power and controllable expenses. The use of a 7.5% rate is consistent with the Board`s letter of June 3, 2015 and the Filing Requirements as issued by the OEB. KWHI has not completed a lead-lag study or equivalent analysis to support a different rate and has submitted this application using the default value of 7.5%.

Capital assets include property, plant and equipment and intangible assets. These have been referred to as "capital" or "fixed assets" throughout this evidence. Distribution assets refer to assets that are used to convey electricity throughout the distribution area and includes poles, wires and transformers. General plant assets support the distribution system and includes office equipment computer hardware and software, vehicles building and equipment.

KWHI has not applied for, nor received any ICM or ACM adjustments.

2.1.1 KWHI Approach to Capital Expenditures

KWHI's last Test Year was 2014 and, once again, as in its last Cost of Service, KWHI has not experienced a balanced typical year. There has been significant volatility in its

capital and OM&A due to the construction of the LRT, requiring $27M in capital that diverted resources from OM&A to capital from 2013 to 2017. The same resources are used at KWHI for construction and maintenance. In addition, the amount of engineering work that was capitalized brought annual engineering costs to zero or close to zero, further reducing OM&A.

Following completion of the LRT in 2017, KWHI's O&M increased by $1.2M over the previous years' levels. The year 2018 was the closest to a typical year that KWHI has had in quite a number of years in the period within which its rates were set (its current cost envelope). In 2018, capital budgets were lowered (by $3M) to make room for replacement of KWHI's CIS. Conversely, operating and maintenance budgets were increased; however, not to the levels that KWHI might have preferred to spend as it endeavoured to remain within its cost envelope. Thus, KWHI's total spend did not reach its expected levels in 2018.

The CIS project, still ongoing, is anticipated for completion in 2020. KWHI does expect an increase to its typical total spend approach for the years of the CIS project; however, KWHI will not apply for adjustments from the Incremental Capital Mechanism but will, rather, balance its future total spends to compensate for any overages – just like it always has.

KWHI's increased spending is expected to continue into the next rebasing period as 2021 and 2022 will see increased expenditures to construct new underground feeders ($2.5M) to downtown Kitchener to accommodate load growth and the years 2023 and 2024 will see increases associated with replacing two power transformers at its No. 5 Transformer Station ($6.4M). KWH's customers will continue to benefit from over $7.0M in annual savings generated by KWHI owning and operating its own transformer stations.

The amount of incremental capital dollars that KWHI requires for this five year rebasing period when compared to its last rebasing period make it impossible for KWHI to

maintain its required capital spend and absorb the difference by reducing its O&M costs without reducing reliability in the supply of electricity – an important need in the eyes of its customers. KWHI's historical and anticipated capital spends are shown below:

Table 2.1.1-1 CAPEX

	Board Approved 2014	2014	2015	2016	2017	2018	2019	2020
CAPEX	20,936	20,403	21,420	25,524	21,115	20,302	25,201	24,574

KWHI's anticipated spend on capital in 2019 and 2020 is an average of $3.1M higher than its 2014 through 2018 spend. Using its total spend approach would require KWHI to reduce its OM&A amounts by roughly the same amount or 12.5% of its anticipated OM&A spend. Given that KWHI is an efficient operator, it could not reduce its budgets by such a large amount and maintain its operations.

For additional details of KWHI's Total Spend Approach, see Exhibit 1, Section 1.1.3 and Exhibit 4, Section 4.1.1.

2.1.2 Rate Base Summary

KWHI has calculated its 2020 Test Year Rate Base to be $239,637,774. Table 2.1.2-1 below illustrates KWHI's Rate Base calculation for all required years, including the 2020 Test Year, which is also used to determine the proposed Revenue Requirement summarized in Exhibit 6. The year to year Rate Base variance analysis will be explained in Section 2.2.

Table 2.1.2-1 – Rate Base Summary 2014 - 2020

	2014 Board Approved	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Bridge	2020 Test
Gross Capital Assets in Service								
Opening Balance	323,385,248	318,804,969	329,464,668	338,790,929	351,437,128	366,441,711	380,376,524	398,166,546
Closing Balance	340,139,579	329,464,668	338,790,929	351,437,128	366,441,711	380,376,524	398,166,546	423,297,302
Accumulated Depreciation								
Opening Balance	143,863,186	141,520,265	148,262,955	153,102,172	159,351,403	166,795,619	173,198,517	181,891,717
Closing Balance	151,667,055	148,262,955	153,102,172	159,351,403	166,795,619	173,198,517	181,891,717	191,902,417
Net Capital Assets in Service								
Opening Balance	179,522,062	177,284,704	181,201,713	185,688,757	192,085,725	199,646,092	207,178,007	216,274,829
Closing Balance	188,472,524	181,201,713	185,688,757	192,085,725	199,646,092	207,178,007	216,274,829	231,394,885
Average Balance	183,997,292	179,243,209	183,445,235	188,887,241	195,865,909	203,412,050	211,726,418	223,834,857
Working Capital Allowance	27,083,243	27,440,853	28,806,837	31,991,586	28,573,738	27,750,138	26,722,431	15,532,917
Total Rate Base	211,080,535	206,684,062	212,252,072	220,878,827	224,439,646	231,162,187	238,448,849	239,367,774

2.1.3 Customer Information System

KWHI will be replacing its in-house Customer Information System (CIS) through the period 2019 and 2020. The full business case is included in the Distribution System Plan (DSP) Appendix P. The replacement of the CIS has been approved by KWHI's Board of Directors. Senior staff are in final contract negotiations and, subject to approval by KWHI's Board of Directors in May of 2019, the project will move forward imminently.

KWHI acknowledged during its oral hearing in 2014 that it had plans to pursue the replacement of its CIS. The journey for KWHI's business decision has been long as KWHI has pursued every avenue to keep costs and any resulting customer bill impacts as low as possible. Since its current CIS is an in-house system maintained by its own programmers, KWHI was cognizant that moving to a system that was not maintained in-house would result in fully incremental costs. A decision had to be made; however, as the state of KWHI's current CIS is not sustainable.

State of Current CIS

- 30+ years old
- Written in COBOL, an obsolete language

- Two recent retirements over the last three years has left only one programmer with the skills to maintain system
- Lack of relational database requires programming and reprogramming of same thing in many different places
- Many manual workarounds required
- Distribution industry billing becoming more complex

Moving Forward

KWHI was part of a consortium of three LDCs that worked together to try to find an affordable CIS solution together to control costs beginning in November 2016. This two-year initiative resulted in vendor proposals with higher costs (both capital and operating) than were expected and the consortium disbanded in May 2018.

Following the breakdown of a consortium, KWHI moved forward on its own. KWHI had the following options:

	Options	Status
1	Restart a consortium (try again)	KWHI did speak to other LDCs to see if restarting a consortium was possible
2	Use another utility's billing platform	Would entail using an instance of another LDCs billing platform Offer was received from another LDC using Oracle CC&B While capital costs manageable, operating costs much too high Risk of host LDC upgrading or moving to another CIS would leave KWHI forced to incur costs again unexpectedly
3	Reissue RFP on a go-alone basis	Reissuing the RFP to the same vendors would likely mean they would answer the RFP twice Additional time lag
4	Ask vendors to resubmit proposals based on a go-alone basis	Asked for offers based on going alone Used consortium RFP excluding gas & water One new vendor made offer

KWHI inquired at other LDC's to see if restarting a consortium was feasible. This option was ultimately rejected as too much time had passed and the risks to KWHI were mounting.

KWHI worked with two other LDC's to see if sharing their platforms was an option for KWHI's CIS solution. An offer was received and rejected as the operating costs were deemed to be too high and other uncontrollable risks were identified such as the hosting LDC discontinuing the software solution which would leave KWHI without a CIS at all.

KWHI considered reissuing the original RFP as a stand-alone customer but rejected option as there would be additional time lag and the same vendors would be involved.

The final option, and the option KWHI selected, is to ask the vendors to resubmit their proposals based on KWHI going it alone.

KWHI received bids from four vendors using six different configurations. One new vendor submitted a proposal. Following KWHI's final decision to pursue a Tier 1 solution, KWHI was left with three vendors. The lowest cost vendor lacks experience in this space but is a trusted solution for KWHI for its JD Edwards installation. To find a way to mitigate the risk due to the lack of experience associated with the project, the system integrator (SI) with the least experience has partnered with another SI with extensive experience to implement Oracle CC&B.

The budgeted capital cost included in KWHI's capital budget for its CIS is $6M inclusive of system integrator, licensing purchase and estimate internal labour. Due to KWHI having an in-house CIS system, all costs (capital and operating) are fully incremental to KWHI. The incremental revenue requirement is estimated to be $910,000 annually, inclusive of all costs and return on capital, resulting in a monthly cost per customer of $0.92 or $11.04 per year.

KWHI believes that the benefits of the Tier 1 system (Oracle CC&B) will assist KWHI in meeting the expectations of its customers. Base expectations today include, at a minimum, timely, accurate access to data. With its current CIS, KWHI is unable to provide this level of service without difficulty, using many manual work arounds. Implementation of the new CIS will allow KWHI to avoid a potential failure of its legacy

CIS and provide customer satisfaction. Further, KWHI will be able to build on its core CIS installation and provide even greater benefits to its customers in time, including outage notifications and a customer portal with self-service options.

KWHI consulted with its customers on this important decision. (Exhibit 1, Section 1.6 and the DSP, section 4.1.3) When presented with the costs of a CIS, KWHI customers supported a core CIS system without the additional costs required to include enhancements such as IVR, customer portal, et. al. KWHI decided to move ahead with a core CIS implementation that has the capability to provide some of the advanced features that customers were not willing to pay for. These enhanced features will not be implemented as part of the project but will be evaluated at a later date and possibly implemented as phase 2 project to minimize bill impacts. KWHI believes that customers expect the enhancements to be part of a basic/core system without the extra cost. This is evident from other customer feedback gather where customers ask for the availability of online bill payments, outage notifications and 24x7 access to their account. KWHI's decision to move forward with its chosen solution was based on several factors including: minimum customer expectations are growing, and a basic billing system would not meet its customer needs. KWHI notes that its home-grown CIS is highly customized and, although it lacks a number of enhancements other off-the-shelf systems provides, it also delivers some items that a base Tier 2 system cannot due to its lack of flexibility and scalability. KWHI would have to pay additional costs to "tack on" to a basic billing system, likely ending up with the same operating costs as the Tier 1 in the long run. Additionally, the industry within which KWHI operates is high complex and a Tier 1 system can be configured to meet the mounting regulatory requirements and reduce the many manual workarounds that a Tier 2 would require. Inquiry at other LDCs running Tier 2 systems gleaned helpful information in KWHI's decision as the operations of Tier 2 systems with their limited functionality meant adding staff in some cases to accommodate their shortcomings.

2.2 Rate Base Variance Analysis

For the purposes of this analysis, KWHI's materiality threshold is $225,000.

Table 2.2-1 – Materiality Threshold

Variance Analysis Threshold	2020 Test
Estimated Distribution Revenue Requirement	45,527,270
0.5% of proposed Distribution Revenue Requirement	227,636
Materiality Threshold for Variance Analysis	**225,000**

Table 2.2-2 – 2014 Board Approved vs 2014 Actual

	2014 Board Approved	2014	Variance	%
Net Capital Assets in Service				
Opening Balance	179,522,062	177,284,704	(2,237,358)	-1%
Ending Balance	188,472,524	181,201,713	(7,270,811)	-4%
Average Balance	183,997,293	179,243,209	(4,754,084)	-3%
Working Capital Allowance	27,083,243	27,440,853	357,610	1%
Total Rate Base	211,080,536	206,684,062	(4,396,474)	-2%

Total actual Rate Base for 2014 is $4,396,474 or 2% lower than Board approved. CAPEX for the year 2014 was only $500K short of Board approved. The main reason for the shortfall in rate base from Board approved is due to increased WIP and very high contributed capital for the year stemming from the construction of the LRT ($1,988,744).

Table 2.2-3 – 2014 Actual vs 2015 Actual

	2014	2015	Variance	%
Net Capital Assets in Service				
Opening Balance	177,284,704	181,201,713	3,917,009	2%
Ending Balance	181,201,713	185,688,757	4,487,044	2%
Average Balance	179,243,209	183,445,235	4,202,027	2%
Working Capital Allowance	27,440,853	28,806,837	1,365,984	5%
Total Rate Base	206,684,062	212,252,072	5,568,010	3%

Total actual Rate Base for 2015 is $5,568,010 or 3% higher than 2014 Actual. Working capital allowance increased $1,365,984 due to the increase in power expenses. A higher CAPEX for the year was offset by all-time high contributed capital stemming from LRT construction; however, assets in service still increased during the year.

Table 2.2-4 – 2015 Actual vs 2016 Actual

	2015	2016	Variance	%
Net Capital Assets in Service				
Opening Balance	181,201,713	185,688,757	4,487,044	2%
Ending Balance	185,688,757	192,085,725	6,396,968	3%
Average Balance	183,445,235	188,887,241	5,442,006	3%
Working Capital Allowance	28,806,837	31,991,586	3,184,749	11%
Total Rate Base	212,252,072	220,878,827	8,626,755	4%

Total actual Rate Base for 2016 is $8,626,755 or 4% higher than 2015 Actual. The working capital allowance increased as a result of the increase in cost of power expenses. 2016 CAPEX was $3.7M above 2014 Board approved due to the ongoing construction of the LRT in the City of Kitchener. A one-time adjustment was made to depreciation in 2016 due to an error made during the transition to IFRS. Rate base was decreased as three years of depreciation on transformers was recorded in one year. In addition, high contributed capital was again collected in 2016 (due to LRT); however, assets in service increased during the year.

Table 2.2-5 – 2016 Actual vs 2017 Actual

	2016	2017	Variance	%
Net Capital Assets in Service				
Opening Balance	185,688,757	192,085,725	6,396,968	3%
Ending Balance	192,085,725	199,646,092	7,560,367	4%
Average Balance	188,887,241	195,865,909	6,978,668	4%
Working Capital Allowance	31,991,586	28,573,738	(3,417,849)	-11%
Total Rate Base	220,878,827	224,439,646	3,560,819	2%

Total actual Rate Base for 2017 is $3,560,819 or 2% higher than 2016 Actual. In 2017, the Fair Hydro Plan was introduced by the Ontario Government resulting in a decrease in the commodity price. CAPEX for 2017 was more closely aligned to the 2014 Board approved. Although contributed capital (due to LRT construction) remained high in 2017, transfers out of WIP to capital additions offset contributed capital incremental reductions. Assets in service increased as a result.

Table 2.2-6 – 2017 Actual vs 2018 Actual

	2017	2018	Variance	%
Net Capital Assets in Service				
Opening Balance	192,085,725	199,646,092	7,560,367	4%
Ending Balance	199,646,092	207,178,007	7,531,915	4%
Average Balance	195,865,909	203,412,050	7,546,141	4%
Working Capital Allowance	28,573,738	27,750,138	(823,600)	-3%
Total Rate Base	224,439,646	231,162,187	6,722,541	3%

Total actual Rate Base for 2018 is $6,722,541 or 3% higher than 2017 Actual. In 2017, the Fair Hydro Plan was introduced by the Ontario Government resulting in a decrease in the commodity price. CAPEX fell in 2018 as KWHI had expected to spend a significant amount on a CIS implementation that got delayed into 2019. In trying to maintain its total spend approach, CAPEX spending was reduced and OPEX increased. Contributed capital returned to more typical levels as LRT construction was completed

in 2017. WIP was also reduced in 2018, increasing fixed asset balances. Assets in service increased as a result in 2017.

Table 2.2-7 – 2018 Actual vs 2019 Bridge

	2018	2019 Bridge	Variance	%
Net Capital Assets in Service				
Opening Balance	199,646,092	207,178,007	7,531,915	4%
Ending Balance	207,178,007	216,274,829	9,096,822	4%
Average Balance	203,412,050	211,726,418	8,314,369	4%
Working Capital Allowance	27,750,138	26,722,431	(1,027,707)	-4%
Total Rate Base	231,162,187	238,448,849	7,286,662	3%

Total Rate Base for 2019 is forecasted to be $7,286,662 or 3% higher than 2018 Actual. The working capital allowance continues to be negatively impacted by the cost of power and declining consumption (refer to Exhibit 3 for Load Forecast information). Assets in service have increased as KWHI's distribution spend remains close to 2018 levels when the CIS implementation is factored out. WIP is also expected to decrease in 2019, increasing assets in service.

Table 2.2-8 – 2019 Bridge vs 2020 Test

	2019 Bridge	2020 Test	Variance	%
Net Capital Assets in Service				
Opening Balance	207,178,007	216,274,829	9,096,822	4%
Ending Balance	216,274,829	231,394,885	15,120,056	7%
Average Balance	211,726,418	223,834,857	12,108,439	6%
Working Capital Allowance	26,722,431	15,532,917	(11,189,514)	-42%
Total Rate Base	238,448,849	239,367,774	918,925	0%

Total Rate Base for 2020 is forecasted to be $918,925 or approximately the same as 2019 Test Year. The primary reason for the decrease in working capital allowance is the decrease in the rate allowed by the Board from 13% to 7.5%. KWHI has used the 7.5% default working capital rate as per the OEB's letter of June 3, 2015. As a result of

KWHI resetting its cost envelope (see Exhibit 1, Section 1.1.3), the capital spend has been increased resulting in higher assets in service in 2020. In addition, KWHI's CIS implementation will be completed in 2020, transferring $4.7M from WIP in 2019 to fixed asset additions in 2020.

2.3 Fixed Asset Continuity Schedule

KWHI has completed the Fixed Asset Continuity Schedules (Board Appendix 2-BA) for the 2014 through 2018 and the 2019 Bridge and 2020 Test Years. These are attached in Appendix 2-1 and in live Excel format (EB-2019-0049_KWHI_Appl_2019_Filing_Req_Chap2_Appendices_20190430).

These schedules present a continuity schedule of KWHI's investment in capital assets, the associated accumulated amortization, and the net book value for each fixed asset account in accordance with the Uniform System of Accounts (USoA).

KWHI does not have any asset retirement obligations. All disposals are clearly marked on the continuity schedules. KWHI adopted MIFRS accounting for fixed assets in 2012. All the continuity schedules are presented in MIFRS.

Table 2.3-1 – Fixed Asset Continuity Schedule 2014

Accounting Standard	MIFRS
Year	2014

		Cost				Accumulated Depreciation				
OEB Account [3]	Description [3]	Opening Balance	Additions [4]	Disposals [6]	Closing Balance	Opening Balance	Additions	Disposals [6]	Closing Balance	Net Book Value
1611	Computer Software (Formally known as Account 1925)	3,795,945	384,294		4,180,239	(3,044,321)	(443,395)	-	(3,487,716)	692,523
1612	Land Rights (Formally known as Account 1906)	265,448			265,448	(257,874)	(2,653)	-	(260,527)	4,921
1805	Land	2,339,958			2,339,958	-	-	-	-	2,339,958
1808	Buildings	9,823,770		(3,372)	9,820,398	(2,419,009)	(210,808)	3,372	(2,626,445)	7,193,953
1815	Transformer Station Equipment >50 kV	62,560,429	1,092,997	(170,704)	63,482,722	(20,336,071)	(1,579,813)	170,704	(21,745,180)	41,737,542
1820	Distribution Station Equipment <50 kV	2,930,968	9,577	(7,627)	2,932,918	(2,005,202)	(49,381)	7,627	(2,046,956)	885,962
1825	Storage Battery Equipment	-			-	-	-	-	-	-
1830	Poles, Towers & Fixtures	34,476,322	2,044,655		36,520,977	(13,872,816)	(681,835)	-	(14,554,651)	21,966,326
1835	Overhead Conductors & Devices	36,019,501	1,328,124		37,347,625	(16,356,833)	(451,141)	-	(16,807,974)	20,539,651
1840	Underground Conduit	26,645,676	3,084,780		29,730,456	(10,104,108)	(344,750)	-	(10,448,858)	19,281,598
1845	Underground Conductors & Devices	41,755,423	3,095,730		44,851,153	(20,831,641)	(762,311)	-	(21,593,952)	23,257,201
1850	Line Transformers	55,053,765	2,329,756	(7,523)	57,375,998	(26,688,890)	(754,220)	7,523	(27,435,587)	29,940,411
1855	Services (Overhead & Underground)	46,548,487	2,014,667		48,563,154	(18,729,644)	(896,802)	-	(19,626,446)	28,936,708
1860	Meters	2,349,703	706,384		3,056,087	(568,636)	(142,904)	-	(711,540)	2,344,547
1860	Meters (Smart Meters)	12,361,936	132,171		12,494,107	(3,211,808)	(828,535)	-	(4,040,343)	8,453,764
1905	Land	1,395,300			1,395,300	-	-	-	-	1,395,300
1908	Buildings & Fixtures	16,544,993	807,288		17,352,281	(4,433,364)	(613,604)	-	(5,046,968)	12,305,313
1915	Office Furniture & Equipment (10 years)	1,263,381	57,713		1,321,094	(902,816)	(70,928)	-	(973,744)	347,350
1920	Computer Equip.-Hardware(Post Mar. 19/07)	2,534,427	175,363	(487,154)	2,222,636	(1,891,762)	(229,493)	487,154	(1,634,101)	588,535
1930	Transportation Equipment	8,954,354	767,172	(192,537)	9,528,989	(5,318,477)	(609,430)	192,538	(5,735,369)	3,793,620
1935	Stores Equipment	64,072	-	-	64,072	(50,129)	(4,724)	-	(54,853)	9,219
1940	Tools, Shop & Garage Equipment	892,235	76,230	-	968,465	(552,854)	(66,746)	-	(619,600)	348,865
1945	Measurement & Testing Equipment	965,036	56,975	-	1,022,011	(763,758)	(34,426)	-	(798,184)	223,827
1950	Power Operated Equipment	818,647	94,765	(62,888)	850,524	(570,046)	(55,442)	60,327	(565,161)	285,363
1955	Communications Equipment	849,352	31,176	-	880,528	(454,066)	(80,088)	-	(534,154)	346,374
1960	Miscellaneous Equipment	109,010	-	-	109,010	(88,848)	(13,393)	-	(102,241)	6,769
1980	System Supervisory Equipment	1,566,480	-	-	1,566,480	(1,551,390)	(4,059)	-	(1,555,449)	11,031
1995	Contributions & Grants	(54,079,649)	-	-	(54,079,649)	13,484,099	1,153,287	-	14,637,386	(39,442,263)
2440	Deferred Revenue	-	(6,698,313)	-	(6,698,313)	-	105,658	-	105,658	(6,592,655)
					-				-	-
	Total PP&E	**318,804,969**	**11,591,504**	**(931,805)**	**329,464,668**	**(141,520,264)**	**(7,671,936)**	**929,245**	**(148,262,955)**	**181,201,713**

Table 2.3-2 – Fixed Asset Continuity Schedule 2015

Accounting Standard	MIFRS
Year	2015

		Cost				Accumulated Depreciation				
OEB Account [3]	Description [3]	Opening Balance	Additions [4]	Disposals [6]	Closing Balance	Opening Balance	Additions	Disposals [6]	Closing Balance	Net Book Value
1611	Computer Software (Formally known as Account 1925)	4,180,239	443,103	-	4,623,342	(3,487,716)	(273,938)		(3,761,654)	861,688
1612	Land Rights (Formally known as Account 1906)	265,448			265,448	(260,527)	(2,653)		(263,180)	2,268
1805	Land	2,339,958			2,339,958	-	-		-	2,339,958
1808	Buildings	9,820,398	(124,006)	(9,158)	9,687,234	(2,626,445)	(211,049)	9,158	(2,828,336)	6,858,898
1815	Transformer Station Equipment >50 kV	63,482,722	(307,610)	(38,826)	63,136,285	(21,745,180)	(1,583,700)	38,826	(23,290,054)	39,846,231
1820	Distribution Station Equipment <50 kV	2,932,918	-	(23,033)	2,909,885	(2,046,956)	(48,787)	23,034	(2,072,709)	837,176
1830	Poles, Towers & Fixtures	36,520,977	3,374,648	-	39,895,625	(14,554,651)	(731,757)		(15,286,408)	24,609,217
1835	Overhead Conductors & Devices	37,347,625	2,995,429	-	40,343,054	(16,807,974)	(490,131)		(17,298,105)	23,044,949
1840	Underground Conduit	29,730,456	4,356,442	-	34,086,898	(10,448,858)	(406,761)		(10,855,619)	23,231,279
1845	Underground Conductors & Devices	44,851,153	2,991,711	-	47,842,864	(21,593,952)	(838,202)		(22,432,154)	25,410,710
1850	Line Transformers	57,375,998	3,236,193	(25,310)	60,586,881	(27,435,587)	(825,114)	20,206	(28,240,495)	32,346,386
1855	Services (Overhead & Underground)	48,563,154	3,335,156	-	51,898,310	(19,626,446)	(960,945)		(20,587,391)	31,310,919
1860	Meters	3,056,087	87,171	-	3,143,258	(711,540)	(97,668)		(809,208)	2,334,050
1860	Meters (Smart Meters)	12,494,107	156,433	-	12,650,540	(4,040,343)	(838,155)		(4,878,498)	7,772,042
1905	Land	1,395,300	-	-	1,395,300	-	-		-	1,395,300
1908	Buildings & Fixtures	17,352,281	88,367	(130,328)	17,310,320	(5,046,968)	(608,466)	130,328	(5,525,106)	11,785,214
1915	Office Furniture & Equipment (10 years)	1,321,094	64,368	(398,346)	987,116	(973,744)	(67,374)	398,346	(642,772)	344,344
1920	Computer Equip.-Hardware(Post Mar. 19/07)	2,222,636	174,117	(105,934)	2,290,819	(1,634,101)	(224,629)	105,385	(1,753,345)	537,474
1930	Transportation Equipment	9,528,989	482,300	(208,990)	9,802,299	(5,735,369)	(661,497)	208,990	(6,187,876)	3,614,423
1935	Stores Equipment	64,072	-	-	64,072	(54,853)	(5,711)		(60,564)	3,508
1940	Tools, Shop & Garage Equipment	968,465	67,712	(285,883)	750,293	(619,600)	(69,763)	285,883	(403,480)	346,813
1945	Measurement & Testing Equipment	1,022,011	18,213	-	1,040,224	(798,184)	(37,576)		(835,760)	204,464
1950	Power Operated Equipment	850,524	179,117	(136,649)	892,992	(565,161)	(62,365)	119,019	(508,507)	384,485
1955	Communications Equipment	880,528	55,700	-	936,228	(534,154)	(84,461)		(618,615)	317,613
1960	Miscellaneous Equipment	109,010	-	-	109,010	(102,241)	(2,031)		(104,272)	4,738
1980	System Supervisory Equipment	1,566,480	-	(1,539,501)	26,979	(1,555,449)	(4,059)	1,539,501	(20,007)	6,972
1995	Contributions & Grants	(54,079,649)	-	13,643	(54,066,006)	14,637,386	1,182,463	(13,643)	15,806,206	(38,259,800)
2440	Deferred Revenue	(6,698,313)	(9,459,986)	-	(16,158,299)	105,658	250,078	-	355,736	(15,802,563)
		-			-	-			-	-
	Total PP&E	**329,464,668**	**12,214,577**	**(2,888,316)**	**338,790,929**	**(148,262,955)**	**(7,704,251)**	**2,865,033**	**(153,102,173)**	**185,688,757**

Table 2.3-3 – Fixed Asset Continuity Schedule 2016

Accounting Standard	MIFRS
Year	2016

-1

		Cost				Accumulated Depreciation				
OEB Account [3]	Description [3]	Opening Balance	Additions [4]	Disposals [6]	Closing Balance	Opening Balance	Additions	Disposals [6]	Closing Balance	Net Book Value
1611	Computer Software (Formally known as Account 1925)	4,623,342	710,078	-	5,333,420	(3,761,654)	(397,815)		(4,159,469)	1,173,951
1612	Land Rights (Formally known as Account 1906)	265,448		-	265,448	(263,180)	(2,269)		(265,449)	(1)
1805	Land	2,339,958		-	2,339,958	-	-		-	2,339,958
1808	Buildings	9,687,234		(11,187)	9,676,047	(2,828,336)	(210,295)	11,187	(3,027,444)	6,648,603
1815	Transformer Station Equipment >50 kV	63,136,285	190,239	(499,325)	62,827,199	(23,290,054)	(1,576,758)	499,325	(24,367,487)	38,459,712
1820	Distribution Station Equipment <50 kV	2,909,885		(16,218)	2,893,667	(2,072,709)	(48,224)	16,218	(2,104,715)	788,952
1830	Poles, Towers & Fixtures	39,895,625	3,525,628	-	43,421,253	(15,286,408)	(836,577)		(16,122,985)	27,298,268
1835	Overhead Conductors & Devices	40,343,054	2,757,286	-	43,100,340	(17,298,105)	(542,946)		(17,841,051)	25,259,289
1840	Underground Conduit	34,086,898	2,655,417	-	36,742,315	(10,855,619)	(465,193)		(11,320,812)	25,421,503
1845	Underground Conductors & Devices	47,842,864	4,941,322	-	52,784,186	(22,432,154)	(933,328)		(23,365,482)	29,418,704
1850	Line Transformers	60,586,881	4,141,737	-	64,728,618	(28,240,495)	(1,710,860)		(29,951,355)	34,777,263
1855	Services (Overhead & Underground)	51,898,310	3,320,173	-	55,218,483	(20,587,391)	(1,040,794)		(21,628,185)	33,590,298
1860	Meters	3,143,258	265,312	-	3,408,570	(809,208)	(143,228)		(952,436)	2,456,134
1860	Meters (Smart Meters)	12,650,540	407,305	-	13,057,845	(4,878,498)	(856,947)		(5,735,445)	7,322,400
1905	Land	1,395,300		-	1,395,300	-	-		-	1,395,300
1908	Buildings & Fixtures	17,310,320	221,770	(1,475,987)	16,056,103	(5,525,106)	(613,557)	1,475,987	(4,662,676)	11,393,427
1915	Office Furniture & Equipment (10 years)	987,116	36,970	(9,747)	1,014,339	(642,772)	(70,563)	9,747	(703,588)	310,751
1920	Computer Equip.-Hardware(Post Mar. 19/07)	2,290,819	90,770	(35,795)	2,345,794	(1,753,345)	(211,185)	35,288	(1,929,242)	416,552
1930	Transportation Equipment	9,802,299	733,066	(503,480)	10,031,885	(6,187,876)	(664,631)	503,480	(6,349,027)	3,682,858
1935	Stores Equipment	64,072	2,552	-	66,624	(60,564)	(3,215)		(63,779)	2,845
1940	Tools, Shop & Garage Equipment	750,293	95,003	-	845,296	(403,480)	(72,734)		(476,214)	369,082
1945	Measurement & Testing Equipment	1,040,224	3,849	-	1,044,073	(835,760)	(36,709)		(872,469)	171,604
1950	Power Operated Equipment	892,992	126,680	(153,996)	865,676	(508,507)	(66,839)	136,605	(438,741)	426,935
1955	Communications Equipment	936,228	61,266	-	997,494	(618,615)	(80,930)		(699,545)	297,949
1960	Miscellaneous Equipment	109,010		-	109,010	(104,272)	(2,031)		(106,303)	2,707
1980	System Supervisory Equipment	26,979		10,800	37,779	(20,007)	(1,943)	(10,800)	(32,750)	5,029
1995	Contributions & Grants	(54,066,006)	-	5,228	(54,060,778)	15,806,206	1,180,976	(5,229)	16,981,953	(37,078,825)
2440	Deferred Revenue	(16,158,299)	(8,950,517)	-	(25,108,816)	355,736	487,557		843,293	(24,265,523)
		-			-	-			-	-
	Total PP&E	**338,790,929**	**15,335,906**	**(2,689,707)**	**351,437,128**	**(153,102,173)**	**(8,921,038)**	**2,671,808**	**(159,351,403)**	**192,085,726**

Table 2.3-4 – Fixed Asset Continuity Schedule 2017

Accounting Standard	MIFRS
Year	2017

-1

		Cost				Accumulated Depreciation				
OEB Account [3]	Description [3]	Opening Balance	Additions [4]	Disposals [6]	Closing Balance	Opening Balance	Additions	Disposals [6]	Closing Balance	Net Book Value
1611	Computer Software (Formally known as Account 1925)	5,333,420	136,147		5,469,567	(4,159,469)	(419,965)		(4,579,434)	890,133
1612	Land Rights (Formally known as Account 1906)	265,448			265,448	(265,449)	-		(265,449)	(1)
1805	Land	2,339,958			2,339,958	-	-		-	2,339,958
1808	Buildings	9,676,047			9,676,047	(3,027,444)	(189,033)		(3,216,477)	6,459,570
1815	Transformer Station Equipment >50 kV	62,827,199	2,484,885		65,312,084	(24,367,487)	(1,520,336)		(25,887,823)	39,424,261
1820	Distribution Station Equipment <50 kV	2,893,667			2,893,667	(2,104,715)	(44,883)		(2,149,598)	744,069
1830	Poles, Towers & Fixtures	43,421,253	2,823,048		46,244,301	(16,122,985)	(899,198)		(17,022,183)	29,222,118
1835	Overhead Conductors & Devices	43,100,340	2,875,991		45,976,331	(17,841,051)	(586,226)		(18,427,277)	27,549,054
1840	Underground Conduit	36,742,315	2,850,149		39,592,464	(11,320,812)	(506,681)		(11,827,493)	27,764,971
1845	Underground Conductors & Devices	52,784,186	2,941,745		55,725,931	(23,365,482)	(1,005,936)		(24,371,418)	31,354,513
1850	Line Transformers	64,728,618	2,712,202	(21,883)	67,418,937	(29,951,355)	(1,378,915)	21,883	(31,308,387)	36,110,550
1855	Services (Overhead & Underground)	55,218,483	3,479,238		58,697,721	(21,628,185)	(1,099,297)		(22,727,482)	35,970,239
1860	Meters	3,408,570	600,897		4,009,467	(952,436)	(159,098)		(1,111,534)	2,897,933
1860	Meters (Smart Meters)	13,057,845	222,909		13,280,754	(5,735,445)	(878,535)		(6,613,980)	6,666,774
1905	Land	1,395,300			1,395,300	-	-		-	1,395,300
1908	Buildings & Fixtures	16,056,103	1,015,633	(24,376)	17,047,360	(4,662,676)	(466,747)	24,376	(5,105,047)	11,942,313
1915	Office Furniture & Equipment (10 years)	1,014,339	53,399	(293,671)	774,067	(703,588)	(68,483)	293,671	(478,400)	295,667
1920	Computer Equip.-Hardware(Post Mar. 19/07)	2,345,794	33,213	(1,099)	2,377,908	(1,929,242)	(193,472)	1,099	(2,121,615)	256,293
1930	Transportation Equipment	10,031,885	39,073	(24,630)	10,046,328	(6,349,027)	(673,162)	24,630	(6,997,559)	3,048,769
1935	Stores Equipment	66,624		(36,630)	29,994	(63,779)	(276)	36,630	(27,425)	2,569
1940	Tools, Shop & Garage Equipment	845,296	76,089	(46,849)	874,536	(476,214)	(77,532)	46,849	(506,897)	367,639
1945	Measurement & Testing Equipment	1,044,073	59,074	(664,730)	438,417	(872,469)	(37,560)	664,730	(245,299)	193,118
1950	Power Operated Equipment	865,676		-	865,676	(438,741)	(69,566)		(508,307)	357,369
1955	Communications Equipment	997,494	190	-	997,684	(699,545)	(84,635)		(784,180)	213,504
1960	Miscellaneous Equipment	109,010	4,993	(98,856)	15,147	(106,303)	(2,114)	98,856	(9,561)	5,586
1980	System Supervisory Equipment	37,779			37,779	(32,750)	(2,204)		(34,954)	2,825
1995	Contributions & Grants	(54,060,778)		51,290	(54,009,488)	16,981,953	1,099,731	(51,290)	18,030,394	(35,979,094)
2440	Deferred Revenue	(25,108,816)	(6,242,858)		(31,351,674)	843,293	658,473		1,501,766	(29,849,908)
		-			-	-			-	-
	Total PP&E	**351,437,128**	**16,166,017**	**(1,161,434)**	**366,441,711**	**(159,351,403)**	**(8,605,650)**	**1,161,434**	**(166,795,619)**	**199,646,093**

Table 2.3-5 – Fixed Asset Continuity Schedule 2018

Accounting Standard	MIFRS
Year	2018

		Cost				Accumulated Depreciation				
OEB Account [3]	Description [3]	Opening Balance	Additions [4]	Disposals [6]	Closing Balance	Opening Balance	Additions	Disposals [6]	Closing Balance	Net Book Value
1611	Computer Software (Formally known as Account 1925)	5,469,567	276,227		5,745,794	(4,579,434)	(450,463)		(5,029,897)	715,897
1612	Land Rights (Formally known as Account 1906)	265,448		-	265,448	(265,449)	-		(265,449)	(1)
1805	Land	2,339,958			2,339,958	-	-		-	2,339,958
1808	Buildings	9,676,047		(11,814)	9,664,233	(3,216,477)	(197,576)	11,814	(3,402,239)	6,261,994
1815	Transformer Station Equipment >50 kV	65,312,084	561,722	(107,777)	65,766,029	(25,887,823)	(1,561,997)	107,777	(27,342,043)	38,423,986
1820	Distribution Station Equipment <50 kV	2,893,667	7,664	-	2,901,331	(2,149,598)	(45,139)		(2,194,737)	706,594
1830	Poles, Towers & Fixtures	46,244,301	2,923,851	-	49,168,152	(17,022,183)	(971,034)		(17,993,217)	31,174,935
1835	Overhead Conductors & Devices	45,976,331	2,834,762	-	48,811,093	(18,427,277)	(640,541)		(19,067,818)	29,743,275
1840	Underground Conduit	39,592,464	2,184,528	-	41,776,992	(11,827,493)	(548,637)		(12,376,130)	29,400,862
1845	Underground Conductors & Devices	55,725,931	1,837,712	-	57,563,643	(24,371,418)	(1,065,171)		(25,436,589)	32,127,054
1850	Line Transformers	67,418,937	3,472,535	(65,434)	70,826,038	(31,308,387)	(1,467,280)	65,434	(32,710,233)	38,115,805
1855	Services (Overhead & Underground)	58,697,721	3,150,848	-	61,848,569	(22,727,482)	(1,178,946)		(23,906,428)	37,942,141
1860	Meters	4,009,467	627,826	-	4,637,293	(1,111,534)	(188,448)		(1,299,982)	3,337,311
1860	Meters (Smart Meters)	13,280,754	539,690	-	13,820,444	(6,613,980)	(903,955)		(7,517,935)	6,302,509
1905	Land	1,395,300		-	1,395,300	-	-		-	1,395,300
1908	Buildings & Fixtures	17,047,360	936,656	(59,121)	17,924,895	(5,105,047)	(465,838)	59,121	(5,511,764)	12,413,131
1915	Office Furniture & Equipment (10 years)	774,067	34,172	-	808,239	(478,400)	(62,256)		(540,656)	267,583
1915	Office Furniture & Equipment (5 years)	-		-	-	-	-		-	-
1930	Transportation Equipment	10,046,328	850,223	(1,012,765)	9,883,786	(6,997,559)	(685,882)	1,006,787	(6,676,654)	3,207,132
1935	Stores Equipment	29,994		-	29,994	(27,425)	(255)		(27,680)	2,314
1940	Tools, Shop & Garage Equipment	874,536	73,813	-	948,349	(506,897)	(75,614)		(582,511)	365,838
1945	Measurement & Testing Equipment	438,417	13,362	-	451,779	(245,299)	(37,169)		(282,468)	169,311
1950	Power Operated Equipment	865,676	277,919	(150,914)	992,681	(508,307)	(68,938)	150,914	(426,331)	566,350
1955	Communications Equipment	997,684	45,955		1,043,639	(784,180)	(85,611)		(869,791)	173,848
1960	Miscellaneous Equipment	15,147	3,464		18,611	(9,561)	(2,195)		(11,756)	6,855
1980	System Supervisory Equipment	37,779			37,779	(34,954)	(2,204)		(37,158)	621
1995	Contributions & Grants	(54,009,488)		18,955	(53,990,533)	18,030,394	1,094,260	(18,955)	19,105,699	(34,884,834)
2440	Deferred Revenue	(31,351,674)	(4,696,647)		(36,048,321)	1,501,766	781,552	-	2,283,318	(33,765,003)
		-			-	-			-	-
	Total PP&E	**366,441,711**	**16,560,659**	**(2,625,846)**	**380,376,524**	**(166,795,619)**	**(9,020,805)**	**2,617,907**	**(173,198,517)**	**207,178,008**

Table 2.3-6 – Fixed Asset Continuity Schedule 2019

Accounting Standard	MIFRS
Year	2019

		Cost				Accumulated Depreciation				
OEB Account [3]	Description [3]	Opening Balance	Additions [4]	Disposals [6]	Closing Balance	Opening Balance	Additions	Disposals [6]	Closing Balance	Net Book Value
1611	Computer Software (Formally known as Account 1925)	5,745,794	854,365		6,600,159	(5,029,897)	(445,400)		(5,475,297)	1,124,862
1612	Land Rights (Formally known as Account 1906)	265,448			265,448	(265,449)	-		(265,449)	(1)
1805	Land	2,339,958			2,339,958	-	-		-	2,339,958
1808	Buildings	9,664,233			9,664,233	(3,402,239)	(197,400)		(3,599,639)	6,064,594
1815	Transformer Station Equipment >50 kV	65,766,029	1,624,500		67,390,529	(27,342,043)	(1,600,000)		(28,942,043)	38,448,486
1820	Distribution Station Equipment <50 kV	2,901,331			2,901,331	(2,194,737)	(45,500)		(2,240,237)	661,094
1830	Poles, Towers & Fixtures	49,168,152	2,959,500		52,127,652	(17,993,217)	(1,059,200)		(19,052,417)	33,075,235
1835	Overhead Conductors & Devices	48,811,093	2,713,640		51,524,733	(19,067,818)	(683,100)		(19,750,918)	31,773,815
1840	Underground Conduit	41,776,992	2,519,600		44,296,592	(12,376,130)	(568,700)		(12,944,830)	31,351,762
1845	Underground Conductors & Devices	57,563,643	1,692,201		59,255,844	(25,436,589)	(1,104,500)		(26,541,089)	32,714,755
1850	Line Transformers	70,826,038	3,124,798		73,950,836	(32,710,233)	(1,494,100)		(34,204,333)	39,746,503
1855	Services (Overhead & Underground)	61,848,569	2,801,461		64,650,030	(23,906,428)	(1,202,400)		(25,108,828)	39,541,202
1860	Meters	4,637,293	307,344		4,944,637	(1,299,982)	(189,100)		(1,489,082)	3,455,555
1860	Meters (Smart Meters)	13,820,444	332,956		14,153,400	(7,517,935)	(918,500)		(8,436,435)	5,716,965
1905	Land	1,395,300			1,395,300	-	-		-	1,395,300
1908	Buildings & Fixtures	17,924,895	750,000		18,674,895	(5,511,764)	(512,500)		(6,024,264)	12,650,631
1915	Office Furniture & Equipment (10 years)	808,239	144,597		952,836	(540,656)	(61,500)		(602,156)	350,680
1920	Computer Equip.-Hardware(Post Mar. 19/07)	1,745,309	344,140		2,089,449	(1,078,068)	(267,600)		(1,345,668)	743,781
1930	Transportation Equipment	9,883,786	1,454,069	(650,000)	10,687,855	(6,676,654)	(712,200)	650,000	(6,738,854)	3,949,001
1935	Stores Equipment	29,994			29,994	(27,680)	(300)		(27,980)	2,014
1940	Tools, Shop & Garage Equipment	948,349	95,000		1,043,349	(582,511)	(70,000)		(652,511)	390,838
1945	Measurement & Testing Equipment	451,779	10,000		461,779	(282,468)	(35,200)		(317,668)	144,111
1950	Power Operated Equipment	992,681	100,000		1,092,681	(426,331)	(83,900)		(510,231)	582,450
1955	Communications Equipment	1,043,639	36,600		1,080,239	(869,791)	(40,000)		(909,791)	170,448
1960	Miscellaneous Equipment	18,611			18,611	(11,756)	(1,300)		(13,056)	5,555
1980	System Supervisory Equipment	37,779			37,779	(37,158)	-		(37,158)	621
1995	Contributions & Grants	(53,990,533)			(53,990,533)	19,105,699	1,092,100		20,197,799	(33,792,734)
2440	Deferred Revenue	(36,048,321)	(3,424,749)		(39,473,070)	2,283,318	857,100		3,140,418	(36,332,652)
		-			-	-			-	-
	Total PP&E	**380,376,524**	**18,440,022**	**(650,000)**	**398,166,546**	**(173,198,517)**	**(9,343,200)**	**650,000**	**(181,891,717)**	**216,274,830**

Table 2.3-7 – Fixed Asset Continuity Schedule 2020

Accounting Standard	MIFRS
Year	2020

		Cost				Accumulated Depreciation				
OEB Account	Description	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
1611	Computer Software (Formally known as Account 1925)	6,600,159	6,710,000		13,310,159	(5,475,297)	(1,194,200)		(6,669,497)	6,640,662
1612	Land Rights (Formally known as Account 1906)	265,448			265,448	(265,449)	-		(265,449)	(1)
1805	Land	2,339,958			2,339,958	-	-		-	2,339,958
1808	Buildings	9,664,233			9,664,233	(3,599,639)	(196,400)		(3,796,039)	5,868,194
1815	Transformer Station Equipment >50 kV	67,390,529	2,004,000		69,394,529	(28,942,043)	(1,635,500)		(30,577,543)	38,816,986
1820	Distribution Station Equipment <50 kV	2,901,331			2,901,331	(2,240,237)	(45,300)		(2,285,537)	615,794
1830	Poles, Towers & Fixtures	52,127,652	3,133,850		55,261,502	(19,052,417)	(1,102,200)		(20,154,617)	35,106,885
1835	Overhead Conductors & Devices	51,524,733	2,893,200		54,417,933	(19,750,918)	(731,800)		(20,482,718)	33,935,215
1840	Underground Conduit	44,296,592	3,524,600		47,821,192	(12,944,830)	(619,700)		(13,564,530)	34,256,662
1845	Underground Conductors & Devices	59,255,844	1,977,201		61,233,045	(26,541,089)	(1,148,600)		(27,689,689)	33,543,356
1850	Line Transformers	73,950,836	3,123,499		77,074,335	(34,204,333)	(1,570,500)		(35,774,833)	41,299,502
1855	Services (Overhead & Underground)	64,650,030	3,025,150		67,675,180	(25,108,828)	(1,269,500)		(26,378,328)	41,296,852
1860	Meters	4,944,637	286,560		5,231,197	(1,489,082)	(200,900)		(1,689,982)	3,541,215
1860	Meters (Smart Meters)	14,153,400	310,440		14,463,840	(8,436,435)	(939,900)		(9,376,335)	5,087,505
1905	Land	1,395,300			1,395,300	-	-		-	1,395,300
1908	Buildings & Fixtures	18,674,895	750,000		19,424,895	(6,024,264)	(549,700)		(6,573,964)	12,850,931
1915	Office Furniture & Equipment (10 years)	952,836	70,000		1,022,836	(602,156)	(57,900)		(660,056)	362,780
1920	Computer Equip.-Hardware(Post Mar. 19/07)	2,089,449	325,000		2,414,449	(1,345,668)	(260,200)		(1,605,868)	808,581
1930	Transportation Equipment	10,687,855	890,000	(465,000)	11,112,855	(6,738,854)	(770,100)	465,000	(7,043,954)	4,068,901
1935	Stores Equipment	29,994			29,994	(27,980)	(300)		(28,280)	1,714
1940	Tools, Shop & Garage Equipment	1,043,349	95,000		1,138,349	(652,511)	(69,200)		(721,711)	416,638
1945	Measurement & Testing Equipment	461,779	10,000		471,779	(317,668)	(34,800)		(352,468)	119,311
1950	Power Operated Equipment	1,092,681	110,000		1,202,681	(510,231)	(84,751)		(594,982)	607,699
1955	Communications Equipment	1,080,239	35,000		1,115,239	(909,791)	(22,149)		(931,940)	183,299
1960	Miscellaneous Equipment	18,611			18,611	(13,056)	(1,300)		(14,356)	4,255
1980	System Supervisory Equipment	37,779			37,779	(37,158)	-		(37,158)	621
1995	Contributions & Grants	(53,990,533)			(53,990,533)	20,197,799	1,089,500		21,287,299	(32,703,234)
2440	Deferred Revenue	(39,473,070)	(3,677,745)		(43,150,815)	3,140,418	939,700		4,080,118	(39,070,697)
		-			-	-			-	-
	Total PP&E	**398,166,546**	**25,595,755**	**(465,000)**	**423,297,301**	**(181,891,717)**	**(10,475,700)**	**465,000**	**(191,902,417)**	**231,394,885**

2.4 Gross Assets – Property Plant and Equipment and Accumulated Depreciation

KWHI classifies its assets into four categories: Transmission Assets, Distribution Assets, General Plant and Contributions and Grants.

Transmission Assets are included in OEB Accounts 1808, 1815 and 1820. They consist of the buildings, equipment of the transmission assets of KWHI. KWHI owns and operates eight (8) transformer stations and seven (7) distribution stations located throughout its service territory. KWHI's transmission assets are deemed as distribution assets.

Distribution assets are the wires, poles, meters and transformers used to distribute electricity through KWHI's service territory. These assets are recorded to OEB accounts 1830 - 1860.

General Plant investments are the assets used by staff to plan, maintain and build the distribution system. It consists on OEB account 1908 – 1980, and includes trucks, computer software and hardware, and the operations centre.

Contributions and Grants consist of the contributed capital or deferred revenue that KWHI has received from developers and others as per the Distribution System Code.

KWHI has not applied for any ACM or ICM adjustments as part of a previous IRM application.

Table 2.4-1 summarizes the categories by year. All opening and closing balances agree to required filing Appendix 2-BA which is filed in live Excel format (EB-2019-0049_KWHI_Appl_2019_Filing_Req_Chap2_Appendices_20190430) and shown in Appendix 2-1.

Table 2.4-1 – Gross Assets by Category

Gross Assets

	2014 Board Approved	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Bridge	2020 Test
Transmission Assets	76,899,833	76,236,038	75,733,404	75,396,913	77,881,798	78,331,593	79,956,093	81,960,093
Distribution Assets	275,428,824	272,544,963	293,052,835	315,067,015	333,551,311	351,057,629	367,509,129	385,783,629
General Plant	44,972,623	41,461,629	40,228,996	40,142,794	40,369,764	41,026,156	44,164,927	52,694,927
Contributions and Grants	(57,161,700)	(60,777,962)	(70,224,305)	(79,169,594)	(85,361,162)	(90,038,854)	(93,463,603)	(97,141,348)
	340,139,580	329,464,668	338,790,929	351,437,128	366,441,711	380,376,524	398,166,546	423,297,301

Accumulated Depreciation

	2014 Board Approved	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Bridge	2020 Test
Transmission Assets	26,799,308	26,418,581	28,191,099	29,499,646	31,253,898	32,939,019	34,781,919	36,659,119
Distribution Assets	116,091,476	115,479,878	120,651,058	127,183,200	133,675,203	140,573,781	147,793,381	155,376,481
General Plant	23,361,167	21,107,540	20,421,958	20,493,803	21,398,678	21,074,734	22,654,634	25,234,234
Contributions and Grants	(14,584,896)	(14,743,044)	(16,161,942)	(17,825,246)	(19,532,160)	(21,389,017)	(23,338,217)	(25,367,417)
	151,667,055	148,262,955	153,102,173	159,351,403	166,795,619	173,198,517	181,891,717	191,902,417

Net Fixed Assets

	2014 Board Approved	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Bridge	2020 Test
Transmission Assets	50,100,525	49,817,457	47,542,305	45,897,267	46,627,900	45,392,574	45,174,174	45,300,974
Distribution Assets	159,337,348	157,065,085	172,401,777	187,883,815	199,876,108	210,483,848	219,715,748	230,407,148
General Plant	21,611,456	20,354,089	19,807,038	19,648,992	18,971,087	19,951,423	21,510,294	27,460,694
Contributions and Grants	(42,576,804)	(46,034,918)	(54,062,363)	(61,344,348)	(65,829,002)	(68,649,837)	(70,125,386)	(71,773,931)
	188,472,525	181,201,713	185,688,757	192,085,726	199,646,093	207,178,008	216,274,830	231,394,885

Table 2.4-2 shows the detail for each of these categories.

Table 2.4-2 – Detailed Gross Assets

Gross Assets

	2014 Board Approved	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Bridge	2020 Test
Transmission Assets								
1808 - Buildings and Fixtures	9,966,889	9,820,398	9,687,234	9,676,047	9,676,047	9,664,233	9,664,233	9,664,233
1815 - Transformer Station Equipment	63,948,186	63,482,722	63,136,285	62,827,199	65,312,084	65,766,029	67,390,529	69,394,529
1820 - Distribution Station Equipment	2,984,758	2,932,918	2,909,885	2,893,667	2,893,667	2,901,331	2,901,331	2,901,331
	76,899,833	76,236,038	75,733,404	75,396,913	77,881,798	78,331,593	79,956,093	81,960,093
Distribution Assets								
1805 - Land	2,339,958	2,339,958	2,339,958	2,339,958	2,339,958	2,339,958	2,339,958	2,339,958
1612 - Land Rights	265,448	265,448	265,448	265,448	265,448	265,448	265,448	265,448
1830 - Poles, Towers and Fixtures	37,612,548	36,520,977	39,895,625	43,421,253	46,244,301	49,168,152	52,127,652	55,261,502
1835 - Overhead Conductors and Devices	38,397,299	37,347,625	40,343,054	43,100,340	45,976,331	48,811,093	51,524,733	54,417,933
1840 - Underground Conduit	28,801,108	29,730,456	34,086,898	36,742,315	39,592,464	41,776,992	44,296,592	47,821,192
1845 - Underground Conductors and Devices	44,826,881	44,851,153	47,842,864	52,784,186	55,725,931	57,563,643	59,255,844	61,233,045
1850 - Line Transformers	58,521,549	57,375,998	60,586,881	64,728,618	67,418,937	70,826,038	73,950,836	77,074,335
1855 - Services	49,026,559	48,563,154	51,898,310	55,218,483	58,697,721	61,848,569	64,650,030	67,675,180
1860 - Meters	15,637,474	15,550,194	15,793,798	16,466,415	17,290,221	18,457,737	19,098,037	19,695,037
	275,428,824	272,544,963	293,052,835	315,067,015	333,551,311	351,057,629	367,509,129	385,783,629
General Plant								
1905 - Land	1,395,300	1,395,300	1,395,300	1,395,300	1,395,300	1,395,300	1,395,300	1,395,300
1908 - Buildings and Fixtures	18,091,658	17,352,281	17,310,320	16,056,103	17,047,360	17,924,895	18,674,895	19,424,895
1915 - Office Furniture and Equipment	1,343,211	1,321,094	987,116	1,014,339	774,067	808,239	952,836	1,022,836
1920 - Computer Equipment - Hardware	3,386,748	2,222,636	2,290,819	2,345,794	2,377,908	1,745,309	2,089,449	2,414,449
1611 - Computer Software	5,051,740	4,180,239	4,623,342	5,333,420	5,469,567	5,745,794	6,600,159	13,310,159
1930 - Transportation Equipment	10,282,669	9,528,989	9,802,299	10,031,885	10,046,328	9,883,786	10,687,855	11,112,855
1935 - Stores Equipment	64,072	64,072	64,072	66,624	29,994	29,994	29,994	29,994
1940 - Tools, Shop and Garage Equipment	1,001,524	968,465	750,293	845,296	874,536	948,349	1,043,349	1,138,349
1945 - Measurement and Testing Equipment	972,568	1,022,011	1,040,224	1,044,073	438,417	451,779	461,779	471,779
1950 - Power Operated Equipment	837,763	850,524	892,992	865,676	865,676	992,681	1,092,681	1,202,681
1955 - Communications Equipment	869,836	880,528	936,228	997,494	997,684	1,043,639	1,080,239	1,115,239
1980 - System Supervisory Equipment	1,566,478	1,566,480	26,979	37,779	37,779	37,779	37,779	37,779
1960 - Miscellaneous Equipment	109,056	109,010	109,010	109,010	15,147	18,611	18,611	18,611
	44,972,623	41,461,629	40,228,996	40,142,794	40,369,764	41,026,156	44,164,927	52,694,927
Contributions and Grants								
1995 - Contributions and Grants	(57,161,700)	(54,079,649)	(54,066,006)	(54,060,778)	(54,009,488)	(53,990,533)	(53,990,533)	(53,990,533)
2440 - Deferred Revenue	-	(6,698,313)	(16,158,299)	(25,108,816)	(31,351,674)	(36,048,321)	(39,473,070)	(43,150,815)
	(57,161,700)	(60,777,962)	(70,224,305)	(79,169,594)	(85,361,162)	(90,038,854)	(93,463,603)	(97,141,348)
	340,139,579	329,464,668	338,790,929	351,437,128	366,441,711	380,376,524	398,166,546	423,297,301

Table 2.4-3 – Detailed Accumulated Depreciation

Accumulated Depreciation

	2014 Board Approved	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Bridge	2020 Test
Transmission Assets								
1808 - Buildings and Fixtures	2,652,146	2,626,445	2,828,336	3,027,444	3,216,477	3,402,239	3,599,639	3,796,039
1815 - Transformer Station Equipment	22,047,738	21,745,180	23,290,054	24,367,487	25,887,823	27,342,043	28,942,043	30,577,543
1820 - Distribution Station Equipment	2,099,424	2,046,956	2,072,709	2,104,715	2,149,598	2,194,737	2,240,237	2,285,537
	26,799,308	26,418,581	28,191,099	29,499,646	31,253,898	32,939,019	34,781,919	36,659,119
Distribution Assets								
1805 - Land	-	-	-	-	-	-	-	-
1612 - Land Rights	260,621	260,527	263,180	265,449	265,449	265,449	265,449	265,449
1830 - Poles, Towers and Fixtures	14,584,425	14,554,651	15,286,408	16,122,985	17,022,183	17,993,217	19,052,417	20,154,617
1835 - Overhead Conductors and Devices	16,816,761	16,807,974	17,298,105	17,841,051	18,427,277	19,067,818	19,750,918	20,482,718
1840 - Underground Conduit	10,442,578	10,448,858	10,855,619	11,320,812	11,827,493	12,376,130	12,944,830	13,564,530
1845 - Underground Conductors and Devices	21,606,190	21,593,952	22,432,154	23,365,482	24,371,418	25,436,589	26,541,089	27,689,689
1850 - Line Transformers	27,899,139	27,435,587	28,240,495	29,951,355	31,308,387	32,710,233	34,204,333	35,774,833
1855 - Services	19,616,226	19,626,446	20,587,391	21,628,185	22,727,482	23,906,428	25,108,828	26,378,328
1860 - Meters	4,865,536	4,751,883	5,687,706	6,687,881	7,725,514	8,817,917	9,925,517	11,066,317
	116,091,476	115,479,878	120,651,058	127,183,200	133,675,203	140,573,781	147,793,381	155,376,481
General Plant								
1905 - Land	-	-	-	-	-	-	-	-
1908 - Buildings and Fixtures	4,950,402	5,046,968	5,525,106	4,662,676	5,105,047	5,511,764	6,024,264	6,573,964
1915 - Office Furniture and Equipment	974,651	973,744	642,772	703,588	478,400	540,656	602,156	660,056
1920 - Computer Equipment - Hardware	2,649,801	1,634,101	1,753,345	1,929,242	2,121,615	1,078,068	1,345,668	1,605,868
1611 - Computer Software	4,131,256	3,487,716	3,761,654	4,159,469	4,579,434	5,029,897	5,475,297	6,669,497
1930 - Transportation Equipment	6,289,451	5,735,369	6,187,876	6,349,027	6,997,559	6,676,654	6,738,854	7,043,954
1935 - Stores Equipment	54,100	54,853	60,564	63,779	27,425	27,680	27,980	28,280
1940 - Tools, Shop and Garage Equipment	642,366	619,600	403,480	476,214	506,897	582,511	652,511	721,711
1945 - Measurement and Testing Equipment	804,701	798,184	835,760	872,469	245,299	282,468	317,668	352,468
1950 - Power Operated Equipment	643,788	565,161	508,507	438,741	508,307	426,331	510,231	594,982
1955 - Communications Equipment	566,302	534,154	618,615	699,545	784,180	869,791	909,791	931,940
1960 - Miscellaneous Equipment	98,817	102,241	104,272	106,303	9,561	11,756	13,056	14,356
1980 - System Supervisory Equipment	1,555,532	1,555,449	20,007	32,750	34,954	37,158	37,158	37,158
	23,361,167	21,107,540	20,421,958	20,493,803	21,398,678	21,074,734	22,654,634	25,234,234
Contributions and Grants								
1995 - Contributions and Grants	(14,584,896)	(14,637,386)	(15,806,206)	(16,981,953)	(18,030,394)	(19,105,699)	(20,197,799)	(21,287,299)
2440 - Deferred Revenue	-	(105,658)	(355,736)	(843,293)	(1,501,766)	(2,283,318)	(3,140,418)	(4,080,118)
	(14,584,896)	(14,743,044)	(16,161,942)	(17,825,246)	(19,532,160)	(21,389,017)	(23,338,217)	(25,367,417)
	151,667,055	148,262,955	153,102,173	159,351,403	166,795,619	173,198,517	181,891,717	191,902,417

Table 2.4-4 – Detailed Net Fixed Assets

Net Fixed Assets

	2014 Board Approved	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Bridge	2020 Test
Transmission Assets								
1808 - Buildings and Fixtures	7,314,743	7,193,953	6,858,898	6,648,603	6,459,570	6,261,994	6,064,594	5,868,194
1815 - Transformer Station Equipment	41,900,448	41,737,542	39,846,231	38,459,712	39,424,261	38,423,986	38,448,486	38,816,986
1820 - Distribution Station Equipment	885,334	885,962	837,176	788,952	744,069	706,594	661,094	615,794
	50,100,525	49,817,457	47,542,305	45,897,267	46,627,900	45,392,574	45,174,174	45,300,974
Distribution Assets								
1805 - Land	2,339,958	2,339,958	2,339,958	2,339,958	2,339,958	2,339,958	2,339,958	2,339,958
1612 - Land Rights	4,827	4,921	2,268	(1)	(1)	(1)	(1)	(1)
1830 - Poles, Towers and Fixtures	23,028,123	21,966,326	24,609,217	27,298,268	29,222,118	31,174,935	33,075,235	35,106,885
1835 - Overhead Conductors and Devices	21,580,538	20,539,651	23,044,949	25,259,289	27,549,054	29,743,275	31,773,815	33,935,215
1840 - Underground Conduit	18,358,530	19,281,598	23,231,279	25,421,503	27,764,971	29,400,862	31,351,762	34,256,662
1845 - Underground Conductors and Devices	23,220,691	23,257,201	25,410,710	29,418,704	31,354,513	32,127,054	32,714,755	33,543,356
1850 - Line Transformers	30,622,410	29,940,411	32,346,386	34,777,263	36,110,550	38,115,805	39,746,503	41,299,502
1855 - Services	29,410,333	28,936,708	31,310,919	33,590,298	35,970,239	37,942,141	39,541,202	41,296,852
1860 - Meters	10,771,938	10,798,311	10,106,092	9,778,534	9,564,707	9,639,820	9,172,520	8,628,720
	159,337,348	157,065,085	172,401,777	187,883,815	199,876,108	210,483,848	219,715,748	230,407,148
General Plant								
1905 - Land	1,395,300	1,395,300	1,395,300	1,395,300	1,395,300	1,395,300	1,395,300	1,395,300
1908 - Buildings and Fixtures	13,141,256	12,305,313	11,785,214	11,393,427	11,942,313	12,413,131	12,650,631	12,850,931
1915 - Office Furniture and Equipment	368,560	347,350	344,344	310,751	295,667	267,583	350,680	362,780
1920 - Computer Equipment - Hardware	736,947	588,535	537,474	416,552	256,293	667,241	743,781	808,581
1611 - Computer Software	920,484	692,523	861,688	1,173,951	890,133	715,897	1,124,862	6,640,662
1930 - Transportation Equipment	3,993,218	3,793,620	3,614,423	3,682,858	3,048,769	3,207,132	3,949,001	4,068,901
1935 - Stores Equipment	9,972	9,219	3,508	2,845	2,569	2,314	2,014	1,714
1940 - Tools, Shop and Garage Equipment	359,158	348,865	346,813	369,082	367,639	365,838	390,838	416,638
1945 - Measurement and Testing Equipment	167,867	223,827	204,464	171,604	193,118	169,311	144,111	119,311
1950 - Power Operated Equipment	193,975	285,363	384,485	426,935	357,369	566,350	582,450	607,699
1955 - Communications Equipment	303,534	346,374	317,613	297,949	213,504	173,848	170,448	183,299
1960 - Miscellaneous Equipment	1,467,661	1,464,239	(77,293)	(68,524)	28,218	26,023	24,723	23,423
1980 - System Supervisory Equipment	(1,446,476)	(1,446,439)	89,003	76,260	(19,807)	(18,547)	(18,547)	(18,547)
	21,611,456	20,354,089	19,807,038	19,648,992	18,971,087	19,951,423	21,510,294	27,460,694
Contributions and Grants								
1995 - Contributions and Grants	(42,576,804)	(39,442,263)	(38,259,800)	(37,078,825)	(35,979,094)	(34,884,834)	(33,792,734)	(32,703,234)
2440 - Deferred Revenue	-	(6,592,655)	(15,802,563)	(24,265,523)	(29,849,908)	(33,765,003)	(36,332,652)	(39,070,697)
	(42,576,804)	(46,034,918)	(54,062,363)	(61,344,348)	(65,829,002)	(68,649,837)	(70,125,386)	(71,773,931)
	188,472,525	181,201,713	185,688,757	192,085,726	199,646,093	207,178,008	216,274,830	231,394,885

KWHI has not applied for any ICM or ACM adjustments and there is no adjustment in the above schedule for these items.

2.4.1 Gross Asset Variance Analysis

Table 2.4.1-1 below shows the gross asset variance for each asset.

Table 2.4.1-1 – 2014-2020 Gross Asset Variance

	2014 Board Approved	2014 Actual	Variance 2014 Actual vs 2014 Board Approved	2015 Actual	Variance 2015 Actual vs 2014 Actual	2016 Actual	Variance 2016 Actual vs 2015 Actual	2017 Actual	Variance 2017 Actual vs 2016 Actual	2018 Actual	Variance 2018 Actual vs 2017 Actual	2019 Bridge	Variance 2019 Actual vs 2018 Actual	2020 Test	Variance 2020 Actual vs 2019 Actual
Transmission Assets															
1808 - Buildings and Fixtures	9,966,889	9,820,398	(146,491)	9,687,234	(133,164)	9,676,047	(11,187)	9,676,047	-	9,664,233	(11,814)	9,664,233	-	9,664,233	-
1815 - Transformer Station Equipment	63,948,186	63,482,722	(465,464)	63,136,285	(346,437)	62,827,199	(309,086)	65,312,084	2,484,885	65,766,029	453,945	67,390,529	1,624,500	69,394,529	2,004,000
1820 - Distribution Station Equipment	2,984,758	2,932,918	(51,840)	2,909,885	(23,033)	2,893,667	(16,218)	2,893,667	-	2,901,331	7,664	2,901,331	-	2,901,331	-
	76,899,833	76,236,038	(663,795)	75,733,404	(502,634)	75,396,913	(336,491)	77,881,798	2,484,885	78,331,593	449,795	79,956,093	1,624,500	81,960,093	2,004,000
Distribution Assets															
1805 - Land	2,339,958	2,339,958	-	2,339,958	-	2,339,958	-	2,339,958	-	2,339,958	-	2,339,958	-	2,339,958	-
1612 - Land Rights	265,448	265,448	-	265,448	-	265,448	-	265,448	-	265,448	-	265,448	-	265,448	-
1830 - Poles, Towers and Fixtures	37,612,548	36,520,977	(1,091,571)	39,895,625	3,374,648	43,421,253	3,525,628	46,244,301	2,823,048	49,168,152	2,923,851	52,127,652	2,959,500	55,261,502	3,133,850
1835 - Overhead Conductors and Device	38,397,299	37,347,625	(1,049,674)	40,343,054	2,995,429	43,100,340	2,757,286	45,976,331	2,875,991	48,811,093	2,834,762	51,524,733	2,713,640	54,417,933	2,893,200
1840 - Underground Conduit	28,801,108	29,730,456	929,348	34,086,898	4,356,442	36,742,315	2,655,417	39,592,464	2,850,149	41,776,992	2,184,528	44,296,592	2,519,600	47,821,192	3,524,600
1845 - Underground Conductors and De	44,826,881	44,851,153	24,272	47,842,864	2,991,711	52,784,186	4,941,322	55,725,931	2,941,745	57,563,643	1,837,712	59,255,844	1,692,201	61,233,045	1,977,201
1850 - Line Transformers	58,521,549	57,375,998	(1,145,551)	60,586,881	3,210,883	64,728,618	4,141,737	67,418,937	2,690,319	70,826,038	3,407,101	73,950,836	3,124,798	77,074,335	3,123,499
1855 - Services	49,026,559	48,563,154	(463,405)	51,898,310	3,335,156	55,218,483	3,320,173	58,697,721	3,479,238	61,848,569	3,150,848	64,650,030	2,801,461	67,675,180	3,025,150
1860 - Meters	15,637,474	15,550,194	(87,280)	15,793,798	243,604	16,466,415	672,617	17,290,221	823,806	18,457,737	1,167,516	19,098,037	640,300	19,695,037	597,000
	275,428,824	272,544,963	(2,883,861)	293,052,835	20,507,872	315,067,015	22,014,180	333,551,311	18,484,296	351,057,629	17,506,318	367,509,129	16,451,500	385,783,629	18,274,500
General Plant															
1905 - Land	1,395,300	1,395,300	-	1,395,300	-	1,395,300	-	1,395,300	-	1,395,300	-	1,395,300	-	1,395,300	-
1908 - Buildings and Fixtures	18,091,658	17,352,281	(739,377)	17,310,320	(41,961)	16,056,103	(1,254,217)	17,047,360	991,257	17,924,895	877,535	18,674,895	750,000	19,424,895	750,000
1915 - Office Furniture and Equipment	1,343,211	1,321,094	(22,117)	987,116	(333,978)	1,014,339	27,223	774,067	(240,272)	808,239	34,172	952,836	144,597	1,022,836	70,000
1920 - Computer Equipment - Hardware	3,386,748	2,222,636	(1,164,112)	2,290,819	68,183	2,345,794	54,975	2,377,908	32,114	1,745,309	(632,599)	2,089,449	344,140	2,414,449	325,000
1611 - Computer Software	5,051,740	4,180,239	(871,501)	4,623,342	443,103	5,333,420	710,078	5,469,567	136,147	5,745,794	276,227	6,600,159	854,365	13,310,159	6,710,000
1930 - Transportation Equipment	10,282,669	9,528,989	(753,680)	9,802,299	273,310	10,031,885	229,586	10,046,328	14,443	9,883,786	(162,542)	10,687,855	804,069	11,112,855	425,000
1935 - Stores Equipment	64,072	64,072	-	64,072	-	66,624	2,552	29,994	(36,630)	29,994	-	29,994	-	29,994	-
1940 - Tools, Shop and Garage Equipme	1,001,524	968,465	(33,059)	750,293	(218,172)	845,296	95,003	874,536	29,240	948,349	73,813	1,043,349	95,000	1,138,349	95,000
1945 - Measurement and Testing Equipr	972,568	1,022,011	49,443	1,040,224	18,213	1,044,073	3,849	438,417	(605,656)	451,779	13,362	461,779	10,000	471,779	10,000
1950 - Power Operated Equipment	837,763	850,524	12,761	892,992	42,468	865,676	(27,316)	865,676	-	992,681	127,005	1,092,681	100,000	1,202,681	110,000
1955 - Communications Equipment	869,836	880,528	10,692	936,228	55,700	997,494	61,266	997,684	190	1,043,639	45,955	1,080,239	36,600	1,115,239	35,000
1960 - Miscellaneous Equipment	109,056	109,010	(46)	109,010	-	109,010	-	15,147	(93,863)	18,611	3,464	18,611	-	18,611	-
1980 - System Supervisory Equipment	1,566,478	1,566,480	2	26,979	(1,539,501)	37,779	10,800	37,779	-	37,779	-	37,779	-	37,779	-
	44,972,623	41,461,629	(3,510,994)	40,228,996	(1,232,633)	40,142,794	(86,201)	40,369,764	226,970	41,026,156	656,392	44,164,927	3,138,771	52,694,927	8,530,000
Contributions and Grants															
1995 - Contributions and Grants	(57,161,700)	(54,079,649)	3,082,051	(54,066,006)	13,643	(54,060,778)	5,228	(54,009,488)	51,290	(53,990,533)	18,955	(53,990,533)	-	(53,990,533)	-
2440 - Deferred Revenue	-	(6,698,313)		(16,158,299)	(9,459,986)	(25,108,816)	(8,950,517)	(31,351,674)	(6,242,858)	(36,048,321)	(4,696,647)	(39,473,070)	(3,424,749)	(43,150,815)	(3,677,745)
	(57,161,700)	(60,777,962)	3,082,051	(70,224,305)	(9,446,343)	(79,169,594)	(8,945,289)	(85,361,162)	(6,191,568)	(90,038,854)	(4,677,692)	(93,463,603)	(3,424,749)	(97,141,348)	(3,677,745)
	340,139,580	329,464,668	(3,976,599)	338,790,929	9,326,261	351,437,128	12,646,199	366,441,711	15,004,583	380,376,524	13,934,813	398,166,546	17,790,022	423,297,301	25,130,755

Variance explanations for each year are described below. As per Section 2.2, KWHI has used a materiality level of $225,000 for its analysis:

Table 2.4.1-2 – 2014 Board Approved vs 2014 Actual

	2014 Board Approved	2014 Actual	2014 Board Approved vs 2014 Actual $	%
Transmission Assets				
1808 - Buildings and Fixtures	9,966,889	9,820,398	(146,491)	-1.5%
1815 - Transformer Station Equipment	63,948,186	63,482,722	(465,464)	-0.7%
1820 - Distribution Station Equipment	2,984,758	2,932,918	(51,840)	-1.7%
	76,899,833	76,236,038	(663,795)	-3.9%
Distribution Assets				
1830 - Poles, Towers and Fixtures	37,612,548	36,520,977	(1,091,571)	-2.9%
1835 - Overhead Conductors and Devices	38,397,299	37,347,625	(1,049,674)	-2.7%
1840 - Underground Conduit	28,801,108	29,730,456	929,348	3.2%
1845 - Underground Conductors and Devices	44,826,881	44,851,153	24,272	0.1%
1850 - Line Transformers	58,521,549	57,375,998	(1,145,551)	-2.0%
1855 - Services	49,026,559	48,563,154	(463,405)	-0.9%
1860 - Meters	15,637,474	15,550,194	(87,280)	-0.6%
1612 - Land Rights	265,448	265,448	-	0.0%
1805 - Land	2,339,958	2,339,958	-	0.0%
	275,428,824	272,544,963	(2,883,861)	-0.6%
General Plant				
1908 - Buildings and Fixtures	18,091,658	17,352,281	(739,377)	-4.1%
1915 - Office Furniture and Equipment	1,343,211	1,321,094	(22,117)	-1.6%
1611 - Computer Software	5,051,740	4,180,239	(871,501)	-17.3%
1930 - Transportation Equipment	10,282,669	9,528,989	(753,680)	-7.3%
1920 - Computer Equipment - Hardware	3,386,748	2,222,636	(1,164,112)	-34.4%
1940 - Tools, Shop and Garage Equipment	1,001,524	968,465	(33,059)	-3.3%
1945 - Measurement and Testing Equipment	972,568	1,022,011	49,443	5.1%
1950 - Power Operated Equipment	837,763	850,524	12,761	1.5%
1955 - Communications Equipment	869,836	880,528	10,692	1.2%
1980 - System Supervisory Equipment	1,566,478	1,566,480	2	0.0%
1960 - Miscellaneous Equipment	109,056	109,010	(46)	0.0%
1905 - Land	1,395,300	1,395,300	-	0.0%
1935 - Stores Equipment	64,072	64,072	-	0.0%
	44,972,623	41,461,629	(3,510,994)	0.0%
Contributions and Grants				
1995 - Contributions and Grants	(57,161,700)	(54,079,649)	3,082,051	-5.4%
2440 - Deferred Revenue	-	(6,698,313)	(6,698,313)	100.0%
	(57,161,700)	(60,777,962)	(3,616,262)	6.3%
	340,139,580	329,464,668	(10,674,912)	-3.1%

Transmission Asset Variance ($663,795)

Disposals of equipment that has reached end of life exceeded Board approved amounts by $0.3M. In addition, there was $368K in WIP at year end.

Distribution Asset Variance ($2,883,861)

2014 Board approved is based on actual asset value from 2012 plus forecasted additions for 2013 and 2014. KWH underspent on this category in 2013 by $1.1M. In addition, WIP was significantly increased at year-end 2014 versus 2013 for this category as well.

General Plant Asset Variance ($3,510,994)

Disposals of equipment that has reached end of life exceeded Board approved amounts by $1.7M. KWHI underspent in this category in 2014 by $699K and 2013's ending balances did not meet the 2013 Board approved amounts.

Contributions and Grants ($3,616,262)

The cost driver for the increase in contributions and grants is the LRT project ($3,324K), road relocations and residential underground distribution projects.

Table 2.4.1-3 – 2014 Actual vs 2015 Actual

	2014 Actual	2015 Actual	2014 Actual vs 2015 Actual $	%
Transmission Assets				
1808 - Buildings and Fixtures	9,820,398	9,687,234	(133,164)	-1.4%
1815 - Transformer Station Equipment	63,482,722	63,136,285	(346,437)	-0.5%
1820 - Distribution Station Equipment	2,932,918	2,909,885	(23,033)	-0.8%
	76,236,038	75,733,404	(502,634)	-0.7%
Distribution Assets				
1830 - Poles, Towers and Fixtures	36,520,977	39,895,625	3,374,648	9.2%
1835 - Overhead Conductors and Devices	37,347,625	40,343,054	2,995,429	8.0%
1840 - Underground Conduit	29,730,456	34,086,898	4,356,442	14.7%
1845 - Underground Conductors and Devices	44,851,153	47,842,864	2,991,711	6.7%
1850 - Line Transformers	57,375,998	60,586,881	3,210,883	5.6%
1855 - Services	48,563,154	51,898,310	3,335,156	6.9%
1860 - Meters	15,550,194	15,793,798	243,604	1.6%
1612 - Land Rights	265,448	265,448	-	0.0%
1805 - Land	2,339,958	2,339,958	-	0.0%
	272,544,963	293,052,835	20,507,872	7.5%
General Plant				
1908 - Buildings and Fixtures	17,352,281	17,310,320	(41,961)	-0.2%
1915 - Office Furniture and Equipment	1,321,094	987,116	(333,978)	-25.3%
1611 - Computer Software	4,180,239	4,623,342	443,103	10.6%
1930 - Transportation Equipment	9,528,989	9,802,299	273,310	2.9%
1920 - Computer Equipment - Hardware	2,222,636	2,290,819	68,183	3.1%
1940 - Tools, Shop and Garage Equipment	968,465	750,293	(218,172)	-22.5%
1945 - Measurement and Testing Equipment	1,022,011	1,040,224	18,213	1.8%
1950 - Power Operated Equipment	850,524	892,992	42,468	5.0%
1955 - Communications Equipment	880,528	936,228	55,700	6.3%
1980 - System Supervisory Equipment	1,566,480	26,979	(1,539,501)	-98.3%
1960 - Miscellaneous Equipment	109,010	109,010	-	0.0%
1905 - Land	1,395,300	1,395,300	-	0.0%
1935 - Stores Equipment	64,072	64,072	-	0.0%
	41,461,629	40,228,996	(1,232,633)	-3.0%
Contributions and Grants				
1995 - Contributions and Grants	(54,079,649)	(54,066,006)	13,643	0.0%
2440 - Deferred Revenue	(6,698,313)	(16,158,299)	(9,459,986)	141.2%
	(60,777,962)	(70,224,305)	(9,446,343)	15.5%
	329,464,668	338,790,929	9,326,261	2.8%

Transmission Asset Variance ($502,634)

A one-time credit was given to KWHI by HONI for Detweiler TS bypass costs which explains the decrease in transmission assets for 2015. When KWHI constructed its No. 9TS in Wilmot Township, a bypass cost was charged by HONI for stranded Detweiler TS assets. After reconciling the project, a refund was given to KWHI. This resulted in an offset in the total expenditures for transmission assets.

Distribution Asset Variance $20,507,872

The primary driver of the increased assets in 2015 included $7,374K for LRT System Access work, $3,406K for Underground Residential Distribution, $2,822K for Roadway Relocations and $1,142K for Commercial, Industrial and Apartment Services. Replacement of Pole Line assets and Transformer replacements accounted for $907K and $1,268K increase respectively. KWHI has provided details of the projects in Section 2.9.3.1 below, and in OEB Filing Requirement Appendix 2-AA filed in live Excel format (EB-2019-0049_KWHI_Appl_2019_Filing_Req_Chap2_Appendices_20190430) and in Appendix 2-1.

General Plant Asset Variance ($1,232,633)

Investment in IT/OT assets of $697K and Vehicles of $661K. Land and Building ($273K). In 2015, Office Furniture, Tools and System Supervisory Equipment reached their end of life resulting in the decrease.

Contributions and Grants ($9,459,986)

The cost driver for the increase in contributions and grants is the LRT project ($4,826K), road relocations and residential underground distribution projects.

Table 2.4.1-4 – 2015 Actual vs 2016 Actual

	2015 Actual	2016 Actual	2015 Actual vs 2016 Actual $	%
Transmission Assets				
1808 - Buildings and Fixtures	9,687,234	9,676,047	(11,187)	-0.1%
1815 - Transformer Station Equipment	63,136,285	62,827,199	(309,086)	-0.5%
1820 - Distribution Station Equipment	2,909,885	2,893,667	(16,218)	-0.6%
	75,733,404	75,396,913	(336,491)	-0.4%
Distribution Assets				
1830 - Poles, Towers and Fixtures	39,895,625	43,421,253	3,525,628	8.8%
1835 - Overhead Conductors and Devices	40,343,054	43,100,340	2,757,286	6.8%
1840 - Underground Conduit	34,086,898	36,742,315	2,655,417	7.8%
1845 - Underground Conductors and Devices	47,842,864	52,784,186	4,941,322	10.3%
1850 - Line Transformers	60,586,881	64,728,618	4,141,737	6.8%
1855 - Services	51,898,310	55,218,483	3,320,173	6.4%
1860 - Meters	15,793,798	16,466,415	672,617	4.3%
1612 - Land Rights	265,448	265,448	-	0.0%
1805 - Land	2,339,958	2,339,958	-	0.0%
	293,052,835	315,067,015	22,014,180	7.5%
General Plant				
1908 - Buildings and Fixtures	17,310,320	16,056,103	(1,254,217)	-7.2%
1915 - Office Furniture and Equipment	987,116	1,014,339	27,223	2.8%
1611 - Computer Software	4,623,342	5,333,420	710,078	15.4%
1930 - Transportation Equipment	9,802,299	10,031,885	229,586	2.3%
1920 - Computer Equipment - Hardware	2,290,819	2,345,794	54,975	2.4%
1940 - Tools, Shop and Garage Equipment	750,293	845,296	95,003	12.7%
1945 - Measurement and Testing Equipment	1,040,224	1,044,073	3,849	0.4%
1950 - Power Operated Equipment	892,992	865,676	(27,316)	-3.1%
1955 - Communications Equipment	936,228	997,494	61,266	6.5%
1980 - System Supervisory Equipment	26,979	37,779	10,800	40.0%
1960 - Miscellaneous Equipment	109,010	109,010	-	0.0%
1905 - Land	1,395,300	1,395,300	-	0.0%
1935 - Stores Equipment	64,072	66,624	2,552	4.0%
	40,228,996	40,142,794	(86,201)	-0.2%
Contributions and Grants				
1995 - Contributions and Grants	(54,066,006)	(54,060,778)	5,228	0.0%
2440 - Deferred Revenue	(16,158,299)	(25,108,816)	(8,950,517)	55.4%
	(70,224,305)	(79,169,594)	(8,945,289)	12.7%
	338,790,929	351,437,128	12,646,199	3.7%

Transmission Asset Variance ($336,491)

The primary driver of the increased assets in 2016 included $1,002K for Transformer and Distribution station renewal. Of these expenditures, $780K was not yet in service and placed into WIP.

Distribution Asset Variance $22,014,180

The primary driver of the increased assets in 2016 included $8,596K for LRT System Access work, $2,589K for Underground Residential Distribution, $2,357K for Roadway Relocations and $734K for Commercial, Industrial and Apartment Services. Replacement of Pole Line assets and Transformer replacements accounted for $1,570K and $1,225K increase respectively. KWHI has provided details of the projects in Section 2.9.3.1 below, and in OEB Filing Requirement Appendix 2-AA filed in Appendix 2-1.

General Plant Asset Variance $86,201

In 2016, KWHI invested $860K in vehicles and $801K in IT/OT infrastructure. $1.458K of building assets reached end of life.

Contributions and Grants ($8,945,289)

The cost driver for the increase in contributions and grants is the LRT project ($4,880K), road relocations and residential underground distribution projects.

Table 2.4.1-5 – 2016 Actual vs 2017 Actual

	2016 Actual	2017 Actual	2016 Actual vs 2017 Actual $	%
Transmission Assets				
1808 - Buildings and Fixtures	9,676,047	9,676,047	-	0.0%
1815 - Transformer Station Equipment	62,827,199	65,312,084	2,484,885	4.0%
1820 - Distribution Station Equipment	2,893,667	2,893,667	-	0.0%
	75,396,913	77,881,798	2,484,885	3.3%
Distribution Assets				
1830 - Poles, Towers and Fixtures	43,421,253	46,244,301	2,823,048	6.5%
1835 - Overhead Conductors and Devices	43,100,340	45,976,331	2,875,991	6.7%
1840 - Underground Conduit	36,742,315	39,592,464	2,850,149	7.8%
1845 - Underground Conductors and Devices	52,784,186	55,725,931	2,941,745	5.6%
1850 - Line Transformers	64,728,618	67,418,937	2,690,319	4.2%
1855 - Services	55,218,483	58,697,721	3,479,238	6.3%
1860 - Meters	16,466,415	17,290,221	823,806	5.0%
1612 - Land Rights	265,448	265,448	-	0.0%
1805 - Land	2,339,958	2,339,958	-	0.0%
	315,067,015	333,551,311	18,484,296	5.9%
General Plant				
1908 - Buildings and Fixtures	16,056,103	17,047,360	991,257	6.2%
1915 - Office Furniture and Equipment	1,014,339	774,067	(240,272)	-23.7%
1611 - Computer Software	5,333,420	5,469,567	136,147	2.6%
1930 - Transportation Equipment	10,031,885	10,046,328	14,443	0.1%
1920 - Computer Equipment - Hardware	2,345,794	2,377,908	32,114	1.4%
1940 - Tools, Shop and Garage Equipment	845,296	874,536	29,240	3.5%
1945 - Measurement and Testing Equipment	1,044,073	438,417	(605,656)	-58.0%
1950 - Power Operated Equipment	865,676	865,676	-	0.0%
1955 - Communications Equipment	997,494	997,684	190	0.0%
1980 - System Supervisory Equipment	37,779	37,779	-	0.0%
1960 - Miscellaneous Equipment	109,010	15,147	(93,863)	-86.1%
1905 - Land	1,395,300	1,395,300	-	0.0%
1935 - Stores Equipment	66,624	29,994	(36,630)	-55.0%
	40,142,794	40,369,764	226,970	0.6%
Contributions and Grants				
1995 - Contributions and Grants	(54,060,778)	(54,009,488)	51,290	-0.1%
2440 - Deferred Revenue	(25,108,816)	(31,351,674)	(6,242,858)	24.9%
	(79,169,594)	(85,361,162)	(6,191,568)	7.8%
	351,437,128	366,441,711	15,004,583	4.3%

Transmission Asset Variance ($2,484,885)

The primary driver of the increased assets in 2017 included $1,011K for Transformers and Distribution station renewal. In addition, $1.487K of expenditures on assets from previous years (WIP) were placed into service.

Distribution Asset Variance $18,484,296

The primary driver of the increased assets in 2017 included $2,977K for LRT System Access work, $3,086K for Underground Residential Distribution, $2,339K for Roadway Relocations and $1,109K for Commercial, Industrial and Apartment Services. Replacement of Pole Line assets and Transformer replacements accounted for $2,382K and $964K increases respectively. KWHI has provided details of the projects in Section 2.9.3.1. below, and in OEB filing Requirement Appendix 2-AA filed in Appendix 2-1.

General Plant Asset Variance ($226,970)

In 201, KWHI invested $1,141K in Buildings, $871 in Vehicles and $593K in IT/OT infrastructure. $664K of Measuring and Testing equipment reached end of life.

Contributions and Grants ($6,191,568)

The cost driver for the increase in contributions and grants is the LRT project ($2,009K), road relocations, and residential underground distribution projects.

Table 2.4.1-6 – 2017 Actual vs 2018 Actual

	2017 Actual	2018 Actual	2017 Actual vs 2018 Actual $	%
Transmission Assets				
1808 - Buildings and Fixtures	9,676,047	9,664,233	(11,814)	-0.1%
1815 - Transformer Station Equipment	65,312,084	65,766,029	453,945	0.7%
1820 - Distribution Station Equipment	2,893,667	2,901,331	7,664	0.3%
	77,881,798	78,331,593	449,795	0.6%
Distribution Assets				
1830 - Poles, Towers and Fixtures	46,244,301	49,168,152	2,923,851	6.3%
1835 - Overhead Conductors and Devices	45,976,331	48,811,093	2,834,762	6.2%
1840 - Underground Conduit	39,592,464	41,776,992	2,184,528	5.5%
1845 - Underground Conductors and Devices	55,725,931	57,563,643	1,837,712	3.3%
1850 - Line Transformers	67,418,937	70,826,038	3,407,101	5.1%
1855 - Services	58,697,721	61,848,569	3,150,848	5.4%
1860 - Meters	17,290,221	18,457,737	1,167,516	6.8%
1612 - Land Rights	265,448	265,448	-	0.0%
1805 - Land	2,339,958	2,339,958	-	0.0%
	333,551,311	351,057,629	17,506,318	5.2%
General Plant				
1908 - Buildings and Fixtures	17,047,360	17,924,895	877,535	5.1%
1915 - Office Furniture and Equipment	774,067	808,239	34,172	4.4%
1611 - Computer Software	5,469,567	5,745,794	276,227	5.1%
1930 - Transportation Equipment	10,046,328	9,883,786	(162,542)	-1.6%
1920 - Computer Equipment - Hardware	2,377,908	1,745,309	(632,599)	-26.6%
1940 - Tools, Shop and Garage Equipment	874,536	948,349	73,813	8.4%
1945 - Measurement and Testing Equipment	438,417	451,779	13,362	3.0%
1950 - Power Operated Equipment	865,676	992,681	127,005	14.7%
1955 - Communications Equipment	997,684	1,043,639	45,955	4.6%
1980 - System Supervisory Equipment	37,779	37,779	-	0.0%
1960 - Miscellaneous Equipment	15,147	18,611	3,464	22.9%
1905 - Land	1,395,300	1,395,300	-	0.0%
1935 - Stores Equipment	29,994	29,994	-	0.0%
	40,369,764	41,026,156	656,392	1.6%
Contributions and Grants				
1995 - Contributions and Grants	(54,009,488)	(53,990,533)	18,955	0.0%
2440 - Deferred Revenue	(31,351,674)	(36,048,321)	(4,696,647)	15.0%
	(85,361,162)	(90,038,854)	(4,677,692)	5.5%
	366,441,711	380,376,524	13,934,813	3.8%

Transmission Asset Variance $449,795

The primary driver of the increased assets in 2018 included $702K for Transformers and Distribution station renewal. $165K was placed into WIP.

Distribution Asset Variance $17,506,318

The primary driver of the increased assets in 2018 included $3,480K for Underground Residential Distribution, $1,720K for Roadway Relocations and $1,161K for Commercial, Industrial and Apartment Services. Other Programs include $3,017K for replacement of pole line assets, $1,175K for voltage conversion, $965K for replacement of primary cables and conduits and $1,210K for distribution transformer installation and replacements. KWHI has provided details of the projects in Section 2.9.3.1 below, and in OEB filing Requirement Appendix 2-AA filed in Appendix 2-1.

General Plant Asset Variance $656,392

In 2018, KWHI invested $750K in Buildings, $875 in Vehicles and $1.165K in IT/OT infrastructure.

Contributions and Grants ($4,677,692)

The cost driver for the increase in contributions and grants is residential underground distribution projects and road relocations. See Section 2.9.3.1 for details.

Table 2.4.1-7 – 2018 Actual vs 2019 Bridge

	2018 Actual	2019 Bridge	2018 Actual vs 2019 Bridge $	2018 Actual vs 2019 Bridge %
Transmission Assets				
1808 - Buildings and Fixtures	9,664,233	9,664,233	-	0.0%
1815 - Transformer Station Equipment	65,766,029	67,390,529	1,624,500	2.5%
1820 - Distribution Station Equipment	2,901,331	2,901,331	-	0.0%
	78,331,593	79,956,093	1,624,500	2.1%
Distribution Assets				
1830 - Poles, Towers and Fixtures	49,168,152	52,127,652	2,959,500	6.0%
1835 - Overhead Conductors and Devices	48,811,093	51,524,733	2,713,640	5.6%
1840 - Underground Conduit	41,776,992	44,296,592	2,519,600	6.0%
1845 - Underground Conductors and Devices	57,563,643	59,255,844	1,692,201	2.9%
1850 - Line Transformers	70,826,038	73,950,836	3,124,798	4.4%
1855 - Services	61,848,569	64,650,030	2,801,461	4.5%
1860 - Meters	18,457,737	19,098,037	640,300	3.5%
1612 - Land Rights	265,448	265,448	-	0.0%
1805 - Land	2,339,958	2,339,958	-	0.0%
	351,057,629	367,509,129	16,451,500	4.7%
General Plant				
1908 - Buildings and Fixtures	17,924,895	18,674,895	750,000	4.2%
1915 - Office Furniture and Equipment	808,239	952,836	144,597	17.9%
1611 - Computer Software	5,745,794	6,600,159	854,365	14.9%
1930 - Transportation Equipment	9,883,786	10,687,855	804,069	8.1%
1920 - Computer Equipment - Hardware	1,745,309	2,089,449	344,140	19.7%
1940 - Tools, Shop and Garage Equipment	948,349	1,043,349	95,000	10.0%
1945 - Measurement and Testing Equipment	451,779	461,779	10,000	2.2%
1950 - Power Operated Equipment	992,681	1,092,681	100,000	10.1%
1955 - Communications Equipment	1,043,639	1,080,239	36,600	3.5%
1980 - System Supervisory Equipment	37,779	37,779	-	0.0%
1960 - Miscellaneous Equipment	18,611	18,611	-	0.0%
1905 - Land	1,395,300	1,395,300	-	0.0%
1935 - Stores Equipment	29,994	29,994	-	0.0%
	41,026,156	44,164,927	3,138,771	7.7%
Contributions and Grants				
1995 - Contributions and Grants	(53,990,533)	(53,990,533)	-	0.0%
2440 - Deferred Revenue	(36,048,321)	(39,473,070)	(3,424,749)	9.5%
	(90,038,854)	(93,463,603)	(3,424,749)	3.8%
	380,376,524	398,166,546	17,790,022	4.7%

Transmission Asset Variance $1,624,500

Major investments in 2019 include installing switchgear arc resistance and remote racking upgrade for TS#5 and Bus P&C relay replacement for TS#3.

Distribution Asset Variance $16,451,500

The primary driver of the increased assets in 2019 includes planned investments of $3,708K for Underground Residential Distribution, $1,550K for Roadway Relocations and $1,084K for Commercial, Industrial and Apartment Services. Other Programs include $2,938K for replacement of pole line assets, $1,400K for voltage conversion and $1,350K for distribution transformer installation and replacements. KWHI has provided details of the projects in Section 2.9.3.1 below, and in OEB filing Requirement Appendix 2-AA filed in Appendix 2-1.

General Plant Asset Variance $3,138,771

In 2019, KWHI plans to invest $750K in Buildings, $975K in Vehicles and $5,190K in IT/OT infrastructure. The CIS will not be in use at year-end and will be placed in WIP (See Section 2.1.3).

Contributions and Grants ($3,424,749)

The cost driver for the increase in contributions and grants is residential underground distribution projects and road relocations. See Section 2.9.3.1 for details.

Table 2.4.1-8 – 2019 Bridge vs 2020 Test

	2019 Bridge	2020 Test	2019 Bridge vs 2020 Test $	2019 Bridge vs 2020 Test %
Transmission Assets				
1808 - Buildings and Fixtures	9,664,233	9,664,233	-	0.0%
1815 - Transformer Station Equipment	67,390,529	69,394,529	2,004,000	3.0%
1820 - Distribution Station Equipment	2,901,331	2,901,331	-	0.0%
	79,956,093	81,960,093	2,004,000	2.5%
Distribution Assets				
1830 - Poles, Towers and Fixtures	52,127,652	55,261,502	3,133,850	6.0%
1835 - Overhead Conductors and Devices	51,524,733	54,417,933	2,893,200	5.6%
1840 - Underground Conduit	44,296,592	47,821,192	3,524,600	8.0%
1845 - Underground Conductors and Devices	59,255,844	61,233,045	1,977,201	3.3%
1850 - Line Transformers	73,950,836	77,074,335	3,123,499	4.2%
1855 - Services	64,650,030	67,675,180	3,025,150	4.7%
1860 - Meters	19,098,037	19,695,037	597,000	3.1%
1612 - Land Rights	265,448	265,448	-	0.0%
1805 - Land	2,339,958	2,339,958	-	0.0%
	367,509,129	385,783,629	18,274,500	5.0%
General Plant				
1908 - Buildings and Fixtures	18,674,895	19,424,895	750,000	4.0%
1915 - Office Furniture and Equipment	952,836	1,022,836	70,000	7.3%
1611 - Computer Software	6,600,159	13,310,159	6,710,000	101.7%
1930 - Transportation Equipment	10,687,855	11,112,855	425,000	4.0%
1920 - Computer Equipment - Hardware	2,089,449	2,414,449	325,000	15.6%
1940 - Tools, Shop and Garage Equipment	1,043,349	1,138,349	95,000	9.1%
1945 - Measurement and Testing Equipment	461,779	471,779	10,000	2.2%
1950 - Power Operated Equipment	1,092,681	1,202,681	110,000	10.1%
1955 - Communications Equipment	1,080,239	1,115,239	35,000	3.2%
1980 - System Supervisory Equipment	37,779	37,779	-	0.0%
1960 - Miscellaneous Equipment	18,611	18,611	-	0.0%
1905 - Land	1,395,300	1,395,300	-	0.0%
1935 - Stores Equipment	29,994	29,994	-	0.0%
	44,164,927	52,694,927	8,530,000	19.3%
Contributions and Grants				
1995 - Contributions and Grants	(53,990,533)	(53,990,533)	-	0.0%
2440 - Deferred Revenue	(39,473,070)	(43,150,815)	(3,677,745)	9.3%
	(93,463,603)	(97,141,348)	(3,677,745)	3.9%
	398,166,546	423,297,301	25,130,755	6.3%

Transmission Asset Variance $2,004,000

Major investments in 2020 include the second phase of installing switchgear arc resistance and remote racking upgrade for TS#5 ($757K), and P&C rebuild TS#6 ($879K).

Distribution Asset Variance $18,274,500

The primary driver of the increased assets in 2020 include $3,708K for Underground Residential Distribution, $1,700K for Roadway Relocations and $1,209K for Commercial, Industrial and Apartment Services. Other programs include $3,404K for replacement of pole line assets, $1,375K for voltage conversion and $1,350K for distribution transformer installation and replacements. KWHI has provided details of the projects in Section 2.9.3.1 below, and in OEB Filing Requirement Appendix 2-AA filed in Appendix 2-1.

General Plant Asset Variance $8,530,000

The two main drivers of the general plant investments in the purchase and installation of the new CIS and vehicles ($1,000K). The CIS expenditures from 2019 will be released from WIP, as the CIS will be functional at year end 2020.

Contributions and Grants ($3,677,745)

The cost driver for the increase in contributions and grants is residential underground distribution projects and road relocations. See Section 2.9.3.1 for details.

2.5 Reconciliation of Depreciation Expense to Continuity Statements

KWHI confirms that the depreciation expense as shown in Exhibit 4, Section 4.9 is the same as shown in the continuity statements and no reconciliation is required.

2.6 Capitalization Policy

2.6.1 Capitalization Policy - Overhead

Overhead is capitalized, as a rule, at a rate of 40% to capital and 60% to OM&A.

KWHI applies overheads at the work order level as well as at the business unit level. At month end, overheads are applied to work orders regardless of whether they are capital or OM&A using the following factors (both past and present) presented below in Table 2.6.1-1 below:

Table 2.6.1-1 – Work Order Overhead Factors

Work Order Overhead Factors		
Overhead Type	2014	2018
Labour	63%	61%
Vehicle	30%	30%
Supervisory	6%	6%
Material	6%	6%
Engineering	14%	13%

Rates are reviewed annually and adjusted based on prior year actuals and current year budgets. Note: Engineering overhead is applied only to capital work orders. KWHI capitalizes a portion of total Engineering costs so this varies annual based on the level of capital work. In 2018, 66% of Engineering costs were capitalized.

Overhead costs are accumulated in business units specific to the type of cost being incurred. They are netted against the work order overheads applied through the work order system. Any residual is applied to capital and OM&A based on the typical work order split of 40% capital and 60% OM&A.

Table 2.6.1-2 below replicates OEB Required Filing Appendix 2-D. Appendix. 2-D and is attached in Appendix 2-1 of this Exhibit. 2019 Bridge Year and 2020 Test Year are

estimates based on forecasted increases to costs. For 2019 and 2020, expected increases to employee benefits are 1.5% and 3.0% respectively. For other salary and wages costs, KWHI has estimated labour inflation at a rate of 2.0% and 2.1% for 2019 and 2020 respectively in line with the increases agreed to through its Collective Agreements.

Table 2.6.1-2 – Capitalized OM&A

Capitalized OM&A	2014	2015	2016	2017	2018	2019 Bridge	2020 Test
Labour Burdens	1,803,365	2,104,810	2,404,088	2,130,424	1,988,910	2,178,200	2,215,800
Fleet Burdens	758,816	858,936	971,570	898,799	849,760	1,021,000	1,038,400
Engineering	1,880,863	2,267,788	2,519,573	1,999,476	1,740,180	1,799,300	1,820,600
Materials	292,392	363,420	399,774	314,778	289,957	325,500	328,700
Total OM&A Capitalized	**4,735,436**	**5,594,954**	**6,295,005**	**5,343,477**	**4,868,806**	**5,324,000**	**5,403,500**

2.6.2 Capitalization Policy

The purpose of capitalizing expenditures is to provide an equitable allocation of costs among existing and future customers. As capital assets are expected to provide future economic benefits for more than one year, any expenditure incurred for the acquisition, construction, development or betterment of the capital assets should be capitalized. These capitalized costs are allocated over the estimated useful life of the assets by amortization.

KWHI has included its Capitalization Policy as Appendix 2-2 to this Exhibit.

KWHI updated it depreciation policies in 2012 as per the OEB's letter dated July 17, 2012. There have been no changes to the Capitalization policy since KWHI last filed a Cost of Service application in June 2013.

2.7 Allowance for Working Capital

The Filing Requirements permit applicants to take one of two approaches for the calculation of the allowance for working capital; the adoption of the Board-prescribed 7.5% allowance or the filing of a lead/lag study. KWHI has used the 7.5% allowance; the working capital allowance is calculated to be 7.5% of the sum of Cost of Power (COP) and controllable expenses (Operations, Maintenance, Billing and Collecting, Community Relations, Administration and General, LEAP Donations and Property Taxes). KWHI did not conduct a lead/lag study nor was it directed to do so.

The working capital allowance for the 2020 Test Year is based upon 7.5% of the COP and controllable expenses. KWHI has also provided the calculation of the working capital allowance for each of 2014 to 2018 Actual, the 2019 Bridge Year and the 2020 Test Year. For 2014 - 2019, KWHI has used 13% for calculating the Working Capital Allowance, consistent with the KWHI's Board approved rate from EB-2013-0147.

Table 2.7-1 – Calculation of Working Capital Allowance and a summary of KWHI's COP and controllable expenses used to calculate working capital allowance for 2014 Board approved, 2014 through 2018 Actuals, and the 2019 Bridge and 2020 Test Years.

Table 2.7-1 – Calculation of Working Capital Allowance

Working Capital Expenses	2014 Board Approved	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Bridge	2020 Test
Distribution Expenses								
Operations	5,661,000	4,503,129	4,198,146	4,499,779	5,143,786	5,813,946	6,123,100	6,707,400
Maintenance	5,619,400	5,613,513	5,179,333	4,998,354	5,480,837	5,996,631	6,453,200	6,454,500
Customer Services	3,841,330	3,415,009	3,775,665	4,468,748	4,296,607	4,615,266	4,210,700	4,981,700
Community Relations	191,300	199,353	238,394	269,179	220,472	241,006	258,300	263,400
Admistration	3,020,230	2,887,150	2,679,129	2,823,528	2,737,694	2,702,205	3,076,000	3,528,700
Donations- LEAP	46,000	49,000	49,000	49,000	49,000	49,000	49,000	55,000
Property Taxes	394,800	348,946	494,597	395,917	402,362	408,253	430,800	436,900
Total Distribution Expenses	**18,774,060**	**17,016,100**	**16,614,264**	**17,504,505**	**18,330,758**	**19,826,307**	**20,601,100**	**22,427,600**
Power Supply Expenses	189,973,376	194,067,387	204,976,789	228,584,621	201,467,225	193,636,292	184,956,061	184,677,958
Total Expenses for Working Capital	**208,747,436**	**211,083,487**	**221,591,053**	**246,089,126**	**219,797,983**	**213,462,599**	**205,557,161**	**207,105,558**
Working Capital Factor	13.0%	13.0%	13.0%	13.0%	13.0%	13.0%	13.0%	7.5%
Total Working Capital Allowance	**27,137,167**	**27,440,853**	**28,806,837**	**31,991,586**	**28,573,738**	**27,750,138**	**26,722,431**	**15,532,917**

2.8 Calculation of Cost of Power

KWHI confirms that the COP is determined by a split between the Regulated Price Plan (RPP) and non-RPP customers based on actual data, use of the most current RPP price, and the use of current Uniform Transmission Rates (UTR). KWHI has calculated the COP for the 2020 Test Year based upon the 2020 Load Forecast adjusted for the impact of Conservation and Demand Management (CDM) activities and in accordance with the Board's Filing Requirements. A summary of the total COP expenses in shown in the Table 2.8-1 below:

Table 2.8-1 – Cost of Power

Cost of Power	2014 Board Approved	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Bridge	2020 Test
4705 - Power Purchased	161,770,175	67,431,715	120,252,524	126,484,686	106,137,759	106,160,556	162,909,583	162,303,535
4707 - Global Adjustment Charges	0	99,212,597	61,148,773	76,892,221	72,967,510	65,016,151	0	0
4708 - Charges Wholesale Market Serv.	10,254,430	10,214,716	6,978,213	9,112,197	7,229,351	6,902,249	6,836,270	6,812,177
4714 - Charges - Network	14,196,935	13,535,854	12,675,584	12,006,517	11,209,860	11,596,729	11,185,654	11,547,910
4716 - Charges - Connection	2,894,776	2,838,854	3,078,610	3,235,068	3,057,899	3,341,676	3,363,276	3,344,043
4751 - Smart Metering Entity Charge	857,060	833,651	843,085	853,933	864,846	618,933	661,278	670,293
	189,973,376	**194,067,387**	**204,976,789**	**228,584,621**	**201,467,225**	**193,636,292**	**184,956,061**	**184,677,958**

In accordance with the Filing Requirements, the commodity price estimate used to calculate the COP must be determined by the split between RPP and non-RPP Class A and Class B customers based on actual data and using the most current RPP (TOU) prices established for the May 1, 2018 to April 30, 2019 period. The Regulated Price Plan and Non-RPP price was obtained from the *"Regulated Price Plan: Price Report - May 1, 2018 to April 30, 2019"*. Chapter 2 Filing Appendix 2-Z is attached as Appendix 2-1 to this exhibit. It should be noted the there are multiple problems with the Required Filing Appendix 2-Z, and KWHI had to make its own schedule for 2-Z. Specifically line 82 in the Filing Requirement 2-Z double counts GS>50 kWhs. The difference between the dollars calculated on KWHI's schedule versus the Filing Requirement Appendix 2-Z are due to rounding, and the aforementioned double counting of kWhs. The kWh numbers on the schedule below are correct and match KWHI's load forecast.

Table 2.8-2 – Appendix 2-Z Commodity Expense

Commodity Expense

Step 1: **Allocation of Commodity**

2018 Historical Actuals

Customer Class Name	Last Actual kWh's	Class A kWh	Class B kWh	non-RPP non GA mod	non-RPP GA mod	non-RPP Total	RPP	Proportions (by Class) non-RPP %	Proportions (by Class) RPP %
Residential	704,744,448	-	704,744,448		13,440,415	13,440,415	691,304,032	*1.91%*	*98.09%*
General Service < 50 kW	249,035,857	-	249,035,857		37,999,724	37,999,724	211,036,134	*15.26%*	*84.74%*
General Service 3000-4999 kW	850,957,160	214,392,510	636,564,650	437,264,469	74,325,072	511,589,541	124,975,109	*85.31%*	*14.69%*
Unmetered Scattered Load	4,150,691	-	4,150,691			-	4,150,691	*0.00%*	*100.00%*
Large User	33,545,884	33,545,884	-	-	-	-	0	*0.00%*	*0.00%*
Street Lighting	7,728,656	-	7,728,656	7,440,589	189,867	7,630,457	98,200	*98.73%*	*1.27%*
other			-				0		
other			-				0		
TOTAL	**1,850,162,696**	**247,938,394**	**1,602,224,302**	**444,705,058**	**125,955,078**	**570,660,137**	**1,031,564,166**		
%	*100.00%*		*100.00%*	*27.76%*	*7.86%*		*64.38%*	*35.62%*	*64.38%*	*100.00%*

Step 2: **Forecasted Commodity Prices**

Step 2a: **GA Modifier**	($/MWh)	non-RPP
		$ (44.38)

Source: Table 1: RPP Prices and GA Modifier: May 1, 2018 to April 30, 2019*

Step 2b: **Forecasted Commodity Prices**

Table 1: Average RPP Supply Cost Summary**

			non-RPP non GA mod	non-RPP GA mod	RPP
HOEP ($/MWh)	Load Weighted Price for RPP Consumers		$21.57	$21.57	
Global Adjustment ($/MWh)	Impact of the Global Adjustment		$103.80	$59.42	
Adjustments ($/MWh)			$1.00	$1.00	
TOTAL ($/MWh)	Average Supply Cost for RPP Consumers		**$126.37**	**$81.99**	**$81.99**
$/kWh			***$0.12637***	***$0.08199***	***$0.08199***
Percentage shares (%)	non-RPP (GA mod/non-GA mod), RPP		27.76%	7.86%	64.38%
WEIGHTED AVERAGE PRICE ($/kWh)	**(Sum of I43, J43 and L43)**	$ 0.0943	**$0.0351**	**$0.0064**	**$0.0528**

Step 3: **Commodity Expense**

(volumes for the bridge and test year are loss adjusted)

Class A

Customer		Revenue	Expense	2019 kWh Volume	2019 kW Volume	2019 HOEP Rate/kWh	2019 Avg GA/kW	2019 Amount	2020 kWh Volume	2020 kW Volume	2020 HOEP Rate/kWh	2020 Avg GA/kW	2020 Amount
General Service 3000-4999 kW		4035	4705	217,357,402	499,673	0.02160	26.76	$18,066,171	218,048,930	502,671	0.02157	26.76	$18,154,794
Large User		4020	4705	34,401,304	68,383	0.02160	1.59	$851,797	35,278,537	70,127	0.02157	1.59	$872,459
				251,758,706	568,056			$18,917,968					$19,027,253

Class B

Customer		Revenue	Expense	2019 Volume	2019 rate ($/kWh):	2019 Amount	2020 Volume	2020 rate ($/kWh):	2020 Amount
Class Name	UoM	USA #	USA #						
Residential	kWh	4006	4705	682,563,361	$ 0.0943	$64,365,725	694,880,072	$0.0943	$65,527,191
General Service < 50 kW	kWh	4035	4705	238,129,933	$ 0.0943	$22,455,653	238,684,635	$0.0943	$22,507,961
General Service 3000-4999 kW	kWh	4035	4705	594,378,086	$ 0.0943	$56,049,854	573,920,258	$0.0943	$54,120,680
Unmetered Scattered Load	kWh	4035	4705	4,234,881	$ 0.0943	$399,349	4,319,245	$0.0943	$407,305
Large User	kWh	4020	4705		$ 0.0943	$0		$0.0943	$0
Street Lighting	kWh	4025	4705	7,646,176	$ 0.0943	$721,034	7,562,513	$0.0943	$713,145
other	kWh	4025	4705		$ 0.0943	$0		$0.0943	$0
other	kWh	4025	4705		$ 0.0943	$0		$0.0943	$0
TOTAL				**1,526,952,439**		**$143,991,615**	**1,519,366,722**		**$143,276,282**

Total

Customer		Revenue	Expense	2019 Volume	2019 avg rate ($/kWh):	2019 Amount	2020 Volume	2020 avg rate ($/kWh):	2020 Amount
Class Name	UoM	USA #	USA #						
Residential	kWh	4006	4705	682,563,361	0.0943	$64,365,725	694,880,072	0.0943	$65,527,191
General Service < 50 kW	kWh	4035	4705	238,129,933	0.0943	$22,455,653	238,684,635	0.0943	$22,507,961
General Service 3000-4999 kW	kWh	4035	4705	811,735,488	0.0913	$74,116,025	791,969,188	0.0913	$72,275,474
Unmetered Scattered Load	kWh	4035	4705	4,234,881	0.0943	$399,349	4,319,245	0.0943	$407,305
Large User	kWh	4020	4705	34,401,304	0.0248	$851,797	35,278,537	0.0247	$872,459
Street Lighting	kWh	4025	4705	7,646,176	0.0943	$721,034	7,562,513	0.0943	$713,145
other	kWh	4025	4705	0		$0	0		$0
other	kWh	4025	4705	0		$0	0		$0
TOTAL				**1,778,711,144**		**$162,909,583**	**1,772,694,190**		**$162,303,535**

For the 2020 Test Year, the COP breaks down as follows:

Table 2.8-2 – Test Year Cost of Power

Cost of Power	2020 Test
4705 - Power Purchased	162,303,535
4707 - Global Adjustment Charges	0
4708 - Charges Wholesale Market Serv.	6,812,177
4714 - Charges - Network	11,547,910
4716 - Charges - Connection	3,344,043
4751 - Smart Metering Entity Charge	670,293
	184,677,958

Table 2.8-3 provides the breakdown of the various components to the COP. KWHI has used the most recent Uniform Transmission Rates (UTRs), Smart Meter Entity charge and regulatory charges to calculate the COP.

Table 2.8-3 – Cost of Power Calculations

Commodity Class per Load Forecast RPP	2020 Loss Factor	2020		
Residential	1.0349	694,880,072	$0.0943	$65,527,191
GS<50 kW	1.0349	238,684,635	$0.0943	$22,507,961
GS>50 kW	1.0349	791,969,188	$0.0943	$72,275,474
Large User	1.0053	35,278,537	$0.0943	$872,459
Streetlights	1.0349	7,562,513	$0.0943	$713,145
USL	1.0349	4,319,245	$0.0943	$407,305
Embedded Distributor	1.0349	0	$0.0943	$0
TOTAL		**1,772,694,190**		**$162,303,535**

Transmission - Network Class per Load Forecast	Volume Metric	2020		
Residential	kWh	694,880,072	$0.0061	$4,238,768
GS<50 kW	kWh	238,684,635	$0.0053	$1,265,029
GS>50 kW	kW	2,008,643	$2.8298	$5,684,058
Large User	kW	70,127	$2.6596	$186,509
Streetlights	kW	20,391	$1.7207	$35,088
USL	kWh	4,319,245	$0.0053	$22,892
Embedded Distributor	kW	43,316	$2.6680	$115,568
TOTAL				**$11,547,910**

Capacity Based Recovery Class per Load Forecast	Volume Metric	2020		
Residential	kWh	694,880,072	$0.0004	$277,952
GS<50 kW	kWh	238,684,635	$0.0004	$95,474
GS>50 kW	kWh	573,920,258	$0.0004	$229,568
Large User	kWh	0	$0.0004	$0
Streetlights	kWh	7,562,513	$0.0004	$3,025
USL	kWh	4,319,245	$0.0004	$1,728
Embedded Distributor	kWh	0	$0.0004	$0
TOTAL		**1,519,366,722**		**$607,747**

Transmission - Connection Class per Load Forecast	Volume Metric	2020		
Residential	kWh	694,880,072	$0.0017	$1,181,296
GS<50 kW	kWh	238,684,635	$0.0015	$358,027
GS>50 kW	kW	2,008,643	$0.8451	$1,697,504
Large User	kW	70,127	$0.7945	$55,716
Streetlights	kW	20,391	$0.5144	$10,489
USL	kWh	4,319,245	$0.0015	$6,479
Embedded Distributor	kW	43,316	$0.7972	$34,532
TOTAL				**$3,344,043**

Rural Rate Assistance Class per Load Forecast	Volume Metric	2020		
Residential	kWh	694,880,072	$0.0005	$347,440
GS<50 kW	kWh	238,684,635	$0.0005	$119,342
GS>50 kW	kWh	791,969,188	$0.0005	$395,985
Large User	kWh	35,278,537	$0.0005	$17,639
Streetlights	kWh	7,562,513	$0.0005	$3,781
USL	kWh	4,319,245	$0.0005	$2,160
Embedded Distributor	kWh	0	$0.0005	$0
TOTAL		**1,772,694,190**		**$886,347**

Wholesale Market Service Class per Load Forecast	Volume Metric	2020		
Residential	kWh	694,880,072	$0.0030	$2,084,640
GS<50 kW	kWh	238,684,635	$0.0030	$716,054
GS>50 kW	kWh	791,969,188	$0.0030	$2,375,908
Large User	kWh	35,278,537	$0.0030	$105,836
Streetlights	kWh	7,562,513	$0.0030	$22,688
USL	kWh	4,319,245	$0.0030	$12,958
Embedded Distributor	kWh	0	$0.0030	$0
TOTAL		**1,772,694,190**		**$5,318,083**

Smart Meter Entity Charge Class per Load Forecast		2020		
Residential		1,078,320	$0.5700	$614,642
GS<50 kW		97,632	$0.5700	$55,650
TOTAL		**1,175,952**		**$670,293**

2.9 Capital Expenditures

2.9.1 Planning

KWHI has prepared a Distribution System Plan (DSP) in accordance with the OEB's *Chapter 5 Consolidated Distribution System Plan Filing Requirements* dated July 12, 2018 (Chapter 5 Filing Requirements) in support of its 2020 Test Year Cost of Service Application. KWHI retained METSCO Energy Solutions Inc. (METSCO) to advise on and assist with the preparation of this DSP.

KWHI's DSP has been prepared to support the four key objectives from the OEB's *Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach* (RRFE):

1. *Customer Focus:* services are provided in a manner that responds to identified customer preferences;

2. *Operational Effectiveness:* continuous improvement in productivity and cost performance is achieved; and utilities deliver on system reliability and quality objectives;

3. *Public Policy Responsiveness:* utilities deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements imposed further to Ministerial directives to the Board); and

4. *Financial Performance:* financial viability is maintained; and savings from operational effectiveness are sustainable.

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

Information related to the Regional Planning process is found in Section 2.2.2 of the DSP.

Historical data have been presented for KWHI for the years 2014 - 2018.

2.9.2 Distribution System Plan

KWHI's DSP is focused on selecting optimal investments that provide sustainable benefits and a maximized operating environment for its customers over the long term, with a short-term focus on continuation of reliable and safe service. The DSP is KWHI's first and is prepared in accordance with the OEB's Filing Requirements. It is meant to describe how KWHI plans to develop, manage and maintain its distribution system equipment to provide a safe, secure, reliable, efficient and cost-effective service to its customers. Furthermore, it identifies and consolidates major initiatives KWHI plans to undertake over the forecast period of 2020 to 2024.

KWHI provides services in the City of Kitchener and the Township of Wilmot serving approximately 97,000 customers, maintaining distribution and infrastructure assets deployed over 425 square kilometers. The service area provided by KWHI is expected to experience moderate urban growth and development over a long-term period. The downtown core of Kitchener is expected to become denser with a larger residential and commercial density as more businesses and job opportunities continue to develop. To meet the demands of the expected growth, large infrastructure developments need to be made such as a highly reliable Light Rail System (LRT) system to reduce congestion. Though it is beneficial for the City of Kitchener, KWHI needs to be well equipped and prepared to connect new buildings, provide the required infrastructure for the LRT system, and meet the forecasted system peak demand while maintaining its existing infrastructure with the current expected levels of reliable and safe service. KWHI continues to be engaged with the City and Region's development plans and carefully examines the outcomes into its own material investments within the DSP.

A key infrastructure development project KWHI continues to support is the LRT. KWHI had significant electrical infrastructure relocation work over the past years to accommodate the LRT system which was completed in 2017. The total cost of relocations for the LRT project was $27M over four years from 2014 to 2017. KWHI was

successful in negotiating recovery of approximately 60% of these costs from the Region of Waterloo. The remaining phases of the LRT will require KWHI to commence relocation works prior to the LRT contractor starting construction of the railway. There are no confirmed dates as to when the remaining phases will begin. Future LRT work will impact capital expenditures but has not been reflected in this DSP as no project timeline has been proposed.

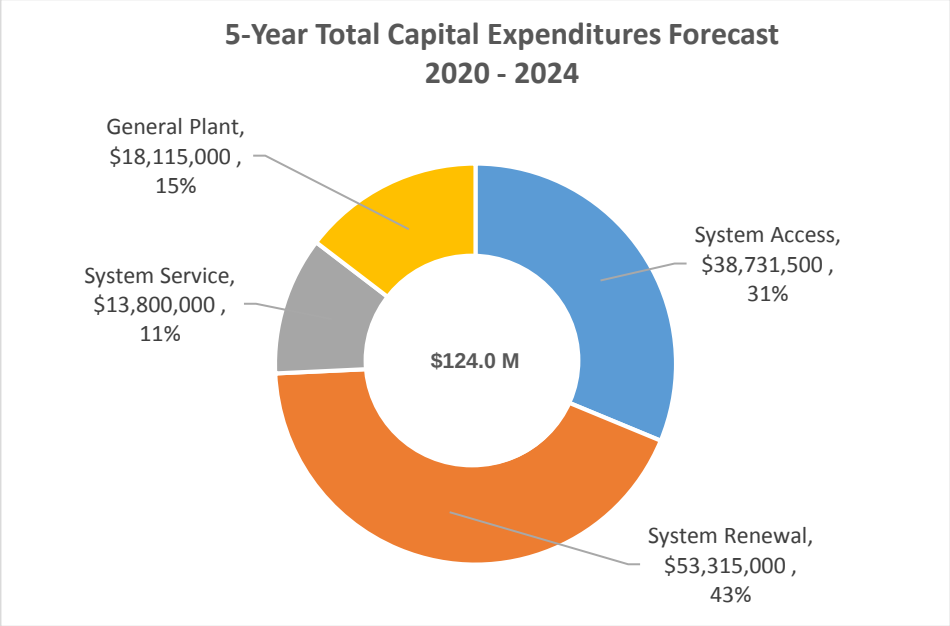
Understanding and responding to the preferences of KWHI's customers has been and continues to be the focus of KWHI's efforts in developing short and long-term plans. KWHI's customer base consists of residential, mid-size and large business customers. Distribution rates continue to be the top priority for low-volume customers and an important priority for larger business customers. Furthermore, ensuring reliable day-to-day electrical service remains an important priority for all customer bases. With respect to reliability, low-volume customers are consistent on priorities such as reducing the number and length of outages and improving restoration times during extreme weather. Mid-market and large business customers appear to prioritize reliability over price, with a focus on power quality and communications during outages to assist with operational planning. Residential and small business customers are generally split on KWHI's approach to planning for the next five years, however, are consistent in supporting KWHI's approach to pacing investments, including keeping spending consistent year-over-year to reduce bill impacts. Overall, there is strong support for KWHI's proposed plan, or even one that exceeds current spending levels in order to improve service levels further. A larger population of residential customers feel that KWHI should be spending more, rather than spending less.

KWHI considers all customer feedback and preferences in determining the pacing of its investments and in optimal selection of projects. Survey results were used to inform the asset management plan and development of the capital investment plan. In addition to the customer feedback, the corporate strategic priorities and asset management objectives form the high-level framework for KWHI's investment programs. Asset

management objectives identify investments that are best aligned from an overall benefit and risk management perspective. An integral part of achieving the asset management objectives are inspection, maintenance and replacement programs, to ensure system performance is sustained during the entire asset service life. To align to asset management best practices and to provide consistency with its Strategic Priorities, KWHI has adopted an Asset Management Strategy. The Asset Management Strategy provides direction for the management of assets while recognizing realistic service and performance goals. The Asset Management Strategy ensures a continual and consistent focus on delivering services in a way that balances risk and long-term costs. In addition to the Asset Management Strategy, KWHI developed an Asset Management Policy that provides the high-level overview of the strategy as part of best practice for asset management.

The combination of KWHI's asset management and capital expenditure planning process leads to a capital expenditure plan consisting of a five-year capital expenditure forecast. The asset management and capital investment process identify System Access, System Renewal, System Service and General Plant requirements. These requirements result in a list of mandatory and added value investments to be executed over the investment period. The final investment portfolio considers the balance between achieving KWHI's Asset Management Objectives and the impact on customer rates. KWHI plans to invest an average of $24.79M in capital expenditures per year across all four investment categories for a gross total of approximately $124M. The figure below shows the 5-year expenditures forecast by investment category.

Table 2.9.2-1 5-Year Expenditures by Investment Category



Expenditures in the System Access category are driven by external requirements such as servicing new customer load and relocating distribution plant to suit road authorities. These expenditures are mandatory. Specific projects such as relocations due to LRT development, which are planned as multi-year projects, are budgeted for based on KWHI's estimates, in conjunction with information from external agencies. KWHI plans to invest an average of $7.75M in capital expenditures per year within the System Access category which accounts for 31% of the gross total over the forecast period.

Expenditures within the System Renewal category are largely driven by the condition of distribution system assets and play a crucial role in the overall reliability, safety and sustainment of the distribution system. The first major program found under the System Renewal framework is the Transformer and Distribution Stations Renewal. The program includes a collection of projects in which power transformers, protection and control devices and switchgear equipment at existing transformer stations are replaced or upgraded due to age, deteriorating condition or functional obsolescence. These equipment types are usually replaced with upgraded or new technologies available at

the time of renewal. KWHI plans to replace two power transformers at its No. 5 TS during the forecast period for an estimated amount of $6.4M. An additional major program under the System Renewal framework is the Replacement of Pole Line Assets. The program consists of a number of overhead rebuild projects that are planned for based on the condition of KWHI's in-service assets. Over the DSP period, 425-450 poles per year are planned for replacement. KWHI had strong customer support for this program and in some cases, customers were willing to pay more to accelerate the program. Another major program planned within the forecast period is Voltage Conversion. The program includes projects that are undertaken for the purpose of voltage conversion from 8.32 kV to 27.6 kV. Voltage Conversion is a subset of rebuild project and is planned when there is a need to increase system capacity for load growth while replacing end of life assets. Voltage Conversion also improves system efficiency (by reducing line losses), improves the voltage profile (regulation), and improves the ability to connect distributed generation. KWHI plans to invest an average of $10.66M in capital expenditures per year within the System Renewal category which accounts for 43% of the gross total over the forecast period.

Expenditures in the System Service category are driven by the need to ensure that the distribution system continues to meet operational objectives (such as reliability, grid flexibility and DER integration) while addressing anticipated future customer electricity service requirements. Expenditures in this category include the addition of feeders to provide service to new developments. New feeders may be constructed to provide service to new customers in areas not previously serviced or may also be constructed in previously serviced areas to increase capacity where load density increases. A major initiative during the forecast period is the construction of a new underground distribution feeder to supply the increasing load demand in downtown Kitchener caused by a number of new high-rise, mixed-use buildings (12-15) under construction or proposed for development in the downtown core. Additionally, in this category, KWHI is constantly looking for ways to cost effectively improve system reliability and efficiency. This can include the installation of automated reclosers and switches, line sensors or conversion

from overhead to underground networks. KWHI plans to invest an average of $2.76M in capital expenditures per year within the System Service category and accounts for 11% of the gross total over the forecast period.

Expenditures in the General Plant category are driven by the need to modify, replace or purchase assets that are not part of the distribution system but support the utility's everyday operations and to permit smart grid functionality. The significant program found under the General Plant framework is the Information Systems and Technology program. Expenditures in this program are driven by the need to acquire, enhance and upgrade computer hardware and software used in information technology (IT) and operation technology (OT) applications. These hardware and software tools are crucial to the day-to-day running of the organization and must be protected and secured to reduce the likelihood of cyber security breaches. The 2020 forecasted expenditures is heavily influence by the costs to replace the 30+ years old legacy Customer Information System (CIS) with a next generation commercial off the shelf product. This is a multi-year project with investments budgeted for in 2019 and 2020. KWHI plans to invest an average of $3.62M in capital expenditures per year within the General Plant category which accounts for 15% of the gross total over the forecast period.

KWHI intends to execute its capital expenditure plan in full within the timeframe presented. Furthermore, the projects comprising the plan have been prioritized within the context of an overall investment strategy.

KWHI's Distribution System Plan (DSP) is attached as Appendix 2-3 to this Exhibit. Table 2.9.2-2 below is Filing Requirement Appendix 2-AB. In the Table, the plan amount for 2014 is the Board approved amount from EB-2013-0147. As this is KWHI's first DSP, the plan amounts for 2015 – 2019 are from KWHI's internal planning documents.

Table 2.9.2-2 – Historical and Forecast Capital Expenditures

CATEGORY	2014			2015			2016			2017			2018			2019	Forecast Period (planned)				
	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	2020	2021	2022	2023	2024
	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000	$ '000				
System Access	10,296	11,687	13.5%	12,255	15,817	29.1%	11,468	16,918	47.5%	8,866	11,815	33.3%	7,465	8,107	8.6%	7,432	7,665	7,767	7,818	7,717	7,767
System Renewal	5,970	4,821	-19.2%	4,791	3,322	-30.7%	4,805	4,616	-3.9%	7,539	5,377	-28.7%	8,159	7,728	-5.3%	8,545	9,415	10,350	10,650	11,400	11,500
System Service	1,520	1,545	1.6%	1,620	839	-48.2%	3,050	2,420	-20.7%	2,630	1,548	-41.1%	2,350	1,476	-37.2%	2,100	3,200	3,200	2,800	2,300	2,300
General Plant	3,150	2,280	-27.6%	1,920	1,859	-3.2%	2,229	2,105	-5.6%	3,760	2,807	-25.3%	5,465	3,030	-44.6%	7,125	4,295	3,275	3,565	3,500	3,480
TOTAL EXPENDITURE	20,936	20,333	-2.9%	20,586	21,837	6.1%	21,552	26,059	20.9%	22,795	21,547	-5.5%	23,439	20,341	-13.2%	25,202	24,575	24,592	24,833	24,917	25,047
Capital Contributions	(3,782)	(6,698)	77.1%		(9,460)	--		(8,951)	--		(6,243)	--		(4,697)	--	(4,000)	(4,000)	(4,000)	(4,000)	(4,000)	(4,000)
Net Capital Expenditures	17,154	13,635	-20.5%		12,377	--		17,108	--		15,304	--		15,644	--	21,202	20,575	20,592	20,833	20,917	21,047
System O&M	11,280	10,116	-10.3%		9,377	--		9,498	--		10,625	--		11,811	--	12,576	13,162	13,162	13,162	13,162	13,162

2.9.3.1 Summary of Capital Projects

Table 2.9.3.1-1 (Filing Requirement Appendix 2-AA), below presents a summary of the gross capital expenditures by project for the historical period 2014 to 2018, the 2019 Bridge Year and 2020 Test Year.

Table 2.9.3.1-1 – Summary of Capital Projects

(all numbers in '000s)

Projects	2014	2015	2016	2017	2018	2019 Bridge	2020 Test
System Access							
LRT Relocations	4,775	7,374	8,596	2,977	-	-	-
Roadway Relocations	1,744	2,822	2,357	2,339	1,720	1,550	1,700
Underground Residential Distribution	3,531	3,406	2,589	3,086	3,480	3,708	3,708
Commercial, Industrial & Apartment Services	412	1,142	734	1,109	1,161	1,084	1,209
Revenue Meters & Generation Connections	656	387	673	824	832	640	597
System Expansion - Customer Growth	8	12	895	592	120	-	-
Miscellaneous U/G Customer Connections	301	370	410	464	493	450	450
Miscellaneous O/H Customer Connections	51	108	578	278	198	-	-
Miscellaneous - Tx installed and Others	209	196	98	145	103	-	-
Sub-Total	11,687	15,817	16,930	11,815	8,107	7,432	7,664
System Renewal							
TS and DS Renewal	1,669	600	1,002	1,011	702	1,625	2,004
Replacement of Pole Line Assets	1,804	907	1,570	2,382	3,017	2,938	3,404
Voltage Conversion	-	-	-	162	1,175	1,400	1,375
Replacement of Primary Cables and Conduits	195	336	486	436	965	800	850
Rebuild Transformer Vaults & Pull Boxes	-	-	-	-	62	240	240
Network Transformer Replacement	96	167	183	296	364	192	192
Distribution Transformer Installation and Replacement	966	1,168	1,225	964	1,210	1,350	1,350
Miscellaneous U/G plant replacements	91	130	134	98	184	-	-
Miscellaneous O/H plant replacements	-	14	17	30	50	-	-
Sub-Total	4,821	3,322	4,616	5,377	7,728	8,545	9,415
System Service							
System Expansion to Supply New Developments - TS	-	(835)	-	-	-	-	-
System Expansion to Supply New Developments - O/H	720	506	579	560	601	600	700
System Expansion to Supply New Developments - U/G	406	613	865	355	487	700	1,700
Innovation and Reliability	211	110	425	503	377	800	800
Voltage Conversion - Reliability/Flexibility	168	389	484	-	-	-	-
Miscellaneous	40	56	67	39	5	-	-
Sub-Total	1,545	839	2,420	1,458	1,470	2,100	3,200
General Plant							
Land & Buildings	725	273	255	1,141	750	750	750
Office Equipment	58	64	37	53	109	70	70
IT/OT Systems	471	697	801	593	1,165	5,190	2,335
Vehicles	862	661	860	871	875	975	1,000
Tools & Equipment	164	164	141	148	131	140	140
Sub-Total	2,280	1,859	2,093	2,807	3,029	7,125	4,295
Miscellaneous							
Total	20,333	21,836	26,058	21,456	20,334	25,202	24,574
Less Renewable Generation Facility Assets and Other Non-Rate-Regulated Utility Assets (input as negative)							
Total	20,333	21,836	26,058	21,456	20,334	25,202	24,574

2014 vs 2015 Capital Expenditure Variance

Table 2.9.3.1-2 – 2014 Actual vs 2015 Actual

CATEGORY	2014 Actual	2015 Actual	2014 vs 2015
System Access	11,687	15,817	4,130
System Renewal	4,821	3,322	(1,499)
System Service	1,545	839	(706)
General Plant	2,280	1,859	(421)
TOTAL EXPENDITURE	20,333	21,837	1,504
Capital Contributions	(6,698)	(9,460)	(2,762)
Net Capital Expenditures	13,635	12,377	(1,258)

System Access - There was a 35% increase in System Access expenditures from 2014 to 2015 actuals. The increase in expenditures in this category is predominantly due to an increase of activities undertaken to enable LRT relocations. The LRT relocations expenditure in 2014 was $ 5,072K compared to $7,524K in 2015 – a $2,452K increase. LRT relocations were driven by the need for KWHI to relocate its overhead and underground distribution plant to suit Regional work associated with building the infrastructure for an LRT system. These expenditures are customer driven and mandatory. Also, in 2015, there were several large commercial projects compared to 2014 that required underground servicing. Relocations due to road works are mandatory projects and timing is generally driven by the road authority. There was an increase in the number of overhead plant relocations required in 2015.

System Renewal - The large decline is directly attributed to the increase in LRT-related work. In order to undertake additional mandatory LRT-related work, KWHI reduced expenditures in other areas (such as pole line replacement due to age and condition) to pace the overall capital expenditure budget, using its Total Spend Approach

System Service - The decrease in expenditures can be attributed to a one-time credit of $835,324 given back to KWHI by HONI for Detweiler TS bypass costs. When KWHI constructed its No. 9TS in Wilmot Township, a bypass cost was charged by HONI for

stranded Detweiler TS assets. After reconciling the project, a refund was given back to KWHI. This resulted in an offset in the total expenditures for System Service since construction of the TS would have been categorized as a System Service investment.

General Plant - The reduction in General Plant capital expenditures in 2015 is a result of reduced expenditures associated with KWHI's Service Centre renovation when compared to 2014. Vehicles also saw a reduction in capital expenditures. This reduction in General Plant expenditures were further offset by an increase in expenditures associated with Information Technology hardware and software.

Capital Contributions – The increase in Capital Contributions is primarily due to the LRT project.

2015 vs 2016 Capital Expenditure Variance

Table 2.9.3.1-3 – 2015 Actual vs 2016 Actual

CATEGORY	2015 Actual	2016 Actual	2015 vs 2016
System Access	15,817	16,918	1,101
System Renewal	3,322	4,616	1,294
System Service	839	2,420	1,581
General Plant	1,859	2,105	246
TOTAL EXPENDITURE	21,837	26,059	4,222
Capital Contributions	(9,460)	(8,951)	509
Net Capital Expenditures	12,377	17,108	4,731

System Access - The increase was driven by increased activities associated with relocations due to LRT and servicing of commercial and industrial customers.

System Renewal - This increase was predominantly due to the increase in activities associated with the replacement of pole line assets due to age/condition and voltage conversion. In 2015, several pole lines rebuild projects were deferred to allow for the execution of time sensitive LRT relocation projects.

System Service - Expenditures associated with System Expansion to Supply New Developments saw an increase from 2015 to 2016. This increase is a result of expansion work done to supply three of the seven traction power substations (TPSS) for LRT, distribution line upgrade along the LRT route and construction of a new distribution feeder to supply load growth in the Sportsworld area of Kitchener. There was increase in expenditures ($110K vs $425K) associated with innovation and reliability activities in 2016. Eight automated reclosers were installed in 2016 vs three in 2015. 2015 expenditures were also lower because of a one-time credit given back to KWHI by HONI for Detweiler TS bypass costs as explained earlier.

General Plant - There are several activities that contribute to the total costs in this category. While the individual activities may vary year over year, the overall variance is within the materiality threshold. One item activity that had a significant variation was purchasing of vehicles. Purchasing of large vehicles may present a timing issue between when the vehicle purchase is made and when the vehicle is delivered, and final payments are made. Therefore, a year over year comparison isn't always the best method to compare expenditures associated with this activity.

Capital Contributions – The decrease in Capital Contributions is primarily due to the LRT project.

2016 vs 2017 Capital Expenditure Variance

Table 2.9.3.1-4 – 2016 Actual vs 2017 Actual

CATEGORY	2016 Actual	2017 Actual	2016 vs 2017
System Access	16,918	11,815	(5,103)
System Renewal	4,616	5,377	761
System Service	2,420	1,548	(872)
General Plant	2,105	2,807	702
TOTAL EXPENDITURE	26,059	21,547	(4,512)
Capital Contributions	(8,951)	(6,243)	2,708
Net Capital Expenditures	17,108	15,304	(1,804)

System Access - The reduction in expenditures in this category was a result of significantly less LRT-related work that was undertaken in 2017.

System Renewal - The main driver for the additional spend was increased activities in pole line replacement due to age and condition. During the period when LRT relocations expenditures were high, a decision was made to defer some system renewal projects to maintain the overall capital expenditures to a reasonable level. In 2017, LRT relocations were projected to wind down, hence, a gradual return to investment in system renewal was undertaken.

System Service - The reduction can be attributed to the decrease in activities to supply new developments and LRT traction power substations relative to 2016. Prior to 2017, voltage conversion activities were deemed as System Service because their trigger was to increase reliability, power quality, and system flexibility. Beginning in 2017, these activities were classified as System Renewal since the main driver was condition of the distribution pole lines and the need to replace them. This resulted in a decrease of $484K in System Access costs when compared to 2016.

General Plant - The main driver for this increase was a building upgrade. In 2017, KWHI undertook a project to replace the external cladding and upgrade the insulation of the main office building located at 301 Victoria Street. This project became necessary because of the age and condition of the exterior cladding.

Capital Contributions – The decrease in Capital Contributions is primarily due to the LRT project.

2017 vs 2018 Capital Expenditure Variance

Table 2.9.3.1-5 - 2017 Actual vs 2018 Actual

CATEGORY	2017 Actual	2018 Actual	2017 vs 2018
System Access	11,815	8,107	(3,708)
System Renewal	5,377	7,728	2,351
System Service	1,548	1,476	(72)
General Plant	2,807	3,030	223
TOTAL EXPENDITURE	21,547	20,341	(1,206)
Capital Contributions	(6,243)	(4,697)	1,546
Net Capital Expenditures	15,304	15,644	340

System Access - The reduction in expenditures in this category was a result of no LRT-related work being undertaken in 2018. Also, there was a 26% (-$620K) decline in capital expenditures associated with road relocation projects in 2018 compared to 2017.

System Renewal - The main driver for the additional spend was increased activities in pole line replacement due to age and condition as well as voltage conversion related projects. In 2018, KWHI continued to ramp up its pole replacement program to accommodate pole replacements that were deferred in earlier years due to increased activities in LRT-related work and roadway relocations work. The level of activities undertaken in this program in 2018 is close to the optimal value of investments that KWHI believes is required to sustain pole line assets.

General Plant - The main driver for this increase in 2018 over 2017 is a combination of changes in land and building investments, and IT/OT investments. Investments in land and buildings decline from $1,141K to $750K while investments in IT/OT systems increased from $593K to $1,165K. The net change between these two programs is $181K. In 2018, the main investments in land and buildings was the renovation of KWHI's control room and IT department and a temporary space in the basement to house both teams during the main space renovation. This project cost was significantly less than the previous year project which included replacement of the external cladding

and upgrading of the building insulation at the main office. With regards to IT/OT investments, the main physical server infrastructure used in virtualization was replaced with a hyper-converged infrastructure. This was a result of the server infrastructure being at end of life.

Capital Contributions – The decrease in Capital Contributions is primarily due to the LRT project.

2018 vs 2019 Bridge Capital Expenditure Variance

Table 2.9.3.1-6 – 2018 Actual vs 2019 Bridge

CATEGORY	2018 Actual	2019 Bridge	2018 vs 2019
System Access	8,107	7,432	(675)
System Renewal	7,728	8,545	817
System Service	1,476	2,100	624
General Plant	3,030	7,125	4,095
TOTAL EXPENDITURE	20,341	25,202	4,861
Capital Contributions	(4,697)	(4,000)	697
Net Capital Expenditures	15,644	21,202	5,558

System Access - The proposed reduction in expenditures in this category is attributed to a reduction in Revenue Meter and Generation Connection costs ($192K). Previous years had substantial costs associated with installing transfer trip and communication facilities to enable large behind the meter generation projects. Also, for budgeting purpose, miscellaneous overhead customer connections and miscellaneous transformers installed are allocated to System Renewal. However, when the actual expenditures occur, they are allocated to the investment category that triggers the investment. 2018 actual for these two programs was $301K with $0 allocated for 2019

System Renewal - The main drivers for this increase are; increase in transformer stations (TS) renewal investment ($923K) and increase in rebuilding network transformer vault roofs ($178K). There is a plan increase in TS renewal investment to

replace the switchgear equipment at the No. 5TS with arc resistance equipment and remote racking capabilities so that the dangers of arc flash can be mitigated. Also, in 2019, KWHI will be rebuilding two below grade network transformer vault roofs compared to one that was rebuilt in 2018.

System Service - The proposed increase can be attributed to the increase in expenditures for the Innovation and Reliability ($423K) program in which two underground switchgear are targeted for upgrade with remote switching and monitoring capabilities to alleviate the issue with crews manually operating the switch in a below grade enclosure. The upgrade will also allow the control room to remotely operate the devices before dispatching a crew and be able to monitor the performance of the switchgear. Also, in 2018 only five of the seven line reclosers budgeted for implementation were installed. 2019 budget includes cost for seven reclosers.

System expansion to supply new developments is proposed to have increase in expenditures ($213K) due to the higher than normal number of new developments that are being built along the LRT route and in other areas of the city of Kitchener.

General Plant - The proposed increase is directly attributed to the replacement of the legacy customer information system which will begin in 2019. The effect of this project on the IT expenditures in 2019 over 2018 is a $4M increase.

Capital Contributions – The decrease in Capital Contributions is primarily due to the LRT project.

2019 Bridge vs 2020 Test Capital Expenditure Variance

Table 2.9.3.1-7 – 2019 Bridge vs 2020 Test

CATEGORY	2019 Bridge	2020 Test	2019 vs 2020
System Access	7,432	7,665	233
System Renewal	8,545	9,415	870
System Service	2,100	3,200	1,100
General Plant	7,125	4,295	(2,830)
TOTAL EXPENDITURE	25,202	24,575	(627)
Capital Contributions	(4,000)	(4,000)	-
Net Capital Expenditures	21,202	20,575	(627)

System Access - There is a 3% proposed increase in System Access expenditures from 2019 to 2020 budget. This increase is not considered to be material. The increase is related to anticipated increases in expenditures for relocations due to roadway relocations ($150K), and servicing costs for commercial, industrial and apartment buildings ($124K).

System Renewal - There is a 10% proposed increase in System Renewal expenditures from 2019 to 2020 budget. The increase is directly attributed to the proposed increase in expenditures for replacement of pole line assets ($466K) to achieve the target of replacing 425-450 poles per year as identified in the ACA (Asset Condition Assessment) and increase in transformer station renewal ($380K). In 2020, KWHI is proposing to continue with the replacement of the P&C and SCADA system at its No. 6 TS which includes replacement of all the end of life electro-mechanical relays with digital relays.

System Service - There is a 52% proposed increase in System Service expenditures from 2019 to 2020 budget. The increase is directly attributed to the proposed construction of a new underground distribution feeder to supply load growth in downtown Kitchener. The project is a multi-year project with $1M budgeted for in 2020 and an overall estimate of $2.5M over three years (2020-2022).

General Plant - There is a 40% proposed decrease in General Plant expenditures from 2019 to 2020 budget. The proposed decrease (-$2.83M) is a result of the CIS replacement project wrapping up in 2020. The project will commence in 2019 with most of the expenditures allocated to that year due to the large upfront capital outlay required to pay for licenses and IT infrastructure.

2.10 Costs of Eligible Investments for Distributors

KWHI previously filed for rate protection amounts in its previous Cost of Service Application (EB-2013-0147). The expenses claimed were for the period 2009-2012. A basic GEA plan was filed in the 2014 application that included OM&A expenses and two capital projects that were to be undertaken in the period 2014-2018. At this time, KWHI has not made the capital investments and has incurred OM&A expenses. KWHI has completed Chapter 2 required filing Appendix 2-FA, and 2-FB in support of the additional claim for rate protection for these retrospective amounts. These appendices are attached in Appendix 2-1 and filed in live Excel format (EB-2019-0049_KWHI_Appl_2019_Filing_Req_Chap2_Appendices_20190430).

As at December 31, 2018, the total OM&A that has not yet been claimed for rate protection is $102,387 including interest. Of this amount, $6,175 is a direct benefit that will be collected from KWHI's rate payers (see Exhibit 9) and the remainder is requested from the IESO as a provincial benefit.

As KWHI's current rate protection amount is based on previous expenditures and not forecasted expenditures, no new capital input is required.

2.11 New Policy Options for the Funding of Capital

KWHI believes in pacing and prioritizing its investments to minimize rate impacts to its ratepayers. KWHI has never used either the ICM or ACM for incremental capital investments.

KWHI has not applied for an ICM in the past; therefore, there are no additions to Rate Base of ICM assets.

2.12 Service Quality and Reliability Performance

KWHI records the following Service Reliability Indices:

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

SAIFI = Total Customer Interruptions/Total Customers Served

CAIDI = Total Customer-Hours of Interruptions/Total Customer Interruptions

MAIFI = Momentary Interruptions/Total Customer Served

The first two indices are reported to the OEB through the RRR reporting requirements (RRR section 2.1.4.2.1 and 2.1.4.2.2). These indices provide KWHI with annual measures of its service performance that are used for internal benchmarking purposes when making comparisons with other distribution companies (e.g. to better understand the rankings that will support the OEB's Incentive Rate Making Mechanism and Performance Based Regulation).

Internally, KWHI also tracks and reports CAIDI and MAIFI. Specifically, MAIFI is important to KWHI's customers and KWHI is trying to understand momentary outages, the root causes, and how they affect the customer.

KWHI follows the Board's Reporting and Record Keeping Requirements Guideline to report its service quality indicators annually.

In accordance with the Filing Requirements, Table 2.12-1 is provided below and is consistent with Chapter 2 Filing Requirements Appendix 2-G, Service Quality Indicators. Chapter 2 Filing Requirements Appendix 2-G is attached in Appendix 2-1. The Table

provides the performance measurements for the last five historical years – 2014 through 2018.

Table 2.12-1 – SAIDI and SAIFI Results

	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Forecast
SAIDI	0.72	0.86	2.70	0.92	1.70
SAIFI	1.03	0.90	1.81	1.02	1.48

	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Forecast
SAIDI	0.72	0.57	2.69	0.92	1.69
SAIFI	1.03	0.77	1.72	1.03	1.41

(excluding Loss of Power)

	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Forecast
SAIDI	0.72	0.57	1.11	0.92	0.70
SAIFI	1.03	0.77	1.11	1.03	0.97

(excluding Loss of Power and Major Events)

KWHI compares reliability statistics compare favourably to the industry as can be seen in the charts below:

Chart 2.12-1 – KWHI SAIDI Compared to Other LDCs

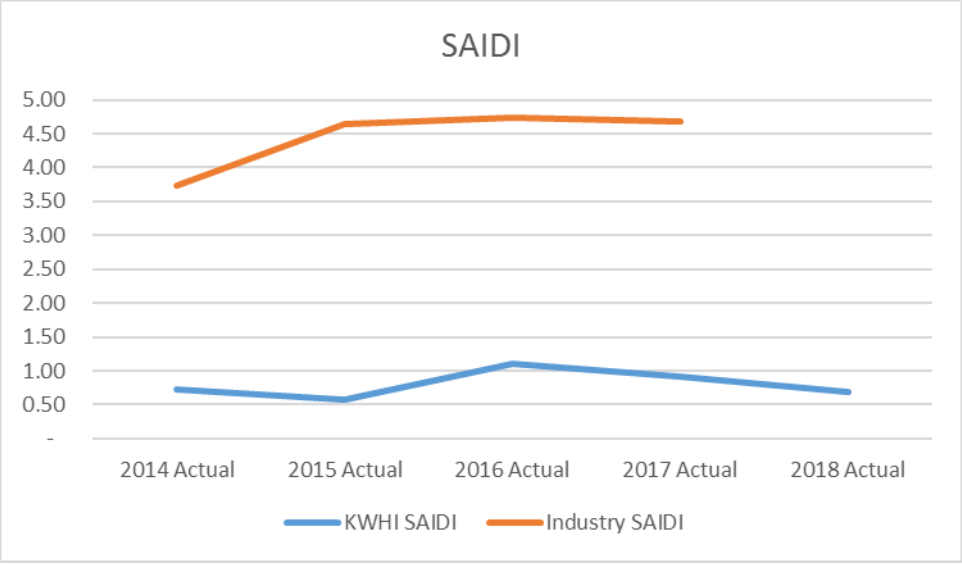
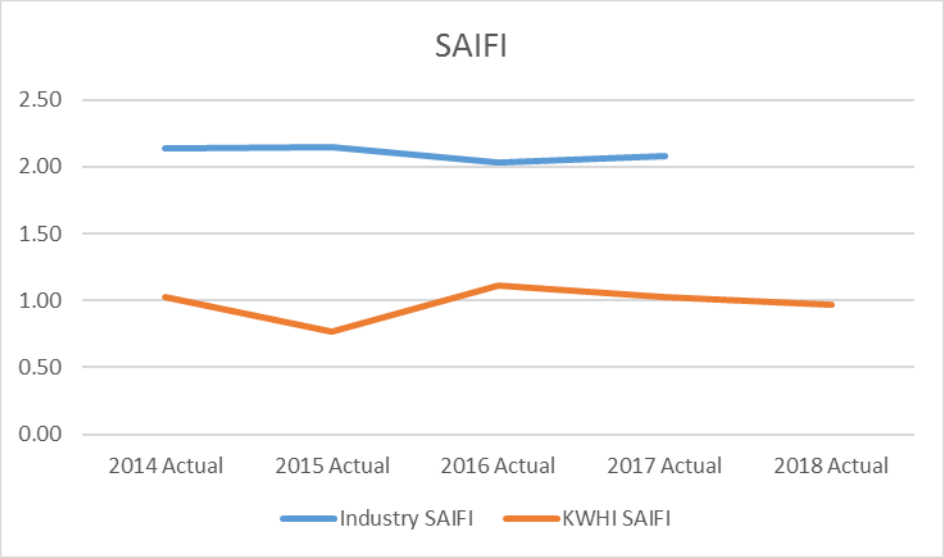


Chart 2.12-2 – KWHI SAIFI compared to Other LDCs



Refer to Section 2.3.1.2 of the Distribution System Plan for a detailed discussion with respect to System Reliability.

Table 2.12-2 provides a summary of Major Events that have occurred over the past five years.

Table 2.12-2 – Major Events

Reporting Year	Cause Code	Number of Interruptions	Number of Customer Interruptions	Number of Hours of Customer Interruptions
2016	Adverse Weather	74	57,372	147,908
2018	Adverse Weather	75	15,430	20,377
2018	Adverse Weather	34	53,610	14,804
2018	Foreign Interference	5	7,392	27,371

KWHI's performance results over the 2014 to 2018 period meet or exceed the Board's approved standards. KWHI's performance is within the range of acceptable performance over the previous five years and no corrective action is required.

Table 2.12-3 – Service Quality Indicators

Indicator	OEB Minimum Standard	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Forecast
Low Voltage Connections	90.0%	90.9%	90.3%	92.5%	98.9%	99.1%
High Voltage Connections	90.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Telephone Accessibility	65.0%	80.4%	78.1%	78.4%	92.8%	91.8%
Appointments Met	90.0%	95.3%	96.2%	97.5%	97.9%	99.2%
Written Response to Enquires	80.0%	99.8%	100.0%	99.9%	100.0%	100.0%
Emergency Urban Response	80.0%	85.4%	83.9%	80.8%	94.7%	88.0%
Emergency Rural Response	80.0%	100.0%	100.0%	94.7%	100.0%	100.0%
Telephone Call Abandon Rate	10.0%	1.7%	2.3%	4.2%	0.7%	1.4%
Appointment Scheduling	90.0%	88.4%	94.1%	96.4%	95.9%	91.1%
Rescheduling a Missed Appointment	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Reconnection Performance Standard	85.0%	100.0%	100.0%	100.0%	100.0%	100.0%

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Appendix 2-1: Required OEB Filing Appendices

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Appendix 2-AA
Capital Projects Table

Projects	2014	2015	2016	2017	2018	2019 Bridge Year	2020 Test Year
Reporting Basis	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**
System Access							
LRT Relocations	4,775	7,374	8,596	2,977	0	0	0
Roadway Relocations	1,744	2,822	2,357	2,339	1,720	1,550	1,700
Underground Residential Distribution	3,531	3,406	2,589	3,086	3,480	3,708	3,708
Commercial, Industrial & Apartment Services	412	1,142	734	1,109	1,161	1,084	1,209
Revenue Meters & Generation Connections	656	387	673	824	832	640	597
System Expansion - Customer Growth	8	12	895	592	120	0	0
Miscellaneous U/G Customer Connections	301	370	410	464	493	450	450
Miscellaneous O/H Customer Connections	51	108	578	278	198	0	0
Miscellaneous - Tx installed and Others	209	196	98	145	103	0	0
Sub-Total	11,687	15,817	16,930	11,815	8,107	7,432	7,664
System Renewal							
TS and DS Renewal	1,669	600	1,002	1,011	702	1,625	2,004
Replacement of Pole Line Assets	1,804	907	1,570	2,382	3,017	2,938	3,404
Voltage Conversion	0	0	0	162	1,175	1,400	1,375
Replacement of Primary Cables and Conduits	195	336	486	436	965	800	850
Rebuild Transformer Vaults & Pull Boxes	0	0	0	0	62	240	240
Network Transformer Replacement	96	167	183	296	364	192	192
Distribution Transformer Installation and Replacement	966	1,168	1,225	964	1,210	1,350	1,350
Miscellaneous U/G plant replacements	91	130	134	98	184	0	0
Miscellaneous O/H plant replacements	0	14	17	30	50	0	0
Sub-Total	4,821	3,322	4,616	5,377	7,728	8,545	9,415
System Service							
System Expansion to Supply New Developments - TS	0	-835	0	0	0	0	0
System Expansion to Supply New Developments - O/H	720	506	579	560	601	600	700
System Expansion to Supply New Developments - U/G	406	613	865	355	487	700	1,700
Innovation and Reliability	211	110	425	503	377	800	800
Voltage Conversion - Reliability/Flexibility	168	389	484	0	0	0	0
Miscellaneous	40	56	67	39	5	0	0
Sub-Total	1,545	839	2,420	1,458	1,470	2,100	3,200
General Plant							
Land & Buildings	725	273	255	1,141	750	750	750
Office Equipment	58	64	37	53	109	70	70
IT/OT Systems	471	697	801	593	1,165	5,190	2,335
Vehicles	862	661	860	871	875	975	1,000
Tools & Equipment	164	164	141	148	131	140	140
Sub-Total	2,280	1,859	2,093	2,807	3,029	7,125	4,295
Miscellaneous							
Total	**20,333**	**21,836**	**26,058**	**21,456**	**20,334**	**25,202**	**24,574**
Less Renewable Generation Facility Assets and Other Non-Rate-Regulated Utility Assets *(input as negative)*							
Total	**20,333**	**21,836**	**26,058**	**21,456**	**20,334**	**25,202**	**24,574**

Notes:

1 Please provide a breakdown of the major components of each capital project undertaken in each year. Please ensure that all projects below the materiality threshold are included in the miscellaneous line. Add more projects as required.

2 The applicant should group projects appropriately and avoid presentations that result in classification of significant components of the capital budget in the miscellaneous category.

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TO BE UPDATED AT THE DRAFT RATE ORDER STAGE

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

First year of Forecast Period:

2020

CATEGORY	Historical Period (previous plan[1] & actual)																		Forecast Period (planned)				
	2014			2015			2016			2017			2018			2019			2020	2021	2022	2023	2024
	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual[2]	Var					
	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000				
System Access	10,296	11,687	13.5%	12,255	15,817	29.1%	11,468	16,918	47.5%	8,866	11,815	33.3%	7,465	8,107	8.6%	7,432		-100.0%	7,665	7,767	7,818	7,717	7,767
System Renewal	5,970	4,821	-19.2%	4,791	3,322	-30.7%	4,805	4,616	-3.9%	7,539	5,377	-28.7%	8,159	7,728	-5.3%	8,545		-100.0%	9,415	10,350	10,650	11,400	11,500
System Service	1,520	1,545	1.6%	1,620	839	-48.2%	3,050	2,420	-20.7%	2,630	1,548	-41.1%	2,350	1,476	-37.2%	2,100		-100.0%	3,200	3,200	2,800	2,300	2,300
General Plant	3,150	2,280	-27.6%	1,920	1,859	-3.2%	2,229	2,105	-5.6%	3,760	2,807	-25.3%	5,465	3,030	-44.6%	7,125		-100.0%	4,295	3,275	3,565	3,500	3,480
TOTAL EXPENDITURE	20,936	20,333	-2.9%	20,586	21,837	6.1%	21,552	26,059	20.9%	22,795	21,547	-5.5%	23,439	20,341	-13.2%	25,202	-	-100.0%	24,575	24,592	24,833	24,917	25,047
Capital Contributions	- 3,782	- 6,698	77.1%		- 9,460	--		- 8,951	--		- 6,243	--		- 4,697	--	- 4,000		-100.0%	- 4,000	- 4,000	- 4,000	- 4,000	- 4,000
Net Capital Expenditures	17,154	13,635	-20.5%		12,377	--		17,108	--		15,304	--		15,644	--		-	--	20,575	20,592	20,833	20,917	21,047
System O&M	$ 11,280	$ 10,116	-10.3%		$ 9,377	--		$ 9,498	--		$ 10,625	--		$ 11,811	--	$ 12,576		-100.0%	$ 13,162	$ 13,162	$ 13,162	$ 13,162	$ 13,162

Notes to the Table:

1. Historical "previous plan" data is not required unless a plan has previously been filed. However, use the last Board-approved, at least on a Total (Capital) Expenditure basis for the last cost of service rebasing year, and the applicant should include their planned budget in each subsequent historical year up to and including the Bridge Year.
2. Indicate the number of months of 'actual' data included in the last year of the Historical Period (normally a 'bridge' year):

Explanatory Notes on Variances (complete only if applicable)
Notes on shifts in forecast vs. historical budgets by category
Notes on year over year Plan vs. Actual variances for Total Expenditures
Notes on Plan vs. Actual variance trends for individual expenditure categories

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Appendix 2-BA

Fixed Asset Continuity Schedule [1]

Accounting Standard CGAAP
Year 2014

CCA Class [2]	OEB Account [3]	Description [3]	Cost: Opening Balance	Cost: Additions [4]	Cost: Disposals [6]	Cost: Closing Balance	Accumulated Depreciation: Opening Balance	Accumulated Depreciation: Additions	Accumulated Depreciation: Disposals [6]	Accumulated Depreciation: Closing Balance	Net Book Value
	1609	Capital Contributions Paid				$ -				$ -	$ -
12	1611	Computer Software (Formally known as Account 1925)	$ 3,795,945	$ 384,294		$ 4,180,239	-$ 3,044,321	-$ 443,395		-$ 3,487,716	$ 692,523
CEC	1612	Land Rights (Formally known as Account 1906)	$ 265,448	$ -		$ 265,448	-$ 257,874	-$ 2,653		-$ 260,527	$ 4,921
N/A	1805	Land	$ 2,339,958	$ -		$ 2,339,958	$ -	$ -		$ -	$ 2,339,958
47	1808	Buildings	$ 9,823,770	$ -	-$ 3,372	$ 9,820,398	-$ 2,419,009	-$ 210,808	$ 3,372	-$ 2,626,445	$ 7,193,953
13	1810	Leasehold Improvements		$ -	$ -	$ -	$ -	$ -		$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ 62,560,429	$ 1,092,997	-$ 170,704	$ 63,482,722	-$ 20,336,071	-$ 1,579,813	$ 170,704	-$ 21,745,180	$ 41,737,542
47	1820	Distribution Station Equipment <50 kV	$ 2,930,968	$ 9,577	-$ 7,627	$ 2,932,918	-$ 2,005,202	-$ 49,381	$ 7,627	-$ 2,046,956	$ 885,962
47	1825	Storage Battery Equipment		$ -	$ -	$ -	$ -	$ -		$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 34,476,322	$ 2,044,655	$ -	$ 36,520,977	-$ 13,872,816	-$ 681,835		-$ 14,554,651	$ 21,966,326
47	1835	Overhead Conductors & Devices	$ 36,019,501	$ 1,328,124	$ -	$ 37,347,625	-$ 16,356,833	-$ 451,141		-$ 16,807,974	$ 20,539,651
47	1840	Underground Conduit	$ 26,645,676	$ 3,084,780	$ -	$ 29,730,456	-$ 10,104,108	-$ 344,750		-$ 10,448,858	$ 19,281,598
47	1845	Underground Conductors & Devices	$ 41,755,423	$ 3,095,730	$ -	$ 44,851,153	-$ 20,831,641	-$ 762,311		-$ 21,593,952	$ 23,257,201
47	1850	Line Transformers	$ 55,053,765	$ 2,329,756	-$ 7,523	$ 57,375,998	-$ 26,688,890	-$ 754,220	$ 7,523	-$ 27,435,587	$ 29,940,411
47	1855	Services (Overhead & Underground)	$ 46,548,487	$ 2,014,667	$ -	$ 48,563,154	-$ 18,729,644	-$ 896,802		-$ 19,626,446	$ 28,936,708
47	1860	Meters	$ 2,349,703	$ 706,384	$ -	$ 3,056,087	-$ 568,636	-$ 142,904		-$ 711,540	$ 2,344,547
47	1860	Meters (Smart Meters)	$ 12,361,936	$ 132,171	$ -	$ 12,494,107	-$ 3,211,808	-$ 828,535		-$ 4,040,343	$ 8,453,764
N/A	1905	Land	$ 1,395,300	$ -	$ -	$ 1,395,300	$ -	$ -		$ -	$ 1,395,300
47	1908	Buildings & Fixtures	$ 16,544,993	$ 807,288	$ -	$ 17,352,281	-$ 4,433,364	-$ 613,604		-$ 5,046,968	$ 12,305,313
13	1910	Leasehold Improvements		$ -	$ -	$ -	$ -	$ -		$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 1,263,381	$ 57,713	$ -	$ 1,321,094	-$ 902,816	-$ 70,928		-$ 973,744	$ 347,350
8	1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -
10	1920	Computer Equipment - Hardware	$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 2,534,427	$ 175,363	-$ 487,154	$ 2,222,636	-$ 1,891,762	-$ 229,493	$ 487,154	-$ 1,634,101	$ 588,535
10	1930	Transportation Equipment	$ 8,954,354	$ 767,172	-$ 192,537	$ 9,528,989	-$ 5,318,477	-$ 609,430	$ 192,538	-$ 5,735,369	$ 3,793,620
8	1935	Stores Equipment	$ 64,072	$ -	$ -	$ 64,072	-$ 50,129	-$ 4,724		-$ 54,853	$ 9,219
8	1940	Tools, Shop & Garage Equipment	$ 892,235	$ 76,230	$ -	$ 968,465	-$ 552,854	-$ 66,746		-$ 619,600	$ 348,865
8	1945	Measurement & Testing Equipment	$ 965,036	$ 56,975	$ -	$ 1,022,011	-$ 763,758	-$ 34,426		-$ 798,184	$ 223,827
8	1950	Power Operated Equipment	$ 818,647	$ 94,765	-$ 62,888	$ 850,524	-$ 570,046	-$ 55,442	$ 60,327	-$ 565,161	$ 285,363
8	1955	Communications Equipment	$ 849,352	$ 31,176	$ -	$ 880,528	-$ 454,066	-$ 80,088		-$ 534,154	$ 346,374
8	1955	Communication Equipment (Smart Meters)	$ -		$ -	$ -	$ -	$ -		$ -	$ -
8	1960	Miscellaneous Equipment	$ 109,010		$ -	$ 109,010	-$ 88,848	-$ 13,393		-$ 102,241	$ 6,769
47	1970	Load Management Controls Customer Premises	$ -		$ -	$ -	$ -	$ -		$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -		$ -	$ -	$ -	$ -		$ -	$ -
47	1980	System Supervisor Equipment	$ 1,566,480		$ -	$ 1,566,480	-$ 1,551,390	-$ 4,059		-$ 1,555,449	$ 11,031
47	1985	Miscellaneous Fixed Assets	$ -			$ -	$ -	$ -		$ -	$ -
47	1990	Other Tangible Property	$ -			$ -	$ -	$ -		$ -	$ -
47	1995	Contributions & Grants	-$ 54,079,649	-$ 6,698,313		-$ 60,777,962	$ 13,484,099	$ 1,258,945		$ 14,743,044	-$ 46,034,918
47	2440	Deferred Revenue [5]					$ -				
						$ -				$ -	$ -
		Sub-Total	**$ 318,804,969**	**$ 11,591,504**	**-$ 931,805**	**$ 329,464,668**	**-$ 141,520,264**	**-$ 7,671,936**	**$ 929,245**	**-$ 148,262,955**	**$ 181,201,713**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ 318,804,969**	**$ 11,591,504**	**-$ 931,805**	**$ 329,464,668**	**-$ 141,520,264**	**-$ 7,671,936**	**$ 929,245**	**-$ 148,262,955**	**$ 181,201,713**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable [6]									
		Total						**-$ 7,671,936**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*
Transportation
Stores Equipment
Net Depreciation -$ 7,671,936

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Appendix 2-BA

Fixed Asset Continuity Schedule [1]

Accounting Standard MIFRS
Year 2015

			Cost				Accumulated Depreciation				
CCA Class [2]	**OEB Account [3]**	**Description [3]**	**Opening Balance**	**Additions [4]**	**Disposals [6]**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals [6]**	**Closing Balance**	**Net Book Value**
	1609	Capital Contributions Paid	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	1611	Computer Software (Formally known as Account 1925)	$ 4,180,239	$ 443,103	$ -	$ 4,623,342	-$ 3,487,716	-$ 273,938	$ -	-$ 3,761,654	$ 861,688
CEC	1612	Land Rights (Formally known as Account 1906)	$ 265,448	$ -	$ -	$ 265,448	-$ 260,527	-$ 2,653	$ -	-$ 263,180	$ 2,268
N/A	1805	Land	$ 2,339,958	$ -	$ -	$ 2,339,958	$ -	$ -	$ -	$ -	$ 2,339,958
47	1808	Buildings	$ 9,820,398	-$ 124,006	-$ 9,158	$ 9,687,234	-$ 2,626,445	-$ 211,049	$ 9,158	-$ 2,828,336	$ 6,858,898
13	1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ 63,482,722	-$ 307,610	-$ 38,826	$ 63,136,285	-$ 21,745,180	-$ 1,583,700	$ 38,826	-$ 23,290,054	$ 39,846,231
47	1820	Distribution Station Equipment <50 kV	$ 2,932,918	$ -	-$ 23,033	$ 2,909,885	-$ 2,046,956	-$ 48,787	$ 23,034	-$ 2,072,709	$ 837,176
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 36,520,977	$ 3,374,648	$ -	$ 39,895,625	-$ 14,554,651	-$ 731,757	$ -	-$ 15,286,408	$ 24,609,217
47	1835	Overhead Conductors & Devices	$ 37,347,625	$ 2,995,429	$ -	$ 40,343,054	-$ 16,807,974	-$ 490,131	$ -	-$ 17,298,105	$ 23,044,949
47	1840	Underground Conduit	$ 29,730,456	$ 4,356,442	$ -	$ 34,086,898	-$ 10,448,858	-$ 406,761	$ -	-$ 10,855,619	$ 23,231,279
47	1845	Underground Conductors & Devices	$ 44,851,153	$ 2,991,711	$ -	$ 47,842,864	-$ 21,593,952	-$ 838,202	$ -	-$ 22,432,154	$ 25,410,710
47	1850	Line Transformers	$ 57,375,998	$ 3,236,193	-$ 25,310	$ 60,586,881	-$ 27,435,587	-$ 825,114	$ 20,206	-$ 28,240,495	$ 32,346,386
47	1855	Services (Overhead & Underground)	$ 48,563,154	$ 3,335,156	$ -	$ 51,898,310	-$ 19,626,446	-$ 960,945	$ -	-$ 20,587,391	$ 31,310,919
47	1860	Meters	$ 3,056,087	$ 87,171	$ -	$ 3,143,258	-$ 711,540	-$ 97,668	$ -	-$ 809,208	$ 2,334,050
47	1860	Meters (Smart Meters)	$ 12,494,107	$ 156,433	$ -	$ 12,650,540	-$ 4,040,343	-$ 838,155	$ -	-$ 4,878,498	$ 7,772,042
N/A	1905	Land	$ 1,395,300	$ -	$ -	$ 1,395,300	$ -	$ -	$ -	$ -	$ 1,395,300
47	1908	Buildings & Fixtures	$ 17,352,281	$ 88,367	-$ 130,328	$ 17,310,320	-$ 5,046,968	-$ 608,466	$ 130,328	-$ 5,525,106	$ 11,785,214
13	1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 1,321,094	$ 64,368	-$ 398,346	$ 987,116	-$ 973,744	-$ 67,374	$ 398,346	-$ 642,772	$ 344,344
8	1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	1920	Computer Equipment - Hardware	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 2,222,636	$ 174,117	-$ 105,934	$ 2,290,819	-$ 1,634,101	-$ 224,629	$ 105,385	-$ 1,753,345	$ 537,474
10	1930	Transportation Equipment	$ 9,528,989	$ 482,300	-$ 208,990	$ 9,802,299	-$ 5,735,369	-$ 661,497	$ 208,990	-$ 6,187,876	$ 3,614,423
8	1935	Stores Equipment	$ 64,072	$ -	$ -	$ 64,072	-$ 54,853	-$ 5,711	$ -	-$ 60,564	$ 3,508
8	1940	Tools, Shop & Garage Equipment	$ 968,465	$ 67,712	-$ 285,883	$ 750,293	-$ 619,600	-$ 69,763	$ 285,883	-$ 403,480	$ 346,813
8	1945	Measurement & Testing Equipment	$ 1,022,011	$ 18,213	$ -	$ 1,040,224	-$ 798,184	-$ 37,576	$ -	-$ 835,760	$ 204,464
8	1950	Power Operated Equipment	$ 850,524	$ 179,117	-$ 136,649	$ 892,992	-$ 565,161	-$ 62,365	$ 119,019	-$ 508,507	$ 384,485
8	1955	Communications Equipment	$ 880,528	$ 55,700	$ -	$ 936,228	-$ 534,154	-$ 84,461	$ -	-$ 618,615	$ 317,613
8	1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1960	Miscellaneous Equipment	$ 109,010	$ -	$ -	$ 109,010	-$ 102,241	-$ 2,031	$ -	-$ 104,272	$ 4,738
47	1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1980	System Supervisor Equipment	$ 1,566,480	$ -	-$ 1,539,501	$ 26,979	-$ 1,555,449	-$ 4,059	$ 1,539,501	-$ 20,007	$ 6,972
47	1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1995	Contributions & Grants	-$ 54,079,649	$ -	$ 13,643	-$ 54,066,006	$ 14,637,386	$ 1,182,463	-$ 13,643	$ 15,806,206	-$ 38,259,800
47	2440	Deferred Revenue [5]	-$ 6,698,313	-$ 9,459,986	$ -		$ 105,658	$ 250,078	$ -		
						$ -				$ -	$ -
		Sub-Total	**$ 329,464,668**	**$ 12,214,577**	**-$ 2,888,316**	**$ 354,949,228**	**-$ 148,262,955**	**-$ 7,704,251**	**$ 2,865,033**	**-$ 153,457,909**	**$ 201,491,320**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ 329,464,668**	**$ 12,214,577**	**-$ 2,888,316**	**$ 354,949,228**	**-$ 148,262,955**	**-$ 7,704,251**	**$ 2,865,033**	**-$ 153,457,909**	**$ 201,491,320**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable [6]									
		Total						**-$ 7,704,251**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*

Transportation	-$ 367,216
Stores Equipment	$ 250,078
Net Depreciation	-$ 7,587,113

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Appendix 2-BA
Fixed Asset Continuity Schedule [1]

Accounting Standard MIFRS
Year **2016**

			Cost				Accumulated Depreciation				
CCA Class [2]	**OEB Account [3]**	**Description [3]**	**Opening Balance**	**Additions [4]**	**Disposals [6]**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals [6]**	**Closing Balance**	**Net Book Value**
	1609	Capital Contributions Paid	$ -			$ -	$ -	$ -		$ -	$ -
12	1611	Computer Software (Formally known as Account 1925)	$ 4,623,342	$ 710,078	$ -	$ 5,333,420	-$ 3,761,654	-$ 397,815		-$ 4,159,469	$ 1,173,951
CEC	1612	Land Rights (Formally known as Account 1906)	$ 265,448		$ -	$ 265,448	-$ 263,180	-$ 2,269		-$ 265,449	-$ 1
N/A	1805	Land	$ 2,339,958		$ -	$ 2,339,958	$ -	$ -		$ -	$ 2,339,958
47	1808	Buildings	$ 9,687,234		-$ 11,187	$ 9,676,047	-$ 2,828,336	-$ 210,295	$ 11,187	-$ 3,027,444	$ 6,648,603
13	1810	Leasehold Improvements	$ -		$ -	$ -	$ -	$ -		$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ 63,136,285	$ 190,239	-$ 499,325	$ 62,827,199	-$ 23,290,054	-$ 1,576,758	$ 499,325	-$ 24,367,487	$ 38,459,712
47	1820	Distribution Station Equipment <50 kV	$ 2,909,885		-$ 16,218	$ 2,893,667	-$ 2,072,709	-$ 48,224	$ 16,218	-$ 2,104,715	$ 788,952
47	1825	Storage Battery Equipment	$ -		$ -	$ -	$ -	$ -		$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 39,895,625	$ 3,525,628	$ -	$ 43,421,253	-$ 15,286,408	-$ 836,577		-$ 16,122,985	$ 27,298,268
47	1835	Overhead Conductors & Devices	$ 40,343,054	$ 2,757,286	$ -	$ 43,100,340	-$ 17,298,105	-$ 542,946		-$ 17,841,051	$ 25,259,289
47	1840	Underground Conduit	$ 34,086,898	$ 2,655,417	$ -	$ 36,742,315	-$ 10,855,619	-$ 465,193		-$ 11,320,812	$ 25,421,503
47	1845	Underground Conductors & Devices	$ 47,842,864	$ 4,941,322	$ -	$ 52,784,186	-$ 22,432,154	-$ 933,328		-$ 23,365,482	$ 29,418,704
47	1850	Line Transformers	$ 60,586,881	$ 4,141,737	$ -	$ 64,728,618	-$ 28,240,495	-$ 1,710,860		-$ 29,951,355	$ 34,777,263
47	1855	Services (Overhead & Underground)	$ 51,898,310	$ 3,320,173	$ -	$ 55,218,483	-$ 20,587,391	-$ 1,040,794		-$ 21,628,185	$ 33,590,298
47	1860	Meters	$ 3,143,258	$ 265,312	$ -	$ 3,408,570	-$ 809,208	-$ 143,228		-$ 952,436	$ 2,456,134
47	1860	Meters (Smart Meters)	$ 12,650,540	$ 407,305	$ -	$ 13,057,845	-$ 4,878,498	-$ 856,947		-$ 5,735,445	$ 7,322,400
N/A	1905	Land	$ 1,395,300		$ -	$ 1,395,300	$ -	$ -		$ -	$ 1,395,300
47	1908	Buildings & Fixtures	$ 17,310,320	$ 221,770	-$ 1,475,987	$ 16,056,103	-$ 5,525,106	-$ 613,557	$ 1,475,987	-$ 4,662,676	$ 11,393,427
13	1910	Leasehold Improvements	$ -		$ -	$ -	$ -	$ -		$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 987,116	$ 36,970	-$ 9,747	$ 1,014,339	-$ 642,772	-$ 70,563	$ 9,747	-$ 703,588	$ 310,751
8	1915	Office Furniture & Equipment (5 years)	$ -		$ -	$ -	$ -	$ -		$ -	$ -
10	1920	Computer Equipment - Hardware	$ -		$ -	$ -	$ -	$ -		$ -	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -		$ -	$ -	$ -	$ -		$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 2,290,819	$ 90,770	-$ 35,795	$ 2,345,794	-$ 1,753,345	-$ 211,185	$ 35,288	-$ 1,929,242	$ 416,552
10	1930	Transportation Equipment	$ 9,802,299	$ 733,066	-$ 503,480	$ 10,031,885	-$ 6,187,876	-$ 664,631	$ 503,480	-$ 6,349,027	$ 3,682,858
8	1935	Stores Equipment	$ 64,072	$ 2,552	$ -	$ 66,624	-$ 60,564	-$ 3,215		-$ 63,779	$ 2,845
8	1940	Tools, Shop & Garage Equipment	$ 750,293	$ 95,003	$ -	$ 845,296	-$ 403,480	-$ 72,734		-$ 476,214	$ 369,082
8	1945	Measurement & Testing Equipment	$ 1,040,224	$ 3,849	$ -	$ 1,044,073	-$ 835,760	-$ 36,709		-$ 872,469	$ 171,604
8	1950	Power Operated Equipment	$ 892,992	$ 126,680	-$ 153,996	$ 865,676	-$ 508,507	-$ 66,839	$ 136,605	-$ 438,741	$ 426,935
8	1955	Communications Equipment	$ 936,228	$ 61,266	$ -	$ 997,494	-$ 618,615	-$ 80,930		-$ 699,545	$ 297,949
8	1955	Communication Equipment (Smart Meters)	$ -		$ -	$ -	$ -	$ -		$ -	$ -
8	1960	Miscellaneous Equipment	$ 109,010		$ -	$ 109,010	-$ 104,272	-$ 2,031		-$ 106,303	$ 2,707
47	1970	Load Management Controls Customer Premises	$ -		$ -	$ -	$ -	$ -		$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -		$ -	$ -	$ -	$ -		$ -	$ -
47	1980	System Supervisor Equipment	$ 26,979		$ 10,800	$ 37,779	-$ 20,007	-$ 1,943	-$ 10,800	-$ 32,750	$ 5,029
47	1985	Miscellaneous Fixed Assets	$ -		$ -	$ -	$ -	$ -		$ -	$ -
47	1990	Other Tangible Property	$ -		$ -	$ -	$ -	$ -		$ -	$ -
47	1995	Contributions & Grants	-$ 54,066,006	$ -	$ 5,228	-$ 54,060,778	$ 15,806,206	$ 1,180,976	-$ 5,229	$ 16,981,953	-$ 37,078,825
47	2440	Deferred Revenue [5]	-$ 16,158,299	-$ 8,950,517	$ -		$ 355,736	$ 487,557			
						$ -				$ -	$ -
		Sub-Total	**$ 338,790,929**	**$ 15,335,906**	**-$ 2,689,707**	**$ 376,545,944**	**-$ 153,102,173**	**-$ 8,921,038**	**$ 2,671,808**	**-$ 160,194,696**	**$ 216,351,249**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ 338,790,929**	**$ 15,335,906**	**-$ 2,689,707**	**$ 376,545,944**	**-$ 153,102,173**	**-$ 8,921,038**	**$ 2,671,808**	**-$ 160,194,696**	**$ 216,351,249**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable [6]									
		Total						**-$ 8,921,038**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*

Transportation	-$ 382,349
Stores Equipment	$ 487,557
Net Depreciation	-$ 9,026,246

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Appendix 2-BA

Fixed Asset Continuity Schedule [1]

Accounting Standard MIFRS
Year 2017

			Cost				Accumulated Depreciation				
CCA Class [2]	**OEB Account [3]**	**Description [3]**	**Opening Balance**	**Additions [4]**	**Disposals [6]**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals [6]**	**Closing Balance**	**Net Book Value**
	1609	Capital Contributions Paid	$ -			$ -	$ -	$ -		$ -	$ -
12	1611	Computer Software (Formally known as Account 1925)	$ 5,333,420	$ 136,147		$ 5,469,567	-$ 4,159,469	-$ 419,965		-$ 4,579,434	$ 890,133
CEC	1612	Land Rights (Formally known as Account 1906)	$ 265,448			$ 265,448	-$ 265,449	$ -		-$ 265,449	-$ 1
N/A	1805	Land	$ 2,339,958			$ 2,339,958	$ -	$ -		$ -	$ 2,339,958
47	1808	Buildings	$ 9,676,047			$ 9,676,047	-$ 3,027,444	-$ 189,033		-$ 3,216,477	$ 6,459,570
13	1810	Leasehold Improvements	$ -			$ -	$ -	$ -		$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ 62,827,199	$ 2,484,885		$ 65,312,084	-$ 24,367,487	-$ 1,520,336		-$ 25,887,823	$ 39,424,261
47	1820	Distribution Station Equipment <50 kV	$ 2,893,667			$ 2,893,667	-$ 2,104,715	-$ 44,883		-$ 2,149,598	$ 744,069
47	1825	Storage Battery Equipment	$ -			$ -	$ -	$ -		$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 43,421,253	$ 2,823,048		$ 46,244,301	-$ 16,122,985	-$ 899,198		-$ 17,022,183	$ 29,222,118
47	1835	Overhead Conductors & Devices	$ 43,100,340	$ 2,875,991		$ 45,976,331	-$ 17,841,051	-$ 586,226		-$ 18,427,277	$ 27,549,054
47	1840	Underground Conduit	$ 36,742,315	$ 2,850,149		$ 39,592,464	-$ 11,320,812	-$ 506,681		-$ 11,827,493	$ 27,764,971
47	1845	Underground Conductors & Devices	$ 52,784,186	$ 2,941,745		$ 55,725,931	-$ 23,365,482	-$ 1,005,936		-$ 24,371,418	$ 31,354,513
47	1850	Line Transformers	$ 64,728,618	$ 2,712,202	-$ 21,883	$ 67,418,937	-$ 29,951,355	-$ 1,378,915	$ 21,883	-$ 31,308,387	$ 36,110,550
47	1855	Services (Overhead & Underground)	$ 55,218,483	$ 3,479,238		$ 58,697,721	-$ 21,628,185	-$ 1,099,297		-$ 22,727,482	$ 35,970,239
47	1860	Meters	$ 3,408,570	$ 600,897		$ 4,009,467	-$ 952,436	-$ 159,098		-$ 1,111,534	$ 2,897,933
47	1860	Meters (Smart Meters)	$ 13,057,845	$ 222,909		$ 13,280,754	-$ 5,735,445	-$ 878,535		-$ 6,613,980	$ 6,666,774
N/A	1905	Land	$ 1,395,300			$ 1,395,300	$ -	$ -		$ -	$ 1,395,300
47	1908	Buildings & Fixtures	$ 16,056,103	$ 1,015,633	-$ 24,376	$ 17,047,360	-$ 4,662,676	-$ 466,747	$ 24,376	-$ 5,105,047	$ 11,942,313
13	1910	Leasehold Improvements	$ -			$ -	$ -	$ -		$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 1,014,339	$ 53,399	-$ 293,671	$ 774,067	-$ 703,588	-$ 68,483	$ 293,671	-$ 478,400	$ 295,667
8	1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -	$ -		$ -	$ -
10	1920	Computer Equipment - Hardware	$ -			$ -	$ -	$ -		$ -	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -			$ -	$ -	$ -		$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 2,345,794	$ 33,213	-$ 1,099	$ 2,377,908	-$ 1,929,242	-$ 193,472	$ 1,099	-$ 2,121,615	$ 256,293
10	1930	Transportation Equipment	$ 10,031,885	$ 39,073	-$ 24,630	$ 10,046,328	-$ 6,349,027	-$ 673,162	$ 24,630	-$ 6,997,559	$ 3,048,769
8	1935	Stores Equipment	$ 66,624		-$ 36,630	$ 29,994	-$ 63,779	-$ 276	$ 36,630	-$ 27,425	$ 2,569
8	1940	Tools, Shop & Garage Equipment	$ 845,296	$ 76,089	-$ 46,849	$ 874,536	-$ 476,214	-$ 77,532	$ 46,849	-$ 506,897	$ 367,639
8	1945	Measurement & Testing Equipment	$ 1,044,073	$ 59,074	-$ 664,730	$ 438,417	-$ 872,469	-$ 37,560	$ 664,730	-$ 245,299	$ 193,118
8	1950	Power Operated Equipment	$ 865,676		$ -	$ 865,676	-$ 438,741	-$ 69,566		-$ 508,307	$ 357,369
8	1955	Communications Equipment	$ 997,494	$ 190	$ -	$ 997,684	-$ 699,545	-$ 84,635		-$ 784,180	$ 213,504
8	1955	Communication Equipment (Smart Meters)	$ -		$ -	$ -	$ -	$ -		$ -	$ -
8	1960	Miscellaneous Equipment	$ 109,010	$ 4,993	-$ 98,856	$ 15,147	-$ 106,303	-$ 2,114	$ 98,856	-$ 9,561	$ 5,586
47	1970	Load Management Controls Customer Premises	$ -			$ -	$ -	$ -		$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -			$ -	$ -	$ -		$ -	$ -
47	1980	System Supervisor Equipment	$ 37,779			$ 37,779	-$ 32,750	-$ 2,204		-$ 34,954	$ 2,825
47	1985	Miscellaneous Fixed Assets	$ -			$ -	$ -	$ -		$ -	$ -
47	1990	Other Tangible Property	$ -			$ -	$ -	$ -		$ -	$ -
47	1995	Contributions & Grants	-$ 54,060,778		$ 51,290	-$ 54,009,488	$ 16,981,953	$ 1,099,731	-$ 51,290	$ 18,030,394	-$ 35,979,094
47	2440	Deferred Revenue [5]	-$ 25,108,816	-$ 6,242,858			$ 843,293	$ 658,473			
						$ -				$ -	$ -
		Sub-Total	**$ 351,437,128**	**$ 16,166,017**	**-$ 1,161,434**	**$ 397,793,385**	**-$ 159,351,403**	**-$ 8,605,650**	**$ 1,161,434**	**-$ 168,297,385**	**$ 229,496,001**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ 351,437,128**	**$ 16,166,017**	**-$ 1,161,434**	**$ 397,793,385**	**-$ 159,351,403**	**-$ 8,605,650**	**$ 1,161,434**	**-$ 168,297,385**	**$ 229,496,001**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable [6]									
		Total						**-$ 8,605,650**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*

Transportation	-$ 386,005
Stores Equipment	$ 658,473
Net Depreciation	-$ 8,878,118

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Appendix 2-BA

Fixed Asset Continuity Schedule [1]

Accounting Standard MIFRS
Year **2018**

			Cost				Accumulated Depreciation				
CCA Class [2]	**OEB Account [3]**	**Description [3]**	**Opening Balance**	**Additions [4]**	**Disposals [6]**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals [6]**	**Closing Balance**	**Net Book Value**
	1609	Capital Contributions Paid	$ -			$ -	$ -			$ -	$ -
12	1611	Computer Software (Formally known as Account 1925)	$ 5,469,567	$ 276,227		$ 5,745,794	-$ 4,579,434	-$ 450,463		-$ 5,029,897	$ 715,897
CEC	1612	Land Rights (Formally known as Account 1906)	$ 265,448		$ -	$ 265,448	-$ 265,449	$ -		-$ 265,449	-$ 1
N/A	1805	Land	$ 2,339,958			$ 2,339,958	$ -	$ -		$ -	$ 2,339,958
47	1808	Buildings	$ 9,676,047		-$ 11,814	$ 9,664,233	-$ 3,216,477	-$ 197,576	$ 11,814	-$ 3,402,239	$ 6,261,994
13	1810	Leasehold Improvements	$ -		$ -	$ -	$ -	$ -		$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ 65,312,084	$ 561,722	-$ 107,777	$ 65,766,029	-$ 25,887,823	-$ 1,561,997	$ 107,777	-$ 27,342,043	$ 38,423,986
47	1820	Distribution Station Equipment <50 kV	$ 2,893,667	$ 7,664	$ -	$ 2,901,331	-$ 2,149,598	-$ 45,139		-$ 2,194,737	$ 706,594
47	1825	Storage Battery Equipment	$ -		$ -	$ -	$ -	$ -		$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 46,244,301	$ 2,923,851	$ -	$ 49,168,152	-$ 17,022,183	-$ 971,034		-$ 17,993,217	$ 31,174,935
47	1835	Overhead Conductors & Devices	$ 45,976,331	$ 2,834,762	$ -	$ 48,811,093	-$ 18,427,277	-$ 640,541		-$ 19,067,818	$ 29,743,275
47	1840	Underground Conduit	$ 39,592,464	$ 2,184,528	$ -	$ 41,776,992	-$ 11,827,493	-$ 548,637		-$ 12,376,130	$ 29,400,862
47	1845	Underground Conductors & Devices	$ 55,725,931	$ 1,837,712	$ -	$ 57,563,643	-$ 24,371,418	-$ 1,065,171		-$ 25,436,589	$ 32,127,054
47	1850	Line Transformers	$ 67,418,937	$ 3,472,535	-$ 65,434	$ 70,826,038	-$ 31,308,387	-$ 1,467,280	$ 65,434	-$ 32,710,233	$ 38,115,805
47	1855	Services (Overhead & Underground)	$ 58,697,721	$ 3,150,848	$ -	$ 61,848,569	-$ 22,727,482	-$ 1,178,946		-$ 23,906,428	$ 37,942,141
47	1860	Meters	$ 4,009,467	$ 627,826	$ -	$ 4,637,293	-$ 1,111,534	-$ 188,448		-$ 1,299,982	$ 3,337,311
47	1860	Meters (Smart Meters)	$ 13,280,754	$ 539,690	$ -	$ 13,820,444	-$ 6,613,980	-$ 903,955		-$ 7,517,935	$ 6,302,509
N/A	1905	Land	$ 1,395,300		$ -	$ 1,395,300	$ -	$ -		$ -	$ 1,395,300
47	1908	Buildings & Fixtures	$ 17,047,360	$ 936,656	-$ 59,121	$ 17,924,895	-$ 5,105,047	-$ 465,838	$ 59,121	-$ 5,511,764	$ 12,413,131
13	1910	Leasehold Improvements	$ -		$ -	$ -	$ -	$ -		$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 774,067	$ 34,172	$ -	$ 808,239	-$ 478,400	-$ 62,256		-$ 540,656	$ 267,583
8	1915	Office Furniture & Equipment (5 years)	$ -		$ -	$ -	$ -	$ -		$ -	$ -
10	1920	Computer Equipment - Hardware	$ -		$ -	$ -	$ -	$ -		$ -	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -		$ -	$ -	$ -	$ -		$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 2,377,908	$ 604,377	-$ 1,236,976	$ 1,745,309	-$ 2,121,615	-$ 191,468	$ 1,235,015	-$ 1,078,068	$ 667,241
10	1930	Transportation Equipment	$ 10,046,328	$ 850,223	-$ 1,012,765	$ 9,883,786	-$ 6,997,559	-$ 685,882	$ 1,006,787	-$ 6,676,654	$ 3,207,132
8	1935	Stores Equipment	$ 29,994		$ -	$ 29,994	-$ 27,425	-$ 255		-$ 27,680	$ 2,314
8	1940	Tools, Shop & Garage Equipment	$ 874,536	$ 73,813	$ -	$ 948,349	-$ 506,897	-$ 75,614		-$ 582,511	$ 365,838
8	1945	Measurement & Testing Equipment	$ 438,417	$ 13,362	$ -	$ 451,779	-$ 245,299	-$ 37,169		-$ 282,468	$ 169,311
8	1950	Power Operated Equipment	$ 865,676	$ 277,919	-$ 150,914	$ 992,681	-$ 508,307	-$ 68,938	$ 150,914	-$ 426,331	$ 566,350
8	1955	Communications Equipment	$ 997,684	$ 45,955		$ 1,043,639	-$ 784,180	-$ 85,611		-$ 869,791	$ 173,848
8	1955	Communication Equipment (Smart Meters)	$ -			$ -	$ -	$ -		$ -	$ -
8	1960	Miscellaneous Equipment	$ 15,147	$ 3,464		$ 18,611	-$ 9,561	-$ 2,195		-$ 11,756	$ 6,855
47	1970	Load Management Controls Customer Premises	$ -			$ -	$ -	$ -		$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -			$ -	$ -	$ -		$ -	$ -
47	1980	System Supervisor Equipment	$ 37,779			$ 37,779	-$ 34,954	-$ 2,204		-$ 37,158	$ 621
47	1985	Miscellaneous Fixed Assets	$ -			$ -	$ -	$ -		$ -	$ -
47	1990	Other Tangible Property	$ -			$ -	$ -	$ -		$ -	$ -
47	1995	Contributions & Grants	-$ 54,009,488		$ 18,955	-$ 53,990,533	$ 18,030,394	$ 1,094,260	-$ 18,955	$ 19,105,699	-$ 34,884,834
47	2440	Deferred Revenue [5]	-$ 31,351,674	-$ 4,696,647			$ 1,501,766	$ 781,552	$ -		
						$ -				$ -	$ -
		Sub-Total	**$ 366,441,711**	**$ 16,560,659**	**-$ 2,625,846**	**$ 416,424,845**	**-$ 166,795,619**	**-$ 9,020,805**	**$ 2,617,907**	**-$ 175,481,835**	**$ 240,943,011**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ 366,441,711**	**$ 16,560,659**	**-$ 2,625,846**	**$ 416,424,845**	**-$ 166,795,619**	**-$ 9,020,805**	**$ 2,617,907**	**-$ 175,481,835**	**$ 240,943,011**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable [6]									
		Total						**-$ 9,020,805**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*

Transportation	-$ 373,065
Stores Equipment	$ 781,552
Net Depreciation	-$ 9,429,292

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Fixed Asset Continuity Schedule [1]

Accounting Standard MIFRS
Year 2019

			Cost				Accumulated Depreciation				
CCA Class [2]	**OEB Account [3]**	**Description [3]**	**Opening Balance**	**Additions [4]**	**Disposals [6]**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals [6]**	**Closing Balance**	**Net Book Value**
	1609	Capital Contributions Paid	$ -			$ -	$ -			$ -	$ -
12	1611	Computer Software (Formally known as Account 1925)	$ 5,745,794	$ 854,365		$ 6,600,159	-$ 5,029,897	-$ 445,400		-$ 5,475,297	$ 1,124,862
CEC	1612	Land Rights (Formally known as Account 1906)	$ 265,448			$ 265,448	-$ 265,449	$ -		-$ 265,449	-$ 1
N/A	1805	Land	$ 2,339,958			$ 2,339,958	$ -	$ -		$ -	$ 2,339,958
47	1808	Buildings	$ 9,664,233			$ 9,664,233	-$ 3,402,239	-$ 197,400		-$ 3,599,639	$ 6,064,594
13	1810	Leasehold Improvements	$ -			$ -	$ -	$ -		$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ 65,766,029	$ 1,624,500		$ 67,390,529	-$ 27,342,043	-$ 1,600,000		-$ 28,942,043	$ 38,448,486
47	1820	Distribution Station Equipment <50 kV	$ 2,901,331			$ 2,901,331	-$ 2,194,737	-$ 45,500		-$ 2,240,237	$ 661,094
47	1825	Storage Battery Equipment	$ -			$ -	$ -	$ -		$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 49,168,152	$ 2,959,500		$ 52,127,652	-$ 17,993,217	-$ 1,059,200		-$ 19,052,417	$ 33,075,235
47	1835	Overhead Conductors & Devices	$ 48,811,093	$ 2,713,640		$ 51,524,733	-$ 19,067,818	-$ 683,100		-$ 19,750,918	$ 31,773,815
47	1840	Underground Conduit	$ 41,776,992	$ 2,519,600		$ 44,296,592	-$ 12,376,130	-$ 568,700		-$ 12,944,830	$ 31,351,762
47	1845	Underground Conductors & Devices	$ 57,563,643	$ 1,692,201		$ 59,255,844	-$ 25,436,589	-$ 1,104,500		-$ 26,541,089	$ 32,714,755
47	1850	Line Transformers	$ 70,826,038	$ 3,124,798		$ 73,950,836	-$ 32,710,233	-$ 1,494,100		-$ 34,204,333	$ 39,746,503
47	1855	Services (Overhead & Underground)	$ 61,848,569	$ 2,801,461		$ 64,650,030	-$ 23,906,428	-$ 1,202,400		-$ 25,108,828	$ 39,541,202
47	1860	Meters	$ 4,637,293	$ 307,344		$ 4,944,637	-$ 1,299,982	-$ 189,100		-$ 1,489,082	$ 3,455,555
47	1860	Meters (Smart Meters)	$ 13,820,444	$ 332,956		$ 14,153,400	-$ 7,517,935	-$ 918,500		-$ 8,436,435	$ 5,716,965
N/A	1905	Land	$ 1,395,300			$ 1,395,300	$ -	$ -		$ -	$ 1,395,300
47	1908	Buildings & Fixtures	$ 17,924,895	$ 750,000		$ 18,674,895	-$ 5,511,764	-$ 512,500		-$ 6,024,264	$ 12,650,631
13	1910	Leasehold Improvements	$ -			$ -	$ -	$ -		$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 808,239	$ 144,597		$ 952,836	-$ 540,656	-$ 61,500		-$ 602,156	$ 350,680
8	1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -	$ -		$ -	$ -
10	1920	Computer Equipment - Hardware	$ -			$ -	$ -	$ -		$ -	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -			$ -	$ -	$ -		$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 1,745,309	$ 344,140		$ 2,089,449	-$ 1,078,068	-$ 267,600		-$ 1,345,668	$ 743,781
10	1930	Transportation Equipment	$ 9,883,786	$ 1,454,069	-$ 650,000	$ 10,687,855	-$ 6,676,654	-$ 712,200	$ 650,000	-$ 6,738,854	$ 3,949,001
8	1935	Stores Equipment	$ 29,994			$ 29,994	-$ 27,680	-$ 300		-$ 27,980	$ 2,014
8	1940	Tools, Shop & Garage Equipment	$ 948,349	$ 95,000		$ 1,043,349	-$ 582,511	-$ 70,000		-$ 652,511	$ 390,838
8	1945	Measurement & Testing Equipment	$ 451,779	$ 10,000		$ 461,779	-$ 282,468	-$ 35,200		-$ 317,668	$ 144,111
8	1950	Power Operated Equipment	$ 992,681	$ 100,000		$ 1,092,681	-$ 426,331	-$ 83,900		-$ 510,231	$ 582,450
8	1955	Communications Equipment	$ 1,043,639	$ 36,600		$ 1,080,239	-$ 869,791	-$ 40,000		-$ 909,791	$ 170,448
8	1955	Communication Equipment (Smart Meters)	$ -			$ -	$ -	$ -		$ -	$ -
8	1960	Miscellaneous Equipment	$ 18,611			$ 18,611	-$ 11,756	-$ 1,300		-$ 13,056	$ 5,555
47	1970	Load Management Controls Customer Premises	$ -			$ -	$ -	$ -		$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -			$ -	$ -	$ -		$ -	$ -
47	1980	System Supervisor Equipment	$ 37,779			$ 37,779	-$ 37,158	$ -		-$ 37,158	$ 621
47	1985	Miscellaneous Fixed Assets	$ -			$ -	$ -	$ -		$ -	$ -
47	1990	Other Tangible Property	$ -			$ -	$ -	$ -		$ -	$ -
47	1995	Contributions & Grants	-$ 53,990,533			-$ 53,990,533	$ 19,105,699	$ 1,092,100		$ 20,197,799	-$ 33,792,734
47	2440	Deferred Revenue [5]	-$ 36,048,321	-$ 3,424,749			$ 2,283,318	$ 857,100			
						$ -				$ -	$ -
		Sub-Total	**$ 380,376,524**	**$ 18,440,022**	**-$ 650,000**	**$ 437,639,616**	**-$ 173,198,517**	**-$ 9,343,200**	**$ 650,000**	**-$ 185,032,135**	**$ 252,607,482**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ 380,376,524**	**$ 18,440,022**	**-$ 650,000**	**$ 437,639,616**	**-$ 173,198,517**	**-$ 9,343,200**	**$ 650,000**	**-$ 185,032,135**	**$ 252,607,482**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable [6]									
		Total						**-$ 9,343,200**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*

Transportation	-$ 380,650
Stores Equipment	$ 857,100
Net Depreciation	-$ 9,819,650

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Appendix 2-BA

Fixed Asset Continuity Schedule [1]

Accounting Standard MIFRS
Year 2020

			Cost				Accumulated Depreciation				
CCA Class [2]	**OEB Account [3]**	**Description [3]**	**Opening Balance**	**Additions [4]**	**Disposals [6]**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals [6]**	**Closing Balance**	**Net Book Value**
	1609	Capital Contributions Paid	$ -			$ -	$ -			$ -	$ -
12	1611	Computer Software (Formally known as Account 1925)	$ 6,600,159	$ 6,710,000		$ 13,310,159	-$ 5,475,297	-$ 1,194,200		-$ 6,669,497	$ 6,640,662
CEC	1612	Land Rights (Formally known as Account 1906)	$ 265,448			$ 265,448	-$ 265,449	$ -		-$ 265,449	-$ 1
N/A	1805	Land	$ 2,339,958			$ 2,339,958	$ -	$ -		$ -	$ 2,339,958
47	1808	Buildings	$ 9,664,233			$ 9,664,233	-$ 3,599,639	-$ 196,400		-$ 3,796,039	$ 5,868,194
13	1810	Leasehold Improvements	$ -			$ -	$ -	$ -		$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ 67,390,529	$ 2,004,000		$ 69,394,529	-$ 28,942,043	-$ 1,635,500		-$ 30,577,543	$ 38,816,986
47	1820	Distribution Station Equipment <50 kV	$ 2,901,331			$ 2,901,331	-$ 2,240,237	-$ 45,300		-$ 2,285,537	$ 615,794
47	1825	Storage Battery Equipment	$ -			$ -	$ -	$ -		$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 52,127,652	$ 3,133,850		$ 55,261,502	-$ 19,052,417	-$ 1,102,200		-$ 20,154,617	$ 35,106,885
47	1835	Overhead Conductors & Devices	$ 51,524,733	$ 2,893,200		$ 54,417,933	-$ 19,750,918	-$ 731,800		-$ 20,482,718	$ 33,935,215
47	1840	Underground Conduit	$ 44,296,592	$ 3,524,600		$ 47,821,192	-$ 12,944,830	-$ 619,700		-$ 13,564,530	$ 34,256,662
47	1845	Underground Conductors & Devices	$ 59,255,844	$ 1,977,201		$ 61,233,045	-$ 26,541,089	-$ 1,148,600		-$ 27,689,689	$ 33,543,356
47	1850	Line Transformers	$ 73,950,836	$ 3,123,499		$ 77,074,335	-$ 34,204,333	-$ 1,570,500		-$ 35,774,833	$ 41,299,502
47	1855	Services (Overhead & Underground)	$ 64,650,030	$ 3,025,150		$ 67,675,180	-$ 25,108,828	-$ 1,269,500		-$ 26,378,328	$ 41,296,852
47	1860	Meters	$ 4,944,637	$ 286,560		$ 5,231,197	-$ 1,489,082	-$ 200,900		-$ 1,689,982	$ 3,541,215
47	1860	Meters (Smart Meters)	$ 14,153,400	$ 310,440		$ 14,463,840	-$ 8,436,435	-$ 939,900		-$ 9,376,335	$ 5,087,505
N/A	1905	Land	$ 1,395,300			$ 1,395,300	$ -	$ -		$ -	$ 1,395,300
47	1908	Buildings & Fixtures	$ 18,674,895	$ 750,000		$ 19,424,895	-$ 6,024,264	-$ 549,700		-$ 6,573,964	$ 12,850,931
13	1910	Leasehold Improvements	$ -			$ -	$ -	$ -		$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 952,836	$ 70,000		$ 1,022,836	-$ 602,156	-$ 57,900		-$ 660,056	$ 362,780
8	1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -	$ -		$ -	$ -
10	1920	Computer Equipment - Hardware	$ -			$ -	$ -	$ -		$ -	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -			$ -	$ -	$ -		$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 2,089,449	$ 325,000		$ 2,414,449	-$ 1,345,668	-$ 260,200		-$ 1,605,868	$ 808,581
10	1930	Transportation Equipment	$ 10,687,855	$ 890,000	-$ 465,000	$ 11,112,855	-$ 6,738,854	-$ 770,100	$ 465,000	-$ 7,043,954	$ 4,068,901
8	1935	Stores Equipment	$ 29,994			$ 29,994	-$ 27,980	-$ 300		-$ 28,280	$ 1,714
8	1940	Tools, Shop & Garage Equipment	$ 1,043,349	$ 95,000		$ 1,138,349	-$ 652,511	-$ 69,200		-$ 721,711	$ 416,638
8	1945	Measurement & Testing Equipment	$ 461,779	$ 10,000		$ 471,779	-$ 317,668	-$ 34,800		-$ 352,468	$ 119,311
8	1950	Power Operated Equipment	$ 1,092,681	$ 110,000		$ 1,202,681	-$ 510,231	-$ 84,751		-$ 594,982	$ 607,699
8	1955	Communications Equipment	$ 1,080,239	$ 35,000		$ 1,115,239	-$ 909,791	-$ 22,149		-$ 931,940	$ 183,299
8	1955	Communication Equipment (Smart Meters)	$ -			$ -	$ -	$ -		$ -	$ -
8	1960	Miscellaneous Equipment	$ 18,611			$ 18,611	-$ 13,056	-$ 1,300		-$ 14,356	$ 4,255
47	1970	Load Management Controls Customer Premises	$ -			$ -	$ -	$ -		$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -			$ -	$ -	$ -		$ -	$ -
47	1980	System Supervisor Equipment	$ 37,779			$ 37,779	-$ 37,158	$ -		-$ 37,158	$ 621
47	1985	Miscellaneous Fixed Assets	$ -			$ -	$ -	$ -		$ -	$ -
47	1990	Other Tangible Property	$ -			$ -	$ -	$ -		$ -	$ -
47	1995	Contributions & Grants	-$ 53,990,533			-$ 53,990,533	$ 20,197,799	$ 1,089,500		$ 21,287,299	-$ 32,703,234
47	2440	Deferred Revenue [5]	-$ 39,473,070	-$ 3,677,745			$ 3,140,418	$ 939,700			
						$ -				$ -	$ -
		Sub-Total	**$ 398,166,546**	**$ 25,595,755**	**-$ 465,000**	**$ 466,448,116**	**-$ 181,891,717**	**-$ 10,475,700**	**$ 465,000**	**-$ 195,982,535**	**$ 270,465,582**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ 398,166,546**	**$ 25,595,755**	**-$ 465,000**	**$ 466,448,116**	**-$ 181,891,717**	**-$ 10,475,700**	**$ 465,000**	**-$ 195,982,535**	**$ 270,465,582**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable [6]									
		Total						**-$ 10,475,700**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*

Transportation	-$ 401,900
Stores Equipment	$ 939,700
Net Depreciation	-$ 11,013,500

Notes:

File Number:	EB-2019-0049
Exhibit:	
Tab:	
Schedule:	
Page:	
Date:	

Appendix 2-BA

Fixed Asset Continuity Schedule [1]

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

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

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

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

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

6 The applicant must ensure that all asset disposals have been clearly identified in the Chapter 2 Appendices for all historic, bridge and test years. Where a distributor for general financial reporting purposes under IFRS has accounted for the amount of gain or loss on the retirement of assets in a pool of like assets as a charge or credit to income, for reporting and rate application filings, the distributor shall reclassify such gains and losses as depreciation expense, and disclose the amount separately.

File Number: EB-2019-0049
Exhibit:
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Schedule:
Page:

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Appendix 2-BB
Service Life Comparison
Table F-1 from Kinetrics Report[1]

Parent*	#	Asset Details: Category | Component | Type			Useful Life: MIN UL	TUL	MAX UL	USoA Account Number	USoA Account Description	Current: Years	Current: Rate	Proposed: Years	Proposed: Rate	Outside Range of Min, Max TUL? Below Min TUL	Above Max TUL
OH	1	Fully Dressed Wood Poles	Overall		35	45	75	1830	Poles Towers and fixtures	40	3%	40	3%	No	No
			Cross Arm	Wood	20	40	55								
				Steel	30	70	95								
	2	Fully Dressed Concrete Poles	Overall		50	60	80								
			Cross Arm	Wood	20	40	55								
				Steel	30	70	95								
	3	Fully Dressed Steel Poles	Overall		60	60	80								
			Cross Arm	Wood	20	40	55								
				Steel	30	70	95								
	4	OH Line Switch			30	45	55	1835	Overhead Conductors and Devices	40	3%	40	3%	No	No
	5	OH Line Switch Motor			15	25	25								
	6	OH Line Switch RTU			15	20	20								
	7	OH Integral Switches			35	45	60								
	8	OH Conductors			50	60	75	1835	Overhead Conductors and Devices	60	2%	60	2%	No	No
	9	OH Transformers & Voltage Regulators			30	40	60	1835	Overhead Conductors and Devices	30	3%	30	3%	No	No
	10	OH Shunt Capacitor Banks			25	30	40	1835	Overhead Conductors and Devices	25	4%	25	4%	No	No
	11	Reclosers			25	40	55	1835	Overhead Conductors and Devices	25	4%	25	4%	No	No
TS & MS	12	Power Transformers	Overall		30	45	60	1815	TS Equipment						
			Bushing		10	20	30								
			Tap Changer		20	30	60								
	13	Station Service Transformer			30	45	55	1815	TS Equipment	40	3%	40	3%	No	No
	14	Station Grounding Transformer			30	40	40								
	15	Station DC System	Overall		10	20	30								
			Battery Bank		10	15	15								
			Charger		20	20	30								
	16	Station Metal Clad Switchgear	Overall		30	40	60	1815	TS Equipment	50	2%	50	2%	No	No
			Removable Breaker		25	40	60								
	17	Station Independent Breakers			35	45	65								
	18	Station Switch			30	50	60								
	19	Electromechanical Relays			25	35	50	1815	TS Equipment	25	4%	25	4%	No	No
	20	Solid State Relays			10	30	45	1815	TS Equipment	25	4%	25	4%	No	No
	21	Digital & Numeric Relays			15	20	20	1815	TS Equipment	15	7%	15	7%	No	No
	22	Rigid Busbars			30	55	60								
	23	Steel Structure			35	50	90	1815	TS Equipment	50	2%	50	2%	No	No
UG	24	Primary Paper Insulated Lead Covered (PILC) Cables			60	65	75	1845	UG Conductors and Devices	60	2%	60	2%	No	No
	25	Primary Ethylene-Propylene Rubber (EPR) Cables			20	25	25	1845	UG Conductors and Devices	40	3%	40	3%	No	Yes
	26	Primary Non-Tree Retardant (TR) Cross Linked Polyethylene (XLPE) Cables Direct Buried			20	25	30	1845	UG Conductors and Devices	40	3%	40	3%	No	Yes
	27	Primary Non-TR XLPE Cables in Duct			20	25	30	1845	UG Conductors and Devices	40	3%	40	3%	No	Yes
	30	Secondary PILC Cables			70	75	80								
	31	Secondary Cables Direct Buried			25	35	40	1845	UG Conductors and Devices	40	3%	40	3%	No	No
	32	Secondary Cables in Duct			35	40	60	1845	UG Conductors and Devices	40	3%	40	3%	No	No
	33	Network Tranformers	Overall		20	35	50	1850	Line Transformers	40	3%	40	3%	No	No
			Protector		20	35	40	1850	Line Transformers	40	3%	40	3%	No	No
	34	Pad-Mounted Transformers			25	40	45	1850	Line Transformers	40	3%	40	3%	No	No
	35	Submersible/Vault Transformers			25	35	45			30	3%	30	3%	No	No
	36	UG Foundation			35	55	70	1850	Line Transformers	60	2%	60	2%	No	No
	37	UG Vaults	Overall		40	60	80	1850	Line Transformers	60	2%	60	2%	No	No
			Roof		20	30	45	1850	Line Transformers	30	3%	30	3%	No	No
	38	UG Vault Switches			20	35	50	1840	UG Conduit	40	3%	40	3%	No	No
	39	Pad-Mounted Switchgear			20	30	45	1840	UG Conduit	40	3%	40	3%	No	No
	40	Ducts			30	50	85	1840	UG Conduit	60	2%	60	2%	No	No
	41	Concrete Encased Duct Banks			35	55	80								
	42	Cable Chambers			50	60	80								
S	43	Remote SCADA			15	20	30								

Table F-2 from Kinetrics Report[1]

#	Asset Details: Category | Component | Type		Useful Life Range		USoA Account Number	USoA Account Description	Current: Years	Current: Rate	Proposed: Years	Proposed: Rate	Outside Range of Min, Max TUL? Below Min Range	Above Max Range
1	Office Equipment		5	15	1915	Office Furniture and Equipment	10	10%	10	10%	No	No
2	Vehicles	Trucks & Buckets	5	15	1930	Transportation Equipment	10	10%	10	10%	No	No
		Trailers	5	20	1930	Transportation Equipment	8	13%	8	13%	No	No
		Vans	5	10	1930	Transportation Equipment	8	13%	8	13%	No	No
3	Administrative Buildings		50	75	1908	Buidlings and Fixtures	50	2%	50	2%	No	No
4	Leasehold Improvements		Lease dependent									
5	Station Buildings	Station Buildings	50	75	1808	Buildings and Fixtures	50	2%	50	2%	No	No
		Parking	25	30								
		Fence	25	60								
		Roof	20	30	1808	Buildings and Fixtures	20	5%	20	5%	No	No
6	Computer Equipment	Hardware	3	5	1920	Computer Hardware	4	25%	4	25%	No	No
		Software	2	5	1611	Computer Software	3	33%	3	33%	No	No
7	Equipment	Power Operated	5	10								
		Stores	5	10								
		Tools, Shop, Garage Equipment	5	10								
		Measurement & Testing Equipment	5	10								
8	Communication	Towers	60	70								
		Wireless	2	10								
9	Residential Energy Meters		25	35	1860	Meters	25	4%	25	4%	No	No
10	Industrial/Commercial Energy Meters		25	35	1860	Meters	25	4%	25	4%	No	No
11	Wholesale Energy Meters		15	30	1860	Meters	25	4%	25	4%	No	No
12	Current & Potential Transformer (CT & PT)		35	50								
13	Smart Meters		5	15	1860	Meters	15	7%	15	7%	No	No
14	Repeaters - Smart Metering		10	15								
15	Data Collectors - Smart Metering		15	20								

TS & MS = Transformer and Municipal Stations UG = Underground Systems S = Monitoring and Control Systems

Note 1: Tables F-1 and F-2 above are to be used as a reference in order to complete columns J, K, L and N.
See pages 17-19 of Kinetrics Report

Appendix 2-C
Depreciation and Amortization Expense

2014

Account	Description	Book Values							Service Lives				Depreciation Expense					
		Opening Net Book Value of Existing Assets as at Date of Policy Change (Jan. 1) [1]	Less Fully Depreciated [7]	Net Amount of Existing Assets Before Policy Change to be Depreciated	Opening Gross Book Value of Assets Acquired After Policy Change [2]	Less Fully Depreciated [8]	Net Amount of Assets Acquired After Policy Change to be Depreciated	Current Year Additions	Average Remaining Life of Assets Existing Before Policy Change [3]	Depreciation Rate Assets Acquired After Policy Change	Life of Assets Acquired After Policy Change [4]	Depreciation Rate on New Additions	Depreciation Expense on Assets Existing Before Policy Change	Depreciation Expense on Assets Acquired After Policy Change	Depreciation Expense on Current Year Additions [5]	Total Current Year Depreciation Expense	Depreciation Expense per Appendix 2-BA Fixed Assets, Column J	Variance [6]
		a	b	c = a-b	d	e	f = d- e	g	h	i = 1/h	j	k = 1/j	l = c/h	m = f/j	n = g*0.5/j	o = l+m+n	p	q = p-o
1611	Computer Software (Formally known as Account 1925)	928,634	$ 484,030	$ 444,604	$ 437,818		$ 437,818	$ 288,888	2.25	44.44%	5.00	20.00%	$ 197,602	$ 87,564	$ 28,889	$ 314,054	$ 331,209	$ 17,154
1611	Computer Software (Formally known as Account 1925)			$ -		$ -	$ -	$ 88,614	-	0.00%	3.00	33.33%	$ -	$ -	$ 14,769	$ 14,769	$ 86,741	$ 71,972
1611	Computer Software (Formally known as Account 1925) - Smart Meters	-		$ -	$ 591,890	$ 518,014	$ 73,876	$ 6,791	-	0.00%	3.00	33.33%	$ -	$ 24,625	$ 1,132	$ 25,757	$ 25,445	-$ 312
1612	Land Rights (Formally known as Account 1906)	12,881		$ 12,881			$ -		4.86	20.60%	50.00	2.00%	$ 2,653	$ -	$ -	$ 2,653	$ 2,653	$ -
1805	Land	2,339,958		$ 2,339,958			$ -		-	0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1808	Buildings - Structure	7,099,490		$ 7,099,490	$ 585,080		$ 585,080	$ -	38.08	2.63%	50.00	2.00%	$ 186,429	$ 11,702	$ -	$ 198,131	$ 198,131	$ -
1808	Buildings - Roof	144,989	$ 34,742	$ 110,247	$ -		$ -	$ -	11.44	8.74%	20.00	5.00%	$ 9,638	$ -	$ -	$ 9,638	$ 12,676	$ 3,037
1810	Leasehold Improvements			$ -			$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1815	Transformer Station Equipment >50 kV 50 yrs	15,658,085	$ 12,312	$ 15,645,773	$ 1,531,177		$ 1,531,177	$ 423,640	41.16	2.43%	50.00	2.00%	$ 380,092	$ 30,624	$ 4,236	$ 414,952	$ 415,251	$ 299
1815	Transformer Station Equipment >50 kV 40 yrs	24,475,179		$ 24,475,179	$ 1,080,100		$ 1,080,100	$ 164,079	28.76	3.48%	40.00	2.50%	$ 851,073	$ 27,003	$ 2,051	$ 880,127	$ 880,127	$ -
1815	Transformer Station Equipment >50 kV 30 yrs			$ -			$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1815	Transformer Station Equipment >50 kV 25 yrs	887,028	$ 25,692	$ 861,336	$ -		$ -	$ -	12.07	8.28%	25.00	4.00%	$ 71,350	$ -	$ -	$ 71,350	$ 73,478	$ 2,128
1815	Transformer Station Equipment >50 kV 20 yrs	392,015	$ 45,826	$ 346,189	$ 23,880		$ 23,880	-$ 389	9.76	10.24%	20.00	5.00%	$ 35,455	$ 1,194	-$ 10	$ 36,640	$ 41,333	$ 4,693
1815	Transformer Station Equipment >50 kV 15 yrs	1,087,574		$ 1,087,574	$ 367,520		$ 367,520	$ 505,667	8.48	11.79%	15.00	6.67%	$ 128,268	$ 24,501	$ 16,856	$ 169,625	$ 169,625	$ -
1820	Distribution Station Equipment <50 kV 50 yrs	200,427		$ 200,427	$ -		$ -	$ -	22.74	4.40%	50.00	2.00%	$ 8,813	$ -	$ -	$ 8,813	$ 8,813	$ -
1820	Distribution Station Equipment <50 kV 40 yrs	649,832		$ 649,832	$ -		$ -	$ -	25.47	3.93%	40.00	2.50%	$ 25,509	$ -	$ -	$ 25,509	$ 25,509	$ -
1820	Distribution Station Equipment <50 kV 25 yrs	13,287		$ 13,287	$ -		$ -	$ -	5.93	16.87%	25.00	4.00%	$ 2,242	$ -	$ -	$ 2,242	$ 2,242	$ -
1820	Distribution Station Equipment <50 kV 20 yrs	6,078	$ 6,078	$ -	$ -		$ -	$ -	5.66	17.66%	20.00	5.00%	$ -	$ -	$ -	$ -	$ 1,074	$ 1,074
1820	Distribution Station Equipment <50 kV 15 hrs	17,551	$ 17,551	$ -	$ 144,060		$ 144,060	$ 9,576	9.64	10.37%	15.00	6.67%	$ -	$ 9,604	$ 319	$ 9,923	$ 11,743	$ 1,820
1825	Storage Battery Equipment			$ -			$ -		-	0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1830	Poles, Towers & Fixtures	17,028,402		$ 17,028,402	$ 4,831,550		$ 4,831,550	$ 2,044,655	32.16	3.11%	40.00	2.50%	$ 529,490	$ 120,789	$ 25,558	$ 675,837	$ 681,835	$ 5,998
1835	Overhead Conductors	14,319,062		$ 14,319,062	$ 3,391,666		$ 3,391,666	$ 1,108,823	51.16	1.95%	60.00	1.67%	$ 279,881	$ 56,528	$ 9,240	$ 345,649	$ 345,649	$ -
1835	Overhead Devices	1,591,007		$ 1,591,007	$ 419,494		$ 419,494	$ 129,915	30.57	3.27%	40.00	2.50%	$ 52,051	$ 10,487	$ 1,624	$ 64,162	$ 64,162	$ -
1835	Voltage Regulators	163,109		$ 163,109	$ -		$ -	$ -	20.00	5.00%	30.00	3.33%	$ 8,155	$ -	$ -	$ 8,155	$ 8,155	$ -
1835	Capacitor Banks	618,096		$ 618,096	$ 4,080		$ 4,080	$ 89,387	19.80	5.05%	25.00	4.00%	$ 31,224	$ 163	$ 1,788	$ 33,175	$ 33,175	$ -
1840	Underground Conduit	12,527,558		$ 12,527,558	$ 4,604,937		$ 4,604,937	$ 3,084,780	51.70	1.93%	60.00	1.67%	$ 242,295	$ 76,749	$ 25,707	$ 344,750	$ 344,750	$ -
1845	Underground Conductors & Devices - PILC	414,000		$ 414,000	$ 465,861		$ 465,861	$ -	58.00	1.72%	60.00	1.67%	$ 7,138	$ 7,764	$ -	$ 14,902	$ 14,902	$ -
1845	Underground Cables	15,726,653		$ 15,726,653	$ 3,513,152		$ 3,513,152	$ 2,778,593	28.66	3.49%	40.00	2.50%	$ 548,637	$ 87,829	$ 34,732	$ 671,198	$ 671,198	$ -
1845	Underground Devices	1,747,406		$ 1,747,406	$ 451,452		$ 451,452	$ 317,137	28.66	3.49%	40.00	2.50%	$ 60,960	$ 11,286	$ 3,964	$ 76,210	$ 76,210	$ -
1850	Line Transformers - Overhead	15,713,833	$ 307,197	$ 15,406,636	$ 1,548,214		$ 1,548,214	$ 825,759	27.98	3.57%	40.00	2.50%	$ 550,545	$ 38,705	$ 10,322	$ 599,572	$ 610,549	$ 10,977
1850	Line Transformers - Network	5,503		$ 5,503	$ 202,577		$ 202,577	$ 99,626	9.38	10.66%	40.00	2.50%	$ 587	$ 5,064	$ 1,245	$ 6,896	$ 6,896	$ -
1850	Line Transformers - Vault	-		$ -	$ 5,849		$ 5,849	$ -	-	0.00%	60.00	1.67%	$ -	$ 97	$ -	$ 97	$ 97	$ -
1850	Line Transformers - Roof	497,948		$ 497,948	$ -		$ -	$ -	23.84	4.19%	30.00	3.33%	$ 20,885	$ -	$ -	$ 20,885	$ 20,885	$ -
1850	Line Transformers -Network Protectors	91,592		$ 91,592	$ 234,492		$ 234,492	$ 81,112	39.50	2.53%	40.00	2.50%	$ 2,319	$ 5,862	$ 1,014	$ 9,195	$ 9,129	-$ 66
1850	Line Transformers - Padmount	3,991,872		$ 3,991,872	$ 1,590,190		$ 1,590,190	$ 551,107	36.77	2.72%	40.00	2.50%	$ 108,567	$ 39,755	$ 6,889	$ 155,210	$ 41,687	-$ 113,523
1850	Line Transformers - Submersible	3,195,923		$ 3,195,923	$ 1,117,616		$ 1,117,616	$ 705,781	24.09	4.15%	30.00	3.33%	$ 132,669	$ 37,254	$ 11,763	$ 181,686	$ 54,134	-$ 127,552
1850	Line Transformers - Foundation	1,427,416		$ 1,427,416	$ 580,905		$ 580,905	$ 66,370	58.08	1.72%	60.00	1.67%	$ 24,575	$ 9,682	$ 553	$ 34,810	$ 10,839	-$ 23,971
1855	Services - Overhead	1,887,728		$ 1,887,728	$ 1,009,574		$ 1,009,574	$ 213,550	52.20	1.92%	60.00	1.67%	$ 36,164	$ 16,826	$ 1,780	$ 54,770	$ 54,770	$ -
1855	Services - Underground	22,543,287		$ 22,543,287	$ 4,063,210		$ 4,063,210	$ 1,801,118	31.40	3.18%	40.00	2.50%	$ 717,938	$ 101,580	$ 22,514	$ 842,032	$ 842,032	$ -
1860	Commercial Meters	1,327,802	$ 158,636	$ 1,169,166	$ 583,615		$ 583,615	$ 311,805	20.97	4.77%	25.00	4.00%	$ 55,753	$ 23,345	$ 6,236	$ 85,333	$ 92,898	$ 7,565
1860	Smart Meters - Non-Qualifying	108,222		$ 108,222	$ -		$ -	$ 240,153	12.00	8.33%	15.00	6.67%	$ 9,018	$ -	$ 8,005	$ 17,023	$ 17,023	$ -
1860	Meters - Renewable Connection			$ -	$ -		$ -	$ 154,427	-	0.00%	15.00	6.67%	$ -	$ -	$ 5,148	$ 5,148	$ 32,983	$ 27,835
1860	Smart Meters			$ -			$ -		-	0.00%	15.00	6.67%	$ -	$ -	$ -	$ -		$ -
1860	Smart Meters	-		$ -	$ 12,361,937		$ 12,361,937	$ 132,171	-	0.00%	15.00	6.67%	$ -	$ 824,129	$ 4,406	$ 828,535	$ 828,535	$ -
1905	Land	1,395,300		$ 1,395,300	$ -		$ -	$ -	-	0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1908	Buildings & Fixtures - Building	5,262,681		$ 5,262,681	$ 4,795,255		$ 4,795,255	$ 82,660	28.71	3.48%	50.00	2.00%	$ 183,326	$ 95,905	$ 827	$ 280,058	$ 280,058	$ -
1908	Buildings & Fixtures - Roof	1,567,291		$ 1,567,291	$ 1,504,780		$ 1,504,780	$ 724,628	6.53	15.33%	20.00	5.00%	$ 240,192	$ 75,239	$ 18,116	$ 333,546	$ 333,546	$ -
1910	Leasehold Improvements	-		$ -	$ -		$ -	$ -	-	0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1915	Office Furniture & Equipment (10 years)	340,212	$ 54,324	$ 285,888	$ 187,702		$ 187,702	$ 57,713	5.10	19.61%	10.00	10.00%	$ 56,056	$ 18,770	$ 2,886	$ 77,712	$ 70,928	-$ 6,784
1915	Office Furniture & Equipment (5 years)			$ -			$ -		-	0.00%	5.00	20.00%	$ -	$ -	$ -	$ -		$ -
1920	Computer Equipment - Hardware	350,464		$ 350,464	$ 123,375		$ 123,375	$ 175,363	2.12	47.12%	5.00	20.00%	$ 165,155	$ 24,675	$ 17,536	$ 207,367	$ 207,367	$ -
1920	Computer Equip.-Hardware - Smart Meters	-		$ -	$ 569,286	$ 437,864	$ 131,422	$ -	-	0.00%	5.00	20.00%	$ -	$ 26,284	$ -	$ 26,284	$ 22,126	-$ 4,158
1920	Computer Equip.-Hardware(Post Mar. 19/07)	-		$ -	$ -		$ -	$ -	-	0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1930	Transportation Equipment	2,781,086		$ 2,781,086	$ 2,066,571		$ 2,066,571	$ 767,172	7.19	13.90%	11.00	9.09%	$ 386,688	$ 187,870	$ 34,871	$ 609,430	$ 609,430	$ -
1935	Stores Equipment	21,484		$ 21,484	$ -		$ -	$ -	4.55	21.99%	10.00	10.00%	$ 4,724	$ -	$ -	$ 4,724	$ 4,724	$ -
1940	Tools, Shop & Garage Equipment	324,953		$ 324,953	$ 140,421		$ 140,421	$ 76,230	6.70	14.93%	10.00	10.00%	$ 48,520	$ 14,042	$ 3,812	$ 66,374	$ 66,374	$ -
1940	Tools - Smart Meters	-		$ -	$ -		$ -	$ -	-	0.00%	10.00	10.00%	$ -	$ -	$ -	$ -	$ 373	$ 373
1945	Measurement & Testing Equipment	163,014		$ 163,014	$ 105,845		$ 105,845	$ 56,975	7.77	12.88%	10.00	10.00%	$ 20,993	$ 10,585	$ 2,849	$ 34,426	$ 34,426	$ -
1950	Power Operated Equipment	306,812		$ 306,812	$ 54,068		$ 54,068	$ 94,765	6.77	14.76%	10.00	10.00%	$ 45,297	$ 5,407	$ 4,738	$ 55,442	$ 55,442	$ -
1955	Communications Equipment	58,880		$ 58,880	$ 1,251		$ 1,251	$ 31,176	6.76	14.80%	10.00	10.00%	$ 8,715	$ 125	$ 1,559	$ 10,399	$ 10,399	$ -
1955	Communication Equipment (Smart Meters)	-		$ -	$ 696,896		$ 696,896	$ -	-	0.00%	10.00	10.00%	$ -	$ 69,690	$ -	$ 69,690	$ 69,690	$ 0
1960	Miscellaneous Equipment	40,970		$ 40,970	$ 10,150		$ 10,150	$ -	3.61	27.74%	5.00	20.00%	$ 11,363	$ 2,030	$ -	$ 13,393	$ 13,393	$ -
1975	Load Management Controls Utility Premises	-		$ -	$ -		$ -	$ -	-	0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1980	System Supervisor Equipment	115,075	$ 91,860	$ 23,215	$ -		$ -	$ -	6.15	16.26%	10.00	10.00%	$ 3,775	$ -	$ -	$ 3,775	$ 4,059	$ 285
1985	Miscellaneous Fixed Assets			$ -			$ -	$ -	-	0.00%		0.00%	$ -	$ -	$ -	$ -		$ -

Appendix 2-C
Depreciation and Amortization Expense

1995	**Contributions & Grants**			$ -			$ -		-	0.00%		0.00%	$ -	$ -	$ -	$ -			$ -
1995	Contributed Capital - Poles, Towers & Fixtures	- 1,626,853		-$ 1,626,853	-$ 1,146,161		-$ 1,146,161	$ -	34.50	2.90%	40.00	2.50%	-$ 47,155	-$ 28,654	$ -	-$ 75,809	-$ 75,299	$ 510
1995	Contributed Capital - Overhead Conductors	- 1,246,129		-$ 1,246,129	-$ 969,095		-$ 969,095	$ -	54.55	1.83%	60.00	1.67%	-$ 22,844	-$ 16,152	$ -	-$ 38,996	-$ 38,996	$ -
1995	Contributed Capital - Overhead Devices	- 138,459		-$ 138,459	-$ 109,089		-$ 109,089	$ -	34.39	2.91%	40.00	2.50%	-$ 4,026	-$ 2,727	$ -	-$ 6,753	-$ 6,753	$ -
1995	Contributed Capital - Overhead Services	- 1,195,490		-$ 1,195,490	-$ 119,872		-$ 119,872	$ -	40.18	2.49%	60.00	1.67%	-$ 29,750	-$ 1,998	$ -	-$ 31,748	-$ 31,748	$ -
1995	Contributed Capital - Underground Trenching & Ductwork	- 5,566,404		-$ 5,566,404	-$ 2,609,506		-$ 2,609,506	$ -	54.02	1.85%	60.00	1.67%	-$ 103,051	-$ 43,492	$ -	-$ 146,543	-$ 146,543	$ -
1995	Contributed Capital - Underground Cables	- 2,292,136		-$ 2,292,136	-$ 2,370,201		-$ 2,370,201	$ -	30.81	3.25%	40.00	2.50%	-$ 74,387	-$ 59,255	$ -	-$ 133,642	-$ 133,642	$ -
1995	Contributed Capital - Underground Devices	- 254,682		-$ 254,682	-$ 167,703		-$ 167,703	$ -	-	0.00%	40.00	2.50%	$ -	-$ 4,193	$ -	-$ 4,193	-$ 4,193	$ -
1995	Contributed Capital - Overhead Transformer	- 2,734,282		-$ 2,734,282	$ 169,874		$ 169,874	$ -	34.03	2.94%	40.00	2.50%	-$ 80,349	$ 4,247	$ -	-$ 76,102	-$ 76,102	$ -
1995	Contributed Capital - Underground Padmount Transformer	- 1,858,357		-$ 1,858,357	-$ 7,920		-$ 7,920	$ -	32.33	3.09%	40.00	2.50%	-$ 57,473	-$ 198	$ -	-$ 57,671	-$ 57,671	$ -
1995	Contributed Capital -Underground Submersible Transformer	- 1,955,810		-$ 1,955,810	-$ 675,874		-$ 675,874	$ -	25.19	3.97%	30.00	3.33%	-$ 77,649	-$ 22,529	$ -	-$ 100,178	-$ 100,178	$ -
1995	Contributed Capital - Underground Services	- 13,453,846		-$ 13,453,846	-$ 953,639		-$ 953,639	$ -	33.74	2.96%	40.00	2.50%	-$ 398,729	-$ 23,841	$ -	-$ 422,570	-$ 422,570	$ -
1995	Contributed Capital - Transformer Foundations	- 798,352		-$ 798,352	-$ 558,073		-$ 558,073	$ -	54.11	1.85%	60.00	1.67%	-$ 14,753	-$ 9,301	$ -	-$ 24,054	-$ 24,054	$ -
1995	Contributed Capital - Meters	- 166,183		-$ 166,183	-$ 132,547		-$ 132,547	$ -	6.15	16.25%	15.00	6.67%	-$ 27,003	-$ 8,836	$ -	-$ 35,839	-$ 35,839	$ -
	Contributed Capital - Meters SOLAR	-		$ -	-$ 152,011		-$ 152,011	$ -	-	0.00%	15.00	6.67%	$ -	-$ 10,134	$ -	-$ 10,134	-$ 10,134	$ -
1995	Contributed Capital - OEB Clearing	68,538		$ 68,538	$ 259,328		$ 259,328	$ -	- 10.00	-10.00%	15.00	6.67%	-$ 6,854	$ 17,289	$ -	$ 10,435	$ 10,435	$ -
2440	**Deferred Revenue**			$ -			$ -		-	0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
2440	Contributed Capital - Poles, Towers & Fixtures	-		$ -			$ -	-$ 480,870	-	0.00%	40.00	2.50%	$ -	$ -	-$ 6,011	-$ 6,011	-$ 6,011	$ -
2440	Contributed Capital - Overhead Conductors	-		$ -			$ -	-$ 311,681	-	0.00%	60.00	1.67%	$ -	$ -	-$ 2,597	-$ 2,597	-$ 2,597	$ -
2440	Contributed Capital - Overhead Devices	-		$ -			$ -	-$ 34,631	-	0.00%	40.00	2.50%	$ -	$ -	-$ 433	-$ 433	-$ 433	$ -
2440	Contributed Capital - Overhead Services	-		$ -			$ -	-$ 26,848	-	0.00%	60.00	1.67%	$ -	$ -	-$ 224	-$ 224	-$ 224	$ -
2440	Contributed Capital - Underground Trenching & Ductwork	-		$ -			$ -	-$ 1,815,028	-	0.00%	60.00	1.67%	$ -	$ -	-$ 15,125	-$ 15,125	-$ 15,125	$ -
2440	Contributed Capital - Underground Cables	-		$ -			$ -	-$ 1,714,066	-	0.00%	40.00	2.50%	$ -	$ -	-$ 21,426	-$ 21,426	-$ 21,426	$ -
2440	Contributed Capital - Underground Devices	-		$ -			$ -	-$ 190,357	-	0.00%	40.00	2.50%	$ -	$ -	-$ 2,379	-$ 2,379	-$ 2,379	$ -
2440	Contributed Capital - Overhead Transformer	-		$ -			$ -	-$ 24,194	-	0.00%	40.00	2.50%	$ -	$ -	-$ 302	-$ 302	-$ 302	$ -
2440	Contributed Capital - Underground Padmount Transformer	-		$ -			$ -	-$ 50,168	-	0.00%	40.00	2.50%	$ -	$ -	-$ 627	-$ 627	-$ 627	$ -
2440	Contributed Capital -Underground Submersible Transformer	-		$ -			$ -	-$ 328,568	-	0.00%	30.00	3.33%	$ -	$ -	-$ 5,476	-$ 5,476	-$ 5,476	$ -
2440	Contributed Capital - Underground Services	-		$ -			$ -	-$ 1,019,308	-	0.00%	40.00	2.50%	$ -	$ -	-$ 12,741	-$ 12,741	-$ 12,741	$ -
2440	Contributed Capital - Transformer Foundations	-		$ -			$ -	-$ 119,509	-	0.00%	60.00	1.67%	$ -	$ -	-$ 996	-$ 996	-$ 996	$ -
2440	Contributed Capital - Meters	-		$ -			$ -	-$ 44,356	-	0.00%	15.00	6.67%	$ -	$ -	-$ 1,479	-$ 1,479	-$ 1,479	$ -
2440	Contributed Capital - Meters Solar	-		$ -			$ -	-$ 152,348	-	0.00%	15.00	6.67%	$ -	$ -	-$ 5,078	-$ 5,078	-$ 5,078	$ -
2440	Contributed Capital - OEB Clearing	-		$ -			$ -	-$ 243,274	-	0.00%	15.00	6.67%	$ -	$ -	-$ 8,109	-$ 8,109	-$ 8,109	$ -
2440	Meters - Renewable Connection - Direct Benefit	-		$ -			$ -	-$ 143,107	-	0.00%	15.00	6.67%	$ -	$ -	-$ 4,770	-$ 4,770	-$ 22,654	-$ 17,884
				$ -			$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
	Total	**$ 148,349,204**	**$ 1,238,248**	**$ 147,110,956**	**$ 46,455,008**	**$ 955,878**	**$ 45,499,130**	**$ 11,591,504**					$ 5,548,758	$ 2,011,559	$ 250,148	$ 7,810,465	$ 7,671,936	-$ 138,530

Appendix 2-C
Depreciation and Amortization Expense

2015

		Book Values							Service Lives				Depreciation Expense						
Account	Description	Opening Net Book Value of Existing Assets as at Date of Policy Change (Jan. 1) [1]	Less Fully Depreciated [7]	Net Amount of Existing Assets Before Policy Change to be Depreciated	Opening Gross Book Value of Assets Acquired After Policy Change [2]	Less Fully Depreciated [8]	Net Amount of Assets Acquired After Policy Change to be Depreciated	Current Year Additions	Average Remaining Life of Assets Existing Before Policy Change [3]	Depreciation Rate Assets Acquired After Policy Change	Life of Assets Acquired After Policy Change [4]	Depreciation Rate on New Additions	Depreciation Expense on Assets Existing Before Policy Change	Depreciation Expense on Assets Acquired After Policy Change	Depreciation Expense on Current Year Additions [5]	Total Current Year Depreciation Expense	Depreciation Expense per Appendix 2-BA Fixed Assets, Column J	Variance [6]
		a	b	c = a-b	d	e	f = d- e	g	h	i = 1/h	j	k = 1/j	l = c/h	m = f/j	n = g*0.5/j	o = l+m+n	p	q = p-o
1611	Computer Software (Formally known as Account 1925)	928,634	$ 706,332	$ 222,302	$ 726,706	$ 134,165	$ 592,541	$ 523,099	2.25	44.44%	5.00	20.00%	$ 98,801	$ 118,508	$ 52,310	$ 269,619	$ 264,294	-$ 5,325
1611	Computer Software (Formally known as Account 1925)			$ -	$ 88,614	$ 79,996	$ 8,618		-	0.00%	3.00	33.33%	$ -	$ 2,873	$ -	$ 2,873		-$ 2,873
1611	Computer Software (Formally known as Account 1925) - Smart Meters	-	$ -	$ -	$ 598,681	$ 558,314	$ 40,367	$ -	-	0.00%	3.00	33.33%	$ -	$ 13,456	$ -	$ 13,456	$ 9,644	-$ 3,812
1612	Land Rights (Formally known as Account 1906)	12,881	$ -	$ 12,881	$ -	$ -	$ -		4.86	20.60%	50.00	2.00%	$ 2,653	$ -	$ -	$ 2,653	$ 2,653	$ -
1805	Land	2,339,958	$ -	$ 2,339,958	$ -	$ -	$ -		-	0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1808	Buildings - Structure	7,099,490	$ -	$ 7,099,490	$ 585,080	$ -	$ 585,080	-$ 121,526	38.08	2.63%	50.00	2.00%	$ 186,429	$ 11,702	-$ 1,215	$ 196,916	$ 199,177	$ 2,261
1808	Buildings - Roof	144,989	$ 38,113	$ 106,876	$ -	$ -	$ -	-$ 2,480	11.44	8.74%	20.00	5.00%	$ 9,344	$ -	-$ 62	$ 9,282	$ 11,872	$ 2,590
1810	Leasehold Improvements		$ -	$ -	$ -	$ -	$ -		-	0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1815	Transformer Station Equipment >50 kV 50 yrs	15,658,085	$ 12,312	$ 15,645,773	$ 1,954,817	$ -	$ 1,954,817	-$ 452,443	41.16	2.43%	50.00	2.00%	$ 380,092	$ 39,096	-$ 4,524	$ 414,663	$ 414,963	$ 299
1815	Transformer Station Equipment >50 kV 40 yrs	24,475,179	$ -	$ 24,475,179	$ 1,244,179	$ -	$ 1,244,179	$ -	28.76	3.48%	40.00	2.50%	$ 851,073	$ 31,104	$ -	$ 882,178	$ 882,178	$ -
1815	Transformer Station Equipment >50 kV 30 yrs		$ -	$ -	$ -	$ -	$ -		-	0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1815	Transformer Station Equipment >50 kV 25 yrs	887,028	$ 168,084	$ 718,944	$ -	$ -	$ -	$ -	12.07	8.28%	25.00	4.00%	$ 59,555	$ -	$ -	$ 59,555	$ 58,000	-$ 1,554
1815	Transformer Station Equipment >50 kV 20 yrs	392,015	$ 47,127	$ 344,888	$ 23,491	$ -	$ 23,491	$ -	9.76	10.24%	20.00	5.00%	$ 35,322	$ 1,175	$ -	$ 36,497	$ 41,142	$ 4,645
1815	Transformer Station Equipment >50 kV 15 yrs	1,087,574	$ 27,010	$ 1,060,564	$ 873,187	$ -	$ 873,187	$ 144,833	8.48	11.79%	15.00	6.67%	$ 125,082	$ 58,212	$ 4,828	$ 188,122	$ 187,417	-$ 705
1820	Distribution Station Equipment <50 kV 50 yrs	200,427	$ -	$ 200,427	$ -	$ -	$ -	$ -	22.74	4.40%	50.00	2.00%	$ 8,813	$ -	$ -	$ 8,813	$ 8,813	$ -
1820	Distribution Station Equipment <50 kV 40 yrs	649,832	$ -	$ 649,832	$ -	$ -	$ -	$ -	25.47	3.93%	40.00	2.50%	$ 25,509	$ -	$ -	$ 25,509	$ 25,509	$ -
1820	Distribution Station Equipment <50 kV 25 yrs	13,287	$ -	$ 13,287	$ -	$ -	$ -	$ -	5.93	16.87%	25.00	4.00%	$ 2,242	$ -	$ -	$ 2,242	$ 1,941	-$ 301
1820	Distribution Station Equipment <50 kV 20 yrs	6,078	$ 6,078	$ -	$ -	$ -	$ -	$ -	5.66	17.66%	20.00	5.00%	$ -	$ -	$ -	$ -	$ 461	$ 461
1820	Distribution Station Equipment <50 kV 15 hrs	17,551	$ 17,551	$ -	$ 153,636	$ -	$ 153,636	$ -	9.64	10.37%	15.00	6.67%	$ -	$ 10,242	$ -	$ 10,242	$ 12,063	$ 1,820
1825	Storage Battery Equipment		$ -	$ -	$ -	$ -	$ -		-	0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1830	Poles, Towers & Fixtures	17,028,402	$ -	$ 17,028,402	$ 6,876,205	$ -	$ 6,876,205	$ 3,374,648	32.16	3.11%	40.00	2.50%	$ 529,490	$ 171,905	$ 42,183	$ 743,578	$ 731,757	-$ 11,821
1835	Overhead Conductors	14,319,062	$ -	$ 14,319,062	$ 4,500,489	$ -	$ 4,500,489	$ 2,501,827	51.16	1.95%	60.00	1.67%	$ 279,881	$ 75,008	$ 20,849	$ 375,738	$ 375,738	$ -
1835	Overhead Devices	1,591,007	$ -	$ 1,591,007	$ 549,409	$ -	$ 549,409	$ 293,766	30.57	3.27%	40.00	2.50%	$ 52,051	$ 13,735	$ 3,672	$ 69,458	$ 69,458	$ -
1835	Voltage Regulators	163,109	$ -	$ 163,109	$ -	$ -	$ -	$ -	20.00	5.00%	30.00	3.33%	$ 8,155	$ -	$ -	$ 8,155	$ 8,155	$ -
1835	Capacitor Banks	618,096	$ -	$ 618,096	$ 93,467	$ -	$ 93,467	$ 199,837	19.80	5.05%	25.00	4.00%	$ 31,224	$ 3,739	$ 3,997	$ 38,959	$ 36,780	-$ 2,179
1840	Underground Conduit	12,527,558	$ -	$ 12,527,558	$ 7,689,717	$ -	$ 7,689,717	$ 4,356,442	51.70	1.93%	60.00	1.67%	$ 242,295	$ 128,162	$ 36,304	$ 406,761	$ 406,761	$ -
1845	Underground Conductors & Devices - PILC	414,000	$ -	$ 414,000	$ 465,861	$ -	$ 465,861	$ 48,503	58.00	1.72%	60.00	1.67%	$ 7,138	$ 7,764	$ 404	$ 15,306	$ 15,306	$ -
1845	Underground Cables	15,726,653	$ -	$ 15,726,653	$ 6,291,745	$ -	$ 6,291,745	$ 2,637,426	28.66	3.49%	40.00	2.50%	$ 548,637	$ 157,294	$ 32,968	$ 738,899	$ 738,899	$ -
1845	Underground Devices	1,747,406	$ -	$ 1,747,406	$ 768,589	$ -	$ 768,589	$ 305,782	28.66	3.49%	40.00	2.50%	$ 60,960	$ 19,215	$ 3,822	$ 83,997	$ 83,997	$ -
1850	Line Transformers - Overhead	15,713,833	$ 314,720	$ 15,399,113	$ 2,373,973	$ -	$ 2,373,973	$ 1,050,382	27.98	3.57%	40.00	2.50%	$ 550,276	$ 59,349	$ 13,130	$ 622,755	$ 629,798	$ 7,043
1850	Line Transformers - Network	5,503	$ -	$ 5,503	$ 302,203	$ -	$ 302,203	$ 95,759	9.38	10.66%	40.00	2.50%	$ 587	$ 7,555	$ 1,197	$ 9,339	$ 9,198	-$ 141
1850	Line Transformers - Vault	-	$ -	$ -	$ 5,849	$ -	$ 5,849	$ -	-	0.00%	60.00	1.67%	$ -	$ 97	$ -	$ 97	$ 97	$ -
1850	Line Transformers - Roof	497,948	$ -	$ 497,948	$ -	$ -	$ -	$ -	23.84	4.19%	30.00	3.33%	$ 20,885	$ -	$ -	$ 20,885	$ 20,683	-$ 203
1850	Line Transformers -Network Protectors	91,592	$ -	$ 91,592	$ 315,604	$ -	$ 315,604	$ 115,455	39.50	2.53%	40.00	2.50%	$ 2,319	$ 7,890	$ 1,443	$ 11,652	$ 11,586	-$ 66
1850	Line Transformers - Padmount	3,991,872	$ -	$ 3,991,872	$ 2,141,297	$ -	$ 2,141,297	$ 1,000,402	36.77	2.72%	40.00	2.50%	$ 108,567	$ 53,532	$ 12,505	$ 174,604	$ 56,125	-$ 118,479
1850	Line Transformers - Submersible	3,195,923	$ -	$ 3,195,923	$ 1,823,397	$ -	$ 1,823,397	$ 745,901	24.09	4.15%	30.00	3.33%	$ 132,669	$ 60,780	$ 12,432	$ 205,881	$ 83,446	-$ 122,435
1850	Line Transformers - Foundation	1,427,416	$ -	$ 1,427,416	$ 647,275	$ -	$ 647,275	$ 228,293	58.08	1.72%	60.00	1.67%	$ 24,575	$ 10,788	$ 1,902	$ 37,266	$ 14,182	-$ 23,084
1855	Services - Overhead	1,887,728	$ -	$ 1,887,728	$ 1,223,124	$ -	$ 1,223,124	$ 441,553	52.20	1.92%	60.00	1.67%	$ 36,164	$ 20,385	$ 3,680	$ 60,229	$ 60,229	$ -
1855	Services - Underground	22,543,287	$ -	$ 22,543,287	$ 5,864,328	$ -	$ 5,864,328	$ 2,893,603	31.40	3.18%	40.00	2.50%	$ 717,938	$ 146,608	$ 36,170	$ 900,716	$ 900,716	$ -
1860	Commercial Meters	1,327,802	$ 158,636	$ 1,169,166	$ 895,420	$ -	$ 895,420	$ 87,170	20.97	4.77%	25.00	4.00%	$ 55,753	$ 35,817	$ 1,743	$ 93,313	$ 97,667	$ 4,355
1860	Smart Meters - Non-Qualifying	108,222		$ 108,222	$ 240,153	$ -	$ 240,153		12.00	8.33%	15.00	6.67%	$ 9,018	$ 16,010	$ -	$ 25,028		-$ 25,028
1860	Meters - Renewable Connection			$ -	$ 154,427	$ -	$ 154,427		-	0.00%	15.00	6.67%	$ -	$ 10,295	$ -	$ 10,295		-$ 10,295
1860	Smart Meters			$ -	$ -	$ -	$ -		-	0.00%	15.00	6.67%	$ -	$ -	$ -	$ -		$ -
1860	Smart Meters	-	$ -	$ -	$ 12,494,108	$ -	$ 12,494,108	$ 156,433	-	0.00%	15.00	6.67%	$ -	$ 832,941	$ 5,214	$ 838,155	$ 838,155	$ -
1905	Land	1,395,300	$ -	$ 1,395,300	$ -	$ -	$ -	$ -	-	0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1908	Buildings & Fixtures - Building	5,262,681	$ -	$ 5,262,681	$ 4,877,915	$ -	$ 4,877,915	$ 32,479	28.71	3.48%	50.00	2.00%	$ 183,326	$ 97,558	$ 325	$ 281,209	$ 274,582	-$ 6,627
1908	Buildings & Fixtures - Roof	1,567,291	$ -	$ 1,567,291	$ 2,229,408	$ -	$ 2,229,408	$ 55,888	6.53	15.33%	20.00	5.00%	$ 240,192	$ 111,470	$ 1,397	$ 353,059	$ 333,884	-$ 19,175
1910	Leasehold Improvements	-	$ -	$ -	$ -	$ -	$ -	$ -	-	0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1915	Office Furniture & Equipment (10 years)	340,212	$ 54,324	$ 285,888	$ 245,415	$ -	$ 245,415	$ 64,368	5.10	19.61%	10.00	10.00%	$ 56,056	$ 24,542	$ 3,218	$ 83,816	$ 67,374	-$ 16,443
1915	Office Furniture & Equipment (5 years)		$ -	$ -	$ -	$ -	$ -		-	0.00%	5.00	20.00%	$ -	$ -	$ -	$ -		$ -
1920	Computer Equipment - Hardware	350,464	$ 86,058	$ 264,406	$ 298,738	$ -	$ 298,738	$ 174,117	2.12	47.12%	5.00	20.00%	$ 124,601	$ 59,748	$ 17,412	$ 201,760	$ 202,503	$ 743
1920	Computer Equip.-Hardware - Smart Meters	-	$ -	$ -	$ 569,286	$ 437,864	$ 131,422	$ -	-	0.00%	5.00	20.00%	$ -	$ 26,284	$ -	$ 26,284	$ 22,126	-$ 4,158
1920	Computer Equip.-Hardware(Post Mar. 19/07)	-	$ -	$ -	$ -	$ -	$ -	$ -	-	0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1930	Transportation Equipment	2,781,086	$ 3,097	$ 2,777,989	$ 2,833,743	$ -	$ 2,833,743	$ 482,300	7.19	13.90%	11.00	9.09%	$ 386,258	$ 257,613	$ 21,923	$ 665,794	$ 661,498	-$ 4,295
1935	Stores Equipment	21,484	$ -	$ 21,484	$ -	$ -	$ -	$ -	4.55	21.99%	10.00	10.00%	$ 4,724	$ -	$ -	$ 4,724	$ 5,711	$ 987
1940	Tools, Shop & Garage Equipment	324,953	$ -	$ 324,953	$ 216,651	$ -	$ 216,651	$ 67,712	6.70	14.93%	10.00	10.00%	$ 48,520	$ 21,665	$ 3,386	$ 73,571	$ 69,390	-$ 4,181
1940	Tools - Smart Meters	-	$ -	$ -	$ -	$ -	$ -	$ -	-	0.00%	10.00	10.00%	$ -	$ -	$ -	$ -	$ 373	$ 373
1945	Measurement & Testing Equipment	163,014	$ -	$ 163,014	$ 162,820	$ -	$ 162,820	$ 18,213	7.77	12.88%	10.00	10.00%	$ 20,993	$ 16,282	$ 911	$ 38,185	$ 37,576	-$ 609
1950	Power Operated Equipment	306,812	$ -	$ 306,812	$ 148,833	$ -	$ 148,833	$ 179,117	6.77	14.76%	10.00	10.00%	$ 45,297	$ 14,883	$ 8,956	$ 69,136	$ 62,365	-$ 6,771
1955	Communications Equipment	58,880	$ -	$ 58,880	$ 32,427	$ -	$ 32,427	$ 55,700	6.76	14.80%	10.00	10.00%	$ 8,715	$ 3,243	$ 2,785	$ 14,743	$ 14,772	$ 29
1955	Communication Equipment (Smart Meters)	-	$ -	$ -	$ 696,896	$ -	$ 696,896	$ -	-	0.00%	10.00	10.00%	$ -	$ 69,690	$ -	$ 69,690	$ 69,690	$ -
1960	Miscellaneous Equipment	40,970	$ -	$ 40,970	$ 10,150	$ -	$ 10,150	$ -	3.61	27.74%	5.00	20.00%	$ 11,363	$ 2,030	$ -	$ 13,393	$ 2,031	-$ 11,362
1975	Load Management Controls Utility Premises	-	$ -	$ -	$ -	$ -	$ -	$ -	-	0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1980	System Supervisor Equipment	115,075	$ 91,860	$ 23,215	$ -	$ -	$ -	$ -	6.15	16.26%	10.00	10.00%	$ 3,775	$ -	$ -	$ 3,775	$ 4,059	$ 285
1985	Miscellaneous Fixed Assets		$ -	$ -	$ -	$ -	$ -	$ -	-	0.00%		0.00%	$ -	$ -	$ -	$ -		$ -

Appendix 2-C
Depreciation and Amortization Expense

1995	**Contributions & Grants**		$ -	$ -	$ -	$ -	$ -		-	0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1995	Contributed Capital - Poles, Towers & Fixtures	- 1,626,853	$ -	-$ 1,626,853	-$ 1,146,161	$ -	-$ 1,146,161	$ -	34.50	2.90%	40.00	2.50%	-$ 47,155	-$ 28,654	$ -	-$ 75,809	-$ 76,140	-$ 331
1995	Contributed Capital - Overhead Conductors	- 1,246,129	$ -	-$ 1,246,129	-$ 969,095	$ -	-$ 969,095	$ -	54.55	1.83%	60.00	1.67%	-$ 22,844	-$ 16,152	$ -	-$ 38,996	-$ 38,983	$ 13
1995	Contributed Capital - Overhead Devices	- 138,459	$ -	-$ 138,459	-$ 109,089	$ -	-$ 109,089	$ -	34.39	2.91%	40.00	2.50%	-$ 4,026	-$ 2,727	$ -	-$ 6,753	-$ 6,773	-$ 20
1995	Contributed Capital - Overhead Services	- 1,195,490	$ -	-$ 1,195,490	-$ 119,872	$ -	-$ 119,872	$ -	40.18	2.49%	60.00	1.67%	-$ 29,750	-$ 1,998	$ -	-$ 31,748	-$ 27,445	$ 4,303
1995	Contributed Capital - Underground Trenching & Ductwork	- 5,566,404	$ -	-$ 5,566,404	-$ 2,609,506	$ -	-$ 2,609,506	$ -	54.02	1.85%	60.00	1.67%	-$ 103,051	-$ 43,492	$ -	-$ 146,543	-$ 146,667	-$ 124
1995	Contributed Capital - Underground Cables	- 2,292,136	$ -	-$ 2,292,136	-$ 2,370,201	$ -	-$ 2,370,201	$ -	30.81	3.25%	40.00	2.50%	-$ 74,387	-$ 59,255	$ -	-$ 133,642	-$ 126,452	$ 7,190
1995	Contributed Capital - Underground Devices	- 254,682	$ -	-$ 254,682	-$ 167,703	$ -	-$ 167,703	$ -	-	0.00%	40.00	2.50%	$ -	-$ 4,193	$ -	-$ 4,193	-$ 11,693	-$ 7,500
1995	Contributed Capital - Overhead Transformer	- 2,734,282	$ -	-$ 2,734,282	$ 169,874	$ -	$ 169,874	$ -	34.03	2.94%	40.00	2.50%	-$ 80,349	$ 4,247	$ -	-$ 76,102	-$ 81,825	-$ 5,723
1995	Contributed Capital - Underground Padmount Transformer	- 1,858,357	$ -	-$ 1,858,357	-$ 7,920	$ -	-$ 7,920	$ -	32.33	3.09%	40.00	2.50%	-$ 57,473	-$ 198	$ -	-$ 57,671	-$ 64,413	-$ 6,742
1995	Contributed Capital -Underground Submersible Transformer	- 1,955,810	$ -	-$ 1,955,810	-$ 675,874	$ -	-$ 675,874	$ -	25.19	3.97%	30.00	3.33%	-$ 77,649	-$ 22,529	$ -	-$ 100,178	-$ 100,178	$ -
1995	Contributed Capital - Underground Services	- 13,453,846	$ -	-$ 13,453,846	-$ 953,639	$ -	-$ 953,639	$ -	33.74	2.96%	40.00	2.50%	-$ 398,729	-$ 23,841	$ -	-$ 422,570	-$ 456,306	-$ 33,736
1995	Contributed Capital - Transformer Foundations	- 798,352	$ -	-$ 798,352	-$ 558,073	$ -	-$ 558,073	$ -	54.11	1.85%	60.00	1.67%	-$ 14,753	-$ 9,301	$ -	-$ 24,054	-$ 24,054	$ -
1995	Contributed Capital - Meters	- 166,183	$ -	-$ 166,183	-$ 132,547	$ -	-$ 132,547	$ -	6.15	16.25%	15.00	6.67%	-$ 27,003	-$ 8,836	$ -	-$ 35,839	-$ 26,572	$ 9,267
	Contributed Capital - Meters SOLAR	-	$ -	$ -	-$ 152,011	$ -	-$ 152,011	$ -	-	0.00%	15.00	6.67%	$ -	-$ 10,134	$ -	-$ 10,134	-$ 13,644	-$ 3,509
1995	Contributed Capital - OEB Clearing	68,538	$ -	$ 68,538	$ 259,328	$ -	$ 259,328	$ -	- 10.00	-10.00%	15.00	6.67%	-$ 6,854	$ 17,289	$ -	$ 10,435	$ 18,682	$ 8,247
2440	**Deferred Revenue**		$ -	$ -	$ -	$ -	$ -		-	0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
2440	Contributed Capital - Poles, Towers & Fixtures	-	$ -	$ -	-$ 480,870	$ -	-$ 480,870	-$ 1,357,297	-	0.00%	40.00	2.50%	$ -	-$ 12,022	-$ 16,966	-$ 28,988	-$ 28,988	$ -
2440	Contributed Capital - Overhead Conductors	-	$ -	$ -	-$ 311,681	$ -	-$ 311,681	-$ 1,127,219	-	0.00%	60.00	1.67%	$ -	-$ 5,195	-$ 9,393	-$ 14,588	-$ 14,588	$ -
2440	Contributed Capital - Overhead Devices	-	$ -	$ -	-$ 34,631	$ -	-$ 34,631	-$ 125,246	-	0.00%	40.00	2.50%	$ -	-$ 866	-$ 1,566	-$ 2,431	-$ 2,431	$ -
2440	Contributed Capital - Overhead Services	-	$ -	$ -	-$ 26,848	$ -	-$ 26,848	-$ 175,586	-	0.00%	60.00	1.67%	$ -	-$ 447	-$ 1,463	-$ 1,911	-$ 1,911	$ -
2440	Contributed Capital - Underground Trenching & Ductwork	-	$ -	$ -	-$ 1,815,028	$ -	-$ 1,815,028	-$ 3,410,836	-	0.00%	60.00	1.67%	$ -	-$ 30,250	-$ 28,424	-$ 58,674	-$ 58,674	$ -
2440	Contributed Capital - Underground Cables	-	$ -	$ -	-$ 1,714,066	$ -	-$ 1,714,066	-$ 1,216,363	-	0.00%	40.00	2.50%	$ -	-$ 42,852	-$ 15,205	-$ 58,056	-$ 58,056	$ -
2440	Contributed Capital - Underground Devices	-	$ -	$ -	-$ 190,357	$ -	-$ 190,357	-$ 135,418	-	0.00%	40.00	2.50%	$ -	-$ 4,759	-$ 1,693	-$ 6,452	-$ 6,452	$ -
2440	Contributed Capital - Overhead Transformer	-	$ -	$ -	-$ 24,194	$ -	-$ 24,194	-$ 9,183	-	0.00%	40.00	2.50%	$ -	-$ 605	-$ 115	-$ 720	-$ 720	$ -
2440	Contributed Capital - Underground Padmount Transformer	-	$ -	$ -	-$ 50,168	$ -	-$ 50,168	-$ 134,178	-	0.00%	40.00	2.50%	$ -	-$ 1,254	-$ 1,677	-$ 2,931	-$ 2,931	$ -
2440	Contributed Capital -Underground Submersible Transformer	-	$ -	$ -	-$ 328,568	$ -	-$ 328,568	-$ 605,194	-	0.00%	30.00	3.33%	$ -	-$ 10,952	-$ 10,087	-$ 21,039	-$ 21,039	$ -
2440	Contributed Capital - Underground Services	-	$ -	$ -	-$ 1,019,308	$ -	-$ 1,019,308	-$ 879,364	-	0.00%	40.00	2.50%	$ -	-$ 25,483	-$ 10,992	-$ 36,475	-$ 36,475	$ -
2440	Contributed Capital - Transformer Foundations	-	$ -	$ -	-$ 119,509	$ -	-$ 119,509	-$ 250,622	-	0.00%	60.00	1.67%	$ -	-$ 1,992	-$ 2,089	-$ 4,080	-$ 4,173	-$ 93
2440	Contributed Capital - Meters	-	$ -	$ -	-$ 44,356	$ -	-$ 44,356	-$ 50,223	-	0.00%	15.00	6.67%	$ -	-$ 2,957	-$ 1,674	-$ 4,631	-$ 4,631	$ -
2440	Contributed Capital - Meters Solar	-	$ -	$ -	-$ 152,348	$ -	-$ 152,348	-$ 117,859	-	0.00%	15.00	6.67%	$ -	-$ 10,157	-$ 3,929	-$ 14,085	-$ 14,085	$ -
2440	Contributed Capital - OEB Clearing	-	$ -	$ -	-$ 243,274	$ -	-$ 243,274	$ -	-	0.00%	15.00	6.67%	$ -	-$ 16,218	$ -	-$ 16,218	-$ 16,218	$ -
2440	Meters - Renewable Connection - Direct Benefit	-	$ -	$ -	-$ 143,107	$ -	-$ 143,107	$ 134,602	-	0.00%	15.00	6.67%	$ -	-$ 9,540	$ 4,487	-$ 5,054	$ 21,295	$ 26,348
				$ -			$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
	Total	**$ 148,349,204**	**$ 1,731,302**	**$ 146,617,902**	**$ 58,046,512**	**$ 1,210,339**	**$ 56,836,173**	**$ 12,294,573**					$ 5,393,295	$ 2,444,923	$ 244,478	$ 8,082,696	$ 7,704,252	-$ 378,444

Appendix 2-C
Depreciation and Amortization Expense

2016

		Book Values							Service Lives				Depreciation Expense					
Account	Description	Opening Net Book Value of Existing Assets as at Date of Policy Change (Jan. 1) [1]	Less Fully Depreciated [7]	Net Amount of Existing Assets Before Policy Change to be Depreciated	Opening Gross Book Value of Assets Acquired After Policy Change [2]	Less Fully Depreciated [8]	Net Amount of Assets Acquired After Policy Change to be Depreciated	Current Year Additions	Average Remaining Life of Assets Existing Before Policy Change [3]	Depreciation Rate Assets Acquired After Policy Change	Life of Assets Acquired After Policy Change [4]	Depreciation Rate on New Additions	Depreciation Expense on Assets Existing Before Policy Change	Depreciation Expense on Assets Acquired After Policy Change	Depreciation Expense on Current Year Additions [5]	Total Current Year Depreciation Expense	Depreciation Expense per Appendix 2-BA Fixed Assets, Column J	Variance [6]
		a	b	c = a-b	d	e	f = d- e	g	h	i = 1/h	j	k = 1/j	l = c/h	m = f/j	n = g*0.5/j	o = l+m+n	p	q = p-o
1611	Computer Software (Formally known as Account 1925)	928,634	$ 706,332	$ 222,302	$ 1,249,805	$ 135,165	$ 1,114,640	$ 710,078	2.25	44.44%	5.00	20.00%	$ 98,801	$ 222,928	$ 71,008	$ 392,737	$ 390,186	-$ 2,551
1611	Computer Software (Formally known as Account 1925)			$ -	$ 88,614	$ 79,996	$ 8,618		-	0.00%	3.00	33.33%	$ -	$ 2,873	$ -	$ 2,873		-$ 2,873
1611	Computer Software (Formally known as Account 1925) - Smart Meters	-	$ -	$ -	$ 598,681	$ 598,681	$ -	$ -	-	0.00%	3.00	33.33%	$ -	$ -	$ -	$ -	$ 7,629	$ 7,629
1612	Land Rights (Formally known as Account 1906)	12,881	$ -	$ 12,881	$ -	$ -	$ -		4.86	20.60%	50.00	2.00%	$ 2,653	$ -	$ -	$ 2,653	$ 2,269	-$ 384
1805	Land	2,339,958	$ -	$ 2,339,958	$ -	$ -	$ -		-	0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1808	Buildings - Structure	7,099,490	$ -	$ 7,099,490	$ 463,554	$ -	$ 463,554	$ -	38.08	2.63%	50.00	2.00%	$ 186,429	$ 9,271	$ -	$ 195,700	$ 200,222	$ 4,521
1808	Buildings - Roof	144,989	$ 47,270	$ 97,719	-$ 2,480	$ -	-$ 2,480	$ -	11.44	8.74%	20.00	5.00%	$ 8,543	-$ 124	$ -	$ 8,419	$ 10,073	$ 1,654
1810	Leasehold Improvements		$ -	$ -	$ -	$ -	$ -		-	0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1815	Transformer Station Equipment >50 kV 50 yrs	15,658,085	$ 12,312	$ 15,645,773	$ 1,502,374	$ -	$ 1,502,374	-$ 32,364	41.16	2.43%	50.00	2.00%	$ 380,092	$ 30,047	-$ 324	$ 409,815	$ 410,477	$ 661
1815	Transformer Station Equipment >50 kV 40 yrs	24,475,179	$ -	$ 24,475,179	$ 1,244,179	$ -	$ 1,244,179	$ -	28.76	3.48%	40.00	2.50%	$ 851,073	$ 31,104	$ -	$ 882,178	$ 882,178	$ -
1815	Transformer Station Equipment >50 kV 30 yrs		$ -	$ -		$ -	$ -		-	0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1815	Transformer Station Equipment >50 kV 25 yrs	887,028	$ 171,854	$ 715,174	$ -	$ -	$ -	$ -	12.07	8.28%	25.00	4.00%	$ 59,242	$ -	$ -	$ 59,242	$ 57,553	-$ 1,690
1815	Transformer Station Equipment >50 kV 20 yrs	392,015	$ 66,888	$ 325,127	$ 23,491	$ -	$ 23,491	$ 164,946	9.76	10.24%	20.00	5.00%	$ 33,298	$ 1,175	$ 4,124	$ 38,596	$ 40,648	$ 2,051
1815	Transformer Station Equipment >50 kV 15 yrs	1,087,574	$ 42,304	$ 1,045,270	$ 1,018,020	$ -	$ 1,018,020	$ 57,657	8.48	11.79%	15.00	6.67%	$ 123,278	$ 67,868	$ 1,922	$ 193,068	$ 185,902	-$ 7,166
1820	Distribution Station Equipment <50 kV 50 yrs	200,427	$ -	$ 200,427	$ -	$ -	$ -	$ -	22.74	4.40%	50.00	2.00%	$ 8,813	$ -	$ -	$ 8,813	$ 8,813	$ -
1820	Distribution Station Equipment <50 kV 40 yrs	649,832	$ -	$ 649,832	$ -	$ -	$ -	$ -	25.47	3.93%	40.00	2.50%	$ 25,509	$ -	$ -	$ 25,509	$ 25,509	$ -
1820	Distribution Station Equipment <50 kV 25 yrs	13,287	$ -	$ 13,287	$ -	$ -	$ -	$ -	5.93	16.87%	25.00	4.00%	$ 2,242	$ -	$ -	$ 2,242	$ 1,575	-$ 667
1820	Distribution Station Equipment <50 kV 20 yrs	6,078	$ 6,078	$ -	$ -	$ -	$ -	$ -	5.66	17.66%	20.00	5.00%	$ -	$ -	$ -	$ -	$ 264	$ 264
1820	Distribution Station Equipment <50 kV 15 hrs	17,551	$ 17,551	$ -	$ 153,636	$ -	$ 153,636	$ -	9.64	10.37%	15.00	6.67%	$ -	$ 10,242	$ -	$ 10,242	$ 12,063	$ 1,820
1825	Storage Battery Equipment		$ -	$ -	$ -	$ -	$ -		-	0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1830	Poles, Towers & Fixtures	17,028,402	$ -	$ 17,028,402	$ 10,250,853	$ -	$ 10,250,853	$ 3,525,628	32.16	3.11%	40.00	2.50%	$ 529,490	$ 256,271	$ 44,070	$ 829,832	$ 836,577	$ 6,745
1835	Overhead Conductors	14,319,062	$ -	$ 14,319,062	$ 7,002,316	$ -	$ 7,002,316	$ 2,302,680	51.16	1.95%	60.00	1.67%	$ 279,881	$ 116,705	$ 19,189	$ 415,775	$ 415,775	-$ 0
1835	Overhead Devices	1,591,007	$ -	$ 1,591,007	$ 843,175	$ -	$ 843,175	$ 305,490	30.57	3.27%	40.00	2.50%	$ 52,051	$ 21,079	$ 3,819	$ 76,949	$ 77,834	$ 885
1835	Voltage Regulators	163,109	$ -	$ 163,109	$ -	$ -	$ -	$ -	20.00	5.00%	30.00	3.33%	$ 8,155	$ -	$ -	$ 8,155	$ 8,155	$ -
1835	Capacitor Banks	618,096	$ -	$ 618,096	$ 293,304	$ -	$ 293,304	$ 149,116	19.80	5.05%	25.00	4.00%	$ 31,224	$ 11,732	$ 2,982	$ 45,938	$ 41,182	-$ 4,757
1840	Underground Conduit	12,527,558	$ -	$ 12,527,558	$ 12,046,159	$ -	$ 12,046,159	$ 2,655,417	51.70	1.93%	60.00	1.67%	$ 242,295	$ 200,769	$ 22,128	$ 465,193	$ 465,193	$ -
1845	Underground Conductors & Devices - PILC	414,000	$ -	$ 414,000	$ 514,364	$ -	$ 514,364	$ 920,319	58.00	1.72%	60.00	1.67%	$ 7,138	$ 8,573	$ 7,669	$ 23,380	$ 23,380	$ -
1845	Underground Cables	15,726,653	$ -	$ 15,726,653	$ 8,929,171	$ -	$ 8,929,171	$ 3,436,932	28.66	3.49%	40.00	2.50%	$ 548,637	$ 223,229	$ 42,962	$ 814,828	$ 814,828	$ -
1845	Underground Devices	1,747,406	$ -	$ 1,747,406	$ 1,074,371	$ -	$ 1,074,371	$ 584,071	28.66	3.49%	40.00	2.50%	$ 60,960	$ 26,859	$ 7,301	$ 95,120	$ 95,120	$ -
1850	Line Transformers - Overhead	15,713,833	$ 323,443	$ 15,390,390	$ 3,424,355	$ -	$ 3,424,355	$ 1,337,162	27.98	3.57%	40.00	2.50%	$ 549,964	$ 85,609	$ 16,715	$ 652,287	$ 659,533	$ 7,246
1850	Line Transformers - Network	5,503	$ -	$ 5,503	$ 397,962	$ -	$ 397,962	$ 362,302	9.38	10.66%	40.00	2.50%	$ 587	$ 9,949	$ 4,529	$ 15,065	$ 10,766	-$ 4,298
1850	Line Transformers - Vault	-	$ -	$ -	$ 5,849	$ -	$ 5,849	$ 192	-	0.00%	60.00	1.67%	$ -	$ 97	$ 2	$ 99	$ 112	$ 13
1850	Line Transformers - Roof	497,948	$ 16,586	$ 481,362	$ -	$ -	$ -	$ -	23.84	4.19%	30.00	3.33%	$ 20,190	$ -	$ -	$ 20,190	$ 20,686	$ 496
1850	Line Transformers -Network Protectors	91,592	$ -	$ 91,592	$ 431,059	$ -	$ 431,059	$ 29,745	39.50	2.53%	40.00	2.50%	$ 2,319	$ 10,776	$ 372	$ 13,467	$ 13,401	-$ 66
1850	Line Transformers - Padmount	3,991,872	$ -	$ 3,991,872	$ 3,141,699	$ -	$ 3,141,699	$ 1,107,226	36.77	2.72%	40.00	2.50%	$ 108,567	$ 78,542	$ 13,840	$ 200,949	$ 423,041	$ 222,091
1850	Line Transformers - Submersible	3,195,923	$ -	$ 3,195,923	$ 2,569,298	$ -	$ 2,569,298	$ 709,291	24.09	4.15%	30.00	3.33%	$ 132,669	$ 85,643	$ 11,822	$ 230,134	$ 490,358	$ 260,224
1850	Line Transformers - Foundation	1,427,416	$ -	$ 1,427,416	$ 875,568	$ -	$ 875,568	$ 595,820	58.08	1.72%	60.00	1.67%	$ 24,575	$ 14,593	$ 4,965	$ 44,133	$ 92,964	$ 48,830
1855	Services - Overhead	1,887,728	$ -	$ 1,887,728	$ 1,664,677	$ -	$ 1,664,677	$ 360,635	52.20	1.92%	60.00	1.67%	$ 36,164	$ 27,745	$ 3,005	$ 66,914	$ 66,914	$ -
1855	Services - Underground	22,543,287	$ -	$ 22,543,287	$ 8,757,931	$ -	$ 8,757,931	$ 2,959,538	31.40	3.18%	40.00	2.50%	$ 717,938	$ 218,948	$ 36,994	$ 973,880	$ 973,880	$ -
1860	Commercial Meters	1,327,802	$ 158,636	$ 1,169,166	$ 982,590	$ -	$ 982,590	$ 265,312	20.97	4.77%	25.00	4.00%	$ 55,753	$ 39,304	$ 5,306	$ 100,362	$ 143,229	$ 42,866
1860	Smart Meters - Non-Qualifying	108,222		$ 108,222	$ 240,153	$ -	$ 240,153		12.00	8.33%	15.00	6.67%	$ 9,018	$ 16,010	$ -	$ 25,028		-$ 25,028
1860	Meters - Renewable Connection			$ -	$ 154,427	$ -	$ 154,427		-	0.00%	15.00	6.67%	$ -	$ 10,295	$ -	$ 10,295		-$ 10,295
1860	Smart Meters			$ -	$ -	$ -	$ -		-	0.00%	15.00	6.67%	$ -	$ -	$ -	$ -		$ -
1860	Smart Meters	-	$ -	$ -	$ 12,650,541	$ -	$ 12,650,541	$ 407,305	-	0.00%	15.00	6.67%	$ -	$ 843,369	$ 13,577	$ 856,946	$ 856,947	$ -
1905	Land	1,395,300	$ -	$ 1,395,300	$ -	$ -	$ -	$ -	-	0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1908	Buildings & Fixtures - Building	5,262,681	$ -	$ 5,262,681	$ 4,910,394	$ -	$ 4,910,394	$ 101,092	28.71	3.48%	50.00	2.00%	$ 183,326	$ 98,208	$ 1,011	$ 282,545	$ 275,191	-$ 7,354
1908	Buildings & Fixtures - Roof	1,567,291	$ -	$ 1,567,291	$ 2,285,296	$ -	$ 2,285,296	$ 120,678	6.53	15.33%	20.00	5.00%	$ 240,192	$ 114,265	$ 3,017	$ 357,473	$ 338,366	-$ 19,107
1910	Leasehold Improvements	-	$ -	$ -	$ -	$ -	$ -	$ -	-	0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1915	Office Furniture & Equipment (10 years)	340,212	$ 54,324	$ 285,888	$ 309,783	$ -	$ 309,783	$ 36,970	5.10	19.61%	10.00	10.00%	$ 56,056	$ 30,978	$ 1,849	$ 88,883	$ 70,563	-$ 18,320
1915	Office Furniture & Equipment (5 years)		$ -	$ -	$ -	$ -	$ -		-	0.00%	5.00	20.00%	$ -	$ -	$ -	$ -		$ -
1920	Computer Equipment - Hardware	350,464	$ 180,516	$ 169,948	$ 472,855	$ 19,504	$ 453,351	$ 90,770	2.12	47.12%	5.00	20.00%	$ 80,088	$ 90,670	$ 9,077	$ 179,835	$ 189,058	$ 9,224
1920	Computer Equip.-Hardware - Smart Meters	-	$ -	$ -	$ 569,286	$ 437,864	$ 131,422	$ -	-	0.00%	5.00	20.00%	$ -	$ 26,284	$ -	$ 26,284	$ 22,126	-$ 4,158
1920	Computer Equip.-Hardware(Post Mar. 19/07)	-	$ -	$ -	$ -	$ -	$ -	$ -	-	0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1930	Transportation Equipment	2,781,086	$ 359,331	$ 2,421,755	$ 3,316,043	$ -	$ 3,316,043	$ 733,066	7.19	13.90%	11.00	9.09%	$ 336,726	$ 301,458	$ 33,321	$ 671,506	$ 664,632	-$ 6,874
1935	Stores Equipment	21,484	$ -	$ 21,484	$ -	$ -	$ -	$ 2,552	4.55	21.99%	10.00	10.00%	$ 4,724	$ -	$ 128	$ 4,852	$ 3,215	-$ 1,637
1940	Tools, Shop & Garage Equipment	324,953	$ -	$ 324,953	$ 284,363	$ -	$ 284,363	$ 95,003	6.70	14.93%	10.00	10.00%	$ 48,520	$ 28,436	$ 4,750	$ 81,707	$ 72,361	-$ 9,346
1940	Tools - Smart Meters	-	$ -	$ -	$ -	$ -	$ -	$ -	-	0.00%	10.00	10.00%	$ -	$ -	$ -	$ -	$ 373	$ 373
1945	Measurement & Testing Equipment	163,014	$ -	$ 163,014	$ 181,033	$ -	$ 181,033	$ 3,849	7.77	12.88%	10.00	10.00%	$ 20,993	$ 18,103	$ 192	$ 39,289	$ 36,709	-$ 2,579
1950	Power Operated Equipment	306,812	$ -	$ 306,812	$ 327,950	$ -	$ 327,950	$ 126,680	6.77	14.76%	10.00	10.00%	$ 45,297	$ 32,795	$ 6,334	$ 84,426	$ 66,839	-$ 17,587
1955	Communications Equipment	58,880	$ -	$ 58,880	$ 88,127	$ -	$ 88,127	$ 61,266	6.76	14.80%	10.00	10.00%	$ 8,715	$ 8,813	$ 3,063	$ 20,591	$ 11,241	-$ 9,350
1955	Communication Equipment (Smart Meters)	-	$ -	$ -	$ 696,896	$ -	$ 696,896	$ -	-	0.00%	10.00	10.00%	$ -	$ 69,690	$ -	$ 69,690	$ 69,690	$ -
1960	Miscellaneous Equipment	40,970	$ 40,970	$ -	$ 10,150	$ -	$ 10,150	$ -	3.61	27.74%	5.00	20.00%	$ -	$ 2,030	$ -	$ 2,030	$ 2,031	$ 1
1975	Load Management Controls Utility Premises	-	$ -	$ -	$ -	$ -	$ -	$ -	-	0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1980	System Supervisor Equipment	115,075	$ 100,327	$ 14,748	$ -	$ -	$ -	$ -	6.15	16.26%	10.00	10.00%	$ 2,398	$ -	$ -	$ 2,398	$ 1,943	-$ 455
1985	Miscellaneous Fixed Assets		$ -	$ -	$ -	$ -	$ -	$ -	-	0.00%		0.00%	$ -	$ -	$ -	$ -		$ -

Appendix 2-C
Depreciation and Amortization Expense

1995	**Contributions & Grants**		$ -	$ -	$ -	$ -	$ -		-	0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1995	Contributed Capital - Poles, Towers & Fixtures	- 1,626,853	$ -	-$ 1,626,853	-$ 1,146,161	$ -	-$ 1,146,161	$ -	34.50	2.90%	40.00	2.50%	-$ 47,155	-$ 28,654	$ -	-$ 75,809	-$ 76,140	-$ 331
1995	Contributed Capital - Overhead Conductors	- 1,246,129	$ -	-$ 1,246,129	-$ 969,095	$ -	-$ 969,095	$ -	54.55	1.83%	60.00	1.67%	-$ 22,844	-$ 16,152	$ -	-$ 38,996	-$ 38,983	$ 13
1995	Contributed Capital - Overhead Devices	- 138,459	$ -	-$ 138,459	-$ 109,089	$ -	-$ 109,089	$ -	34.39	2.91%	40.00	2.50%	-$ 4,026	-$ 2,727	$ -	-$ 6,753	-$ 6,773	-$ 20
1995	Contributed Capital - Overhead Services	- 1,195,490	$ -	-$ 1,195,490	-$ 119,872	$ -	-$ 119,872	$ -	40.18	2.49%	60.00	1.67%	-$ 29,750	-$ 1,998	$ -	-$ 31,748	-$ 27,445	$ 4,303
1995	Contributed Capital - Underground Trenching & Ductwork	- 5,566,404	$ -	-$ 5,566,404	-$ 2,609,506	$ -	-$ 2,609,506	$ -	54.02	1.85%	60.00	1.67%	-$ 103,051	-$ 43,492	$ -	-$ 146,543	-$ 146,667	-$ 124
1995	Contributed Capital - Underground Cables	- 2,292,136	$ -	-$ 2,292,136	-$ 2,370,201	$ -	-$ 2,370,201	$ -	30.81	3.25%	40.00	2.50%	-$ 74,387	-$ 59,255	$ -	-$ 133,642	-$ 126,453	$ 7,189
1995	Contributed Capital - Underground Devices	- 254,682	$ -	-$ 254,682	-$ 167,703	$ -	-$ 167,703	$ -	-	0.00%	40.00	2.50%	$ -	-$ 4,193	$ -	-$ 4,193	-$ 11,694	-$ 7,501
1995	Contributed Capital - Overhead Transformer	- 2,734,282	$ -	-$ 2,734,282	$ 169,874	$ -	$ 169,874	$ -	34.03	2.94%	40.00	2.50%	-$ 80,349	$ 4,247	$ -	-$ 76,102	-$ 81,825	-$ 5,724
1995	Contributed Capital - Underground Padmount Transformer	- 1,858,357	$ -	-$ 1,858,357	-$ 7,920	$ -	-$ 7,920	$ -	32.33	3.09%	40.00	2.50%	-$ 57,473	-$ 198	$ -	-$ 57,671	-$ 64,413	-$ 6,742
1995	Contributed Capital -Underground Submersible Transformer	- 1,955,810	$ -	-$ 1,955,810	-$ 675,874	$ -	-$ 675,874	$ -	25.19	3.97%	30.00	3.33%	-$ 77,649	-$ 22,529	$ -	-$ 100,178	-$ 100,178	$ -
1995	Contributed Capital - Underground Services	- 13,453,846	$ -	-$ 13,453,846	-$ 953,639	$ -	-$ 953,639	$ -	33.74	2.96%	40.00	2.50%	-$ 398,729	-$ 23,841	$ -	-$ 422,570	-$ 456,306	-$ 33,736
1995	Contributed Capital - Transformer Foundations	- 798,352	$ -	-$ 798,352	-$ 558,073	$ -	-$ 558,073	$ -	54.11	1.85%	60.00	1.67%	-$ 14,753	-$ 9,301	$ -	-$ 24,054	-$ 24,054	$ -
1995	Contributed Capital - Meters	- 166,183	$ -	-$ 166,183	-$ 132,547	$ -	-$ 132,547	$ -	6.15	16.25%	15.00	6.67%	-$ 27,003	-$ 8,836	$ -	-$ 35,839	-$ 25,085	$ 10,755
	Contributed Capital - Meters SOLAR	-	$ -	$ -	-$ 152,011	$ -	-$ 152,011	$ -	-	0.00%	15.00	6.67%	$ -	-$ 10,134	$ -	-$ 10,134	-$ 13,644	-$ 3,509
1995	Contributed Capital - OEB Clearing	68,538	$ -	$ 68,538	$ 259,328	$ -	$ 259,328	$ -	- 10.00	-10.00%	15.00	6.67%	-$ 6,854	$ 17,289	$ -	$ 10,435	$ 18,682	$ 8,247
2440	**Deferred Revenue**		$ -	$ -	$ -	$ -	$ -		-	0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
2440	Contributed Capital - Poles, Towers & Fixtures	-	$ -	$ -	-$ 1,838,167	$ -	-$ 1,838,167	-$ 916,906	-	0.00%	40.00	2.50%	$ -	-$ 45,954	-$ 11,461	-$ 57,416	-$ 57,416	$ -
2440	Contributed Capital - Overhead Conductors	-	$ -	$ -	-$ 1,438,900	$ -	-$ 1,438,900	-$ 510,353	-	0.00%	60.00	1.67%	$ -	-$ 23,982	-$ 4,253	-$ 28,235	-$ 28,235	$ -
2440	Contributed Capital - Overhead Devices	-	$ -	$ -	-$ 159,877	$ -	-$ 159,877	-$ 56,448	-	0.00%	40.00	2.50%	$ -	-$ 3,997	-$ 706	-$ 4,703	-$ 4,703	$ -
2440	Contributed Capital - Overhead Services	-	$ -	$ -	-$ 202,434	$ -	-$ 202,434	-$ 106,303	-	0.00%	60.00	1.67%	$ -	-$ 3,374	-$ 886	-$ 4,260	-$ 4,260	$ -
2440	Contributed Capital - Underground Trenching & Ductwork	-	$ -	$ -	-$ 5,225,864	$ -	-$ 5,225,864	-$ 1,923,685	-	0.00%	60.00	1.67%	$ -	-$ 87,098	-$ 16,031	-$ 103,128	-$ 103,128	$ -
2440	Contributed Capital - Underground Cables	-	$ -	$ -	-$ 2,930,429	$ -	-$ 2,930,429	-$ 2,447,256	-	0.00%	40.00	2.50%	$ -	-$ 73,261	-$ 30,591	-$ 103,851	-$ 103,851	$ -
2440	Contributed Capital - Underground Devices	-	$ -	$ -	-$ 325,775	$ -	-$ 325,775	-$ 271,722	-	0.00%	40.00	2.50%	$ -	-$ 8,144	-$ 3,397	-$ 11,541	-$ 11,541	$ -
2440	Contributed Capital - Overhead Transformer	-	$ -	$ -	-$ 33,377	$ -	-$ 33,377	-$ 30,238	-	0.00%	40.00	2.50%	$ -	-$ 834	-$ 378	-$ 1,212	-$ 1,212	$ -
2440	Contributed Capital - Underground Padmount Transformer	-	$ -	$ -	-$ 184,346	$ -	-$ 184,346	-$ 125,939	-	0.00%	40.00	2.50%	$ -	-$ 4,609	-$ 1,574	-$ 6,183	-$ 6,183	$ -
2440	Contributed Capital -Underground Submersible Transformer	-	$ -	$ -	-$ 933,762	$ -	-$ 933,762	-$ 581,471	-	0.00%	30.00	3.33%	$ -	-$ 31,125	-$ 9,691	-$ 40,817	-$ 40,817	$ -
2440	Contributed Capital - Underground Services	-	$ -	$ -	-$ 1,898,672	$ -	-$ 1,898,672	-$ 1,491,907	-	0.00%	40.00	2.50%	$ -	-$ 47,467	-$ 18,649	-$ 66,116	-$ 66,116	$ -
2440	Contributed Capital - Transformer Foundations	-	$ -	$ -	-$ 370,131	$ -	-$ 370,131	-$ 412,447	-	0.00%	60.00	1.67%	$ -	-$ 6,169	-$ 3,437	-$ 9,606	-$ 9,883	-$ 277
2440	Contributed Capital - Meters	-	$ -	$ -	-$ 94,579	$ -	-$ 94,579	-$ 22,651	-	0.00%	15.00	6.67%	$ -	-$ 6,305	-$ 755	-$ 7,060	-$ 7,060	$ -
2440	Contributed Capital - Meters Solar	-	$ -	$ -	-$ 270,207	$ -	-$ 270,207	-$ 53,192	-	0.00%	15.00	6.67%	$ -	-$ 18,014	-$ 1,773	-$ 19,787	-$ 19,787	$ -
2440	Contributed Capital - OEB Clearing	-	$ -	$ -	-$ 243,274	$ -	-$ 243,274	$ -	-	0.00%	15.00	6.67%	$ -	-$ 16,218	$ -	-$ 16,218	-$ 16,218	$ -
2440	Meters - Renewable Connection - Direct Benefit	-	$ -	$ -	-$ 8,505	$ -	-$ 8,505	$ -	-	0.00%	15.00	6.67%	$ -	-$ 567	$ -	-$ 567	-$ 7,147	-$ 6,580
				$ -			$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
	Total	**$ 148,349,204**	**$ 2,304,722**	**$ 146,044,482**	**$ 70,341,085**	**$ 1,271,210**	**$ 69,069,875**	**$ 15,335,906**					**$ 5,280,562**	**$ 2,916,323**	**$ 297,138**	**$ 8,494,023**	**$ 8,921,037**	**$ 427,014**

Appendix 2-C
Depreciation and Amortization Expense

2017

Account	Description	Book Values							Service Lives				Depreciation Expense					
		Opening Net Book Value of Existing Assets as at Date of Policy Change (Jan. 1) [1]	Less Fully Depreciated [7]	Net Amount of Existing Assets Before Policy Change to be Depreciated	Opening Gross Book Value of Assets Acquired After Policy Change [2]	Less Fully Depreciated [8]	Net Amount of Assets Acquired After Policy Change to be Depreciated	Current Year Additions	Average Remaining Life of Assets Existing Before Policy Change [3]	Depreciation Rate Assets Acquired After Policy Change	Life of Assets Acquired After Policy Change [4]	Depreciation Rate on New Additions	Depreciation Expense on Assets Existing Before Policy Change	Depreciation Expense on Assets Acquired After Policy Change	Depreciation Expense on Current Year Additions [5]	Total Current Year Depreciation Expense	Depreciation Expense per Appendix 2-BA Fixed Assets, Column J	Variance [6]
		a	b	c = a-b	d	e	f = d- e	g	h	i = 1/h	j	k = 1/j	l = c/h	m = f/j	n = g*0.5/j	o = l+m+n	p	q = p-o
1611	Computer Software (Formally known as Account 1925)	928,634	$ 858,332	$ 70,302	$ 1,959,883	$ 135,165	$ 1,824,718	$ 136,147	2.25	44.44%	5.00	20.00%	$ 31,245	$ 364,944	$ 13,615	$ 409,804	$ 418,460	$ 8,656
1611	Computer Software (Formally known as Account 1925)	-		$ -	$ 88,614	$ 79,996	$ 8,618		-	0.00%	3.00	33.33%	$ -	$ 2,873	$ -	$ 2,873		-$ 2,873
1611	Computer Software (Formally known as Account 1925) - Smart Meters	-	$ -	$ -	$ 598,681	$ 598,681	$ -	$ -	-	0.00%	3.00	33.33%	$ -	$ -	$ -	$ -	$ 1,506	$ 1,506
1612	Land Rights (Formally known as Account 1906)	12,881	$ -	$ 12,881	$ -	$ -	$ -		4.86	20.60%	50.00	2.00%	$ 2,653	$ -	$ -	$ 2,653	$ -	-$ 2,653
1805	Land	2,339,958	$ -	$ 2,339,958	$ -	$ -	$ -		-	0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1808	Buildings - Structure	7,099,490	$ -	$ 7,099,490	$ 463,554	$ -	$ 463,554	$ -	38.08	2.63%	50.00	2.00%	$ 186,429	$ 9,271	$ -	$ 195,700	$ 190,769	-$ 4,931
1808	Buildings - Roof	144,989	$ 58,456	$ 86,533	-$ 2,480	$ -	-$ 2,480	$ -	11.44	8.74%	20.00	5.00%	$ 7,565	-$ 124	$ -	$ 7,441	-$ 1,736	-$ 9,178
1810	Leasehold Improvements	-	$ -	$ -	$ -	$ -	$ -		-	0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1815	Transformer Station Equipment >50 kV 50 yrs	15,658,085	$ 12,312	$ 15,645,773	$ 1,470,010	$ -	$ 1,470,010	$ 1,196,559	41.16	2.43%	50.00	2.00%	$ 380,092	$ 29,400	$ 11,966	$ 421,457	$ 412,340	-$ 9,118
1815	Transformer Station Equipment >50 kV 40 yrs	24,475,179	$ -	$ 24,475,179	$ 1,244,179	$ -	$ 1,244,179	$ 253,651	28.76	3.48%	40.00	2.50%	$ 851,073	$ 31,104	$ 3,171	$ 885,348	$ 851,596	-$ 33,752
1815	Transformer Station Equipment >50 kV 30 yrs	-	$ -	$ -		$ -	$ -	$ 71,591	-	0.00%		0.00%	$ -	$ -	$ -	$ -	$ 1,193	$ 1,193
1815	Transformer Station Equipment >50 kV 25 yrs	887,028	$ 176,718	$ 710,310	$ -	$ -	$ -	$ 233,388	12.07	8.28%	25.00	4.00%	$ 58,839	$ -	$ 4,668	$ 63,507	$ 57,640	-$ 5,867
1815	Transformer Station Equipment >50 kV 20 yrs	392,015	$ 163,703	$ 228,312	$ 188,437	$ -	$ 188,437	$ -	9.76	10.24%	20.00	5.00%	$ 23,383	$ 9,422	$ -	$ 32,805	$ 33,621	$ 816
1815	Transformer Station Equipment >50 kV 15 yrs	1,087,574	$ 439,950	$ 647,624	$ 1,075,677	$ -	$ 1,075,677	$ 729,696	8.48	11.79%	15.00	6.67%	$ 76,380	$ 71,712	$ 24,323	$ 172,415	$ 163,946	-$ 8,470
1820	Distribution Station Equipment <50 kV 50 yrs	200,427	$ -	$ 200,427	$ -	$ -	$ -	$ -	22.74	4.40%	50.00	2.00%	$ 8,813	$ -	$ -	$ 8,813	$ 8,543	-$ 271
1820	Distribution Station Equipment <50 kV 40 yrs	649,832	$ -	$ 649,832	$ -	$ -	$ -	$ -	25.47	3.93%	40.00	2.50%	$ 25,509	$ -	$ -	$ 25,509	$ 24,261	-$ 1,249
1820	Distribution Station Equipment <50 kV 25 yrs	13,287	$ -	$ 13,287	$ -	$ -	$ -	$ -	5.93	16.87%	25.00	4.00%	$ 2,242	$ -	$ -	$ 2,242	$ 990	-$ 1,252
1820	Distribution Station Equipment <50 kV 20 yrs	6,078	$ 6,078	$ -	$ -	$ -	$ -	$ -	5.66	17.66%	20.00	5.00%	$ -	$ -	$ -	$ -	$ 241	$ 241
1820	Distribution Station Equipment <50 kV 15 hrs	17,551	$ 17,551	$ -	$ 153,636	$ -	$ 153,636	$ -	9.64	10.37%	15.00	6.67%	$ -	$ 10,242	$ -	$ 10,242	$ 10,848	$ 606
1825	Storage Battery Equipment	-	$ -	$ -	$ -	$ -	$ -		-	0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1830	Poles, Towers & Fixtures	17,028,402	$ -	$ 17,028,402	$ 13,776,481	$ -	$ 13,776,481	$ 2,823,048	32.16	3.11%	40.00	2.50%	$ 529,490	$ 344,412	$ 35,288	$ 909,190	$ 899,198	-$ 9,992
1835	Overhead Conductors	14,319,062	$ -	$ 14,319,062	$ 9,304,996	$ -	$ 9,304,996	$ 1,873,840	51.16	1.95%	60.00	1.67%	$ 279,881	$ 155,083	$ 15,615	$ 450,579	$ 445,438	-$ 5,142
1835	Overhead Devices	1,591,007	$ -	$ 1,591,007	$ 1,148,665	$ -	$ 1,148,665	$ 320,357	30.57	3.27%	40.00	2.50%	$ 52,051	$ 28,717	$ 4,004	$ 84,772	$ 83,002	-$ 1,770
1835	Voltage Regulators	163,109	$ -	$ 163,109	$ -	$ -	$ -	$ -	20.00	5.00%	30.00	3.33%	$ 8,155	$ -	$ -	$ 8,155	$ 7,767	-$ 388
1835	Capacitor Banks	618,096	$ -	$ 618,096	$ 442,420	$ -	$ 442,420	$ 681,794	19.80	5.05%	25.00	4.00%	$ 31,224	$ 17,697	$ 13,636	$ 62,556	$ 50,019	-$ 12,537
1840	Underground Conduit	12,527,558	$ -	$ 12,527,558	$ 14,701,576	$ -	$ 14,701,576	$ 2,850,149	51.70	1.93%	60.00	1.67%	$ 242,295	$ 245,026	$ 23,751	$ 511,072	$ 506,681	-$ 4,391
1845	Underground Conductors & Devices - PILC	414,000	$ -	$ 414,000	$ 1,434,683	$ -	$ 1,434,683	$ 121,856	58.00	1.72%	60.00	1.67%	$ 7,138	$ 23,911	$ 1,015	$ 32,065	$ 31,944	-$ 121
1845	Underground Cables	15,726,653	$ -	$ 15,726,653	$ 12,366,103	$ -	$ 12,366,103	$ 2,592,288	28.66	3.49%	40.00	2.50%	$ 548,637	$ 309,153	$ 32,404	$ 890,193	$ 870,881	-$ 19,312
1845	Underground Devices	1,747,406	$ -	$ 1,747,406	$ 1,658,442	$ -	$ 1,658,442	$ 227,601	28.66	3.49%	40.00	2.50%	$ 60,960	$ 41,461	$ 2,845	$ 105,266	$ 103,111	-$ 2,155
1850	Line Transformers - Overhead	15,713,833	$ 323,443	$ 15,390,390	$ 4,761,517	$ -	$ 4,761,517	$ 767,488	27.98	3.57%	40.00	2.50%	$ 549,964	$ 119,038	$ 9,594	$ 678,596	$ 505,852	-$ 172,744
1850	Line Transformers - Network	5,503	$ -	$ 5,503	$ 760,264	$ -	$ 760,264	$ 297,068	9.38	10.66%	40.00	2.50%	$ 587	$ 19,007	$ 3,713	$ 23,307	$ 35,514	$ 12,207
1850	Line Transformers - Vault	-	$ -	$ -	$ 6,041	$ -	$ 6,041	$ -	-	0.00%	60.00	1.67%	$ -	$ 101	$ -	$ 101	$ 200	$ 99
1850	Line Transformers - Roof	497,948	$ 16,586	$ 481,362	$ -	$ -	$ -	$ -	23.84	4.19%	30.00	3.33%	$ 20,190	$ -	$ -	$ 20,190	$ 18,897	-$ 1,293
1850	Line Transformers -Network Protectors	91,592	$ -	$ 91,592	$ 460,804	$ -	$ 460,804	$ 85,710	39.50	2.53%	40.00	2.50%	$ 2,319	$ 11,520	$ 1,071	$ 14,910	$ 12,015	-$ 2,895
1850	Line Transformers - Padmount	3,991,872	$ -	$ 3,991,872	$ 4,248,925	$ -	$ 4,248,925	$ 496,924	36.77	2.72%	40.00	2.50%	$ 108,567	$ 106,223	$ 6,212	$ 221,001	$ 154,558	-$ 66,443
1850	Line Transformers - Submersible	3,195,923	$ -	$ 3,195,923	$ 3,278,589	$ -	$ 3,278,589	$ 796,852	24.09	4.15%	30.00	3.33%	$ 132,669	$ 109,286	$ 13,281	$ 255,236	$ 607,269	$ 352,033
1850	Line Transformers - Foundation	1,427,416	$ -	$ 1,427,416	$ 1,471,388	$ -	$ 1,471,388	$ 268,160	58.08	1.72%	60.00	1.67%	$ 24,575	$ 24,523	$ 2,235	$ 51,333	$ 44,611	-$ 6,722
1855	Services - Overhead	1,887,728	$ -	$ 1,887,728	$ 2,025,312	$ -	$ 2,025,312	$ 345,926	52.20	1.92%	60.00	1.67%	$ 36,164	$ 33,755	$ 2,883	$ 72,802	$ 72,162	-$ 640
1855	Services - Underground	22,543,287	$ -	$ 22,543,287	$ 11,717,469	$ -	$ 11,717,469	$ 3,133,312	31.40	3.18%	40.00	2.50%	$ 717,938	$ 292,937	$ 39,166	$ 1,050,041	$ 1,027,135	-$ 22,906
1860	Commercial Meters	1,327,802	$ 158,636	$ 1,169,166	$ 1,247,902	$ -	$ 1,247,902	$ 600,897	20.97	4.77%	25.00	4.00%	$ 55,753	$ 49,916	$ 12,018	$ 117,687	$ 159,098	$ 41,411
1860	Smart Meters - Non-Qualifying	108,222		$ 108,222	$ 240,153	$ -	$ 240,153		12.00	8.33%	15.00	6.67%	$ 9,018	$ 16,010	$ -	$ 25,028		-$ 25,028
1860	Meters - Renewable Connection	-		$ -	$ 154,427	$ -	$ 154,427		-	0.00%	15.00	6.67%	$ -	$ 10,295	$ -	$ 10,295		-$ 10,295
1860	Smart Meters	-		$ -	$ -	$ -	$ -		-	0.00%	15.00	6.67%	$ -	$ -	$ -	$ -		$ -
1860	Smart Meters	-	$ -	$ -	$ 13,057,846	$ -	$ 13,057,846	$ 222,909	-	0.00%	15.00	6.67%	$ -	$ 870,523	$ 7,430	$ 877,953	$ 878,535	$ 582
1905	Land	1,395,300	$ -	$ 1,395,300	$ -	$ -	$ -	$ -	-	0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1908	Buildings & Fixtures - Building	5,262,681	$ -	$ 5,262,681	$ 5,011,486	$ -	$ 5,011,486	$ 951,671	28.71	3.48%	50.00	2.00%	$ 183,326	$ 100,230	$ 9,517	$ 293,073	$ 280,390	-$ 12,683
1908	Buildings & Fixtures - Roof	1,567,291	$ 905,931	$ 661,360	$ 2,405,974	$ -	$ 2,405,974	$ 63,962	6.53	15.33%	20.00	5.00%	$ 101,355	$ 120,299	$ 1,599	$ 223,253	$ 186,357	-$ 36,896
1910	Leasehold Improvements	-	$ -	$ -	$ -	$ -	$ -	$ -	-	0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1915	Office Furniture & Equipment (10 years)	340,212	$ 49,150	$ 291,062	$ 346,753	$ -	$ 346,753	$ 53,399	5.10	19.61%	10.00	10.00%	$ 57,071	$ 34,675	$ 2,670	$ 94,416	$ 68,483	-$ 25,933
1915	Office Furniture & Equipment (5 years)	-	$ -	$ -	$ -	$ -	$ -		-	0.00%	5.00	20.00%	$ -	$ -	$ -	$ -		$ -
1920	Computer Equipment - Hardware	350,464		$ 350,464	$ 563,625	$ 458,791	$ 104,834	$ 33,213	2.12	47.12%	5.00	20.00%	$ 165,155	$ 20,967	$ 3,321	$ 189,444	$ 171,346	-$ 18,097
1920	Computer Equip.-Hardware - Smart Meters	-	$ -	$ -	$ 569,286	$ 437,864	$ 131,422	$ -	-	0.00%	5.00	20.00%	$ -	$ 26,284	$ -	$ 26,284	$ 22,126	-$ 4,158
1920	Computer Equip.-Hardware(Post Mar. 19/07)	-	$ -	$ -	$ -	$ -	$ -	$ -	-	0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1930	Transportation Equipment	2,781,086	$ 715,565	$ 2,065,521	$ 4,049,109	$ -	$ 4,049,109	$ 39,073	7.19	13.90%	11.00	9.09%	$ 287,195	$ 368,101	$ 1,776	$ 657,072	$ 673,162	$ 16,090
1935	Stores Equipment	21,484	$ -	$ 21,484	$ 2,552	$ -	$ 2,552	$ -	4.55	21.99%	10.00	10.00%	$ 4,724	$ 255	$ -	$ 4,979	$ 276	-$ 4,703
1940	Tools, Shop & Garage Equipment	324,953	$ -	$ 324,953	$ 379,366	$ -	$ 379,366	$ 76,089	6.70	14.93%	10.00	10.00%	$ 48,520	$ 37,937	$ 3,804	$ 90,261	$ 77,159	-$ 13,102
1940	Tools - Smart Meters	-	$ -	$ -	$ -	$ -	$ -	$ -	-	0.00%	10.00	10.00%	$ -	$ -	$ -	$ -	$ 373	$ 373
1945	Measurement & Testing Equipment	163,014	$ -	$ 163,014	$ 184,882	$ -	$ 184,882	$ 59,074	7.77	12.88%	10.00	10.00%	$ 20,993	$ 18,488	$ 2,954	$ 42,435	$ 37,560	-$ 4,875
1950	Power Operated Equipment	306,812	$ 98,740	$ 208,072	$ 454,630	$ -	$ 454,630	$ -	6.77	14.76%	10.00	10.00%	$ 30,719	$ 45,463	$ -	$ 76,182	$ 69,566	-$ 6,616
1955	Communications Equipment	58,880	$ -	$ 58,880	$ 149,393	$ -	$ 149,393	$ 190	6.76	14.80%	10.00	10.00%	$ 8,715	$ 14,939	$ 10	$ 23,664	$ 14,945	-$ 8,718
1955	Communication Equipment (Smart Meters)	-	$ -	$ -	$ 696,896	$ -	$ 696,896	$ -	-	0.00%	10.00	10.00%	$ -	$ 69,690	$ -	$ 69,690	$ 69,690	$ -
1960	Miscellaneous Equipment	40,970	$ 40,970	$ -	$ 10,150	$ -	$ 10,150	$ 4,993	3.61	27.74%	5.00	20.00%	$ -	$ 2,030	$ 499	$ 2,529	$ 2,114	-$ 415
1975	Load Management Controls Utility Premises	-	$ -	$ -	$ -	$ -	$ -	$ -	-	0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1980	System Supervisor Equipment	115,075	$ 100,327	$ 14,748	$ -	$ -	$ -	$ -	6.15	16.26%	10.00	10.00%	$ 2,398	$ -	$ -	$ 2,398	$ 2,204	-$ 194
1985	Miscellaneous Fixed Assets	-	$ -	$ -	$ -	$ -	$ -	$ -	-	0.00%		0.00%	$ -	$ -	$ -	$ -		$ -

Appendix 2-C
Depreciation and Amortization Expense

1995	**Contributions & Grants**	-	$ -	$ -	$ -	$ -	$ -		-	0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1995	Contributed Capital - Poles, Towers & Fixtures	- 1,626,853	$ -	-$ 1,626,853	-$ 1,146,161	$ -	-$ 1,146,161	$ -	34.50	2.90%	40.00	2.50%	-$ 47,155	-$ 28,654	$ -	-$ 75,809	-$ 74,779	$ 1,030
1995	Contributed Capital - Overhead Conductors	- 1,246,129	$ -	-$ 1,246,129	-$ 969,095	$ -	-$ 969,095	$ -	54.55	1.83%	60.00	1.67%	-$ 22,844	-$ 16,152	$ -	-$ 38,996	-$ 38,570	$ 426
1995	Contributed Capital - Overhead Devices	- 138,459	$ -	-$ 138,459	-$ 109,089	$ -	-$ 109,089	$ -	34.39	2.91%	40.00	2.50%	-$ 4,026	-$ 2,727	$ -	-$ 6,753	-$ 6,658	$ 95
1995	Contributed Capital - Overhead Services	- 1,195,490	$ -	-$ 1,195,490	-$ 119,872	$ -	-$ 119,872	$ -	40.18	2.49%	60.00	1.67%	-$ 29,750	-$ 1,998	$ -	-$ 31,748	-$ 24,333	$ 7,415
1995	Contributed Capital - Underground Trenching & Ductwork	- 5,566,404	$ -	-$ 5,566,404	-$ 2,609,506	$ -	-$ 2,609,506	$ -	54.02	1.85%	60.00	1.67%	-$ 103,051	-$ 43,492	$ -	-$ 146,543	-$ 144,784	$ 1,759
1995	Contributed Capital - Underground Cables	- 2,292,136	$ -	-$ 2,292,136	-$ 2,370,201	$ -	-$ 2,370,201	$ -	30.81	3.25%	40.00	2.50%	-$ 74,387	-$ 59,255	$ -	-$ 133,642	-$ 124,494	$ 9,147
1995	Contributed Capital - Underground Devices	- 254,682	$ -	-$ 254,682	-$ 167,703	$ -	-$ 167,703	$ -	-	0.00%	40.00	2.50%	$ -	-$ 4,193	$ -	-$ 4,193	-$ 11,476	-$ 7,284
1995	Contributed Capital - Overhead Transformer	- 2,734,282	$ -	-$ 2,734,282	$ 169,874	$ -	$ 169,874	$ -	34.03	2.94%	40.00	2.50%	-$ 80,349	$ 4,247	$ -	-$ 76,102	-$ 79,517	-$ 3,415
1995	Contributed Capital - Underground Padmount Transformer	- 1,858,357	$ -	-$ 1,858,357	-$ 7,920	$ -	-$ 7,920	$ -	32.33	3.09%	40.00	2.50%	-$ 57,473	-$ 198	$ -	-$ 57,671	-$ 62,762	-$ 5,091
1995	Contributed Capital -Underground Submersible Transformer	- 1,955,810	$ -	-$ 1,955,810	-$ 675,874	$ -	-$ 675,874	$ -	25.19	3.97%	30.00	3.33%	-$ 77,649	-$ 22,529	$ -	-$ 100,178	-$ 97,024	$ 3,154
1995	Contributed Capital - Underground Services	- 13,453,846	$ -	-$ 13,453,846	-$ 953,639	$ -	-$ 953,639	$ -	33.74	2.96%	40.00	2.50%	-$ 398,729	-$ 23,841	$ -	-$ 422,570	-$ 399,263	$ 23,307
1995	Contributed Capital - Transformer Foundations	- 798,352	$ -	-$ 798,352	-$ 558,073	$ -	-$ 558,073	$ -	54.11	1.85%	60.00	1.67%	-$ 14,753	-$ 9,301	$ -	-$ 24,054	-$ 23,786	$ 268
1995	Contributed Capital - Meters	- 166,183	$ -	-$ 166,183	-$ 132,547	$ -	-$ 132,547	$ -	6.15	16.25%	15.00	6.67%	-$ 27,003	-$ 8,836	$ -	-$ 35,839	-$ 24,110	$ 11,729
	Contributed Capital - Meters SOLAR	-	$ -	$ -	-$ 152,011	$ -	-$ 152,011	$ -	-	0.00%	15.00	6.67%	$ -	-$ 10,134	$ -	-$ 10,134	-$ 13,644	-$ 3,509
1995	Contributed Capital - OEB Clearing	68,538	$ -	$ 68,538	$ 259,328	$ -	$ 259,328	$ -	- 10.00	-10.00%	15.00	6.67%	-$ 6,854	$ 17,289	$ -	$ 10,435	$ 25,468	$ 15,033
2440	**Deferred Revenue**	-	$ -	$ -	$ -	$ -	$ -		-	0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
2440	Contributed Capital - Poles, Towers & Fixtures	-	$ -	$ -	-$ 2,755,073	$ -	-$ 2,755,073	-$ 510,177	-	0.00%	40.00	2.50%	$ -	-$ 68,877	-$ 6,377	-$ 75,254	-$ 75,254	$ -
2440	Contributed Capital - Overhead Conductors	-	$ -	$ -	-$ 1,949,253	$ -	-$ 1,949,253	-$ 357,371	-	0.00%	60.00	1.67%	$ -	-$ 32,488	-$ 2,978	-$ 35,466	-$ 35,466	$ -
2440	Contributed Capital - Overhead Devices	-	$ -	$ -	-$ 216,325	$ -	-$ 216,325	-$ 39,708	-	0.00%	40.00	2.50%	$ -	-$ 5,408	-$ 496	-$ 5,904	-$ 5,904	$ -
2440	Contributed Capital - Overhead Services	-	$ -	$ -	-$ 308,737	$ -	-$ 308,737	-$ 183,544	-	0.00%	60.00	1.67%	$ -	-$ 5,146	-$ 1,530	-$ 6,675	-$ 6,675	$ -
2440	Contributed Capital - Underground Trenching & Ductwork	-	$ -	$ -	-$ 7,149,549	$ -	-$ 7,149,549	-$ 1,249,203	-	0.00%	60.00	1.67%	$ -	-$ 119,159	-$ 10,410	-$ 129,569	-$ 129,569	$ -
2440	Contributed Capital - Underground Cables	-	$ -	$ -	-$ 5,377,685	$ -	-$ 5,377,685	-$ 1,290,807	-	0.00%	40.00	2.50%	$ -	-$ 134,442	-$ 16,135	-$ 150,577	-$ 150,577	$ -
2440	Contributed Capital - Underground Devices	-	$ -	$ -	-$ 597,497	$ -	-$ 597,497	-$ 141,758	-	0.00%	40.00	2.50%	$ -	-$ 14,937	-$ 1,772	-$ 16,709	-$ 16,709	$ -
2440	Contributed Capital - Overhead Transformer	-	$ -	$ -	-$ 63,615	$ -	-$ 63,615	-$ 32,870	-	0.00%	40.00	2.50%	$ -	-$ 1,590	-$ 411	-$ 2,001	-$ 2,001	$ -
2440	Contributed Capital - Underground Padmount Transformer	-	$ -	$ -	-$ 310,285	$ -	-$ 310,285	-$ 44,598	-	0.00%	40.00	2.50%	$ -	-$ 7,757	-$ 557	-$ 8,315	-$ 8,315	$ -
2440	Contributed Capital -Underground Submersible Transformer	-	$ -	$ -	-$ 1,515,233	$ -	-$ 1,515,233	-$ 347,448	-	0.00%	30.00	3.33%	$ -	-$ 50,508	-$ 5,791	-$ 56,299	-$ 56,299	$ -
2440	Contributed Capital - Underground Services	-	$ -	$ -	-$ 3,390,579	$ -	-$ 3,390,579	-$ 1,785,365	-	0.00%	40.00	2.50%	$ -	-$ 84,764	-$ 22,317	-$ 107,082	-$ 107,082	$ -
2440	Contributed Capital - Transformer Foundations	-	$ -	$ -	-$ 782,578	$ -	-$ 782,578	-$ 122,340	-	0.00%	60.00	1.67%	$ -	-$ 13,043	-$ 1,020	-$ 14,062	-$ 14,440	-$ 378
2440	Contributed Capital - Meters	-	$ -	$ -	-$ 117,230	$ -	-$ 117,230	-$ 58,416	-	0.00%	15.00	6.67%	$ -	-$ 7,815	-$ 1,947	-$ 9,763	-$ 9,763	$ -
2440	Contributed Capital - Meters Solar	-	$ -	$ -	-$ 323,399	$ -	-$ 323,399	-$ 79,253	-	0.00%	15.00	6.67%	$ -	-$ 21,560	-$ 2,642	-$ 24,202	-$ 24,202	$ -
2440	Contributed Capital - OEB Clearing	-	$ -	$ -	-$ 243,274	$ -	-$ 243,274	$ -	-	0.00%	15.00	6.67%	$ -	-$ 16,218	$ -	-$ 16,218	-$ 16,218	$ -
2440	Meters - Renewable Connection - Direct Benefit	-	$ -	$ -	-$ 8,505	$ -	-$ 8,505	$ -	-	0.00%	15.00	6.67%	$ -	-$ 567	$ -	-$ 567	$ -	$ 567
				$ -			$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
	Total	**$ 148,349,204**	**$ 4,142,448**	**$ 144,206,756**	**$ 85,676,991**	**$ 1,710,497**	**$ 83,966,494**	**$ 16,166,017**					**$ 5,037,949**	**$ 3,422,741**	**$ 235,671**	**$ 8,696,361**	**$ 8,605,650**	**-$ 90,711**

Appendix 2-C
Depreciation and Amortization Expense

2018

Account	Description	Book Values							Service Lives				Depreciation Expense					
		Opening Net Book Value of Existing Assets as at Date of Policy Change (Jan. 1) [1]	Less Fully Depreciated [7]	Net Amount of Existing Assets Before Policy Change to be Depreciated	Opening Gross Book Value of Assets Acquired After Policy Change [2]	Less Fully Depreciated [8]	Net Amount of Assets Acquired After Policy Change to be Depreciated	Current Year Additions	Average Remaining Life of Assets Existing Before Policy Change [3]	Depreciation Rate Assets Acquired After Policy Change	Life of Assets Acquired After Policy Change [4]	Depreciation Rate on New Additions	Depreciation Expense on Assets Existing Before Policy Change	Depreciation Expense on Assets Acquired After Policy Change	Depreciation Expense on Current Year Additions [5]	Total Current Year Depreciation Expense	Depreciation Expense per Appendix 2-BA Fixed Assets, Column J	Variance [6]
		a	b	c = a-b	d	e	f = d- e	g	h	i = 1/h	j	k = 1/j	l = c/h	m = f/j	n = g*0.5/j	o = l+m+n	p	q = p-o
1611	Computer Software (Formally known as Account 1925)	928,634	$ 928,634	$ -	$ 2,096,030	$ 135,165	$ 1,960,865	$ 276,227	2.25	44.44%	5.00	20.00%	$ -	$ 392,173	$ 27,623	$ 419,796	$ 450,463	$ 30,668
1611	Computer Software (Formally known as Account 1925)	-		$ -	$ 88,614	$ 88,614	$ -		-	0.00%	3.00	33.33%	$ -	$ -	$ -	$ -		$ -
1611	Computer Software (Formally known as Account 1925) - Smart Meters	-	$ -	$ -	$ 598,681	$ 598,681	$ -	$ -	-	0.00%	3.00	33.33%	$ -	$ -	$ -	$ -	$ -	$ -
1612	Land Rights (Formally known as Account 1906)	12,881	$ 12,881	$ -	$ -	$ -	$ -		4.86	20.60%	50.00	2.00%	$ -	$ -	$ -	$ -	$ -	$ -
1805	Land	2,339,958	$ -	$ 2,339,958	$ -	$ -	$ -		-	0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1808	Buildings - Structure	7,099,490	$ -	$ 7,099,490	$ 463,554	$ -	$ 463,554	$ -	38.08	2.63%	50.00	2.00%	$ 186,429	$ 9,271	$ -	$ 195,700	$ 190,769	-$ 4,931
1808	Buildings - Roof	144,989	$ 58,456	$ 86,533	-$ 2,480	$ -	-$ 2,480	$ -	11.44	8.74%	20.00	5.00%	$ 7,565	-$ 124	$ -	$ 7,441	$ 6,806	-$ 635
1810	Leasehold Improvements	-	$ -	$ -	$ -	$ -	$ -		-	0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1815	Transformer Station Equipment >50 kV 50 yrs	15,658,085	$ 12,312	$ 15,645,773	$ 2,666,569	$ -	$ 2,666,569	$ 431,228	41.16	2.43%	50.00	2.00%	$ 380,092	$ 53,331	$ 4,312	$ 437,735	$ 428,617	-$ 9,118
1815	Transformer Station Equipment >50 kV 40 yrs	24,475,179	$ -	$ 24,475,179	$ 1,497,830	$ -	$ 1,497,830	$ 15,407	28.76	3.48%	40.00	2.50%	$ 851,073	$ 37,446	$ 193	$ 888,712	$ 852,393	-$ 36,319
1815	Transformer Station Equipment >50 kV 30 yrs	-	$ -	$ -	$ 71,591	$ -	$ 71,591	$ -	-	0.00%		0.00%	$ -	$ -	$ -	$ -	$ 2,386	$ 2,386
1815	Transformer Station Equipment >50 kV 25 yrs	887,028	$ 176,718	$ 710,310	$ 233,388	$ -	$ 233,388	$ -	12.07	8.28%	25.00	4.00%	$ 58,839	$ 9,336	$ -	$ 68,175	$ 59,515	-$ 8,660
1815	Transformer Station Equipment >50 kV 20 yrs	392,015	$ 163,703	$ 228,312	$ 188,437	$ -	$ 188,437	$ 27,942	9.76	10.24%	20.00	5.00%	$ 23,383	$ 9,422	$ 699	$ 33,503	$ 31,357	-$ 2,146
1815	Transformer Station Equipment >50 kV 15 yrs	1,087,574	$ 439,950	$ 647,624	$ 1,805,373	$ -	$ 1,805,373	$ 87,145	8.48	11.79%	15.00	6.67%	$ 76,380	$ 120,358	$ 2,905	$ 199,643	$ 187,728	-$ 11,915
1820	Distribution Station Equipment <50 kV 50 yrs	200,427	$ -	$ 200,427	$ -	$ -	$ -	$ -	22.74	4.40%	50.00	2.00%	$ 8,813	$ -	$ -	$ 8,813	$ 8,543	-$ 271
1820	Distribution Station Equipment <50 kV 40 yrs	649,832	$ -	$ 649,832	$ -	$ -	$ -	$ -	25.47	3.93%	40.00	2.50%	$ 25,509	$ -	$ -	$ 25,509	$ 24,261	-$ 1,249
1820	Distribution Station Equipment <50 kV 25 yrs	13,287	$ -	$ 13,287	$ -	$ -	$ -	$ -	5.93	16.87%	25.00	4.00%	$ 2,242	$ -	$ -	$ 2,242	$ 990	-$ 1,252
1820	Distribution Station Equipment <50 kV 20 yrs	6,078	$ 6,078	$ -	$ -	$ -	$ -	$ -	5.66	17.66%	20.00	5.00%	$ -	$ -	$ -	$ -	$ 241	$ 241
1820	Distribution Station Equipment <50 kV 15 hrs	17,551	$ 17,551	$ -	$ 153,636	$ -	$ 153,636	$ 7,664	9.64	10.37%	15.00	6.67%	$ -	$ 10,242	$ 255	$ 10,498	$ 11,104	$ 606
1825	Storage Battery Equipment	-	$ -	$ -	$ -	$ -	$ -		-	0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1830	Poles, Towers & Fixtures	17,028,402	$ -	$ 17,028,402	$ 16,599,529	$ -	$ 16,599,529	$ 2,923,851	32.16	3.11%	40.00	2.50%	$ 529,490	$ 414,988	$ 36,548	$ 981,026	$ 971,034	-$ 9,992
1835	Overhead Conductors	14,319,062	$ -	$ 14,319,062	$ 11,178,836	$ -	$ 11,178,836	$ 2,223,728	51.16	1.95%	60.00	1.67%	$ 279,881	$ 186,314	$ 18,531	$ 484,726	$ 479,580	-$ 5,146
1835	Overhead Devices	1,591,007	$ -	$ 1,591,007	$ 1,469,022	$ -	$ 1,469,022	$ 151,905	30.57	3.27%	40.00	2.50%	$ 52,051	$ 36,726	$ 1,899	$ 90,675	$ 88,905	-$ 1,770
1835	Voltage Regulators	163,109	$ -	$ 163,109	$ -	$ -	$ -	$ -	20.00	5.00%	30.00	3.33%	$ 8,155	$ -	$ -	$ 8,155	$ 7,767	-$ 388
1835	Capacitor Banks	618,096	$ -	$ 618,096	$ 1,124,214	$ -	$ 1,124,214	$ 459,129	19.80	5.05%	25.00	4.00%	$ 31,224	$ 44,969	$ 9,183	$ 85,375	$ 64,289	-$ 21,086
1840	Underground Conduit	12,527,558	$ -	$ 12,527,558	$ 17,551,725	$ -	$ 17,551,725	$ 2,184,528	51.70	1.93%	60.00	1.67%	$ 242,295	$ 292,529	$ 18,204	$ 553,028	$ 548,637	-$ 4,391
1845	Underground Conductors & Devices - PILC	414,000	$ -	$ 414,000	$ 1,556,539	$ -	$ 1,556,539	$ -	58.00	1.72%	60.00	1.67%	$ 7,138	$ 25,942	$ -	$ 33,080	$ 32,959	-$ 121
1845	Underground Cables	15,726,653	$ -	$ 15,726,653	$ 14,958,391	$ -	$ 14,958,391	$ 1,457,275	28.66	3.49%	40.00	2.50%	$ 548,637	$ 373,960	$ 18,216	$ 940,813	$ 921,501	-$ 19,312
1845	Underground Devices	1,747,406	$ -	$ 1,747,406	$ 1,886,043	$ -	$ 1,886,043	$ 380,437	28.66	3.49%	40.00	2.50%	$ 60,960	$ 47,151	$ 4,755	$ 112,866	$ 110,711	-$ 2,155
1850	Line Transformers - Overhead	15,713,833	$ 345,325	$ 15,368,508	$ 5,529,005	$ -	$ 5,529,005	$ 940,314	27.98	3.57%	40.00	2.50%	$ 549,182	$ 138,225	$ 11,754	$ 699,161	$ 535,757	-$ 163,405
1850	Line Transformers - Network	5,503	$ -	$ 5,503	$ 1,057,332	$ -	$ 1,057,332	$ 220,474	9.38	10.66%	40.00	2.50%	$ 587	$ 26,433	$ 2,756	$ 29,776	$ 44,652	$ 14,876
1850	Line Transformers - Vault	-	$ -	$ -	$ 6,041	$ -	$ 6,041	$ -	-	0.00%	60.00	1.67%	$ -	$ 101	$ -	$ 101	$ 99	-$ 2
1850	Line Transformers - Roof	497,948	$ 16,586	$ 481,362	$ -	$ -	$ -	$ -	23.84	4.19%	30.00	3.33%	$ 20,190	$ -	$ -	$ 20,190	$ 18,897	-$ 1,293
1850	Line Transformers -Network Protectors	91,592	$ -	$ 91,592	$ 546,514	$ -	$ 546,514	$ 133,668	39.50	2.53%	40.00	2.50%	$ 2,319	$ 13,663	$ 1,671	$ 17,652	$ 13,086	-$ 4,566
1850	Line Transformers - Padmount	3,991,872	$ -	$ 3,991,872	$ 4,745,849	$ -	$ 4,745,849	$ 1,041,700	36.77	2.72%	40.00	2.50%	$ 108,567	$ 118,646	$ 13,021	$ 240,234	$ 171,326	-$ 68,908
1850	Line Transformers - Submersible	3,195,923	$ -	$ 3,195,923	$ 4,075,441	$ -	$ 4,075,441	$ 716,514	24.09	4.15%	30.00	3.33%	$ 132,669	$ 135,848	$ 11,942	$ 280,459	$ 633,018	$ 352,559
1850	Line Transformers - Foundation	1,427,416	$ -	$ 1,427,416	$ 1,739,548	$ -	$ 1,739,548	$ 419,866	58.08	1.72%	60.00	1.67%	$ 24,575	$ 28,992	$ 3,499	$ 57,067	$ 50,445	-$ 6,621
1855	Services - Overhead	1,887,728	$ -	$ 1,887,728	$ 2,371,238	$ -	$ 2,371,238	$ 428,550	52.20	1.92%	60.00	1.67%	$ 36,164	$ 39,521	$ 3,571	$ 79,256	$ 78,616	-$ 640
1855	Services - Underground	22,543,287	$ -	$ 22,543,287	$ 14,850,781	$ -	$ 14,850,781	$ 2,722,298	31.40	3.18%	40.00	2.50%	$ 717,938	$ 371,270	$ 34,029	$ 1,123,236	$ 1,100,330	-$ 22,906
1860	Commercial Meters	1,327,802	$ 158,636	$ 1,169,166	$ 1,848,799	$ -	$ 1,848,799	$ 627,826	20.97	4.77%	25.00	4.00%	$ 55,753	$ 73,952	$ 12,557	$ 142,261	$ 188,448	$ 46,187
1860	Smart Meters - Non-Qualifying	108,222		$ 108,222	$ 240,153	$ -	$ 240,153		12.00	8.33%	15.00	6.67%	$ 9,018	$ 16,010	$ -	$ 25,028		-$ 25,028
1860	Meters - Renewable Connection	-		$ -	$ 154,427	$ -	$ 154,427		-	0.00%	15.00	6.67%	$ -	$ 10,295	$ -	$ 10,295		-$ 10,295
1860	Smart Meters	-		$ -	$ -	$ -	$ -		-	0.00%	15.00	6.67%	$ -	$ -	$ -	$ -		$ -
1860	Smart Meters	-	$ -	$ -	$ 13,280,755	$ -	$ 13,280,755	$ 539,690	-	0.00%	15.00	6.67%	$ -	$ 885,384	$ 17,990	$ 903,373	$ 903,955	$ 582
1905	Land	1,395,300	$ -	$ 1,395,300	$ -	$ -	$ -	$ -	-	0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1908	Buildings & Fixtures - Building	5,262,681	$ -	$ 5,262,681	$ 5,963,157	$ -	$ 5,963,157	$ 918,456	28.71	3.48%	50.00	2.00%	$ 183,326	$ 119,263	$ 9,185	$ 311,774	$ 299,091	-$ 12,683
1908	Buildings & Fixtures - Roof	1,567,291	$ 965,052	$ 602,239	$ 2,469,936	$ -	$ 2,469,936	$ 18,200	6.53	15.33%	20.00	5.00%	$ 92,295	$ 123,497	$ 455	$ 216,247	$ 166,747	-$ 49,500
1910	Leasehold Improvements	-	$ -	$ -	$ -	$ -	$ -	$ -	-	0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1915	Office Furniture & Equipment (10 years)	340,212	$ 54,104	$ 286,108	$ 400,152	$ -	$ 400,152	$ 34,172	5.10	19.61%	10.00	10.00%	$ 56,100	$ 40,015	$ 1,709	$ 97,823	$ 62,256	-$ 35,568
1915	Office Furniture & Equipment (5 years)	-	$ -	$ -	$ -	$ -	$ -		-	0.00%	5.00	20.00%	$ -	$ -	$ -	$ -		$ -
1920	Computer Equipment - Hardware	350,464	$ 319,593	$ 30,871	$ 596,838	$ 458,791	$ 138,047	$ 604,377	2.12	47.12%	5.00	20.00%	$ 14,548	$ 27,609	$ 60,438	$ 102,595	$ 169,342	$ 66,747
1920	Computer Equip.-Hardware - Smart Meters	-	$ -	$ -	$ 569,286	$ 437,864	$ 131,422	$ -	-	0.00%	5.00	20.00%	$ -	$ 26,284	$ -	$ 26,284	$ 22,126	-$ 4,158
1920	Computer Equip.-Hardware(Post Mar. 19/07)	-	$ -	$ -	$ -	$ -	$ -	$ -	-	0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1930	Transportation Equipment	2,781,086	$ 766,935	$ 2,014,151	$ 4,088,182	$ -	$ 4,088,182	$ 850,223	7.19	13.90%	11.00	9.09%	$ 280,052	$ 371,653	$ 38,647	$ 690,351	$ 685,883	-$ 4,468
1935	Stores Equipment	21,484	$ -	$ 21,484	$ 2,552	$ -	$ 2,552	$ -	4.55	21.99%	10.00	10.00%	$ 4,724	$ 255	$ -	$ 4,979	$ 255	-$ 4,724
1940	Tools, Shop & Garage Equipment	324,953	$ -	$ 324,953	$ 455,455	$ -	$ 455,455	$ 73,813	6.70	14.93%	10.00	10.00%	$ 48,520	$ 45,546	$ 3,691	$ 97,756	$ 75,241	-$ 22,515
1940	Tools - Smart Meters	-	$ -	$ -	$ -	$ -	$ -	$ -	-	0.00%	10.00	10.00%	$ -	$ -	$ -	$ -	$ 373	$ 373
1945	Measurement & Testing Equipment	163,014	$ -	$ 163,014	$ 243,956	$ -	$ 243,956	$ 13,362	7.77	12.88%	10.00	10.00%	$ 20,993	$ 24,396	$ 668	$ 46,057	$ 37,167	-$ 8,890
1950	Power Operated Equipment	306,812	$ 98,740	$ 208,072	$ 454,630	$ -	$ 454,630	$ 277,919	6.77	14.76%	10.00	10.00%	$ 30,719	$ 45,463	$ 13,896	$ 90,078	$ 68,938	-$ 21,140
1955	Communications Equipment	58,880	$ -	$ 58,880	$ 149,583	$ -	$ 149,583	$ 45,955	6.76	14.80%	10.00	10.00%	$ 8,715	$ 14,958	$ 2,298	$ 25,971	$ 15,922	-$ 10,049
1955	Communication Equipment (Smart Meters)	-	$ -	$ -	$ 696,896	$ -	$ 696,896	$ -	-	0.00%	10.00	10.00%	$ -	$ 69,690	$ -	$ 69,690	$ 69,690	$ -
1960	Miscellaneous Equipment	40,970	$ 40,970	$ -	$ 15,143	$ -	$ 15,143	$ 3,464	3.61	27.74%	5.00	20.00%	$ -	$ 3,029	$ 346	$ 3,375	$ 2,195	-$ 1,180
1975	Load Management Controls Utility Premises	-	$ -	$ -	$ -	$ -	$ -	$ -	-	0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1980	System Supervisor Equipment	115,075	$ 100,327	$ 14,748	$ -	$ -	$ -	$ -	6.15	16.26%	10.00	10.00%	$ 2,398	$ -	$ -	$ 2,398	$ 2,204	-$ 194
1985	Miscellaneous Fixed Assets	-	$ -	$ -	$ -	$ -	$ -	$ -	-	0.00%		0.00%	$ -	$ -	$ -	$ -		$ -

Appendix 2-C
Depreciation and Amortization Expense

1995	**Contributions & Grants**	-	$ -	$ -	$ -	$ -	$ -		-	0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1995	Contributed Capital - Poles, Towers & Fixtures	- 1,626,853	$ -	-$ 1,626,853	-$ 1,146,161	$ -	-$ 1,146,161	$ -	34.50	2.90%	40.00	2.50%	-$ 47,155	-$ 28,654	$ -	-$ 75,809	-$ 74,779	$ 1,030
1995	Contributed Capital - Overhead Conductors	- 1,246,129	$ -	-$ 1,246,129	-$ 969,095	$ -	-$ 969,095	$ -	54.55	1.83%	60.00	1.67%	-$ 22,844	-$ 16,152	$ -	-$ 38,996	-$ 38,570	$ 426
1995	Contributed Capital - Overhead Devices	- 138,459	$ -	-$ 138,459	-$ 109,089	$ -	-$ 109,089	$ -	34.39	2.91%	40.00	2.50%	-$ 4,026	-$ 2,727	$ -	-$ 6,753	-$ 6,658	$ 95
1995	Contributed Capital - Overhead Services	- 1,195,490	$ -	-$ 1,195,490	-$ 119,872	$ -	-$ 119,872	$ -	40.18	2.49%	60.00	1.67%	-$ 29,750	-$ 1,998	$ -	-$ 31,748	-$ 24,333	$ 7,415
1995	Contributed Capital - Underground Trenching & Ductwork	- 5,566,404	$ -	-$ 5,566,404	-$ 2,609,506	$ -	-$ 2,609,506	$ -	54.02	1.85%	60.00	1.67%	-$ 103,051	-$ 43,492	$ -	-$ 146,543	-$ 144,784	$ 1,759
1995	Contributed Capital - Underground Cables	- 2,292,136	$ -	-$ 2,292,136	-$ 2,370,201	$ -	-$ 2,370,201	$ -	30.81	3.25%	40.00	2.50%	-$ 74,387	-$ 59,255	$ -	-$ 133,642	-$ 124,494	$ 9,147
1995	Contributed Capital - Underground Devices	- 254,682	$ -	-$ 254,682	-$ 167,703	$ -	-$ 167,703	$ -	-	0.00%	40.00	2.50%	$ -	-$ 4,193	$ -	-$ 4,193	-$ 11,476	-$ 7,284
1995	Contributed Capital - Overhead Transformer	- 2,734,282	$ -	-$ 2,734,282	$ 169,874	$ -	$ 169,874	$ -	34.03	2.94%	40.00	2.50%	-$ 80,349	$ 4,247	$ -	-$ 76,102	-$ 79,517	-$ 3,415
1995	Contributed Capital - Underground Padmount Transformer	- 1,858,357	$ -	-$ 1,858,357	-$ 7,920	$ -	-$ 7,920	$ -	32.33	3.09%	40.00	2.50%	-$ 57,473	-$ 198	$ -	-$ 57,671	-$ 62,762	-$ 5,091
1995	Contributed Capital -Underground Submersible Transformer	- 1,955,810	$ -	-$ 1,955,810	-$ 675,874	$ -	-$ 675,874	$ -	25.19	3.97%	30.00	3.33%	-$ 77,649	-$ 22,529	$ -	-$ 100,178	-$ 97,024	$ 3,154
1995	Contributed Capital - Underground Services	- 13,453,846	$ -	-$ 13,453,846	-$ 953,639	$ -	-$ 953,639	$ -	33.74	2.96%	40.00	2.50%	-$ 398,729	-$ 23,841	$ -	-$ 422,570	-$ 399,263	$ 23,307
1995	Contributed Capital - Transformer Foundations	- 798,352	$ -	-$ 798,352	-$ 558,073	$ -	-$ 558,073	$ -	54.11	1.85%	60.00	1.67%	-$ 14,753	-$ 9,301	$ -	-$ 24,054	-$ 23,786	$ 268
1995	Contributed Capital - Meters	- 166,183	$ -	-$ 166,183	-$ 132,547	$ -	-$ 132,547	$ -	6.15	16.25%	15.00	6.67%	-$ 27,003	-$ 8,836	$ -	-$ 35,839	-$ 18,639	$ 17,200
	Contributed Capital - Meters SOLAR	-	$ -	$ -	-$ 152,011	$ -	-$ 152,011	$ -	-	0.00%	15.00	6.67%	$ -	-$ 10,134	$ -	-$ 10,134	-$ 13,644	-$ 3,509
1995	Contributed Capital - OEB Clearing	68,538	$ -	$ 68,538	$ 259,328	$ -	$ 259,328	$ -	- 10.00	-10.00%	15.00	6.67%	-$ 6,854	$ 17,289	$ -	$ 10,435	$ 25,468	$ 15,033
2440	**Deferred Revenue**	-	$ -	$ -	$ -	$ -	$ -		-	0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
2440	Contributed Capital - Poles, Towers & Fixtures	-	$ -	$ -	-$ 3,265,250	-$ 419,536	-$ 2,845,714	-$ 157,256	-	0.00%	40.00	2.50%	$ -	-$ 71,143	-$ 1,966	-$ 73,109	-$ 78,353	-$ 5,244
2440	Contributed Capital - Overhead Conductors	-	$ -	$ -	-$ 2,306,624	$ -	-$ 2,306,624	-$ 144,993	-	0.00%	60.00	1.67%	$ -	-$ 38,444	-$ 1,208	-$ 39,652	-$ 37,446	$ 2,206
2440	Contributed Capital - Overhead Devices	-	$ -	$ -	-$ 256,033	$ -	-$ 256,033	-$ 15,410	-	0.00%	40.00	2.50%	$ -	-$ 6,401	-$ 193	-$ 6,593	-$ 6,226	$ 368
2440	Contributed Capital - Overhead Services	-	$ -	$ -	-$ 492,281	$ -	-$ 492,281	-$ 96,217	-	0.00%	60.00	1.67%	$ -	-$ 8,205	-$ 802	-$ 9,006	-$ 8,684	$ 323
2440	Contributed Capital - Underground Trenching & Ductwork	-	$ -	$ -	-$ 8,398,752	$ -	-$ 8,398,752	-$ 871,534	-	0.00%	60.00	1.67%	$ -	-$ 139,979	-$ 7,263	-$ 147,242	-$ 146,524	$ 718
2440	Contributed Capital - Underground Cables	-	$ -	$ -	-$ 6,668,492	$ -	-$ 6,668,492	-$ 505,487	-	0.00%	40.00	2.50%	$ -	-$ 166,712	-$ 6,319	-$ 173,031	-$ 171,553	$ 1,478
2440	Contributed Capital - Underground Devices	-	$ -	$ -	-$ 739,255	$ -	-$ 739,255	-$ 56,165	-	0.00%	40.00	2.50%	$ -	-$ 18,481	-$ 702	-$ 19,183	-$ 19,019	$ 164
2440	Contributed Capital - Overhead Transformer	-	$ -	$ -	-$ 96,485	$ -	-$ 96,485	-$ 2,645	-	0.00%	40.00	2.50%	$ -	-$ 2,412	-$ 33	-$ 2,445	-$ 2,109	$ 336
2440	Contributed Capital - Underground Padmount Transformer	-	$ -	$ -	-$ 354,883	$ -	-$ 354,883	-$ 180,147	-	0.00%	40.00	2.50%	$ -	-$ 8,872	-$ 2,252	-$ 11,124	-$ 11,124	$ -
2440	Contributed Capital -Underground Submersible Transformer	-	$ -	$ -	-$ 1,862,681	$ -	-$ 1,862,681	-$ 443,956	-	0.00%	30.00	3.33%	$ -	-$ 62,089	-$ 7,399	-$ 69,489	-$ 69,363	$ 126
2440	Contributed Capital - Underground Services	-	$ -	$ -	-$ 5,175,944	$ -	-$ 5,175,944	-$ 1,824,310	-	0.00%	40.00	2.50%	$ -	-$ 129,399	-$ 22,804	-$ 152,202	-$ 150,865	$ 1,337
2440	Contributed Capital - Transformer Foundations	-	$ -	$ -	-$ 904,918	$ -	-$ 904,918	-$ 128,313	-	0.00%	60.00	1.67%	$ -	-$ 15,082	-$ 1,069	-$ 16,151	-$ 16,508	-$ 357
2440	Contributed Capital - Meters	-	$ -	$ -	-$ 175,646	$ -	-$ 175,646	-$ 39,723	-	0.00%	15.00	6.67%	$ -	-$ 11,710	-$ 1,324	-$ 13,034	-$ 13,034	$ -
2440	Contributed Capital - Meters Solar	-	$ -	$ -	-$ 402,652	$ -	-$ 402,652	-$ 230,489	-	0.00%	15.00	6.67%	$ -	-$ 26,843	-$ 7,683	-$ 34,526	-$ 34,526	$ -
2440	Contributed Capital - OEB Clearing	-	$ -	$ -	-$ 243,274	$ -	-$ 243,274	-$ 3	-	0.00%	15.00	6.67%	$ -	-$ 16,218	-$ 0	-$ 16,218	-$ 16,218	$ -
2440	Meters - Renewable Connection - Direct Benefit	-	$ -	$ -	-$ 8,505	$ -	-$ 8,505	$ -	-	0.00%	15.00	6.67%	$ -	-$ 567	$ -	-$ 567	$ -	$ 567
				$ -			$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
	Total	**$ 148,349,204**	**$ 4,682,551**	**$ 143,666,653**	**$ 101,843,008**	**$ 1,299,579**	**$ 100,543,429**	**$ 16,560,659**					**$ 4,835,486**	**$ 3,901,699**	**$ 326,427**	**$ 9,063,612**	**$ 9,020,804**	**-$ 42,808**

Appendix 2-C
Depreciation and Amortization Expense

2019

Account	Description	Book Values							Service Lives				Depreciation Expense						
		Opening Net Book Value of Existing Assets as at Date of Policy Change (Jan. 1) [1]	Less Fully Depreciated [7]	Net Amount of Existing Assets Before Policy Change to be Depreciated	Opening Gross Book Value of Assets Acquired After Policy Change [2]	Less Fully Depreciated [8]	Net Amount of Assets Acquired After Policy Change to be Depreciated	Current Year Additions	Average Remaining Life of Assets Existing Before Policy Change [3]	Depreciation Rate Assets Acquired After Policy Change	Life of Assets Acquired After Policy Change [4]	Depreciation Rate on New Additions	Depreciation Expense on Assets Existing Before Policy Change	Depreciation Expense on Assets Acquired After Policy Change	Depreciation Expense on Current Year Additions [5]	Total Current Year Depreciation Expense	Depreciation Expense per Appendix 2-BA Fixed Assets, Column J	Variance [6]
		a	b	c = a-b	d	e	f = d- e	g	h	i = 1/h	j	k = 1/j	l = c/h	m = f/j	n = g*0.5/j	o = l+m+n	p	q = p-o
1611	Computer Software (Formally known as Account 1925)	928,634	$ 928,634	$ -	$ 2,372,257	$ 135,165	$ 2,237,092	$ 854,365	2.25	44.44%	5.00	20.00%	$ -	$ 447,418	$ 85,437	$ 532,855	$ 445,400	-$ 87,455
1611	Computer Software (Formally known as Account 1925)	-		$ -	$ 88,614	$ 88,614	$ -		-	0.00%	3.00	33.33%	$ -	$ -	$ -	$ -		$ -
1611	Computer Software (Formally known as Account 1925) - Smart Meters	-	$ -	$ -	$ 598,681	$ 598,681	$ -	$ -	-	0.00%	3.00	33.33%	$ -	$ -	$ -	$ -	$ -	$ -
1612	Land Rights (Formally known as Account 1906)	12,881	$ 12,881	$ -	$ -	$ -	$ -		4.86	20.60%	50.00	2.00%	$ -	$ -	$ -	$ -	$ -	$ -
1805	Land	2,339,958	$ -	$ 2,339,958	$ -	$ -	$ -		-	0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1808	Buildings - Structure	7,099,490	$ -	$ 7,099,490	$ 463,554	$ -	$ 463,554	$ -	38.08	2.63%	50.00	2.00%	$ 186,429	$ 9,271	$ -	$ 195,700	$ 190,900	-$ 4,800
1808	Buildings - Roof	144,989	$ 58,456	$ 86,533	-$ 2,480	$ -	-$ 2,480	$ -	11.44	8.74%	20.00	5.00%	$ 7,565	-$ 124	$ -	$ 7,441	$ 6,500	-$ 941
1810	Leasehold Improvements	-	$ -	$ -	$ -	$ -	$ -		-	0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1815	Transformer Station Equipment >50 kV 50 yrs	15,658,085	$ 12,312	$ 15,645,773	$ 3,097,797	$ -	$ 3,097,797	$ 815,500	41.16	2.43%	50.00	2.00%	$ 380,092	$ 61,956	$ 8,155	$ 450,203	$ 439,400	-$ 10,803
1815	Transformer Station Equipment >50 kV 40 yrs	24,475,179	$ -	$ 24,475,179	$ 1,513,237	$ -	$ 1,513,237	$ 56,200	28.76	3.48%	40.00	2.50%	$ 851,073	$ 37,831	$ 703	$ 889,607	$ 862,400	-$ 27,207
1815	Transformer Station Equipment >50 kV 30 yrs	-	$ -	$ -	$ 71,591	$ -	$ 71,591	$ -	-	0.00%		0.00%	$ -	$ -	$ -	$ -	$ 2,400	$ 2,400
1815	Transformer Station Equipment >50 kV 25 yrs	887,028	$ 176,718	$ 710,310	$ 233,388	$ -	$ 233,388	$ -	12.07	8.28%	25.00	4.00%	$ 58,839	$ 9,336	$ -	$ 68,175	$ 56,400	-$ 11,775
1815	Transformer Station Equipment >50 kV 20 yrs	392,015	$ 163,703	$ 228,312	$ 216,379	$ -	$ 216,379	$ 25,900	9.76	10.24%	20.00	5.00%	$ 23,383	$ 10,819	$ 648	$ 34,849	$ 31,000	-$ 3,849
1815	Transformer Station Equipment >50 kV 15 yrs	1,087,574	$ 439,950	$ 647,624	$ 1,892,518	$ -	$ 1,892,518	$ 726,900	8.48	11.79%	15.00	6.67%	$ 76,380	$ 126,168	$ 24,230	$ 226,778	$ 208,400	-$ 18,378
1820	Distribution Station Equipment <50 kV 50 yrs	200,427	$ -	$ 200,427	$ -	$ -	$ -	$ -	22.74	4.40%	50.00	2.00%	$ 8,813	$ -	$ -	$ 8,813	$ 8,600	-$ 213
1820	Distribution Station Equipment <50 kV 40 yrs	649,832	$ -	$ 649,832	$ -	$ -	$ -	$ -	25.47	3.93%	40.00	2.50%	$ 25,509	$ -	$ -	$ 25,509	$ 24,300	-$ 1,209
1820	Distribution Station Equipment <50 kV 25 yrs	13,287	$ -	$ 13,287	$ -	$ -	$ -	$ -	5.93	16.87%	25.00	4.00%	$ 2,242	$ -	$ -	$ 2,242	$ 1,000	-$ 1,242
1820	Distribution Station Equipment <50 kV 20 yrs	6,078	$ 6,078	$ -	$ -	$ -	$ -	$ -	5.66	17.66%	20.00	5.00%	$ -	$ -	$ -	$ -	$ 700	$ 700
1820	Distribution Station Equipment <50 kV 15 hrs	17,551	$ 17,551	$ -	$ 161,300	$ -	$ 161,300	$ -	9.64	10.37%	15.00	6.67%	$ -	$ 10,753	$ -	$ 10,753	$ 10,900	$ 147
1825	Storage Battery Equipment	-	$ -	$ -	$ -	$ -	$ -		-	0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1830	Poles, Towers & Fixtures	17,028,402	$ -	$ 17,028,402	$ 19,523,380	$ -	$ 19,523,380	$ 2,959,500	32.16	3.11%	40.00	2.50%	$ 529,490	$ 488,085	$ 36,994	$ 1,054,568	$ 1,059,200	$ 4,632
1835	Overhead Conductors	14,319,062	$ -	$ 14,319,062	$ 13,402,564	$ -	$ 13,402,564	$ 2,442,240	51.16	1.95%	60.00	1.67%	$ 279,881	$ 223,376	$ 20,352	$ 523,609	$ 515,000	-$ 8,609
1835	Overhead Devices	1,591,007	$ -	$ 1,591,007	$ 1,620,927	$ -	$ 1,620,927	$ 271,400	30.57	3.27%	40.00	2.50%	$ 52,051	$ 40,523	$ 3,393	$ 95,966	$ 96,100	$ 134
1835	Voltage Regulators	163,109	$ -	$ 163,109	$ -	$ -	$ -	$ -	20.00	5.00%	30.00	3.33%	$ 8,155	$ -	$ -	$ 8,155	$ 7,800	-$ 355
1835	Capacitor Banks	618,096	$ -	$ 618,096	$ 1,583,343	$ -	$ 1,583,343	$ -	19.80	5.05%	25.00	4.00%	$ 31,224	$ 63,334	$ -	$ 94,557	$ 64,200	-$ 30,357
1840	Underground Conduit	12,527,558	$ -	$ 12,527,558	$ 19,736,253	$ -	$ 19,736,253	$ 2,519,600	51.70	1.93%	60.00	1.67%	$ 242,295	$ 328,938	$ 20,997	$ 592,229	$ 568,700	-$ 23,529
1845	Underground Conductors & Devices - PILC	414,000	$ -	$ 414,000	$ 1,556,539	$ -	$ 1,556,539	$ -	58.00	1.72%	60.00	1.67%	$ 7,138	$ 25,942	$ -	$ 33,080	$ 33,000	-$ 80
1845	Underground Cables	15,726,653	$ -	$ 15,726,653	$ 16,415,666	$ -	$ 16,415,666	$ 1,522,982	28.66	3.49%	40.00	2.50%	$ 548,637	$ 410,392	$ 19,037	$ 978,066	$ 959,300	-$ 18,766
1845	Underground Devices	1,747,406	$ -	$ 1,747,406	$ 2,266,480	$ -	$ 2,266,480	$ 169,220	28.66	3.49%	40.00	2.50%	$ 60,960	$ 56,662	$ 2,115	$ 119,737	$ 112,200	-$ 7,537
1850	Line Transformers - Overhead	15,713,833	$ 345,325	$ 15,368,508	$ 6,469,319	$ -	$ 6,469,319	$ 970,000	27.98	3.57%	40.00	2.50%	$ 549,182	$ 161,733	$ 12,125	$ 723,040	$ 544,500	-$ 178,540
1850	Line Transformers - Network	5,503	$ -	$ 5,503	$ 1,277,806	$ -	$ 1,277,806	$ 192,000	9.38	10.66%	40.00	2.50%	$ 587	$ 31,945	$ 2,400	$ 34,932	$ 50,400	$ 15,468
1850	Line Transformers - Vault	-	$ -	$ -	$ 6,041	$ -	$ 6,041	$ -	-	0.00%	60.00	1.67%	$ -	$ 101	$ -	$ 101	$ 100	-$ 1
1850	Line Transformers - Roof	497,948	$ 16,586	$ 481,362	$ -	$ -	$ -	$ -	23.84	4.19%	30.00	3.33%	$ 20,190	$ -	$ -	$ 20,190	$ 18,900	-$ 1,290
1850	Line Transformers -Network Protectors	91,592	$ -	$ 91,592	$ 680,182	$ -	$ 680,182	$ -	39.50	2.53%	40.00	2.50%	$ 2,319	$ 17,005	$ -	$ 19,323	$ 13,100	-$ 6,223
1850	Line Transformers - Padmount	3,991,872	$ -	$ 3,991,872	$ 5,787,549	$ -	$ 5,787,549	$ 735,526	36.77	2.72%	40.00	2.50%	$ 108,567	$ 144,689	$ 9,194	$ 262,449	$ 172,000	-$ 90,449
1850	Line Transformers - Submersible	3,195,923	$ -	$ 3,195,923	$ 4,791,955	$ -	$ 4,791,955	$ 736,898	24.09	4.15%	30.00	3.33%	$ 132,669	$ 159,732	$ 12,282	$ 304,683	$ 638,500	$ 333,817
1850	Line Transformers - Foundation	1,427,416	$ -	$ 1,427,416	$ 2,159,414	$ -	$ 2,159,414	$ 490,375	58.08	1.72%	60.00	1.67%	$ 24,575	$ 35,990	$ 4,086	$ 64,652	$ 56,600	-$ 8,052
1855	Services - Overhead	1,887,728	$ -	$ 1,887,728	$ 2,799,788	$ -	$ 2,799,788	$ 513,300	52.20	1.92%	60.00	1.67%	$ 36,164	$ 46,663	$ 4,278	$ 87,105	$ 87,300	$ 195
1855	Services - Underground	22,543,287	$ -	$ 22,543,287	$ 17,573,079	$ -	$ 17,573,079	$ 2,288,160	31.40	3.18%	40.00	2.50%	$ 717,938	$ 439,327	$ 28,602	$ 1,185,867	$ 1,115,100	-$ 70,767
1860	Commercial Meters	1,327,802	$ 158,636	$ 1,169,166	$ 2,476,625	$ -	$ 2,476,625	$ 307,344	20.97	4.77%	25.00	4.00%	$ 55,753	$ 99,065	$ 6,147	$ 160,964	$ 198,700	$ 37,736
1860	Smart Meters - Non-Qualifying	108,222		$ 108,222	$ 240,153	$ -	$ 240,153		12.00	8.33%	15.00	6.67%	$ 9,018	$ 16,010	$ -	$ 25,028		-$ 25,028
1860	Meters - Renewable Connection	-		$ -	$ 154,427	$ -	$ 154,427		-	0.00%	15.00	6.67%	$ -	$ 10,295	$ -	$ 10,295		-$ 10,295
1860	Smart Meters	-		$ -	$ -	$ -	$ -		-	0.00%	15.00	6.67%	$ -	$ -	$ -	$ -		$ -
1860	Smart Meters	-	$ -	$ -	$ 13,820,445	$ -	$ 13,820,445	$ 332,956	-	0.00%	15.00	6.67%	$ -	$ 921,363	$ 11,099	$ 932,462	$ 908,900	-$ 23,562
1905	Land	1,395,300	$ -	$ 1,395,300	$ -	$ -	$ -	$ -	-	0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1908	Buildings & Fixtures - Building	5,262,681	$ -	$ 5,262,681	$ 6,881,613	$ -	$ 6,881,613	$ -	28.71	3.48%	50.00	2.00%	$ 183,326	$ 137,632	$ -	$ 320,959	$ 294,000	-$ 26,959
1908	Buildings & Fixtures - Roof	1,567,291	$ 966,958	$ 600,333	$ 2,488,136	$ -	$ 2,488,136	$ 750,000	6.53	15.33%	20.00	5.00%	$ 92,003	$ 124,407	$ 18,750	$ 235,159	$ 218,500	-$ 16,659
1910	Leasehold Improvements	-	$ -	$ -	$ -	$ -	$ -	$ -	-	0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1915	Office Furniture & Equipment (10 years)	340,212	$ 54,104	$ 286,108	$ 434,324	$ -	$ 434,324	$ 144,596	5.10	19.61%	10.00	10.00%	$ 56,100	$ 43,432	$ 7,230	$ 106,762	$ 61,500	-$ 45,262
1915	Office Furniture & Equipment (5 years)	-	$ -	$ -	$ -	$ -	$ -		-	0.00%	5.00	20.00%	$ -	$ -	$ -	$ -		$ -
1920	Computer Equipment - Hardware	350,464	$ 319,593	$ 30,871	$ 1,201,215	$ 458,791	$ 742,424	$ 344,140	2.12	47.12%	5.00	20.00%	$ 14,548	$ 148,485	$ 34,414	$ 197,447	$ 256,500	$ 59,053
1920	Computer Equip.-Hardware - Smart Meters	-	$ -	$ -	$ 569,286	$ 437,864	$ 131,422	$ -	-	0.00%	5.00	20.00%	$ -	$ 26,284	$ -	$ 26,284	$ 11,100	-$ 15,184
1920	Computer Equip.-Hardware(Post Mar. 19/07)	-	$ -	$ -	$ -	$ -	$ -	$ -	-	0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1930	Transportation Equipment	2,781,086	$ 1,019,162	$ 1,761,924	$ 4,938,405	$ -	$ 4,938,405	$ 1,454,069	7.19	13.90%	11.00	9.09%	$ 244,982	$ 448,946	$ 66,094	$ 760,022	$ 712,200	-$ 47,822
1935	Stores Equipment	21,484	$ -	$ 21,484	$ 2,552	$ -	$ 2,552	$ -	4.55	21.99%	10.00	10.00%	$ 4,724	$ 255	$ -	$ 4,979	$ 300	-$ 4,679
1940	Tools, Shop & Garage Equipment	324,953	$ -	$ 324,953	$ 529,268	$ -	$ 529,268	$ 95,000	6.70	14.93%	10.00	10.00%	$ 48,520	$ 52,927	$ 4,750	$ 106,197	$ 69,600	-$ 36,597
1940	Tools - Smart Meters	-	$ -	$ -	$ -	$ -	$ -	$ -	-	0.00%	10.00	10.00%	$ -	$ -	$ -	$ -	$ 400	$ 400
1945	Measurement & Testing Equipment	163,014	$ -	$ 163,014	$ 257,318	$ -	$ 257,318	$ 10,000	7.77	12.88%	10.00	10.00%	$ 20,993	$ 25,732	$ 500	$ 47,225	$ 35,200	-$ 12,025
1950	Power Operated Equipment	306,812	$ 109,903	$ 196,909	$ 732,549	$ -	$ 732,549	$ 100,000	6.77	14.76%	10.00	10.00%	$ 29,071	$ 73,255	$ 5,000	$ 107,326	$ 83,900	-$ 23,426
1955	Communications Equipment	58,880	$ -	$ 58,880	$ 195,538	$ -	$ 195,538	$ 1,600	6.76	14.80%	10.00	10.00%	$ 8,715	$ 19,554	$ 80	$ 28,349	$ -	-$ 28,349
1955	Communication Equipment (Smart Meters)	-	$ -	$ -	$ 696,896	$ -	$ 696,896	$ 35,000	-	0.00%	10.00	10.00%	$ -	$ 69,690	$ 1,750	$ 71,440	$ 40,000	-$ 31,440
1960	Miscellaneous Equipment	40,970	$ 40,970	$ -	$ 18,607	$ -	$ 18,607	$ -	3.61	27.74%	5.00	20.00%	$ -	$ 3,721	$ -	$ 3,721	$ 1,300	-$ 2,421
1975	Load Management Controls Utility Premises	-	$ -	$ -	$ -	$ -	$ -	$ -	-	0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1980	System Supervisor Equipment	115,075	$ 115,075	$ -	$ -	$ -	$ -	$ -	6.15	16.26%	10.00	10.00%	$ -	$ -	$ -	$ -	$ -	$ -
1985	Miscellaneous Fixed Assets	-	$ -	$ -	$ -	$ -	$ -	$ -	-	0.00%		0.00%	$ -	$ -	$ -	$ -		$ -

Appendix 2-C
Depreciation and Amortization Expense

1995	**Contributions & Grants**	-	$ -	$ -	$ -	$ -	$ -		-	0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1995	Contributed Capital - Poles, Towers & Fixtures	- 1,626,853	$ -	-$ 1,626,853	-$ 1,146,161	$ -	-$ 1,146,161	$ -	34.50	2.90%	40.00	2.50%	-$ 47,155	-$ 28,654	$ -	-$ 75,809	-$ 74,800	$ 1,009
1995	Contributed Capital - Overhead Conductors	- 1,246,129	$ -	-$ 1,246,129	-$ 969,095	$ -	-$ 969,095	$ -	54.55	1.83%	60.00	1.67%	-$ 22,844	-$ 16,152	$ -	-$ 38,996	-$ 38,600	$ 396
1995	Contributed Capital - Overhead Devices	- 138,459	$ -	-$ 138,459	-$ 109,089	$ -	-$ 109,089	$ -	34.39	2.91%	40.00	2.50%	-$ 4,026	-$ 2,727	$ -	-$ 6,753	-$ 6,700	$ 53
1995	Contributed Capital - Overhead Services	- 1,195,490	$ -	-$ 1,195,490	-$ 119,872	$ -	-$ 119,872	$ -	40.18	2.49%	60.00	1.67%	-$ 29,750	-$ 1,998	$ -	-$ 31,748	-$ 24,400	$ 7,348
1995	Contributed Capital - Underground Trenching & Ductwork	- 5,566,404	$ -	-$ 5,566,404	-$ 2,609,506	$ -	-$ 2,609,506	$ -	54.02	1.85%	60.00	1.67%	-$ 103,051	-$ 43,492	$ -	-$ 146,543	-$ 144,800	$ 1,743
1995	Contributed Capital - Underground Cables	- 2,292,136	$ -	-$ 2,292,136	-$ 2,370,201	$ -	-$ 2,370,201	$ -	30.81	3.25%	40.00	2.50%	-$ 74,387	-$ 59,255	$ -	-$ 133,642	-$ 124,500	$ 9,142
1995	Contributed Capital - Underground Devices	- 254,682	$ -	-$ 254,682	-$ 167,703	$ -	-$ 167,703	$ -	-	0.00%	40.00	2.50%	$ -	-$ 4,193	$ -	-$ 4,193	-$ 11,500	-$ 7,307
1995	Contributed Capital - Overhead Transformer	- 2,734,282	$ -	-$ 2,734,282	$ 169,874	$ -	$ 169,874	$ -	34.03	2.94%	40.00	2.50%	-$ 80,349	$ 4,247	$ -	-$ 76,102	-$ 79,600	-$ 3,498
1995	Contributed Capital - Underground Padmount Transformer	- 1,858,357	$ -	-$ 1,858,357	-$ 7,920	$ -	-$ 7,920	$ -	32.33	3.09%	40.00	2.50%	-$ 57,473	-$ 198	$ -	-$ 57,671	-$ 62,800	-$ 5,129
1995	Contributed Capital -Underground Submersible Transformer	- 1,955,810	$ -	-$ 1,955,810	-$ 675,874	$ -	-$ 675,874	$ -	25.19	3.97%	30.00	3.33%	-$ 77,649	-$ 22,529	$ -	-$ 100,178	-$ 97,100	$ 3,078
1995	Contributed Capital - Underground Services	- 13,453,846	$ -	-$ 13,453,846	-$ 953,639	$ -	-$ 953,639	$ -	33.74	2.96%	40.00	2.50%	-$ 398,729	-$ 23,841	$ -	-$ 422,570	-$ 399,300	$ 23,270
1995	Contributed Capital - Transformer Foundations	- 798,352	$ -	-$ 798,352	-$ 558,073	$ -	-$ 558,073	$ -	54.11	1.85%	60.00	1.67%	-$ 14,753	-$ 9,301	$ -	-$ 24,054	-$ 23,800	$ 254
1995	Contributed Capital - Meters	- 166,183	$ -	-$ 166,183	-$ 132,547	$ -	-$ 132,547	$ -	6.15	16.25%	15.00	6.67%	-$ 27,003	-$ 8,836	$ -	-$ 35,839	-$ 16,000	$ 19,839
	Contributed Capital - Meters SOLAR	-	$ -	$ -	-$ 152,011	$ -	-$ 152,011	$ -	-	0.00%	15.00	6.67%	$ -	-$ 10,134	$ -	-$ 10,134	-$ 13,700	-$ 3,566
1995	Contributed Capital - OEB Clearing	68,538	$ -	$ 68,538	$ 259,328	$ -	$ 259,328	$ -	- 10.00	-10.00%	15.00	6.67%	-$ 6,854	$ 17,289	$ -	$ 10,435	$ 25,500	$ 15,065
2440	**Deferred Revenue**	-	$ -	$ -	$ -	$ -	$ -		-	0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
2440	Contributed Capital - Poles, Towers & Fixtures	-	$ -	$ -	-$ 3,422,506	-$ 419,536	-$ 3,002,970	-$ 169,500	-	0.00%	40.00	2.50%	$ -	-$ 75,074	-$ 2,119	-$ 77,193	-$ 85,000	-$ 7,807
2440	Contributed Capital - Overhead Conductors	-	$ -	$ -	-$ 2,451,617	$ -	-$ 2,451,617	-$ 130,176	-	0.00%	60.00	1.67%	$ -	-$ 40,860	-$ 1,085	-$ 41,945	-$ 41,500	$ 445
2440	Contributed Capital - Overhead Devices	-	$ -	$ -	-$ 271,443	$ -	-$ 271,443	-$ 14,464	-	0.00%	40.00	2.50%	$ -	-$ 6,786	-$ 181	-$ 6,967	-$ 7,000	-$ 33
2440	Contributed Capital - Overhead Services	-	$ -	$ -	-$ 588,498	$ -	-$ 588,498	-$ 24,860	-	0.00%	60.00	1.67%	$ -	-$ 9,808	-$ 207	-$ 10,015	-$ 9,100	$ 915
2440	Contributed Capital - Underground Trenching & Ductwork	-	$ -	$ -	-$ 9,270,286	$ -	-$ 9,270,286	-$ 592,065	-	0.00%	60.00	1.67%	$ -	-$ 154,505	-$ 4,934	-$ 159,439	-$ 154,400	$ 5,039
2440	Contributed Capital - Underground Cables	-	$ -	$ -	-$ 7,173,979	$ -	-$ 7,173,979	-$ 453,591	-	0.00%	40.00	2.50%	$ -	-$ 179,349	-$ 5,670	-$ 185,019	-$ 185,200	-$ 181
2440	Contributed Capital - Underground Devices	-	$ -	$ -	-$ 795,420	$ -	-$ 795,420	-$ 50,399	-	0.00%	40.00	2.50%	$ -	-$ 19,886	-$ 630	-$ 20,515	-$ 20,700	-$ 185
2440	Contributed Capital - Overhead Transformer	-	$ -	$ -	-$ 99,130	$ -	-$ 99,130	$ -	-	0.00%	40.00	2.50%	$ -	-$ 2,478	$ -	-$ 2,478	-$ 2,500	-$ 22
2440	Contributed Capital - Underground Padmount Transformer	-	$ -	$ -	-$ 535,030	$ -	-$ 535,030	-$ 226,125	-	0.00%	40.00	2.50%	$ -	-$ 13,376	-$ 2,827	-$ 16,202	-$ 17,500	-$ 1,298
2440	Contributed Capital -Underground Submersible Transformer	-	$ -	$ -	-$ 2,306,637	$ -	-$ 2,306,637	-$ 226,125	-	0.00%	30.00	3.33%	$ -	-$ 76,888	-$ 3,769	-$ 80,657	-$ 73,600	$ 7,057
2440	Contributed Capital - Underground Services	-	$ -	$ -	-$ 7,000,254	$ -	-$ 7,000,254	-$ 1,386,694	-	0.00%	40.00	2.50%	$ -	-$ 175,006	-$ 17,334	-$ 192,340	-$ 175,100	$ 17,240
2440	Contributed Capital - Transformer Foundations	-	$ -	$ -	-$ 1,033,231	$ -	-$ 1,033,231	-$ 150,750	-	0.00%	60.00	1.67%	$ -	-$ 17,221	-$ 1,256	-$ 18,477	-$ 19,300	-$ 823
2440	Contributed Capital - Meters	-	$ -	$ -	-$ 215,369	$ -	-$ 215,369	$ -	-	0.00%	15.00	6.67%	$ -	-$ 14,358	$ -	-$ 14,358	-$ 15,900	-$ 1,542
2440	Contributed Capital - Meters Solar	-	$ -	$ -	-$ 633,141	$ -	-$ 633,141	$ -	-	0.00%	15.00	6.67%	$ -	-$ 42,209	$ -	-$ 42,209	-$ 34,000	$ 8,209
2440	Contributed Capital - OEB Clearing	-	$ -	$ -	-$ 243,277	$ -	-$ 243,277	$ -	-	0.00%	15.00	6.67%	$ -	-$ 16,218	$ -	-$ 16,218	-$ 16,300	-$ 82
2440	Meters - Renewable Connection - Direct Benefit	-	$ -	$ -	-$ 8,505	$ -	-$ 8,505	$ -	-	0.00%	15.00	6.67%	$ -	-$ 567	$ -	-$ 567	$ -	$ 567
				$ -			$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
	Total	**$ 148,349,204**	**$ 4,962,595**	**$ 143,386,609**	**$ 118,403,667**	**$ 1,299,579**	**$ 117,104,088**	**$ 18,440,022**					**$ 4,796,078**	**$ 4,554,552**	**$ 410,828**	**$ 9,761,458**	**$ 9,343,200**	**-$ 418,258**

Appendix 2-C
Depreciation and Amortization Expense

2020

Account	Description	Book Values							Service Lives				Depreciation Expense						
		Opening Net Book Value of Existing Assets as at Date of Policy Change (Jan. 1) [1]	Less Fully Depreciated [7]	Net Amount of Existing Assets Before Policy Change to be Depreciated	Opening Gross Book Value of Assets Acquired After Policy Change [2]	Less Fully Depreciated [8]	Net Amount of Assets Acquired After Policy Change to be Depreciated	Current Year Additions	Average Remaining Life of Assets Existing Before Policy Change [3]	Depreciation Rate Assets Acquired After Policy Change	Life of Assets Acquired After Policy Change [4]	Depreciation Rate on New Additions	Depreciation Expense on Assets Existing Before Policy Change	Depreciation Expense on Assets Acquired After Policy Change	Depreciation Expense on Current Year Additions [5]	Total Current Year Depreciation Expense	Depreciation Expense per Appendix 2-BA Fixed Assets, Column J	Variance [6]
		a	b	c = a-b	d	e	f = d- e	g	h	i = 1/h	j	k = 1/j	l = c/h	m = f/j	n = g*0.5/j	o = l+m+n	p	q = p-o
1611	Computer Software (Formally known as Account 1925)	928,634	$ 928,634	$ -	$ 3,226,622	$ 572,983	$ 2,653,639	$ 6,710,000	2.25	44.44%	5.00	20.00%	$ -	$ 530,728	$ 671,000	$ 1,201,728	$ 1,194,200	-$ 7,528
1611	Computer Software (Formally known as Account 1925)	-		$ -	$ 88,614	$ 88,614	$ -		-	0.00%	3.00	33.33%	$ -	$ -	$ -	$ -		$ -
1611	Computer Software (Formally known as Account 1925) - Smart Meters	-	$ -	$ -	$ 598,681	$ 598,681	$ -	$ -	-	0.00%	3.00	33.33%	$ -	$ -	$ -	$ -	$ -	$ -
1612	Land Rights (Formally known as Account 1906)	12,881	$ 12,881	$ -	$ -	$ -	$ -		4.86	20.60%	50.00	2.00%	$ -	$ -	$ -	$ -	$ -	$ -
1805	Land	2,339,958	$ -	$ 2,339,958	$ -	$ -	$ -		-	0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1808	Buildings - Structure	7,099,490	$ -	$ 7,099,490	$ 463,554	$ -	$ 463,554	$ -	38.08	2.63%	50.00	2.00%	$ 186,429	$ 9,271	$ -	$ 195,700	$ 190,900	-$ 4,800
1808	Buildings - Roof	144,989	$ 58,456	$ 86,533	-$ 2,480	$ -	-$ 2,480	$ -	11.44	8.74%	20.00	5.00%	$ 7,565	-$ 124	$ -	$ 7,441	$ 5,500	-$ 1,941
1810	Leasehold Improvements	-	$ -	$ -	$ -	$ -	$ -		-	0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1815	Transformer Station Equipment >50 kV 50 yrs	15,658,085	$ 12,312	$ 15,645,773	$ 3,913,297	$ -	$ 3,913,297	$ 1,332,200	41.16	2.43%	50.00	2.00%	$ 380,092	$ 78,266	$ 13,322	$ 471,680	$ 460,900	-$ 10,780
1815	Transformer Station Equipment >50 kV 40 yrs	24,475,179	$ -	$ 24,475,179	$ 1,569,437	$ -	$ 1,569,437	$ 398,700	28.76	3.48%	40.00	2.50%	$ 851,073	$ 39,236	$ 4,984	$ 895,293	$ 848,800	-$ 46,493
1815	Transformer Station Equipment >50 kV 30 yrs	-	$ -	$ -	$ 71,591	$ -	$ 71,591	$ -	-	0.00%		0.00%	$ -	$ -	$ -	$ -	$ 2,400	$ 2,400
1815	Transformer Station Equipment >50 kV 25 yrs	887,028	$ 176,718	$ 710,310	$ 233,388	$ -	$ 233,388	$ -	12.07	8.28%	25.00	4.00%	$ 58,839	$ 9,336	$ -	$ 68,175	$ 56,300	-$ 11,875
1815	Transformer Station Equipment >50 kV 20 yrs	392,015	$ 163,703	$ 228,312	$ 242,279	$ -	$ 242,279	$ 49,400	9.76	10.24%	20.00	5.00%	$ 23,383	$ 12,114	$ 1,235	$ 36,732	$ 32,300	-$ 4,432
1815	Transformer Station Equipment >50 kV 15 yrs	1,087,574	$ 439,950	$ 647,624	$ 2,619,418	$ -	$ 2,619,418	$ 223,700	8.48	11.79%	15.00	6.67%	$ 76,380	$ 174,628	$ 7,457	$ 258,465	$ 234,800	-$ 23,665
1820	Distribution Station Equipment <50 kV 50 yrs	200,427	$ -	$ 200,427	$ -	$ -	$ -	$ -	22.74	4.40%	50.00	2.00%	$ 8,813	$ -	$ -	$ 8,813	$ 8,600	-$ 213
1820	Distribution Station Equipment <50 kV 40 yrs	649,832	$ -	$ 649,832	$ -	$ -	$ -	$ -	25.47	3.93%	40.00	2.50%	$ 25,509	$ -	$ -	$ 25,509	$ 24,300	-$ 1,209
1820	Distribution Station Equipment <50 kV 25 yrs	13,287	$ -	$ 13,287	$ -	$ -	$ -	$ -	5.93	16.87%	25.00	4.00%	$ 2,242	$ -	$ -	$ 2,242	$ 800	-$ 1,442
1820	Distribution Station Equipment <50 kV 20 yrs	6,078	$ 6,078	$ -	$ -	$ -	$ -	$ -	5.66	17.66%	20.00	5.00%	$ -	$ -	$ -	$ -	$ 700	$ 700
1820	Distribution Station Equipment <50 kV 15 hrs	17,551	$ 17,551	$ -	$ 161,300	$ -	$ 161,300	$ -	9.64	10.37%	15.00	6.67%	$ -	$ 10,753	$ -	$ 10,753	$ 10,900	$ 147
1825	Storage Battery Equipment	-	$ -	$ -	$ -	$ -	$ -		-	0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1830	Poles, Towers & Fixtures	17,028,402	$ -	$ 17,028,402	$ 22,482,880	$ -	$ 22,482,880	$ 3,133,850	32.16	3.11%	40.00	2.50%	$ 529,490	$ 562,072	$ 39,173	$ 1,130,735	$ 1,102,200	-$ 28,535
1835	Overhead Conductors	14,319,062	$ -	$ 14,319,062	$ 15,844,804	$ -	$ 15,844,804	$ 2,603,880	51.16	1.95%	60.00	1.67%	$ 279,881	$ 264,080	$ 21,699	$ 565,660	$ 556,700	-$ 8,960
1835	Overhead Devices	1,591,007	$ -	$ 1,591,007	$ 1,892,327	$ -	$ 1,892,327	$ 289,320	30.57	3.27%	40.00	2.50%	$ 52,051	$ 47,308	$ 3,617	$ 102,975	$ 103,100	$ 125
1835	Voltage Regulators	163,109	$ -	$ 163,109	$ -	$ -	$ -	$ -	20.00	5.00%	30.00	3.33%	$ 8,155	$ -	$ -	$ 8,155	$ 7,800	-$ 355
1835	Capacitor Banks	618,096	$ -	$ 618,096	$ 1,583,343	$ -	$ 1,583,343	$ -	19.80	5.05%	25.00	4.00%	$ 31,224	$ 63,334	$ -	$ 94,557	$ 64,200	-$ 30,357
1840	Underground Conduit	12,527,558	$ -	$ 12,527,558	$ 22,255,853	$ -	$ 22,255,853	$ 3,524,600	51.70	1.93%	60.00	1.67%	$ 242,295	$ 370,931	$ 29,372	$ 642,598	$ 619,700	-$ 22,898
1845	Underground Conductors & Devices - PILC	414,000	$ -	$ 414,000	$ 1,556,539	$ -	$ 1,556,539	$ -	58.00	1.72%	60.00	1.67%	$ 7,138	$ 25,942	$ -	$ 33,080	$ 33,000	-$ 80
1845	Underground Cables	15,726,653	$ -	$ 15,726,653	$ 17,938,648	$ -	$ 17,938,648	$ 1,779,481	28.66	3.49%	40.00	2.50%	$ 548,637	$ 448,466	$ 22,244	$ 1,019,347	$ 999,700	-$ 19,647
1845	Underground Devices	1,747,406	$ -	$ 1,747,406	$ 2,435,700	$ -	$ 2,435,700	$ 197,720	28.66	3.49%	40.00	2.50%	$ 60,960	$ 60,893	$ 2,472	$ 124,324	$ 115,900	-$ 8,424
1850	Line Transformers - Overhead	15,713,833	$ 345,325	$ 15,368,508	$ 7,439,319	$ -	$ 7,439,319	$ 970,000	27.98	3.57%	40.00	2.50%	$ 549,182	$ 185,983	$ 12,125	$ 747,290	$ 568,700	-$ 178,590
1850	Line Transformers - Network	5,503	$ -	$ 5,503	$ 1,469,806	$ -	$ 1,469,806	$ 192,000	9.38	10.66%	40.00	2.50%	$ 587	$ 36,745	$ 2,400	$ 39,732	$ 56,900	$ 17,168
1850	Line Transformers - Vault	-	$ -	$ -	$ 6,041	$ -	$ 6,041	$ -	-	0.00%	60.00	1.67%	$ -	$ 101	$ -	$ 101	$ 100	-$ 1
1850	Line Transformers - Roof	497,948	$ 16,586	$ 481,362	$ -	$ -	$ -	$ -	23.84	4.19%	30.00	3.33%	$ 20,190	$ -	$ -	$ 20,190	$ 18,800	-$ 1,390
1850	Line Transformers -Network Protectors	91,592	$ -	$ 91,592	$ 680,182	$ -	$ 680,182	$ -	39.50	2.53%	40.00	2.50%	$ 2,319	$ 17,005	$ -	$ 19,323	$ 13,100	-$ 6,223
1850	Line Transformers - Padmount	3,991,872	$ -	$ 3,991,872	$ 6,523,075	$ -	$ 6,523,075	$ 735,562	36.77	2.72%	40.00	2.50%	$ 108,567	$ 163,077	$ 9,195	$ 280,838	$ 189,700	-$ 91,138
1850	Line Transformers - Submersible	3,195,923	$ -	$ 3,195,923	$ 5,528,853	$ -	$ 5,528,853	$ 735,563	24.09	4.15%	30.00	3.33%	$ 132,669	$ 184,295	$ 12,259	$ 329,224	$ 658,700	$ 329,476
1850	Line Transformers - Foundation	1,427,416	$ -	$ 1,427,416	$ 2,649,789	$ -	$ 2,649,789	$ 490,375	58.08	1.72%	60.00	1.67%	$ 24,575	$ 44,163	$ 4,086	$ 72,825	$ 64,500	-$ 8,325
1855	Services - Overhead	1,887,728	$ -	$ 1,887,728	$ 3,313,088	$ -	$ 3,313,088	$ 601,950	52.20	1.92%	60.00	1.67%	$ 36,164	$ 55,218	$ 5,016	$ 96,398	$ 95,500	-$ 898
1855	Services - Underground	22,543,287	$ -	$ 22,543,287	$ 19,861,239	$ -	$ 19,861,239	$ 2,423,199	31.40	3.18%	40.00	2.50%	$ 717,938	$ 496,531	$ 30,290	$ 1,244,759	$ 1,174,000	-$ 70,759
1860	Commercial Meters	1,327,802	$ 158,636	$ 1,169,166	$ 2,783,969	$ -	$ 2,783,969	$ 286,560	20.97	4.77%	25.00	4.00%	$ 55,753	$ 111,359	$ 5,731	$ 172,843	$ 210,400	$ 37,557
1860	Smart Meters - Non-Qualifying	108,222		$ 108,222	$ 240,153	$ -	$ 240,153		12.00	8.33%	15.00	6.67%	$ 9,018	$ 16,010	$ -	$ 25,028		-$ 25,028
1860	Meters - Renewable Connection	-		$ -	$ 154,427	$ -	$ 154,427		-	0.00%	15.00	6.67%	$ -	$ 10,295	$ -	$ 10,295		-$ 10,295
1860	Smart Meters	-		$ -	$ -	$ -	$ -		-	0.00%	15.00	6.67%	$ -	$ -	$ -	$ -		$ -
1860	Smart Meters	-	$ -	$ -	$ 14,153,401	$ -	$ 14,153,401	$ 310,440	-	0.00%	15.00	6.67%	$ -	$ 943,560	$ 10,348	$ 953,908	$ 930,300	-$ 23,608
1905	Land	1,395,300	$ -	$ 1,395,300	$ -	$ -	$ -	$ -	-	0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1908	Buildings & Fixtures - Building	5,262,681	$ -	$ 5,262,681	$ 6,881,613	$ -	$ 6,881,613	$ -	28.71	3.48%	50.00	2.00%	$ 183,326	$ 137,632	$ -	$ 320,959	$ 294,000	-$ 26,959
1908	Buildings & Fixtures - Roof	1,567,291	$ 971,497	$ 595,794	$ 3,238,136	$ -	$ 3,238,136	$ 750,000	6.53	15.33%	20.00	5.00%	$ 91,307	$ 161,907	$ 18,750	$ 271,964	$ 255,700	-$ 16,264
1910	Leasehold Improvements	-	$ -	$ -	$ -	$ -	$ -	$ -	-	0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1915	Office Furniture & Equipment (10 years)	340,212	$ 54,104	$ 286,108	$ 578,920	$ -	$ 578,920	$ 70,000	5.10	19.61%	10.00	10.00%	$ 56,100	$ 57,892	$ 3,500	$ 117,492	$ 57,900	-$ 59,592
1915	Office Furniture & Equipment (5 years)	-	$ -	$ -	$ -	$ -	$ -		-	0.00%	5.00	20.00%	$ -	$ -	$ -	$ -		$ -
1920	Computer Equipment - Hardware	350,464	$ 350,464	$ -	$ 1,545,355	$ 458,791	$ 1,086,564	$ 325,000	2.12	47.12%	5.00	20.00%	$ -	$ 217,313	$ 32,500	$ 249,813	$ 260,200	$ 10,387
1920	Computer Equip.-Hardware - Smart Meters	-	$ -	$ -	$ 569,286	$ 569,286	$ -	$ -	-	0.00%	5.00	20.00%	$ -	$ -	$ -	$ -	$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)	-	$ -	$ -	$ -	$ -	$ -	$ -	-	0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1930	Transportation Equipment	2,781,086	$ 1,019,162	$ 1,761,924	$ 6,392,474	$ -	$ 6,392,474	$ 890,000	7.19	13.90%	11.00	9.09%	$ 244,982	$ 581,134	$ 40,455	$ 866,570	$ 770,100	-$ 96,470
1935	Stores Equipment	21,484	$ -	$ 21,484	$ 2,552	$ -	$ 2,552	$ -	4.55	21.99%	10.00	10.00%	$ 4,724	$ 255	$ -	$ 4,979	$ 300	-$ 4,679
1940	Tools, Shop & Garage Equipment	324,953	$ -	$ 324,953	$ 624,268	$ -	$ 624,268	$ 95,000	6.70	14.93%	10.00	10.00%	$ 48,520	$ 62,427	$ 4,750	$ 115,697	$ 69,200	-$ 46,497
1940	Tools - Smart Meters	-	$ -	$ -	$ -	$ -	$ -	$ -	-	0.00%	10.00	10.00%	$ -	$ -	$ -	$ -	$ -	$ -
1945	Measurement & Testing Equipment	163,014	$ -	$ 163,014	$ 267,318	$ -	$ 267,318	$ 10,000	7.77	12.88%	10.00	10.00%	$ 20,993	$ 26,732	$ 500	$ 48,225	$ 34,800	-$ 13,425
1950	Power Operated Equipment	306,812	$ 109,903	$ 196,909	$ 832,549	$ -	$ 832,549	$ 110,000	6.77	14.76%	10.00	10.00%	$ 29,071	$ 83,255	$ 5,500	$ 117,826	$ 84,751	-$ 33,075
1955	Communications Equipment	58,880	$ -	$ 58,880	$ 197,138	$ -	$ 197,138	$ -	6.76	14.80%	10.00	10.00%	$ 8,715	$ 19,714	$ -	$ 28,429	$ -	-$ 28,429
1955	Communication Equipment (Smart Meters)	-	$ -	$ -	$ 731,896	$ -	$ 731,896	$ 35,000	-	0.00%	10.00	10.00%	$ -	$ 73,190	$ 1,750	$ 74,940	$ 22,149	-$ 52,791
1960	Miscellaneous Equipment	40,970	$ 40,970	$ -	$ 18,607	$ -	$ 18,607	$ -	3.61	27.74%	5.00	20.00%	$ -	$ 3,721	$ -	$ 3,721	$ 1,300	-$ 2,421
1975	Load Management Controls Utility Premises	-	$ -	$ -	$ -	$ -	$ -	$ -	-	0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1980	System Supervisor Equipment	115,075	$ 115,075	$ -	$ -	$ -	$ -	$ -	6.15	16.26%	10.00	10.00%	$ -	$ -	$ -	$ -	$ -	$ -
1985	Miscellaneous Fixed Assets	-	$ -	$ -	$ -	$ -	$ -	$ -	-	0.00%		0.00%	$ -	$ -	$ -	$ -		$ -

Appendix 2-C
Depreciation and Amortization Expense

1995	**Contributions & Grants**	-	$ -	$ -	$ -	$ -	$ -		-	0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1995	Contributed Capital - Poles, Towers & Fixtures	- 1,626,853	$ -	-$ 1,626,853	-$ 1,146,161	$ -	-$ 1,146,161	$ -	34.50	2.90%	40.00	2.50%	-$ 47,155	-$ 28,654	$ -	-$ 75,809	-$ 74,800	$ 1,009
1995	Contributed Capital - Overhead Conductors	- 1,246,129	$ -	-$ 1,246,129	-$ 969,095	$ -	-$ 969,095	$ -	54.55	1.83%	60.00	1.67%	-$ 22,844	-$ 16,152	$ -	-$ 38,996	-$ 38,600	$ 396
1995	Contributed Capital - Overhead Devices	- 138,459	$ -	-$ 138,459	-$ 109,089	$ -	-$ 109,089	$ -	34.39	2.91%	40.00	2.50%	-$ 4,026	-$ 2,727	$ -	-$ 6,753	-$ 6,700	$ 53
1995	Contributed Capital - Overhead Services	- 1,195,490	$ -	-$ 1,195,490	-$ 119,872	$ -	-$ 119,872	$ -	40.18	2.49%	60.00	1.67%	-$ 29,750	-$ 1,998	$ -	-$ 31,748	-$ 24,400	$ 7,348
1995	Contributed Capital - Underground Trenching & Ductwork	- 5,566,404	$ -	-$ 5,566,404	-$ 2,609,506	$ -	-$ 2,609,506	$ -	54.02	1.85%	60.00	1.67%	-$ 103,051	-$ 43,492	$ -	-$ 146,543	-$ 144,800	$ 1,743
1995	Contributed Capital - Underground Cables	- 2,292,136	$ -	-$ 2,292,136	-$ 2,370,201	$ -	-$ 2,370,201	$ -	30.81	3.25%	40.00	2.50%	-$ 74,387	-$ 59,255	$ -	-$ 133,642	-$ 124,500	$ 9,142
1995	Contributed Capital - Underground Devices	- 254,682	$ -	-$ 254,682	-$ 167,703	$ -	-$ 167,703	$ -	-	0.00%	40.00	2.50%	$ -	-$ 4,193	$ -	-$ 4,193	-$ 11,500	-$ 7,307
1995	Contributed Capital - Overhead Transformer	- 2,734,282	$ -	-$ 2,734,282	$ 169,874	$ -	$ 169,874	$ -	34.03	2.94%	40.00	2.50%	-$ 80,349	$ 4,247	$ -	-$ 76,102	-$ 79,600	-$ 3,498
1995	Contributed Capital - Underground Padmount Transformer	- 1,858,357	$ -	-$ 1,858,357	-$ 7,920	$ -	-$ 7,920	$ -	32.33	3.09%	40.00	2.50%	-$ 57,473	-$ 198	$ -	-$ 57,671	-$ 62,800	-$ 5,129
1995	Contributed Capital -Underground Submersible Transformer	- 1,955,810	$ -	-$ 1,955,810	-$ 675,874	$ -	-$ 675,874	$ -	25.19	3.97%	30.00	3.33%	-$ 77,649	-$ 22,529	$ -	-$ 100,178	-$ 97,100	$ 3,078
1995	Contributed Capital - Underground Services	- 13,453,846	$ -	-$ 13,453,846	-$ 953,639	$ -	-$ 953,639	$ -	33.74	2.96%	40.00	2.50%	-$ 398,729	-$ 23,841	$ -	-$ 422,570	-$ 399,300	$ 23,270
1995	Contributed Capital - Transformer Foundations	- 798,352	$ -	-$ 798,352	-$ 558,073	$ -	-$ 558,073	$ -	54.11	1.85%	60.00	1.67%	-$ 14,753	-$ 9,301	$ -	-$ 24,054	-$ 23,800	$ 254
1995	Contributed Capital - Meters	- 166,183	$ -	-$ 166,183	-$ 132,547	$ -	-$ 132,547	$ -	6.15	16.25%	15.00	6.67%	-$ 27,003	-$ 8,836	$ -	-$ 35,839	-$ 13,300	$ 22,539
	Contributed Capital - Meters SOLAR	-	$ -	$ -	-$ 152,011	$ -	-$ 152,011	$ -	-	0.00%	15.00	6.67%	$ -	-$ 10,134	$ -	-$ 10,134	-$ 13,700	-$ 3,566
1995	Contributed Capital - OEB Clearing	68,538	$ -	$ 68,538	$ 259,328	$ -	$ 259,328	$ -	- 10.00	-10.00%	15.00	6.67%	-$ 6,854	$ 17,289	$ -	$ 10,435	$ 25,500	$ 15,065
2440	**Deferred Revenue**	-	$ -	$ -	$ -	$ -	$ -		-	0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
2440	Contributed Capital - Poles, Towers & Fixtures	-	$ -	$ -	-$ 3,592,006	-$ 419,536	-$ 3,172,470	-$ 169,500	-	0.00%	40.00	2.50%	$ -	-$ 79,312	-$ 2,119	-$ 81,431	-$ 89,200	-$ 7,770
2440	Contributed Capital - Overhead Conductors	-	$ -	$ -	-$ 2,581,793	$ -	-$ 2,581,793	-$ 130,176	-	0.00%	60.00	1.67%	$ -	-$ 43,030	-$ 1,085	-$ 44,115	-$ 43,700	$ 415
2440	Contributed Capital - Overhead Devices	-	$ -	$ -	-$ 285,907	$ -	-$ 285,907	-$ 14,464	-	0.00%	40.00	2.50%	$ -	-$ 7,148	-$ 181	-$ 7,328	-$ 7,300	$ 28
2440	Contributed Capital - Overhead Services	-	$ -	$ -	-$ 613,358	$ -	-$ 613,358	-$ 24,860	-	0.00%	60.00	1.67%	$ -	-$ 10,223	-$ 207	-$ 10,430	-$ 9,500	$ 930
2440	Contributed Capital - Underground Trenching & Ductwork	-	$ -	$ -	-$ 9,862,351	$ -	-$ 9,862,351	-$ 705,490	-	0.00%	60.00	1.67%	$ -	-$ 164,373	-$ 5,879	-$ 170,252	-$ 165,200	$ 5,052
2440	Contributed Capital - Underground Cables	-	$ -	$ -	-$ 7,627,570	$ -	-$ 7,627,570	-$ 486,714	-	0.00%	40.00	2.50%	$ -	-$ 190,689	-$ 6,084	-$ 196,773	-$ 196,900	-$ 127
2440	Contributed Capital - Underground Devices	-	$ -	$ -	-$ 845,819	$ -	-$ 845,819	-$ 54,079	-	0.00%	40.00	2.50%	$ -	-$ 21,145	-$ 676	-$ 21,821	-$ 22,000	-$ 179
2440	Contributed Capital - Overhead Transformer	-	$ -	$ -	-$ 99,130	$ -	-$ 99,130	$ -	-	0.00%	40.00	2.50%	$ -	-$ 2,478	$ -	-$ 2,478	-$ 2,500	-$ 22
2440	Contributed Capital - Underground Padmount Transformer	-	$ -	$ -	-$ 761,155	$ -	-$ 761,155	-$ 226,125	-	0.00%	40.00	2.50%	$ -	-$ 19,029	-$ 2,827	-$ 21,855	-$ 23,200	-$ 1,345
2440	Contributed Capital -Underground Submersible Transformer	-	$ -	$ -	-$ 2,532,762	$ -	-$ 2,532,762	-$ 226,125	-	0.00%	30.00	3.33%	$ -	-$ 84,425	-$ 3,769	-$ 88,194	-$ 81,200	$ 6,994
2440	Contributed Capital - Underground Services	-	$ -	$ -	-$ 8,386,948	$ -	-$ 8,386,948	-$ 1,489,462	-	0.00%	40.00	2.50%	$ -	-$ 209,674	-$ 18,618	-$ 228,292	-$ 211,000	$ 17,292
2440	Contributed Capital - Transformer Foundations	-	$ -	$ -	-$ 1,183,981	$ -	-$ 1,183,981	-$ 150,750	-	0.00%	60.00	1.67%	$ -	-$ 19,733	-$ 1,256	-$ 20,989	-$ 21,800	-$ 811
2440	Contributed Capital - Meters	-	$ -	$ -	-$ 215,369	$ -	-$ 215,369	$ -	-	0.00%	15.00	6.67%	$ -	-$ 14,358	$ -	-$ 14,358	-$ 15,900	-$ 1,542
2440	Contributed Capital - Meters Solar	-	$ -	$ -	-$ 633,141	$ -	-$ 633,141	$ -	-	0.00%	15.00	6.67%	$ -	-$ 42,209	$ -	-$ 42,209	-$ 34,000	$ 8,209
2440	Contributed Capital - OEB Clearing	-	$ -	$ -	-$ 243,277	$ -	-$ 243,277	$ -	-	0.00%	15.00	6.67%	$ -	-$ 16,218	$ -	-$ 16,218	-$ 16,300	-$ 82
2440	Meters - Renewable Connection - Direct Benefit	-	$ -	$ -	-$ 8,505	$ -	-$ 8,505	$ -	-	0.00%	15.00	6.67%	$ -	-$ 567	$ -	-$ 567	$ -	$ 567
				$ -			$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
	Total	**$ 148,349,204**	**$ 4,998,005**	**$ 143,351,199**	**$ 136,843,689**	**$ 1,868,819**	**$ 134,974,870**	**$ 25,595,755**					**$ 4,780,835**	**$ 5,262,361**	**$ 973,028**	**$ 11,016,223**	**$ 10,475,700**	**-$ 540,523**

General: Applicants are to complete this appendix to show the reasonability of the depreciation expense that is included in rate base via. Accumulated depreciation and the revenue requirement.
Applicants must provide a breakdown of depreciation and amortization expense in the above format for all relevant accounts. Balances presented in the table should exclude asset retirement obligations (AROs) and the related depreciation and accretion expense. These should be disclosed separately consistent with the Notes of historical Audited Financial Statements.

Notes:

1 This is the net book value of assets that existed as at the date of the utility's change in depreciation policies (i.e. as at Jan. 1, 2012 or Jan. 1, 2013). These assets are to be depreciated at the average remaining service life. This amount will not change in years subsequent to the date of the utility's change in depreciation policies. This column is expected to be used until the assets
2 This is the opening gross book value of assets that have been acquired after the date of the utilities change in depreciation policies (i.e. additions starting in 2012/2013 for those who changed policies Jan. 1, 2012/2013). These assets are to be depreciated at the revised service life. The amount is expected to be equal to the gross book value of the prior year plus the prior year's
3 A recalculation should be performed to determine the average remaining life of opening balance of assets (i.e. excluding current year's additions) under the change in policies under CGAAP. For example, Asset A had a useful life of 20 years under CGAAP without the change in policies. On January 1 of the year of policy changes, Asset A was 3 years depreciated. As a result,
4 The useful life used should be consistent with the OEB's regulatory accounting policies as set out in the Accounting Procedures Handbook for Electricity Distributors, effective Jan. 1, 2012 and also with the Report of the Board, Transition to International Financial Reporting Standards, EB-2008-0408, and the Kinectrics Report.
5 Board policy of the "half-year" rule - the applicant must ensure that additions in the year attract a half-year depreciation expense in the first year. Deviations from this standard practice must be supported in the application.
6 The applicant must provide an explanation of material variances in evidence.
7 This should include assets in column a (excel column C) that become fully depreciated since the date of the policy change. The amount input in b (excel column D) should equal the net book value of the asset as at the date of depreciation policy change
8 This should include assets in column d (excel column f) that have become fully depreciated. The amount input in e (excel column G) should equal the gross book value of the asset

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Appendix 2-D
Overhead Expense

Applicants are to provide a breakdown of OM&A before capitalization in the below table. OM&A before capitalization may be broken down by cost center, program, drivers or another forma best suited to focus on capitalized vs. uncapitalized OM&A.

OM&A Before Capitalization	**2014** **Historical Year**	**2015** **Historical Year**	**2016** **Historical Year**	**2017** **Historical Year**	**2018** **Historical Year**	**2019** **Bridge Year**	**2020** **Test Year**
Operating and Maintenance	$ 12,756,321	$ 12,504,204	$ 12,989,276	$ 13,522,898	$ 14,400,441	$ 15,410,100	$ 16,029,100
Billing and collecting	$ 3,415,009	$ 3,775,665	$ 4,468,748	$ 4,296,607	$ 4,615,266	$ 4,210,700	$ 4,981,700
Community Relations	$ 199,353	$ 238,394	$ 269,179	$ 220,473	$ 241,006	$ 258,300	$ 263,400
General and Administrative	$ 5,029,353	$ 5,195,055	$ 5,674,740	$ 5,227,397	$ 5,029,811	$ 5,655,400	$ 6,145,800
Total OM&A Before Capitalization (B)	$ 21,400,036	$ 21,713,318	$ 23,401,943	$ 23,267,375	$ 24,286,524	$ 25,534,500	$ 27,420,000

Applicants are to provide a breakdown of capitalized OM&A in the below table. Capitalized OM&A may be broken down using the categories listed in the table below if possible. Otherwise, applicants are to provide its own break down of capitalized OM&A.

Capitalized OM&A	**2014** **Historical Year**	**2015** **Historical Year**	**2016** **Historical Year**	**2017** **Historical Year**	**2018** **Historical Year**	**2019** **Bridge Year**	**2020** **Test Year**	**Directly Attributable?** **(Yes/No)**	**Explanation for Change in Overhead Capitalized**
Employee Benefits	$ 1,803,365	$ 2,104,810	$ 2,404,088	$ 2,130,424	$ 1,988,736	$ 2,207,900	$ 2,233,400	Yes	Directly attributable to labour costs charged to capital
Cost of Site Preparation									
Initial Delivery and Handling Costs	$ 292,392	$ 363,420	$ 399,774	$ 314,778	$ 289,957	$ 325,500	$ 328,700	Yes	Directly attributable to labour costs charged to capital
Cost of testing whether the asset is functioning properly									
Professional Fees									
Fleet Costs	$ 758,816	$ 858,936	$ 971,570	$ 898,799	$ 849,682	$ 1,034,500	$ 1,046,600	Yes	Directly attributable to labour costs charged to capital
Costs of opening a new facility									
Cost of introducing a new product or service (including costs of advertising and promotional activities)									
Cost of conducting business in a new location or with a new class of customer (including costs of staff training)									
Administration and other general overhead costs	$ 1,880,863	$ 2,267,788	$ 2,519,573	$ 1,999,476	$ 1,740,180	$ 1,799,300	$ 1,820,600	Yes	Directly attributable to labour costs charged to capital
Insert description of additional item(s) and new rows if needed									
Total Capitalized OM&A (A)	$ 4,735,436	$ 5,594,954	$ 6,295,005	$ 5,343,477	$ 4,868,555	$ 5,367,200	$ 5,429,300		
% of Capitalized OM&A (=A/B)	22%	26%	27%	23%	20%	21%	20%		

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Appendix 2-FA
Renewable Generation Connection Investment Summary (past investments or over the future rate setting period)

Enter the details of the Renewable Generation Connection projects as described in the appropriate section of the Filing Requirements.
All costs entered on this page will be transferred to the appropriate cells in the appendices that follow.

For Part A, Renewable Enabling Improvements (REI), these amounts will be transferred to Appendix 2 - FB
For Part B, Expansions, these amounts will be transferred to Appendix 2 - FC

If there are more than **five** projects proposed to be in-service in a certain year, please amend the tables below and ensure that the formulae for the Total Amounts in any given rate year are updated.
Based on the current methodology and allocation, amounts allocated represent 6% for REI Connection Investments and 17% for Expansion Investments. (EB-2009-0349, 6-10-2010, p. 15, note 9)

There are two scenarios described below. Separate sets of spreadsheets (2-FA, 2-FB, 2-FC) should be submited for each scenario as required.

Scenario 1: **Past Investments with No Recovery.** The distributor has made investments in the past (during the IRM Years), but has not received approval for these projects and therefore did not receive revenue from the IESO under Regulation 330/09 and did not receive ratepayer revenue for the direct benefit portion of the investment.
The WCA percentage, debt percentages, interest rates, kWh, tax rates, amortization period, CCA Class and percentage should correspond to the distributor's last Cost of Service approval.
The Direct Benefit portion of the calculated Revenue Requirement for each year should be summed and can be applied for recovery from the distributor's ratepayers through a rate rider.
The Provincial Recovery portion of the calculated Revenue Requirement for each year should be summed and can be applied for recovery from the IESO through a separate orde

Scenario 2: **Investments in the Test Year and Beyond.** Distributor plans to make investments in 2017 and/or beyond. These investments should be added to 2-FA in the appropriate year.
The WCA percentage, debt percentages, interest rates, kWh, tax rates, amortization period, CCA Class and percentage should correspond to the distributor's current application.

Part A

REI Investments (Direct Benefit at 6%)	Test Year 2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Project 1											
Name: REI Connection Project											
Capital Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
OM&A (Start-Up)	$39,516	$7,464	$8,637	$42,161	$4,609	$0	$0	$0	$0	$0	$0
OM&A (Ongoing)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Project 2											
Name: REI Connection Project											
Capital Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
OM&A (Start-Up)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
OM&A (Ongoing)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Project 3											
Name: REI Connection Project											
Capital Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
OM&A (Start-Up)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
OM&A (Ongoing)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Project 4											
Name: REI Connection Project											
Capital Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
OM&A (Start-Up)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
OM&A (Ongoing)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Project 5											
Name: REI Connection Project											
Capital Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
OM&A (Start-Up)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
OM&A (Ongoing)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Capital Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total OM&A (Start-Up)	$ 39,516	$ 7,464	$ 8,637	$ 42,161	$ 4,609	$ -	$ -	$ -	$ -	$ -	$ -
Total OM&A (Ongoing)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Part B

Expansion Investments (Direct Benefit at 17%)	Test Year 2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Project 1											
Name: Expansion Connection Project											
Capital Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
OM&A (Start-Up)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
OM&A (Ongoing)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Project 2											
Name: Expansion Connection Project											
Capital Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
OM&A (Start-Up)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
OM&A (Ongoing)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Project 3											
Name: Expansion Connection Project											
Capital Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
OM&A (Start-Up)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
OM&A (Ongoing)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Project 4											
Name: Expansion Connection Project											
Capital Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
OM&A (Start-Up)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
OM&A (Ongoing)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Project 5											
Name: Expansion Connection Project											
Capital Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
OM&A (Start-Up)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
OM&A (Ongoing)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Capital Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total OM&A (Start-Up)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total OM&A (Ongoing)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

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Appendix 2-FB

Calculation of Renewable Generation Connection Direct Benefits/Provincial Amount: Renewable Enabling Improvement Investments

This table will calculate the distributor/provincial shares of the investments entered in Part A of Appendix 2-FA.
Enter values in green shaded cells: WCA percentage, debt percentages, interest rates, kWh, tax rates, amortization period, CCA Class and percentage.
For historical investments, enter these variables for your last cost of service test year. For 2017 and beyond, enter variables as in the application.
Rate Riders are not calculated for the Test Year as these assets and costs are already in the distributor's rate base/revenue requirement.

		2014			2015			2016			2017			2018			2019			
		Total	Direct Benefit 6%	Provincial 94%	Total	Direct Benefit 6%	Provincial 94%	Total	Direct Benefit 6%	Provincial 94%	Total	Direct Benefit 6%	Provincial 94%	Total	Direct Benefit 6%	Provincial 94%	Total	Direct Benefit 6%	Provincial 94%	Total
Net Fixed Assets (average)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Incremental OM&A (on-going, N/A for Provincial Recovery)		$0	$ -		$0	$ -		$0	$ -		$0	$ -		$0	$ -		$0	$ -		$0
Incremental OM&A (start-up, applicable for Provincial Recovery)		$39,516	$ 2,371	$ 37,145	$7,464	$ 448	$ 7,016	$8,637	$ 518	$ 8,119	$42,161	$ 2,530	$ 39,631	$4,609	$ 277	$ 4,333	$0	$ -	$ -	$0
WCA	8%		$ 178	$ 2,786		$ 34	$ 526		$ 39	$ 609		$ 190	$ 2,972		$ 21	$ 325		$ -	$ -	
Rate Base			$ 178	$ 2,786		$ 34	$ 526		$ 39	$ 609		$ 190	$ 2,972		$ 21	$ 325		$ -	$ -	
Deemed ST Debt	4%		$ 7	$ 111		$ 1	$ 21		$ 2	$ 24		$ 8	$ 119		$ 1	$ 13		$ -	$ -	
Deemed LT Debt	56%		$ 100	$ 1,560		$ 19	$ 295		$ 22	$ 341		$ 106	$ 1,665		$ 12	$ 182		$ -	$ -	
Deemed Equity	40%		$ 71	$ 1,114		$ 13	$ 210		$ 16	$ 244		$ 76	$ 1,189		$ 8	$ 130		$ -	$ -	
ST Interest	3%		$ 0	$ 3		$ 0	$ 1		$ 0	$ 1		$ 0	$ 3		$ 0	$ 0		$ -	$ -	
LT Interest	4%		$ 4	$ 64		$ 1	$ 12		$ 1	$ 14		$ 4	$ 69		$ 0	$ 8		$ -	$ -	
ROE	9%		$ 6	$ 100		$ 1	$ 19		$ 1	$ 22		$ 7	$ 107		$ 1	$ 12		$ -	$ -	
Cost of Capital Total			$ 11	$ 168		$ 2	$ 32		$ 2	$ 37		$ 11	$ 179		$ 1	$ 20		$ -	$ -	
OM&A			$ 2,371	$ 37,145		$ 448	$ 7,016		$ 518	$ 8,119		$ 2,530	$ 39,631		$ 277	$ 4,333		$ -	$ -	
Amortization		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Grossed-up PILs			$ -	$ -		$ 0	$ 7		$ 1	$ 8		$ 2	$ 38		$ 0	$ 4		$ -	$ -	
Revenue Requirement			$ 2,382	$ 37,313		$ 450	$ 7,055		$ 521	$ 8,163		$ 2,544	$ 39,849		$ 278	$ 4,357		$ -	$ -	
Provincial Rate Protection				$ 37,313			$ 7,055			$ 8,163			$ 39,849			$ 4,357			$ -	
Monthly Amount Paid by IESO				$ 3,109			$ 588			$ 680			$ 3,321			$ 363			$ -	

Note 1: The difference between the actual costs of approved eligible investments and revenue received from the IESO should be recorded in a variance account. The Board may provi
regulatory accounting guidance regarding a variance account either in an individual proceeding or on a generic basi
Note 2: For the 2016 Test Year, Costs and Revenues of the Direct Benefit are to be included in the test year applicant Rate Base and Revenues.

PILs Calculation

Income Tax	2014 Direct Benefit	2014 Provincial	2015 Direct Benefit	2015 Provincial	2016 Direct Benefit	2016 Provincial	2017 Direct Benefit	2017 Provincial	2018 Direct Benefit	2018 Provincial	2019 Direct Benefit	2019 Provincial
Net Income - ROE on Rate Base	$ 6	$ 100	$ 1	$ 19	$ 1	$ 22	$ 7	$ 107	$ 1	$ 12	$ -	$ -
Amortization (6% DB and 94% P)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CCA (6% DB and 94% P)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Taxable income	$ 6	$ 100	$ 1	$ 19	$ 1	$ 22	$ 7	$ 107	$ 1	$ 12	$ -	$ -
Tax Rate (to be entered)			26.50%	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%
Income Taxes Payable	$ -	$ -	$ 0.32	$ 5.01	$ 0.37	$ 5.80	$ 1.81	$ 28.29	$ 0.20	$ 3.09	$ -	$ -
Gross Up												
Income Taxes Payable	$ -	$ -	$ 0.44	$ 6.82	$ 0.50	$ 7.89	$ 2.46	$ 38.49	$ 0.27	$ 4.21	$ -	$ -
Grossed Up PILs	$ -	$ -	$ 0	$ 7	$ 1	$ 8	$ 2	$ 38	$ 0	$ 4	$ -	$ -

Net Fixed Assets

		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Enter applicable amortization in years:	25											
Opening Gross Fixed Assets				$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Gross Capital Additions		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Closing Gross Fixed Assets		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Opening Accumulated Amortization					$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Current Year Amortization (before additions)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Additions (half year)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Closing Accumulated Amortization		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Opening Net Fixed Assets		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Closing Net Fixed Assets		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Average Net Fixed Assets		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

UCC for PILs Calculation

		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Opening UCC				$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Capital Additions (from Appendix 2-FA)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
UCC Before Half Year Rule		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Half Year Rule (1/2 Additions - Disposals)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Reduced UCC		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CCA Rate Class (to be entered)	47	0	47	47	47	47	47	47	47	47	47	47
CCA Rate (to be entered)	8%	0%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%
CCA		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Closing UCC		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

2020 Test Year			2021			2022			2023			2024		
Direct Benefit 6%	Provincial 94%	Total	Direct Benefit 6%	Provincial 94%	Total	Direct Benefit 6%	Provincial 94%	Total	Direct Benefit 6%	Provincial 94%	Total	Direct Benefit 6%	Provincial 94%	
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
$ -		$0	$ -		$0	$ -		$0	$ -		$0	$ -		
$ -	$ -	$0	$ -	$ -	$0	$ -	$ -	$0	$ -	$ -	$0	$ -	$ -	
$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -	
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$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -	
	$ -			$ -			$ -			$ -			$ -	
	$ -			$ -			$ -			$ -			$ -	

2020 Test Year		2021		2022			2023			2024	
Direct Benefit	Provincial	Direct Benefit	Provincial	Direct Benefit	Provincial	Total	Direct Benefit	Provincial	Total	Direct Benefit	Provincial
$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -		$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -		$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -		$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -		$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -		$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -		$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -		$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -		$ -	$ -

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Appendix 2-G
Service Reliability and Quality Indicators
2011 - 2015

Service Reliability

Index	Including outages caused by loss of supply					Excluding outages caused by loss of supply					Excluding Major Event Days				
	2014	2015	2016	2017	2018	2014	2015	2016	2017	2018	2014	2015	2016	2017	2018
SAIDI	0.720	0.860	2.707	0.915	1.692	0.720	0.570	2.698	0.915	1.681	0.720	0.570	1.111	0.915	0.688
SAIFI	1.030	0.903	1.811	1.024	1.478	1.030	0.770	1.725	1.024	1.410	1.030	0.769	1.109	1.024	0.971

5 Year Historical Average

SAIDI				1.379					1.317	0.801
SAIFI				1.249					1.192	0.981

SAIDI = System Average Interruption Duration Index

SAIFI = System Average Interruption Frequency Index

Service Quality

Indicator	OEB Minimum Standard	2014	2015	2016	2017	2018
Low Voltage Connections	90.0%	90.9%	90.3%	92.5%	98.9%	99.1%
High Voltage Connections	90.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Telephone Accessibility	65.0%	80.4%	78.1%	78.4%	92.8%	91.9%
Appointments Met	90.0%	95.3%	96.2%	97.5%	97.9%	99.2%
Written Response to Enquires	80.0%	99.8%	100.0%	99.9%	100.0%	99.6%
Emergency Urban Response	80.0%	85.4%	83.9%	80.8%	94.7%	88.0%
Emergency Rural Response	80.0%	100.0%	100.0%	94.7%	100.0%	100.0%
Telephone Call Abandon Rate	10.0%	1.7%	2.3%	4.2%	0.7%	1.4%
Appointment Scheduling	90.0%	88.4%	94.1%	96.4%	95.9%	91.1%
Rescheduling a Missed Appointment	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Reconnection Performance Standard	85.0%	100.0%	100.0%	100.0%	100.0%	100.0%

In the green shaded cell (row 18-26) enter the most recent 12-month actual data. If there is a material difference between actual and forecasted consumption data, use forecasted data and provide an explanation

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Commodity Expense

Step 1: **Allocation of Commodity**

2018 Historical Actuals

Customer Class Name		Last Actual kWh's	Class A kWh	Class B kWh	non-RPP non GA mod	non-RPP GA mod	non-RPP Total	RPP	Proportions (by Class) non-RPP %	Proportions (by Class) RPP %
Residential		704,744,448		704,744,448		13,440,415	13,440,415	691,304,032	*1.91%*	*98.09%*
General Service < 50 kW		249,035,857		249,035,857		37,999,724	37,999,724	211,036,134	*15.26%*	*84.74%*
General Service 50 to 2999 kW		-		-	-	-	-	0	*#DIV/0!*	*#DIV/0!*
General Service 3000-4999 kW		850,957,160	214,392,510	636,564,650	437,264,469	74,325,072	511,589,541	124,975,109	*60.12%*	*14.69%*
Unmetered Scattered Load		4,150,691		4,150,691			-	4,150,691	*0.00%*	*100.00%*
Sentinel Lighting				-			-	0	*#DIV/0!*	*#DIV/0!*
Street Lighting		7,728,656		7,728,656	7,440,589	189,867	7,630,457	98,200	*98.73%*	*1.27%*
Large User		33,545,884	33,545,884	-				0		
other				-				0		
TOTAL		**1,850,162,696**	**247,938,394**	**1,602,224,302**	**444,705,058**	**125,955,078**	**570,660,137**	**1,031,564,166**		
%		*100.00%*		*100.00%*	*27.76%*	*7.86%*		*64.38%*	*35.62%*	*64.38%*	*100.00%*

Step 2: **Forecasted Commodity Prices**

Step 2a: **GA Modifier** ($/MWh)

non-RPP	
$	(44.38)

Source: Table 1: RPP Prices and GA Modifier: May 1, 2018 to April 30, 2019*

Step 2b: **Forecasted Commodity Prices** Table 1: Average RPP Supply Cost Summary*¹

			non-RPP non GA mod	non-RPP GA mod	RPP
HOEP ($/MWh)	Load-Weighted Price for RPP Consumers		$21.57	$21.57	
Global Adjustment ($/MWh)	Impact of the Global Adjustment		$103.80	$59.42	
Adjustments ($/MWh)			$1.00	$1.00	
TOTAL ($/MWh)	Average Supply Cost for RPP Consumers		**$126.37**	**$81.99**	**$81.99**
$/kWh			***$0.12637***	***$0.08199***	***$0.08199***
Percentage shares (%)	non-RPP (GA mod/non-GA mod), RPP		27.76%	7.86%	64.38%
WEIGHTED AVERAGE PRICE ($/kWh)	**(Sum of I43, J43 and L43)**	$ 0.0943	**$0.0351**	**$0.0064**	**$0.0528**

Step 3: **Commodity Expense**

(volumes for the bridge and test year are loss adjusted)

Class A

Customer		Revenue	Expense	2018 kWh Volume	2018 kW Volume	2018 HOEP Rate/kWh	2018 Avg GA/kW	2018 Amount	2019 kWh Volume	2019 kW Volume	2019 HOEP Rate/kWh	2019 Avg GA/kW	2019 Amount
General Service 50 to 2999 kW		4035	4705	217,357,402	499,673	0.02157	26.76	$18,059,650	218,048,930	502,671	0.02157	26.76	$18,154,794
Large User		4010	4705	34,401,304	68,383	0.02157	1.59	$850,765	35,278,537	70,127	0.02157	1.59	$872,459
				251,758,706	568055.8909			$18,910,415					$19,027,253

Class B

Customer		Revenue	Expense	2018					2019				
Class Name	UoM	USA #	USA #	Volume	rate ($/kWh):			Amount	Volume	rate ($/kWh):			Amount
Residential	kWh	4006	4705	682,563,361	$ 0.0943			$64,371,105	694,880,072	$0.0943			$65,532,668
General Service < 50 kW	kWh	4010	4705	238,129,933	0.094307882			$22,457,530	238,684,635	$0.0943			$22,509,842
General Service 50 to 2999 kW	kWh	4035	4705		0.094307882			$0		$0.0943			$0
General Service 3000-4999 kW	kWh	4010	4705	594,378,086	0.094307882			$56,054,539	573,920,258	$0.0943			$54,125,204
Unmetered Scattered Load	kWh	4025	4705	4,234,881	0.094307882			$399,383	4,319,245	$0.0943			$407,339
Sentinel Lighting	kWh	4025	4705		0.094307882			$0		$0.0943			$0
Street Lighting	kWh	4025	4705	7,646,176	0.094307882			$721,095	7,562,513	$0.0943			$713,205
Large User	kWh	4025	4705		0.094307882			$0		$0.0943			$0
other	kWh	4025	4705		0.094307882			$0		$0.0943			$0
TOTAL				**1,526,952,439**				**$144,003,651**	**1,519,366,723**				**$143,288,258**

Total

Customer		Revenue	Expense	2018					2019				
Class Name	UoM	USA #	USA #	Volume	avg rate ($/kWh):			Amount	Volume	avg rate ($/kWh):			Amount
Residential	kWh	4006	4705	682,563,361	0.094307882			$64,371,105	694,880,072	0.0943			$65,532,668
General Service < 50 kW	kWh	4010	4705	238,129,933	0.094307882			$22,457,530	238,684,635	0.0943			$22,509,842
General Service 50 to 2999 kW	kWh	4035	4705	217,357,402	0.0831			$18,059,650	218,048,930	0.0833			$18,154,794
General Service 3000-4999 kW	kWh	4010	4705	628,779,391	0.0905			$56,905,303	609,198,795	0.0903			$54,997,663
Unmetered Scattered Load	kWh	4025	4705	4,234,881	0.094307882			$399,383	4,319,245	0.0943			$407,339
Sentinel Lighting	kWh	4025	4705	0	#DIV/0!			$0	0	#DIV/0!			$0
Street Lighting	kWh	4025	4705	7,646,176	0.094307882			$721,095	7,562,513	0.0943			$713,205
Large User	kWh	4025	4705	34,401,304	0.024730598			$850,765	35,278,537	0.0247			$872,459
other	kWh	4025	4705	0	0			$0	0	#DIV/0!			$0
TOTAL				**1,813,112,449**				**$163,764,831**	**1,807,972,728**				**$163,187,971**

**Regulated Price Plan Prices and the Global Adjustment Modifier for the Period May 1, 2018 – April 30, 2019*

*** Regulated Price Plan Cost Suppy Report May 1, 2018 - April 30, 2019*

Appendix 2-2: KWHI Capitalization Policy

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Kitchener-Wilmot Hydro Inc.
Capitalization Policy for Capital Assets
January 26, 2019

The purpose of capitalizing expenditures is to provide an equitable allocation of costs among existing and future customers. As capital assets are expected to provide future economic benefits for more than one year, any expenditure incurred for the acquisition, construction, development or betterment of the capital assets should be capitalized. These capitalized costs are allocated over the estimated useful life of the assets by amortization.

The Company adopts the full cost accounting in accordance with guidance in the CPA Canada Handbook - Accounting.

- Asset Cost

  Costs for capital assets installed or erected by the Company include:

  - Direct material
  - Direct labour
  - Directly attributable overheads for material, labour and vehicle
  - Sub-contracting cost, if any

  Definition of cost (extract from CPA Canada Handbook – Accounting 3061.03.b):

  > Cost is the amount of consideration given up to acquire, construct, develop, or better an item of property, plant and equipment and includes all costs directly attributable to the acquisition, construction, development or betterment of the capital asset including installing it at the location and in the condition necessary for its intended use.

  A betterment is a cost, which is incurred to enhance the service potential of a capital asset. Expenditures for betterments are capitalized. This enhancement in service potential can include an increase in the physical output or service capacity, decrease in associated operations costs, extension in the useful life of the asset, or improvement in the quality of the asset's output.

  Definition of betterment (extract from CPA Canada Handbook – Accounting 3061.14):

  > The cost incurred to enhance the service potential of an item of property, plant and equipment is a betterment. Service potential may be enhanced when there is an increase in the previously assessed physical output or service capacity, associated operating costs are lowered, the life or useful life is extended, or the quality of output is improved. The cost incurred in the maintenance of the service potential of an item of property, plant and equipment is a repair, not betterment. If a cost has the attributes of

both a repair and a betterment, the portion considered to be a betterment is included in the cost of the asset.

- Asset Recognition

  Property, plant and equipment that meet the definition of a capital asset as provided in the CICA Handbook are capitalized. Expenditures that do not meet the definition are expensed in the current year.

  Definition of assets (extract CPA Canada Handbook – Accounting 1000.24):

  - Assets are economic resources controlled by an entity as a result of past transactions or events and from which future economic benefits may be obtained.

  - Assets have three essential characteristics (extract CPA Canada Handbook – Accounting 1000.25):

  a. they embody a future benefit that involves a capacity, singly or in combination with other assets, in the case of profit-oriented enterprises, to contribute directly or indirectly to future net cash flows;
  b. the entity can control access to the benefit; and
  c. the transaction or event giving rise to the entity's right to, or control of, the benefit has already occurred.

- Capitalization Threshold

  Theoretically, any expenditure that meets the asset cost and asset recognition criteria would be recorded as a capital asset. However, for practical reasons, qualifying costs would only be capitalized if it has a useful life of more than one year; and the item cost is greater than $1,000 for readily identifiable assets. This threshold may be changed at the discretion of the Vice-President Finance. Land will always be capitalized, regardless of cost.

- Construction in Progress

  Capital assets under construction at year-end are referred to as construction in progress and disclosed as a component of capital assets. Construction in progress is recognized as a capital asset and amortized when either the asset is put into service or construction is substantially completed.

- Spare transformers and meters

  Spare transformers and meters are accounted for as capital assets since they form an integral part of the reliability program for a distribution system. They are not intended for resale and can be classified as property, plant and equipment in accordance with the CPA Canada Handbook: Accounting Section 3031.03

- Allowance for Funds Used During Construction (AFUDC)

  In regard to the measurement of the carrying costs of a capital asset under construction and the capitalization of interest costs, the CPA Canada Handbook: Accounting notes that the cost of an

item of property, plant and equipment that is acquired, constructed, or developed over time includes carrying costs directly attributable to the acquisition, construction, or development activity. For an item of rate-regulated property, plant and equipment, the cost includes the directly attributable allowance for funds used during construction allowed by the regulator per s.3061.11. The financing charge will be at the rate deemed by the Ontario Energy Board ("OEB") for rate setting purposes.

The Company does not capitalize interest costs where capital assets are financed internally from the Company's working capital.

- Amortization

  Amortization is provided on a straight-line basis for capital assets available for use over their estimated service lives, at the following annual rates:

		CGAAP	MIFRS	IFRS
1808	Buildings	2.00%		
	Structure		2.00%	2.00%
	Roof & Other		5.00%	5.00%
1908	Buildings	2.00%		
	Structure		2.00%	2.00%
	Roof & Other		5.00%	5.00%
1815	Transformer Station Equipment ->50kV	2.50%		
	Switch Gear & Steel Structures		2.00%	2.00%
	Transformers & Grounding System		2.50%	2.50%
	Protection and Control Devices		4.00%	4.00%
	DC System		5.00%	5.00%
	Relays - P&C Devices/SCADA Equipment		6.67%	6.67%
1820	Distribution Station Equipment - <50kV	3.33%		
	Switch Gear & Steel Structures		2.00%	2.00%
	Transformers & Grounding System		2.50%	2.50%
	Protection and Control Devices		4.00%	4.00%
	DC System		5.00%	5.00%
	Relays - P&C Devices/SCADA Equipment		6.67%	6.67%
1830	Poles, Towers & Fixtures	4.00%	2.50%	2.50%
1835	Overhead Conductors	4.00%		
	Conductors		1.67%	1.67%
	Devices		2.50%	2.50%
	Voltage Regulators		3.33%	3.33%
	Capacitor Banks		4.00%	4.00%
1840	Underground Conduit	4.00%	1.67%	1.67%

		CGAAP	MIFRS	IFRS
1845	Underground Conductors & Devices	4.00%		
	PILC		167.00%	167.00%
	Cables and Devices		250.00%	250.00%
1850	Line Transformers	4.00%		
	Pole Top & Padmount		2.50%	2.50%
	Submersible		3.33%	3.33%
	Foundations & Vaults		1.67%	1.67%
1855	Services	4.00%		
	Overhead		2.50%	2.50%
	Services		1.67%	1.67%
1860	Metering	4.00%	4.00%	4.00%
1915	Furniture & Equipment	10.00%	10.00%	10.00%
1920	Computer Hardware	20.00%	14.3%-25%	14.3%-25%
1925	Computer Software	20.00%	20% - 33.33%	10% - 33.33%
1930	Transportation Equipment < 3 Tonnes	20.00%	12.50%	12.50%
1930	Transportation Equipment > 3 Tonnes	12.50%	10.00%	10.00%
1935	Stores Equipment	10.00%	10.00%	10.00%
1940	Tools, Shop & Garage Equipment	10.00%	10.00%	10.00%
1945	Measurement & Testing Equipment	10.00%	10.00%	10.00%
1950	Power Operated Equipment	12.50%	12.50%	12.50%
1955	Communication Equipment	10.00%	10.00%	10.00%
1960	Miscellaneous Equipment	20.00%	20.00%	20.00%
1995	Contributed Capital	4.00%	Matches Related Asset	Matches Related Asset

Amortization on general equipment directly used in the installation of other capital assets is capitalized to the new assets based on a pro-ration of the time during the year they are used for such purposes.

The half year rule for depreciation (IAS 16) is applied in the year of acquisition of the asset. This convention for depreciation calculates the depreciation on the basis that the assets are brought into use half way through a fiscal year. This relieves the corporation of the burden associated with tracking the dates of acquisition and disposal of an asset. Only half of the full year depreciation is allowed in the first year, the remaining balance is deducted in the final year of the depreciation schedule.

- Disposals and Write Downs

  For all assets taken out of service, the asset cost and related accumulated amortization is removed from the records. Differences between the proceeds, if any and the unamortized asset amount plus removal costs are recorded as a gain or loss in the year of disposal.

- Betterments versus Maintenance and Repairs

  Questions to determine if costs incurred are for betterment of the capital asset or expensed as maintenance and repairs:

	Yes	No
o Increase in the previously assessed physical output or service capacity?		
o Lower the associated operating costs?		
o Substantial improvement in the quality or efficiency of output? (>10%)		
o Is the life of the asset extended?		

Criteria

  - At least one question must be a "Yes" to qualify for betterment.

Appendix 2-3: Distribution System Plan

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Kitchener-Wilmot Hydro Inc.

Distribution System Plan

2019 Cost of Service Application



Historical Period: 2014 – 2019

Forecast Period: 2020 – 2024

April 2019

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GLOSSARY

ACA – Asset Condition Assessment

AM – Asset Management

AMI – Advanced Metering Infrastructure

AMP – Asset Management Process

APN – Access Point Network

CDM – Conservation and Demand Management

CAIDI – Customer Average Interruption Duration Index

CEMI – Customers Experiencing Multiple Interruptions

CELDI – Customers Experiencing Long Duration Interruptions

CI – Customers Interrupted

CIS – Customer Information Systems

CHI – Customer Hours Interrupted

CSA – Canadian Standard Association

DG – Distributed Generation

DS – Distribution Station

DSC – Distribution System Code

DSP – Distribution System Plan

EA – Environmental Assessment

EOL – End of Life

ESA – Electrical Safety Authority

FIT – Feed-In-Tariff

GATR – Guelph Area Transmission Reinforcement

GEA - Green Energy Act

GIS – Geographic Information System

GS – General Service

GUP – Good Utility Practices

HILP – High-Impact/Low-Probability

HONI – Hydro One Networks Inc.

IESO – Independent Electricity System Operator

IRRP – Integrated Regional Resource Planning

IST – Information Systems and Technology

IT – Information Technology

KPI – Key Performance Indicator

KWCG – Kitchener – Waterloo – Cambridge – Guelph

KWHI – Kitchener-Wilmot Hydro Inc.

LDC – Local Distribution Company

LOS – Loss of Supply

LRT – Light Rail Transit

LTEP – Long Term Energy Plan

LTLT – Long Term Load Transfer

MAIFI – Momentary Average Interruption Frequency Index

MED – Major Event Day

MTO - Ministry of Transportation of Ontario

MWO – Maintenance Work Order

NRCC – National Research Council Canada

O/H or OH - Overhead

O&M – Operation & Maintenance

O&M – Operation, Maintenance & Administration

ODS – Operational Data Store

OEB – Ontario Energy Board

OMS – Outage Management System

ORTAC – Ontario Resource and Transmission Assessment Criteria

OT – Operation Technology

PILC – Paper Insulated Lead Cable

PUCC – Public Utilities Coordinating Committee

REG – Renewable Energy Generation

RESOP – Renewable Energy Standard Offer Program

RIP – Regional Infrastructure Planning

ROE – Return on Equity

RRFE – Renewed Regulatory Framework for Electricity Distributors

RTU – Remote Terminal Units

SAIDI – System Average Interruption Duration Index

SAIFI – System Average Interruption Frequency Index

SAN – Storage Area Network

SCADA – Supervisory Control And Data Acquisition

SEII – Serious Electrical Incidents

the Board – Ontario Energy Board

the City – City of Kitchener

the Region – Region of Waterloo

the Township – Wilmot Township

TPSS – Traction Power Substations

TRXLPE – Tree-Retardant Cross-Linked Polyethylene

TUL – Typical Useful Life

TS – Transmission Station or Transformer Station

U/G or UG – Underground

UCC – Utilities Coordinating Committee

ULTC – Under-Load Tap Changing

URD – Underground Residential Distribution

USF – Utilities Standards Forum

WNHI – Waterloo North Hydro Inc

XFMR – Transformer

XLPE – Cross-Linked Polyethylene

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EXECUTIVE SUMMARY

KWHI's DSP is focused on selecting optimal investments that provide sustainable benefits and a maximized operating environment for its customers over the long term, with a short-term focus on continuation of reliable and safe service. The DSP is KWHI's first and is prepared in accordance with the OEB's Filing Requirements. It is meant to describe how KWHI plans to develop, manage and maintain its distribution system equipment to provide a safe, secure, reliable, efficient and cost-effective service to its customers. Furthermore, it identifies and consolidates major initiatives KWHI plans to undertake over the forecast period of 2020 to 2024.

KWHI provides services in the City of Kitchener and the Township of Wilmot serving approximately 97,000 customers, maintaining distribution and infrastructure assets deployed over 425 square kilometers. The service area provided by KWHI is expected to experience moderate urban growth and development over a long-term period. The Downtown Core of Kitchener is expected to become denser with a larger residential and commercial density as more businesses and job opportunities continue to develop. To meet the demands of the expected growth, large infrastructure developments need to be made such as a highly reliable Light Rail System (LRT) system to reduce congestion. Though it is beneficial for the City of Kitchener, KWHI needs to be well equipped and prepared to connect new buildings, provide the required infrastructure for the LRT system, and meet the forecasted system peak demand while maintaining its existing infrastructure with the current expected levels of reliable and safe service. KWHI continues to be engaged with the City and Region's development plans and carefully examines the outcomes into its own material investments within the DSP.

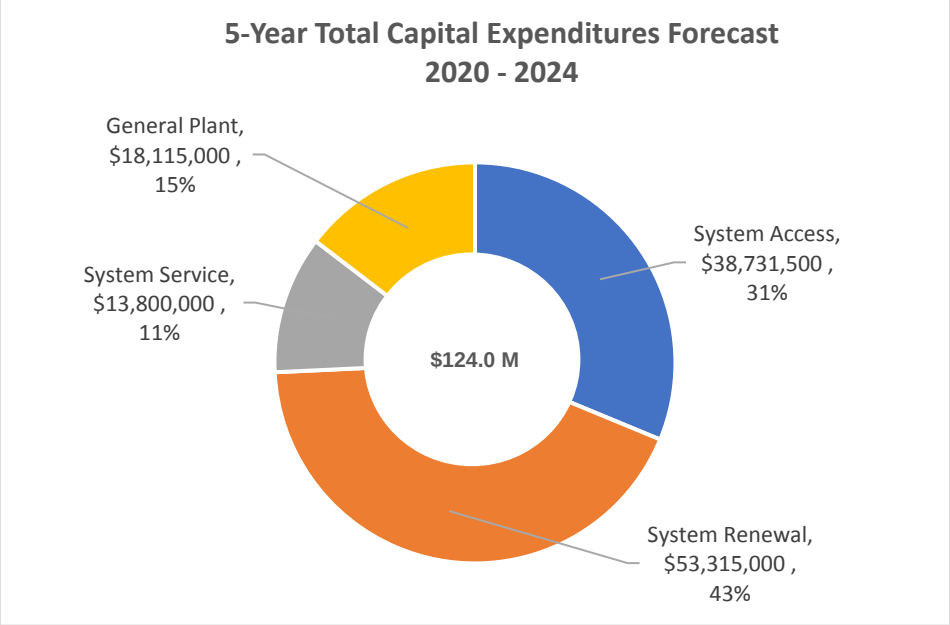
A key infrastructure development project KWHI continues to support is the LRT. KWHI had significant electrical infrastructure relocation work over the past years to accommodate the LRT system which was completed in 2017. The total cost of relocations for the LRT project was $27M over four years from 2014 to 2017. KWHI was successful in negotiating recovery of approximately 60% of these costs from the Region of Waterloo. The remaining phases of the LRT will require KWHI to commence relocation works prior to the LRT contractor starting construction of the railway. There are no confirmed dates as to when the remaining phases will begin. Future LRT work will impact capital expenditures but has not been reflected in this DSP as no project timeline has been proposed.

Understanding and responding to the preferences of KWHI's customers has been and continues to be the focus of KWHI's efforts in developing short and long-term plans. KWHI's customer base consists of residential, mid-size and large business customers. Distribution rates continue to be the top priority for low-volume customers and an important priority for larger business customers. Furthermore, ensuring reliable day-to-day electrical service remains an important priority for all customer bases. With respect to reliability, low-volume customers are consistent on priorities such as reducing the number and length of outages and improving restoration times during extreme weather. Mid-market and large business customers appear to prioritize reliability over price, with a focus on power quality and communications during outages to assist with operational planning. Residential and small business customers are generally split on KWHI's approach to planning for the next five years, however, are consistent in supporting KWHI's approach to pacing investments, including keeping spending consistent year-over-year to reduce bill impacts. Overall, there is strong support for KWHI's proposed plan, or even one that exceeds current spending levels in order to improve service levels further. A larger population of residential customers feel that KWHI should be spending more, rather than spending less.

KWHI considers all customer feedback and preferences in determining the pacing of its investments and in optimal selection of projects. Survey results were used to inform the asset management plan

and development of the capital investment plan. In addition to the customer feedback, the corporate strategic priorities and asset management objectives form the high-level framework for KWHI's investment programs. Asset management objectives identify investments that are best aligned from an overall benefit and risk management perspective. An integral part of achieving the asset management objectives are inspection, maintenance and replacement programs, to ensure system performance is sustained during the entire asset service life. To align to asset management best practices and to provide consistency with its Strategic Priorities, KWHI has adopted an Asset Management Strategy. The Asset Management Strategy provides direction for the management of assets while recognizing realistic service and performance goals. The Asset Management Strategy ensures a continual and consistent focus on delivering services in a way that balances risk and long-term costs. In addition to the Asset Management Strategy, KWHI developed an Asset Management Policy that provides the high-level overview of the strategy as part of best practice for asset management.

The combination of KWHI's asset management and capital expenditure planning process leads to a capital expenditure plan consisting of a five-year capital expenditure forecast. The asset management and capital investment process identify System Access, System Renewal, System Service and General Plant requirements. These requirements result in a list of mandatory and added value investments to be executed over the investment period. The final investment portfolio considers the balance between achieving KWHI's Asset Management Objectives and the impact on customer rates. KWHI plans to invest an average of $24.79M in capital expenditures per year across all four investment categories for a gross total of approximately $124M. The figure below shows the 5-year expenditures forecast by investment category.



Expenditures in the System Access category are driven by external requirements such as servicing new customer load and relocating distribution plant to suit road authorities. These expenditures are mandatory. Specific projects such as relocations due to LRT development, which are planned as multi-year projects, are budgeted for based on KWHI's estimates, in conjunction with information from external agencies. KWHI plans to invest an average of $7.75M in capital expenditures per year within the System Access category which accounts for 31% of the gross total over the forecast period.

Expenditures within the System Renewal category are largely driven by the condition of distribution system assets and play a crucial role in the overall reliability, safety and sustainment of the distribution system. The first major program found under the System Renewal framework is the Transformer and Distribution Stations Renewal. The program includes a collection of projects in which power transformers, protection and control devices and switchgear equipment at existing transformer stations are replaced or upgraded due to age, deteriorating condition or functional obsolescence. These equipment types are usually replaced with upgraded or new technologies available at the time of renewal. KWHI plans to replace two power transformers at its No. 5 TS during the forecast period for an estimated amount of $6.4M. An additional major program under the System Renewal framework is the Replacement of Pole Line Assets. The program consists of a number of overhead rebuild projects that are planned for based on the condition of KWHI's in-service assets. Over the DSP period, 425-450 poles per year are planned for replacement. KWHI had strong customer support for this program and in some cases, customers were willing to pay more to accelerate the program. Another major program planned within the forecast period is Voltage Conversion. The program includes projects that are undertaken for the purpose of voltage conversion from 8.32 kV to 27.6 kV. Voltage Conversion is a subset of rebuild project and is planned when there is a need to increase system capacity for load growth while replacing end of life assets. Voltage Conversion also improves system efficiency (by reducing line losses), improves the voltage profile (regulation), and improves the ability to connect distributed generation. KWHI plans to invest an average of $10.66M in capital expenditures per year within the System Renewal category which accounts for 43% of the gross total over the forecast period.

Expenditures in the System Service category are driven by the need to ensure that the distribution system continues to meet operational objectives (such as reliability, grid flexibility and DER integration) while addressing anticipated future customer electricity service requirements. Expenditures in this category include the addition of feeders to provide service to new developments. New feeders may be constructed to provide service to new customers in areas not previously serviced or may also be constructed in previously serviced areas to increase capacity where load density increases. A major initiative during the forecast period is the construction of a new underground distribution feeder to supply the increasing load demand in downtown Kitchener caused by a number of new high-rise, mixed-use buildings (12-15) under construction or proposed for development in the downtown core. Additionally, in this category, KWHI is constantly looking for ways to cost effectively improve system reliability and efficiency. This can include the installation of automated reclosers and switches, line sensors or conversion from overhead to underground networks. KWHI plans to invest an average of $2.76M in capital expenditures per year within the System Service category which accounts for 11% of the gross total over the forecast period.

Expenditures in the General Plant category are driven by the need to modify, replace or purchase assets that are not part of the distribution system but support the utility's everyday operations and to permit smart grid functionality. The significant program found under the General Plant framework is the Information Systems and Technology program. Expenditures in this program are driven by the need to acquire, enhance and upgrade computer hardware and software used in information technology (IT) and operation technology (OT) applications. These hardware and software tools are crucial to the day-to-day running of the organization and must be protected and secured to reduce the likelihood of cyber security breaches. The 2020 forecasted expenditures is heavily influence by the costs to replace the 30+ years old legacy Customer Information System (CIS) with a next generation commercial off the shelf product. This is a multi year project with investments budgeted for in 2019 and 2020. KWHI plans to invest an average of $3.62M in capital expenditures per year within the General Plant category which accounts for 15% of the gross total over the forecast period.

KWHI intends to execute its capital expenditure plan in full within the timeframe presented. Furthermore, the projects comprising the plan have been prioritized within the context of an overall investment strategy.

1 INTRODUCTION

Kitchener-Wilmot Hydro Inc. (KWHI) has prepared this Distribution System Plan (DSP) in accordance with the Ontario Energy Board's (OEB's) *Chapter 5 Consolidated Distribution System Plan Filing Requirements* dated 12 July 2018 (the Filing Requirements) as part of its 2019 Cost of Service Application (the Application). KWHI retained METSCO Energy Solutions Inc. (METSCO) to advise on and assist with the preparation of this DSP.

1.1 OBJECTIVES & SCOPE OF WORK

The KWHI DSP is a stand-alone document and is filed in support of KWHI's Application. KWHI's DSP describes and substantiates KWHI's asset management processes and capital expenditure plan for the 2020-2024 period. The DSP documents the practices, policies and processes that are in-place to ensure that investment decisions support KWHI's desired outcomes in a cost-effective manner and provide value to customers.

KWHI's DSP is designed to support the achievement of the four key OEB established Renewed Regulatory Framework for Electricity (RRFE) performance outcomes:

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

1.2 OUTLINE OF REPORT

This is KWHI's first consolidated DSP prepared in accordance with OEB's Filing Requirements. This DSP describes how KWHI plans to develop, manage and maintain its distribution system equipment to provide a safe, secure, reliable, efficient and cost-effective service to its customers. The DSP identifies the major initiatives and projects to be undertaken over the filed planning period. Preparation of the DSP in this format is intended to supplement KWHI's Application. The DSP spans an eleven-year period, with the historical period covering 2014 to 2019 (2019 being the Bridge Year) and the forecast period of 2020 to 2024 (2020 being the Test Year). KWHI's last Board Approved budget was for 2014.

The report contains four sections including this introductory Section 1. Section 2 provides a high-level overview of the DSP, including coordinated planning with third parties and performance measurement for continuous improvement. Section 3 provides an overview of KWHI's asset management process, including an overview of the assets managed and asset lifecycle optimization policies and practices. Section 4 provides a summary of KWHI's capital expenditure plan, including an overview of the capital expenditure planning process, an assessment of the system capability for Renewable Energy Generation (REG), and justification of material projects (above the materiality threshold of $200,000).

KWHI's DSP is focused on providing the most viable, value added operating environment possible for its consumers over the long term, with a short-term focus on continuation of reliable and safe service.

KWHI intends to execute its capital expenditure plan in full within the timeframe presented. The projects comprising the plan have been prioritized within the context of an overall investment strategy.

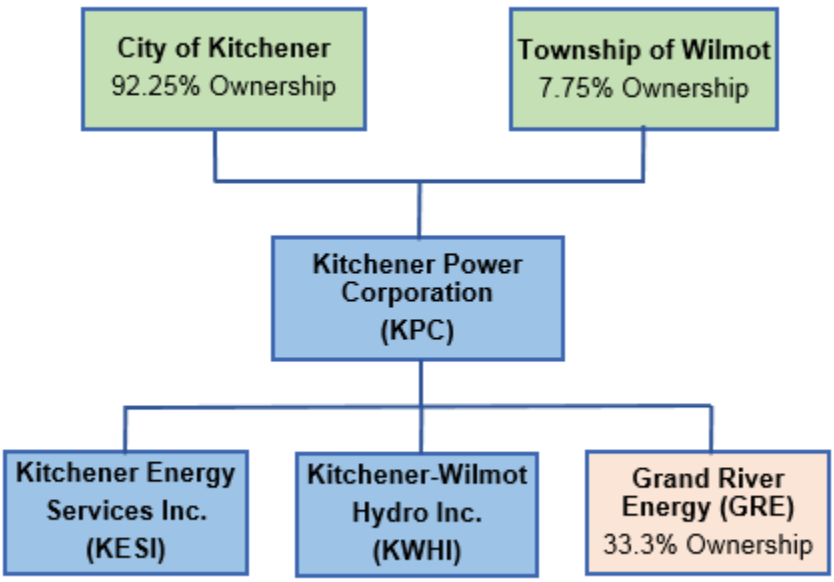
Where relevant, the DSP is organized using the same section headings indicated in the OEB's Filing Requirements and addresses the information outlined in each section. Other relevant information is included in separately identified sections and is intended to complement the prescribed data.

1.3 Description of the Utility Company

KWHI is an electricity distributor licensed by the OEB in accordance with its Distribution License ED-2002-0573. KWHI provides electricity distribution services in the City of Kitchener and the Township of Wilmot, serving approximately 97,000 customers.

KWHI is incorporated under the Ontario Business Corporations Act and is a subsidiary of Kitchener Power Corporation (KPC) whose shareholders are the City of Kitchener and the Township of Wilmot, with ownership interests of 92.25% and 7.75% respectively. KPC also owns Kitchener Energy Services Inc. (KESI) and one third (33.3%) of Grand River Energy Solutions Corporation (GRE) along with Cambridge and North Dumfries Energy Plus Inc. and Waterloo North Hydro Holding Corporation. KESI provides street light maintenance services within the City of Kitchener and the Township of Wilmot which is a non-regulated activity. GRE is a generation and renewable energy solutions company whose mission is to help customers reach their energy management goals by tapping into the benefits of clean energy technologies such as solar, combined heat and power, electric vehicle integration, and carbon reduction goals. Figure 1.1 depicts the corporate structure for KPC.

Figure 1.1: KPC Corporate Structure



KWHI receives power from Hydro One Networks Inc. (HONI) and delivers electricity to its customers via eight high voltage transformer stations and seven distribution substations. KWHI is responsible for maintaining distribution and infrastructure assets deployed over 425 square kilometers (including over 3,100 kilometers of overhead and underground lines) within the Kitchener and Wilmot service areas.

1.3.1 Mission, Vision, & Core Values Statement

The following are KWHI's mission, vision, and core values that were developed by management and staff and approved by KWHI's Board of Directors.

Mission

We care for our customers, community, employees, and stakeholders and provide value through the distribution of safe, efficient and reliable power.

Vision

Empowered by a dedicated and responsive team, we will be the preferred energy provider and trusted partner for our community.

Core Values

Our core values are our beliefs, guiding principles, the motivational constructs that guide our day-to-day decisions and actions.

Financial responsibility *- we respect customer and shareholder interests and maintain reasonable rates by making thoughtful spending decisions that maximize value*.

Safety *- we are committed to protecting our employees and community by taking a proactive approach to safety and wellness at work and at home. We set the example*.

Customer focus *- customers are at the centre of what we do. We aim to exceed expectations through caring and respectful interactions and providing reliable service.*

Communication *- we are committed to engaging our customers and employees through timely, respectful, transparent and reliable communications.*

Accountability *- we are responsible for our decisions and actions. We learn from failures and build on successes.*

Trust *- Trust is essential for meaningful and empowering relationships. We earn the confidence of our customers and fellow employees by being honest and considerate in all we do*.

1.3.2 Strategic Priorities

The corporation established a Business Plan in 1993 which has been updated periodically. The latest Business Plan (2019) confirms the strategic priorities of the corporation as follows:

Figure 1.2: KWHI Strategic Priorities

RESPONSIVE TO CUSTOMER NEEDS	GROWTH & SUSTAINABILITY	OPERATIONAL EXCELLENCE	HIGH PERFORMING CULTURE
Customer Engagement Outreach Decisions informed by customer preferences, cost effective delivery of services that matter to customers ***CIS/CRM*** Leverage technology to enhance customer service interactions, interfaces and allow customer choices ***CDM*** Assist customers with electricity conservation to reduce costs	***Strong Financial Stability*** Meet and/or exceed OEB deemed ROE, Total Debt/Equity, and Liquidity Ratios ***Adaptability*** Plan development of the distribution system to meet future customer needs ***ERM*** Identify & mitigate risk to protect the business, customers & employees	***OEB Scorecard*** Meet and/or exceed industry benchmarks ***Collaboration*** Increase efficiencies & customer value, synergize operations through GSC cooperative buying power & other initiatives ***Asset Management*** Proactive management of our physical infrastructure to improve grid resiliency and reliability	***People & Culture*** Attract, retain, engage & develop the right capabilities, to support a Customer Centric organization ***Safety*** Develop a proactive Leading Indicator Safety culture, concerned with employees' well-being to ensure a fit and ready workforce

Responsive to Customer Needs

- Enhance customer satisfaction through high quality service.
- Continue to deliver reliable electricity at the lowest reasonable rates.
- Leverage technology to enhance customer service interactions, interfaces and allow customer choices.
- Promote the efficient use of electricity - assist customers with electricity conservation to reduce costs.

Growth & Sustainability

- Maintain sound financial performance - meet or exceed OEB deemed ROE, Total Debt/Equity, and Liquidity Ratios.
- Build value for our Shareholders, the City of Kitchener and Township of Wilmot.
- Plan expansion of the distribution system to meet the electrical needs of customers.
- Identify & mitigate risk to protect the business/customers/employees.
- Support environmental programs (Reduce, Reuse, Recycle).

Operational Excellence

- Meet and/or exceed industry benchmarks
- Continue to reduce system outages.
- Increase efficiencies & customer value, synergize operations through GridSmartCity cooperative buying power & other initiatives.
- Proactive management of our physical infrastructure to improve grid resiliency and reliability.
- Seek out non-wires alternatives to meet demand.

High Performance Culture

- Attract, retain, engage & develop the right staff, to support a Customer Centric organization.
- Provide adequate tools, equipment and training to improve productivity and allow staff to serve the Corporation and its customers effectively and efficiently.
- Promote safety performance for staff and the public.
- Create a proactive Leading Indicator "Safety Culture" within the Corporation.

- Create a healthy environment for staff.

1.3.3 Customers Served

In 2018, KWHI served 96,826 electricity distribution customers across its service area.

The two communities KWHI serves have distinct characteristics. Kitchener is a dense urban community with an expanding population and distribution system. It has been identified as an Urban Growth Centre in the Province's Places to Grow Act. The Wilmot service area contains mostly residential customers located in a mix of light urban, seasonal, and rural areas, with minimal population growth in recent years.

The table below illustrates the changes in KWHI's customer base over the historical period, which includes residential, general service less than 50 kW, general service greater or equal to 50 kW, and large users. Distribution system investments to date have focused on sustaining the existing distribution system infrastructure with a minimal cost impact to customers and expanding the distribution system to meet customer needs.

Table 1-1: KWHI's 2014-2018 actual customer base

Annual Year	Residential	General Service <50 kW	General Service ≥50kW	Large Use > 5MW
2014 Actual	82,425	7,776	942	2
2015 Actual	83,642	7,818	944	1
2016 Actual	85,248	7,875	935	1
2017 Actual	86,846	7,964	947	1
2018 Actual	87,846	8,031	949	1

1.3.4 System Demand and Efficiency

Table 1-2 shows the annual peak demand (kW) for KWHI's distribution system.

Table 1-2: Peak system demand statistics

Annual Year	Winter Peak (kW)	Summer Peak (kW)	Average Peak (kW)
2014 Actual	322,515	322,990	292,684
2015 Actual	293,132	328,007	284,684
2016 Actual	293,555	360,767	293,626
2017 Actual	279,305	329,672	277,081
2018 Actual	287,300	370,680	298,443

KWHI experiences its overall system peak during summer months. Peak data shown includes the net effect of embedded loads and generators. Variances in seasonal peaks are attributable to annual changes in summer weather conditions and loading impacts associated with the number of degree days and CDM initiatives. Table 1-3 indicates the efficiency of the kilowatt hour purchased by KWHI.

Table 1-3: Efficiency of kWh purchased by KWHI

Annual kWh Purchased	Total kWh Delivered (excluding losses)	Total Distribution Losses (kWh)	Total kWh Purchased	Losses as % of Purchased
2014 Actual	1,819,233,991	50,295,951	1,869,529,942	2.7
2015 Actual	1,787,065,782	68,311,749	1,855,377,531	3.7
2016 Actual	1,786,816,053	52,915,942	1,839,731,995	2.9
2017 Actual	1,730,611,664	55,287,617	1,785,899,281	3.1
2018 Actual	1,818,689,251	51,072,209	1,869,761,460	2.7

1.4 Background & Drivers

The Filing Requirements outline four categories of investments into which projects and programs must be grouped. The drivers for each investment category align with those listed in the Filing Requirements. For reporting purposes, a project or program involving two or more drivers associated with different categories is included in the category corresponding to the trigger driver. However, all drivers of a given project or activity were considered in the analysis of capital investment options and are further described in Section 4 of the DSP.

Table 1-4: KWHI category drivers for DSP identified projects

OEB Category	Driver	Projects/Programs
System Access	Customer Service Requests	Underground Residential Distribution
		Commercial, Industrial & Apartment Services
		Misc. Underground Distribution
	Third Party Infrastructure	Relocations Due to Roadway Modifications
	Mandated Service Obligations	Revenue Meters
System Renewal	Failure Risk	Transformer and Distribution Stations Renewal
		Replacement of Pole Line Assets
		Replacement of Primary Cables and Conduits
		Rebuild Transformer Vaults & Pull Boxes
		Network Transformer Replacement
		Distribution Transformer Installation & Replacement
	Functional Obsolescence	Voltage Conversion
System Service	System Constraints	System Expansion to Supply New Development & Load Growth
	System Operational Objectives	Innovation and Reliability
General Plant	System Maintenance Support	Land & Buildings
		Office Equipment
	Business Operations Efficiency	Information Systems and Technology
	Non-system Physical	Vehicles
		Tools & Equipment

System Access

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

System Renewal

These investments involve replacing and/or refurbishing system assets to extend the original service life of the assets and thereby maintain the ability of KWHI's distribution system to provide customers with electricity services.

System Service

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

General Plant

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

2 DISTRIBUTION SYSTEM PLAN (5.2)

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

2.1 DISTRIBUTION SYSTEM PLAN OVERVIEW (5.2.1)

This section provides the OEB and stakeholders with a high-level overview of the information filed in the DSP, including key elements of the DSP, sources of expected cost efficiencies, the period covered by the DSP, the vintage of the information, an indication of important changes to KWHI's asset management processes, and aspects of the DSP that are contingent on the outcome of ongoing activities or future events.

2.1.1 Key Elements of the DSP (5.2.1a)

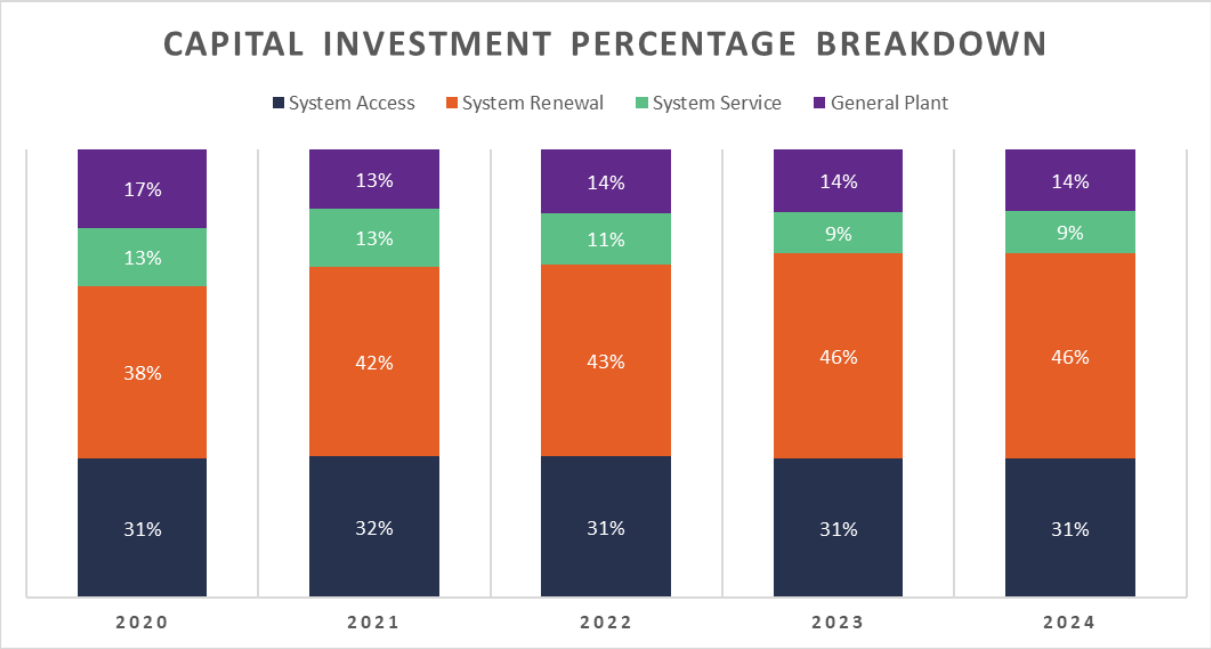
The electric distribution system is capital-intensive in nature, and prudent capital investments and maintenance plans are essential to ensure the sustainability of the distribution network. KWHI's DSP outlines the practices, policies and processes that are in-place to ensure that decisions on capital investments and maintenance plans support KWHI's desired outcomes in a cost-effective manner and provide value to the customer. Table 2-1 presents the capital expenditures by investment category and the system operations and maintenance (O&M) costs for both the historical and forecast period. Figure 2.1 shows a percentage breakdown of the capital expenditures by year and investment category.

Table 2-1: Historical and forecast capital expenditures and system O&M

Category	Historical ($ '000)						Forecast ($ '000)				
	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
System Access (Gross)	11,687	15,817	16,918	11,815	8,107	7,432	7,664	7,767	7,817	7,717	7,767
System Renewal (Gross)	4,821	3,322	4,616	5,377	7,728	8,545	9,415	10,350	10,650	11,400	11,500
System Service (Gross)	1,545	839	2,420	1,458	1,470	2,100	3,200	3,200	2,800	2,300	2,300
General Plant (Gross)	2,280	1,859	2,105	2,807	3,030	7,125	4,295	3,275	3,565	3,500	3,480
Gross Capital Expenses	**20,333**	**21,838**	**26,059**	**21,457**	**20,335**	**25,201**	**24,574**	**24,592**	**24,832**	**24,917**	**25,047**
Contributed Capital	6,698	9,593	6,101	8,950	4,696	4,000	4,000	4,000	4,000	4,000	4,000
Net Capital Expenses after Contributions	13,635	12,245	19,958	12,507	15,639	21,201	20,574	20,592	20,832	20,917	21,047
System O&M	10,117	9,320	9,498	10,625	11,811	12,576	13,162	13,162	13,162	13,162	13,162

**0 months of actual expenditures included in 2019*

Figure 2.1: Capital Investment Summary 2020-2024 Percentages



KWHI expects that the operational and service requirements driving its capital expenditures that comprise this DSP, will generally remain consistent through the 2020 to 2024 planning horizon. The projected expenditures for 2020 and going forward reflect the following planning considerations:

- typical spending needs of a distribution electric utility serving a growing customer base;
- focused planned capital sustainment investments required to replace the aging assets found in KWHI's distribution system; and

- incremental investments in grid modernization to make the distribution system more responsive in monitoring, locating and responding more quickly to power outages, permitting higher penetration of DERs, and providing customers with timely information to enable consumption-related decision making.

Specific investment category spending requirements include:

- System Access spending driven by customer connection needs and third-party infrastructure needs requiring mandatory plant relocation;
- System Renewal investments required to replace end of life assets and/or assets in deteriorating condition, including poles, wires and transformers;
- System Service investments such as new underground feeder to supply load growth in downtown Kitchener, and overhead switch automation;
- General plant investments to meet the building, fleet and IT needs. Replacement of the legacy Customer Information System (CIS) is included in the IT cost.

KWHI forecast period expenditures represent a consistent total budget envelope across all years, balancing annual variations in anticipated non-discretionary System Access work with changes in the other three investment categories, which the utility can usually pace and prioritize with a greater degree of control – thus facilitating the overall smoothness and predictability of rate changes over the plan timeline.

KWHI's DSP is a product of multiple inputs from initiatives, processes and documents involving several stakeholders. These input sources include the following:

- Regional and Provincial growth plans
- KCWG Regional Planning Supply Study
- City and Region road projects requiring plant relocation/removal
- KWHI's Business Plan
- KWHI's Asset Management Strategy
- Regulatory obligations (e.g. 2015 – 2020 CDM targets)
- Outputs of KWHI's asset management program – including maintenance and EOL replacement
- Customer Engagements
- Ontario's Long-Term Energy Plan 2017

The 2020 – 2024 DSP was developed with the objective of not only addressing the short-term and medium-term needs but also to ensure that the system has sufficient resilience and flexibility to achieve safe and reliable distribution in the long term based on effective financial planning.

2.1.1.1 Key Challenge: Urban Growth

Ontario Places to Grow Act (2005) / Growth Plan for the Greater Golden Horseshoe (2017)[1]

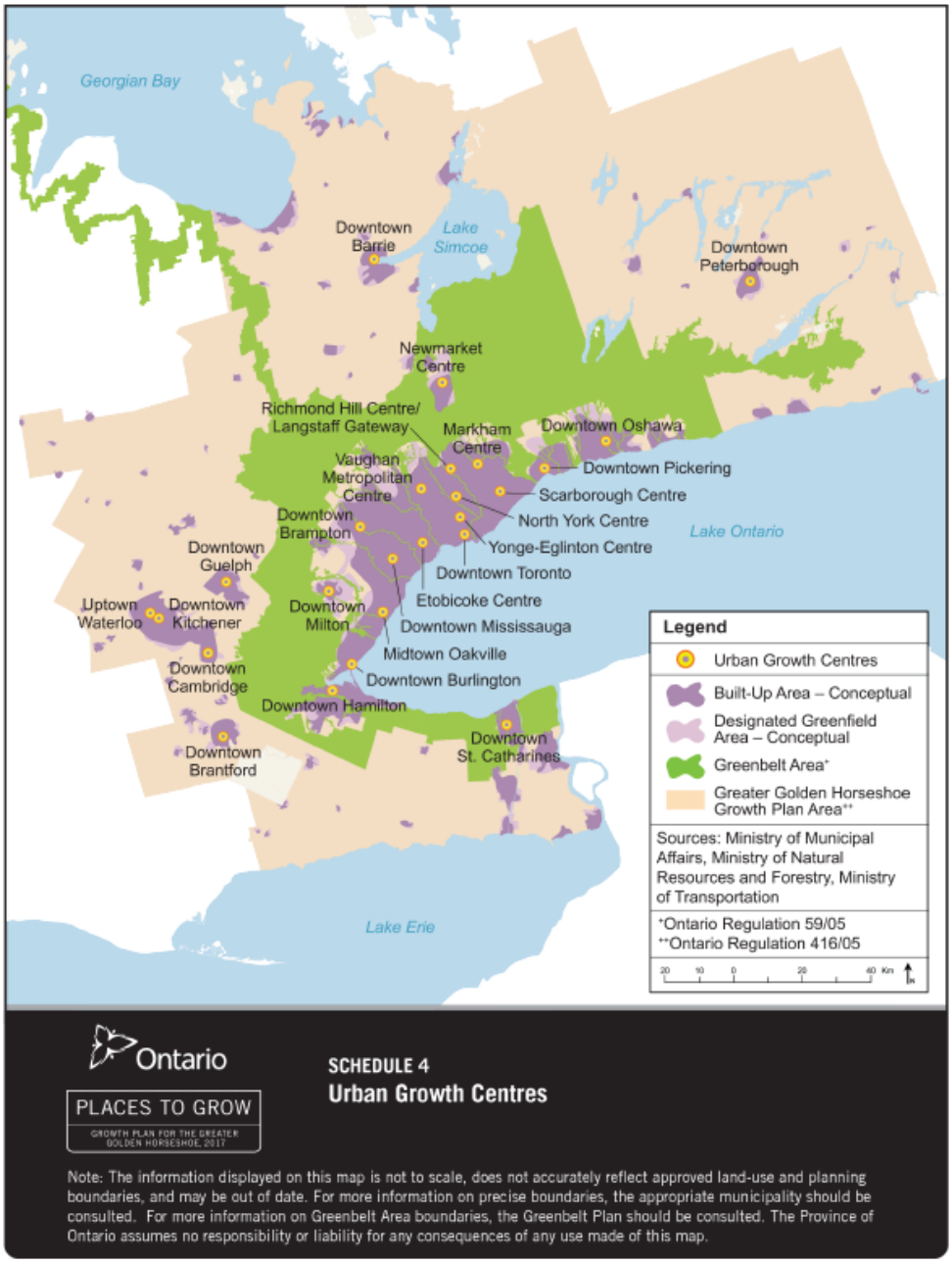
Downtown Kitchener has been identified in *the Act* as one of the Urban Growth Centres in the Greater Golden Horseshoe. As an urban growth centre, Kitchener is expected to be planned:

1. as a focal area for investment in institutional and region-wide public services, as well as commercial, recreational, cultural and entertainment uses;
2. to accommodate and support major transit infrastructure;

[1] https://files.ontario.ca/appendix_-_growth_plan_2017_-_oc-10242017.pdf

3. to serve as a high-density major employment centre that will attract provincially, nationally or internationally significant employment uses;
4. to accommodate a significant share of the Waterloo Region's population and employment growth.

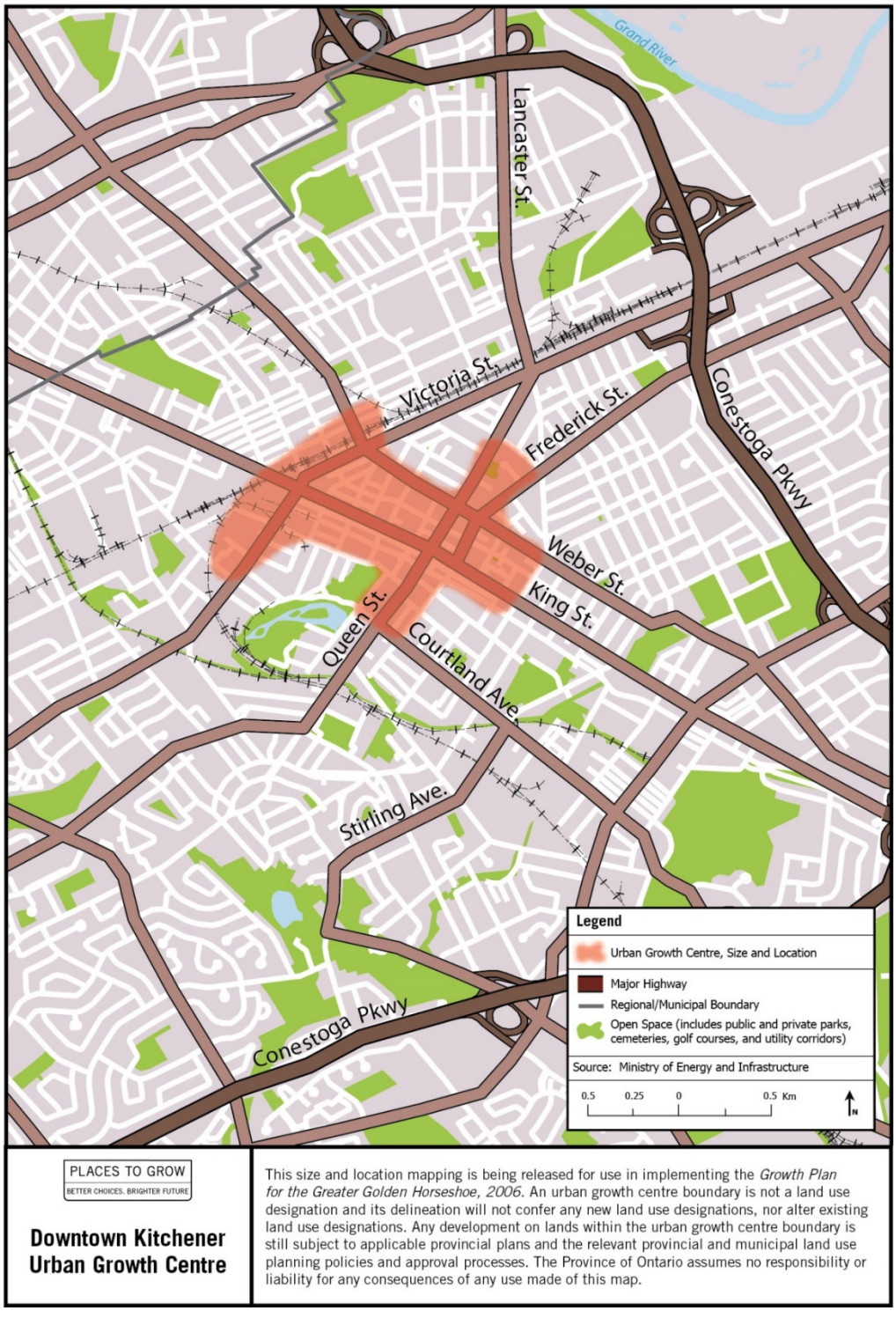
Figure 2.2: Urban Growth Centres – Ontario Places to Grow



The Growth Plan loosely defines the Kitchener Urban Growth Centre as the area bounded by Victoria St., Queen St., King St., and Weber St. (Figure 2.3). For greater details see Figure 2.5. The Growth Plan mandates that Urban Growth Centres account for a significant amount of the province's future population and employment growth. The Growth Plan also mandates that the Downtown Kitchener

Urban Growth Centre be planned to achieve a minimum density of 200 residents and jobs combined per gross hectare by 2031.

Figure 2.3: Downtown Kitchener Urban Growth Centre



The Growth Plan also recognizes Major Transit Station Areas as areas that are planned to achieve increased residential and employment densities. Downtown Kitchener serves as the hub of an

integrated regional and provincial transportation network, with regional bus service and a rail station within short walking distance of King Street. The Growth Plan states that Major Transit Station areas will be planned to achieve a mix of residential, office, institutional and commercial development as appropriate to support ridership along these routes.

Having come into effect on July 1, 2017 the latest Growth Plan for the Greater Golden Horseshoe replaces the inaugural 2006 Growth Plan. The plan provides population and employment forecasts for the Greater Golden Horseshoe through 2041. The 2006 Growth Plan identified 25 urban growth centres and the current version continues to recognize those urban growth centres as regional focal points for accommodating population and employment growth.

Continuous infrastructure growth for the Greater Golden Horseshoe is expected to be planned in coordination with the energy infrastructure as part of an integrated approach. Of specific interest is transportation infrastructure planning. Public transit will be the priority for transportation infrastructure planning. Collaborative local energy infrastructure planning will play an important role in assisting transit infrastructure planning in meeting provincial greenhouse gas emissions reduction targets. The Growth Plan specifically supports the fostering of collaboration between public and private sectors for joint development projects within major transit areas.

The Downtown Kitchener Urban Growth Centre is supplied by an underground infrastructure consisting of a 13.8kV medium voltage loop system with below and above grade vault-mounted switchgear and a 125/216V low voltage secondary grid network system with below grade vault mounted network transformers and protectors. Expansion of these systems to add new load typically requires significantly more effort than a traditional overhead distribution system.

DSP IMPACT

The land use planning framework presented in the Greater Golden Horseshoe Growth Plan (2017) will require capital investment to provide for new connections and capacity. Connection spending is forecast to be relatively consistent, year over year, during the 2020 – 2024 planning period, however forecasts beyond the 5-year planning period may experience a change. New feeder capacity is required during the DSP period to supply the anticipated load growth within the Urban Growth Centre. KWHI has begun designs for a new underground distribution system to downtown Kitchener and is undertaking a non-wires alternative study to determine the feasibility of offsetting the need for multiple distribution feeders.

All connection requests are mandatory and KWHI is required to address all requests. Resource allocation is adequately planned and prioritized to address connections which consequently reduces the resources to be used for other system infrastructure projects. In addition to the increase of connections and capacity, the expected infrastructure growth is projected to increase the use and wear of existing in-service assets. KWHI is tasked to adequately manage the existing in-service assets under an increased load and service usage due to the increase of connections and capacity upgrades required to accommodate the expected infrastructure and energy growth.

Waterloo Region Official Plan (2015)[2]

Waterloo Region includes the Cities of Cambridge, Kitchener, and Waterloo and the Townships of North Dumfries, Wellesley, Wilmot, and Woolwich (Area Municipalities), blending a unique balance of urban and rural centres. The Waterloo Region Official Plan forecasts that by 2031 it is projected to

[2] https://www.regionofwaterloo.ca/en/resources/Regional-Official-Plan/Chapter_2_Consolidated_New_ROP_2015-access.pdf

reach 729,000 residents and 366,000 jobs. The City of Kitchener is projected to reach 319,500 residents and 132,500 jobs by 2031. Wilmot Township is projected to reach 28,500 residents and 10,000 jobs by 2031.

Table 2-2: Regional Population and Employment Forecasts

Municipality	2006 Population	2031 Population	2006 Employment	2031 Employment
Cambridge	123,900	176,00	75,020	102,500
Kitchener	214,500	319,500	99,380	132,500
North Dumfries	9,200	16,00	6,080	8,700
Waterloo	101,700	140,000	64,070	89,000
Wellesley	10,100	12,500	3,290	4,300
Wilmot	17,700	28,500	6,730	10,000
Woolwich	20,100	36,500	13,540	19,000
Region	**497,200**	**729,00**	**268,310**	**366,000**

The Plan also encourages energy conservation, including undertaking pilot projects and Community Energy Plans, to reduce the need for energy and non-renewable resources. Community Energy Plans detail the municipality's energy use requirements and establish a plan to reduce energy demand and consider the use of alternative and renewable energy generation options and district energy systems and ensure that communities are designed to optimize passive solar gains thus impacting the energy requirements to be obtained from the electrical distribution grid.

DSP IMPACT

System Access needs for new connections are expected to remain steady over the forecast period and similar to historical levels. System Access needs for plant relocation are expected to be lower than historical levels due to completion of the Light Rail Transit (LRT) Phase 1 in 2017. Economic growth is expected to have a steady impact on System Renewal, System Service and General Plant needs over the forecast period. However, with the historical project deferrals within System Renewal, KWHI is projecting to heavily invest in renewing its system to be better equipped for the projected growth within the region.

City of Kitchener Official Plan (2014)[3]

The City of Kitchener Official Plan implements the Urban Centres and Regional Corridors policies of the Provincial Growth Plan and the Waterloo Region Official Plan through the identification of the Downtown Urban Growth Centre and Major Transit Station Areas.

The plan mirrors the population and employment forecast of the Greater Golden Horseshoe Growth Plan (2017). The plan places increasing emphasis on intensification, particularly in the Urban Growth Centre (Downtown), Major Transit Station Areas, nodes and corridors, which maximizes the use of existing infrastructure and services.

The Kitchener Official Plan Policy states that the Urban Growth Centre (Downtown) is planned to achieve, by 2031 or earlier, a minimum density of 225 residents and jobs combined per hectare. Additionally, "*the City plans to achieve, by 2016 and each year thereafter, a minimum annual residential intensification target of 50 percent within the City*"[3]. This means that the City plans to have on-going development or redevelopment projects that target existing buildings and areas within the

[3] https://www.kitchener.ca/en/building-and-development/official-plan.aspx#City-of-Kitchener-Official-Plan-A-Complete--Healthy-Kitchener-2014

existing urban area at a density higher than what currently exists. This results in an increase of service connections and introduces the need to manage demand within the existing service areas being targeted by residential intensification.

Furthermore, the Kitchener Official Plan Policy states that: *"Where feasible, utilities within new development and redevelopment should be located underground. Upon replacement, utilities within the Built-Up Area are encouraged to be located underground where technically and economically feasible"*.[3]

The Region of Waterloo currently has an incentive program available to developers and property owners called the Downtown Core Exemption. The downtown core exemption applies to all lands within the Downtown Core Boundary. These lands are exempted from both City of Kitchener and Regional development charges, including the Regional development charges for waste and transit. The exemption will expire on February 28, 2019. The upcoming expiration coupled with the recently installed LRT system in Kitchener has resulted in a significant bump in development activity in Kitchener downtown, levels of which KWHI has never experienced before. To meet this surge in demand for electrical infrastructure, KWHI will be required to construct at minimum of two 13.8kV underground distribution feeders from its No. 4 Transformer Station to the downtown core. Major Transit Station Areas are located along the LRT corridor.

Figure 2.4: Kitchener Official Plan – Urban Structure

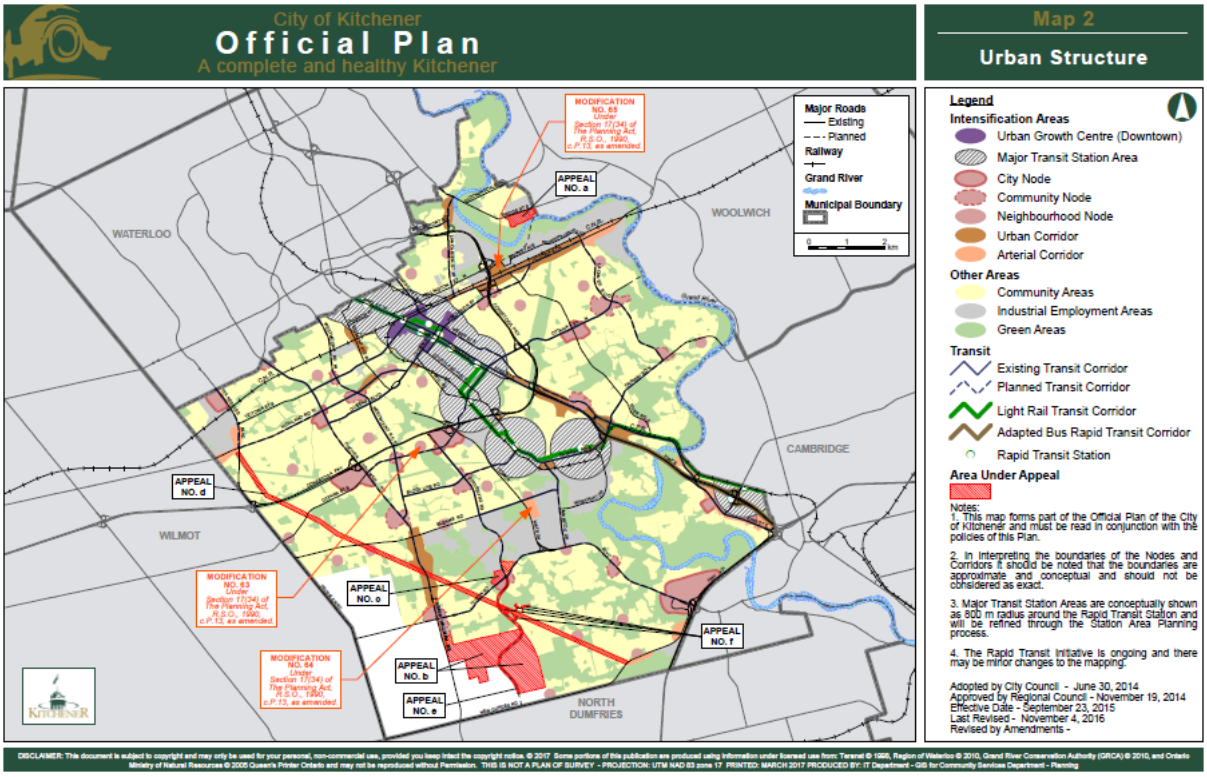
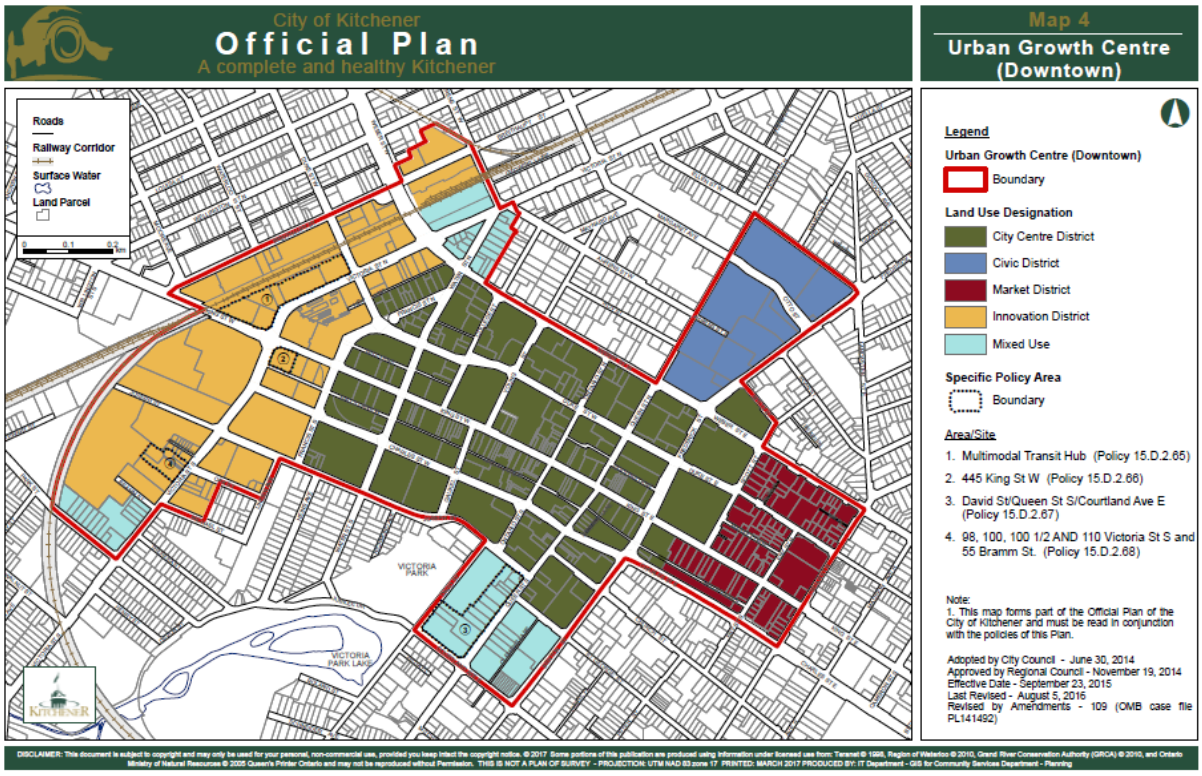


Figure 2.5: Kitchener Official Plan – Urban Growth Centre



DSP IMPACT

Similar to existing forecast plans presented in the Waterloo Region Official Plan and Growth Plan for the Greater Golden Horseshoe, System Access needs for new connections are expected to increase significantly over the forecast period to expand the distribution system to connect up to 22 new high-rise developments within the Downtown Urban Growth Centre of Kitchener. System Access needs for plant relocation are expected to be lower than historical levels due to completion of the LRT Phase 1 project. Economic growth and infrastructure development are projected to have a steady impact on System Renewal, System Service and General Plant needs over the forecast period. Appendix B contains a visualization of KWHI's proposed downtown developments for the current DSP period.

Wilmot Township Official Plan (2006)[4]

The Township of Wilmot is located in south-western Ontario and is one of seven lower-tier municipalities which comprise the Regional Municipality of Waterloo. While rural in character, the Township's 26,590 hectares also house two larger urban environments and several smaller settlement areas. The Official Plan reflects the Township's policies relating to the future development of the Municipality. The Plan is based on the premise that the Municipality is projected to remain predominantly rural in nature with major (Baden and New Hamburg) and minor settlement areas.

DSP IMPACT

Currently, there are no specific DSP program spending impacts driven by this Plan. KWHI plans to continue monitoring for any category spending changes due to the Plan's implementation. Note that

[4] https://www.wilmot.ca/en/doing-business/resources/Documents/Official_Plan/OPText.pdf

since 1995 KWHI has been undertaking a 27.6kV conversion program in Wilmot Township and this will be continuing over the forecast period. However, this work has been ongoing and is not associated with the Wilmot Plan.

2.1.1.2 Key Challenge: Infrastructure Development

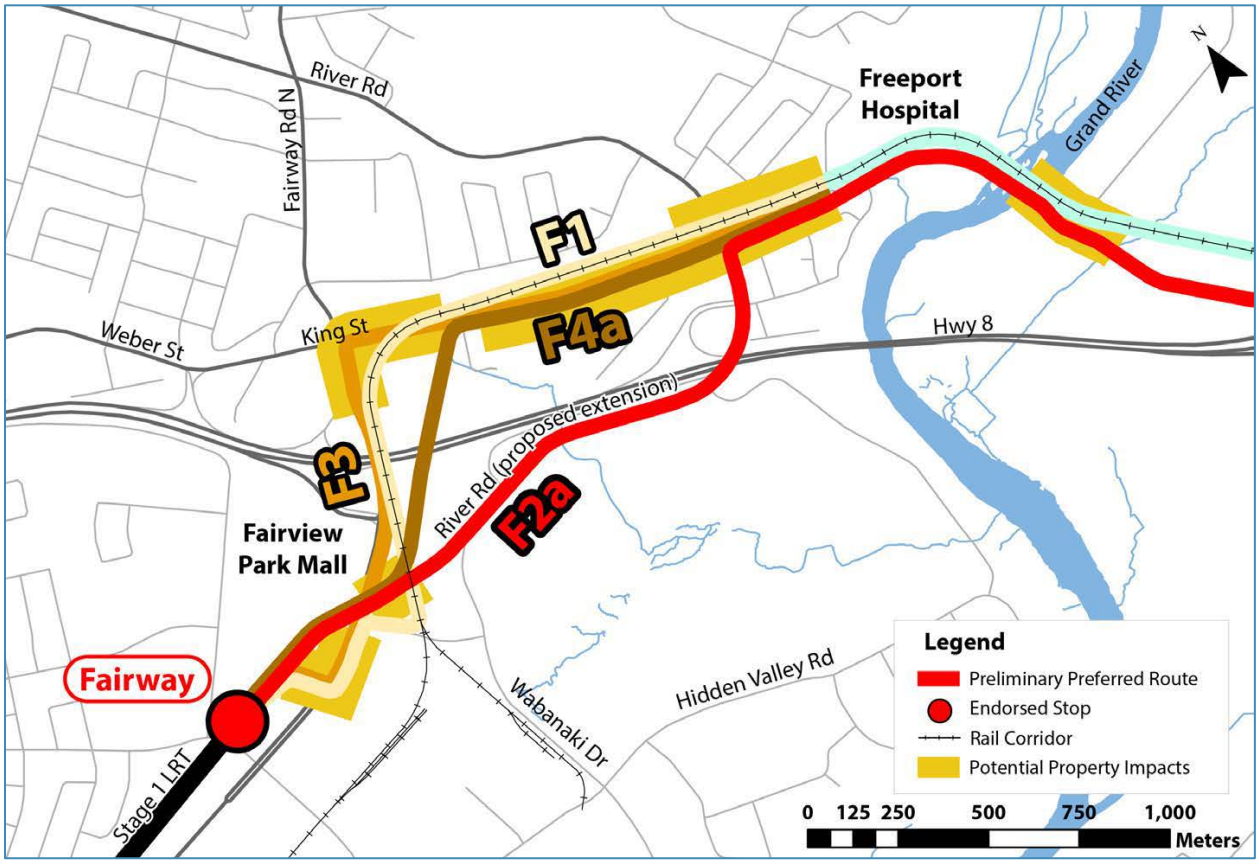
Kitchener LRT (Stage 2)

The Region of Waterloo's light rail rapid transit (LRT) service, which was approved by Council in June 2011, is a plan that is designed to help shape the community for the future, by bringing LRT to the region in two stages. Stage 1 includes a 19-kilometre LRT route from the Conestoga Mall transit terminal in Waterloo to the Fairview Park Mall transit terminal in Kitchener. Stage 1 of the Kitchener LRT project (from Waterloo to Kitchener) was completed in 2017. KWHI had significant electrical infrastructure relocation work undertaken in Stage 1, ranging from relocation of poles to complete rebuild of below-grade network transformer vaults with size up to 11' W x 22' L x 10' H. KWHI's relocation work began in 2013 and wrapped up in late 2017 with an estimated overall cost of $27M. The earliest Stage 2 of the Kitchener LRT project (from Kitchener to Cambridge) is expected to start is 2022. This will see the Region replace the Kitchener to Cambridge Bus Rapid Transit (BRT) line with LRT that will require some relocation of KWHI's existing distribution plant.

DSP IMPACT

In comparison to Stage 1, only a small part of the Stage 2 route will traverse KWHI service territory. LRT construction will require road widening and relocation of utilities including KWHI plant. The Region recently approved the preferred route for Stage 2 (see Figure 2.6) and is currently conducting an Environmental Assessment. While there are no firm plans for the commencement of Stage 2 it is anticipated that construction would commence within five to ten years of Stage 1 going into service, provided that funding is available. This will require KWHI to commence relocation works prior to the Region's contractor starting construction of the railway. Based on the approved preferred route, there will be impact on underground feeder cable and duct structures near KWHI's No. 7TS and pole line along King St. East. At this time, no expenditures for LRT Stage 2 relocation have been included in the 5-year forecast period.

Figure 2.6: Stage 2 Preferred LRT Route in Kitchener



City of Kitchener, Wilmot Township, and MTO Road Projects

The City of Kitchener, Township of Wilmot, and Ministry of Transportation Ontario (MTO) has ongoing road rehabilitation and widening projects some of which may require the relocation of KWHI plant. There are approximately 20 road widening projects scheduled for 2020.

DSP IMPACT

The current road project schedule has a limited impact on System Access spending in the DSP. Future changes to the road schedule, within the period of the DSP, may require reallocation of resources to System Access spending from other capital investments.

Waterloo Region Road Projects

Waterloo Region has ongoing road rehabilitation and widening projects most of which will require the relocation of KWHI plant.

DSP IMPACT

Current road project schedule has significant impact on System Access spending in the DSP. Regional roads tend to have distribution pole lines with multiple circuits on them. Future changes to the road schedule, within the period of the DSP, may require reallocation of resources to System Access spending from other capital investments.

2.1.1.3 Key Challenge: System Loading

Station Loading

KWHI's station loading indicates that there is sufficient capacity to accommodate growth over the period of the DSP.

DSP IMPACT

No extraordinary station related System Service spending to accommodate growth over the forecast period is included in the plan. Prioritized and paced System Renewal spending is planned to be undertaken over the forecast period to maintain station reliability performance.

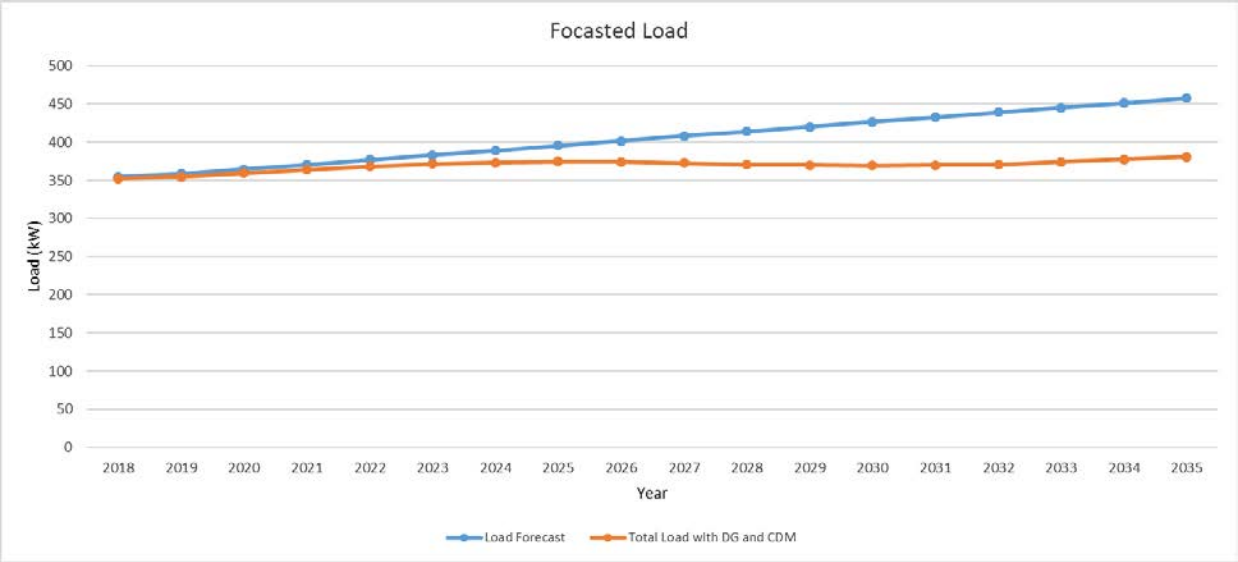
KWHI Peak Demand Forecast

KWHI's peak demand is forecasted to grow by 6% over the 2018 – 2024 period as noted in the Kitchener – Waterloo – Cambridge – Guelph (KWCG) Regional Infrastructure Plan (RIP). This represents an average annual growth rate of 0.85%, see Table 2-3 and Figure 2.7. The forecast values in the table below are based on the best available information at the time when the load forecast was prepared. The annual percentage growth is expected to be in line with the forecast as identified within the Needs Assessment Report (Appendix C).

Table 2-3: Peak Demand Forecast (kW)

Year	2019	2020	2021	2022	2023	2024
Total Load	358.65	364.47	370.69	376.91	383.13	389.35
DG combined	0.82	0.82	0.82	0.82	0.82	0.82
CDM combined	3.06	3.88	6.11	7.77	10.64	14.99
Net Load	354.76	359.77	363.75	368.32	371.66	373.54

Figure 2.7: Peak Demand Forecast (kW)



DSP IMPACT

System Access and System Service needs are expected to be relatively steady over the forecast period. This helps KWHI to properly plan and select projects for the forecast period, preventing deferrals. In the past, KWHI experienced significant number of deferrals of other projects to

accommodate System Access projects. This resulted in a lack of investment in the remaining OEB categories. With the current expectation and forecast, KWHI projects avoiding making significant project deferrals within other categories.

2.1.1.4 Key Challenge: Deteriorating Assets

Due to KWHI's efforts to prolong the lifetimes of its installed assets in order to moderate any increases in its customers' bills, the distribution system has evolved into an array of equipment of different vintages spanning several technological eras. Funds were not spent on replacing functioning equipment to simply have more modern technologies in place. KWHI has identified a need to proactively manage the replacement of assets that are at, or near, end of life. Age and deteriorating conditions are beginning to affect reliability performance, demonstrated by the increase of outage counts on account of defective equipment. Replacement plans covering a multiyear period have been developed to begin dealing with key assets at end of life. Replacement plans ensure that planning objectives related to reliability, customer satisfaction and operating cost control are achieved.

DSP IMPACT

It is recognized that System Renewal investments' greater degree of discretion as to timing for execution and annual program spending is a trade-off between the risk of outages due to equipment failure and maintaining current levels of reliability. KWHI's objective is to ensure that the future distribution system is designed to deliver power at the quality and reliability levels desired by customers and to minimize the lifetime cost by balancing preventative maintenance, life-extending refurbishment, and end-of life replacement. In this DSP, System Renewal spending is paced throughout the forecast period of the DSP to accommodate annual spending variances in the other investment categories to maintain overall budget envelope spending. While continuing the progress of replacing end of life assets in a timely and cost-effective manner, KWHI believes it can maintain current levels of reliability. In short, the system is projected to meet the customers' needs for quality and reliability of power at a reasonable and affordable cost to customers.

2.1.1.5 Key Challenge: Continuous Business Requirements

KWHI Asset Management Strategy

The Asset Management Strategy is based upon KWHI 's Corporate Strategic goals with respect to Asset Management which are:

- plan expansion of the transformation and distribution systems to meet the electrical needs of customers;
- continue to refurbish aging plant facilities; and
- continue to reduce system outages.

The strategy considers the following in developing the Asset Management Process:

- opportunities for improved efficiencies;
- activities should demonstrate good stewardship in the long term up-keep of the distribution system;
- service delivery should be safe, fair and consistent within all customer groups;
- measures to improve performance should demonstrate progress towards and/or achievement of the goals within reasonable budget considerations;
- maintenance plans should be consistent with good utility practice but capture specific items from the annual assessments and any specific customer needs;

- capital budgets should justify proposed expenditures and be flexible to respond to new priorities and extended life expectancies;
- recommendations from the strategy should provide placeholders in the Capital Expenditures Program; and
- annual reviews of the strategies and procedures should be a priority.

Asset management is not viewed as a static end product, but an evolving discipline. As such, it is expected that the Asset Management Strategy will evolve over time.

DSP IMPACT

The Asset Management Strategy is the guide to developing KWHI's Asset Management Process which together with the Capital Investment Plan forms the DSP. It allows for KWHI to create and prioritize projects that will effectively develop KWHI's business, improve existing processes and update KWHI's asset management.

OEB 2015 CDM Guidelines

The guidelines were issued in December 2014 and reflect the OEB's expectations with respect to coordination and integration between electricity and natural gas and putting conservation first into distribution planning. KWHI is expected to achieve 105.71GWh of CDM savings in the 2015 – 2020 period.

DSP IMPACT

CDM savings are expected to impact net load growth on the system. Targeted savings are not expected to have a significant impact on DSP category spending during the forecast period.

Business Conditions

KWHI is the largest of three electrical distribution companies within the Regional Municipality of Waterloo and serves an area of approximately 405 square kilometers that is 1/3 urban and 2/3 rural. Waterloo Region has a diverse economy that is home to a mix of high-tech businesses, commercial and retail operations and manufacturing companies. In Kitchener, residential and commercial growth has been steady for many years and continues to be stable. The manufacturing sector, however, has been in decline for several years now, especially since the downturn in 2008. The number of Large Use customers has declined from 4 to 1 in 2017 which has contributed to lower consumption and lower demand in recent years. The resulting loss of employment has been a challenge, especially for older workers. There are new opportunities, however, for young workers with the right skills in the high-tech sector as the traditional manufacturing economy in Kitchener is being transformed into a new, modern knowledge-based economy. The new businesses are typically smaller in size and much less energy intensive than the manufacturing businesses that they replaced, but are very sensitive to power outages. They also prefer to locate downtown with other similar businesses, which require additional new supply that is extremely reliable.

DSP IMPACT

Expected growth in general service categories are not expected to require significant System Service investments over the DSP forecast period. No new stations are proposed in the forecast period. Some feeder extensions and reconfigurations are required in the forecast period to access available capacity for growth servicing. Smart grid activities such as line monitoring, feeder hardening and installation of automated switches and reclosers are forecasted to continue in order to meet the expectation of high reliability.

2.1.2 Overview Customer Preferences and Expectations (5.2.1b)

Understanding and responding to the preferences of KWHI's customers has been and continues to be the focus of KWHI's efforts in developing short and long-term plans. KWHI uses a variety of activities to engage customers and determine their preferences for the development of KWHI's distribution system going forward. This aids in investment decision making. KWHI has noted that customer consultation is challenging for some issues, due to their complexity, however the customers do appreciate the opportunity to be heard especially on issues of a local nature.

KWHI surveys cover residential, small commercial and large commercial customers, which provides a high-level assessment of customer preferences with respect to service reliability and operational effectiveness. In 2018, KWHI engaged Innovative Research Group (INNOVATIVE) to conduct a survey of its customers preferences and feedback on the proposed DSP and capital plans. The table below summarizes the scope of the various customer engagement activities.

Table 2-4: KWHI 2018 customer engagement activities

Customer Engagement Activity	Methodology	Customers Engaged
Low-volume focus groups	In-person	**14**
Mid-Market and Large Business Workshops	In-person	**37**
Low-volume online workbook	Online	**1,749**
Low-volume telephone surveys	Telephone	**715**
Total number of customers who participated in the engagement:		**2,515**

Overall, there does not appear to be a gap between the services that KWHI is currently providing and the services that customers expect. However, there is an opportunity for KWHI to improve its role as a business partner amongst larger business customers. Distribution rates continue to be the top priority for low-volume customers and an important priority for larger business customers. Furthermore, ensuring reliable day-to-day electrical service remains an important priority for all customer bases.

With respect to reliability, low-volume customers are consistent on priorities such as reducing the number and length of outages and improving restoration times during extreme weather. Whereas mid-market and large business customers appear to prioritize reliability over price, with a focus on power quality and communications during outages to assist with operational planning.

Residential and small business customers are generally split on KWHI's approach to planning for the next five years, however, are consistent in supporting KWHI's approach to pacing investments, including keeping spending consistent year-over-year to reduce bill impacts.

Regarding KWHI's capital plans, low-volume customers are strongly supportive of accelerating the speed in which poles and power transformers are replaced, as well as the installation of more automated switches and software. There is strong support for accelerated pole replacement and this resonates with most residential customers. A strong support among majority of residential customers is also present for KWHI's accelerated transformer replacement program. With respect to System Service investments, low-volume customers are generally split on grid modernization investments. In the context of reducing outage lengths through automated switches, there is support on for KWHI's

proposed approach. Mid-market and large business customers appear to be more supportive of investments that directly improve services for their organization, rather than system-wide improvements.

Overall, there is strong support for KWHI's proposed plan, or even one that exceeds current spending levels in order to improve service levels further. A larger population of residential customers feel that KWHI should be spending more, rather than spending less. As previously mentioned, small business customers are generally less supportive of a plan that spends beyond what's currently proposed and believe KWHI should spend less compared to spend more. Mid-market and large business customers trust KWHI, however, expect to understand how the DSP specifically impacts them.

Survey results inform the asset management plan considered in the development of the asset management strategy, objectives and initial stages of annual plan development. KWHI considers all customer feedback and preferences in determining the pacing of its investments and in optimal selection of projects. Furthermore, KWHI has been prudent when incurring costs since customer satisfaction survey results indicate that the low price of electricity is an important factor to customers.

Appendix D contains the detailed results from KWHI's efforts in engaging with the customer in identifying their needs and preferences. Projects in response to customer preferences are highlighted in Section 4.1.3.3.

2.1.3 Anticipated Sources of Cost Savings (5.2.1c)

KWHI's planning and investment processes follow Good Utility Practices (GUP) that are communicated through the DSP. GUP have inherent cost savings through sound decision making, thoughtful compromises, right timing and optimum expenditure levels. This includes adhering to the OEB's Distribution System Code that sets out both GUP, minimum performance standards for electricity distribution systems in Ontario, and minimum inspection requirements for distribution equipment. Consistent with good practices, over the years KWHI has maintained its equipment in safe and reliable working order and, only when economically justified or asset management objectives are met, upgraded or replaced its equipment. Consistent maintenance of its equipment has permitted KWHI to, in some circumstances, extract an extended useful working life from certain assets (i.e. painting distribution transformers, overhead switch maintenance, etc.). Historically, this has been achieved with only a moderate increase in the customers' bills.

Most cost savings achieved during the forecast period are based on existing practices such as the following:

- Plant relocation related to road authority work will be coordinated with City of Kitchener/Region and other utility work schedules to ensure that plant is not replaced prematurely and then replaced again shortly afterwards. Savings are built in to the forecast amounts.
- Asset condition inspections and comprehensive data collection provides a better understanding of each asset's stage in its lifecycle which will lead to more cost-effective decisions with respect to maintenance, refurbishment and replacement decisions. Savings are built in to the forecast amounts.
- Proactive maintenance and replacement of plant reduces reactive maintenance costs and improves service to the customer, resulting in fewer and shorter duration outages, which in turn has a beneficial impact on the cost of outages to customers. A structured program will also smooth out financial rate impacts in an effort to avoid disruptive rate spikes when addressing the volume of plant reaching end of life. Savings are built in to the forecast amounts.

- Improved use of the Geographic Information System (GIS) to capture/access plant attribute data (i.e. nameplate data, condition, inspection/maintenance histories, etc.) are expected to aid in cost control through the provision of the most up-to-date asset information available to engineering and operations staff in their long- and short-term decision making. Savings are built in to the forecast amounts

- Prudent investment in distribution automation such as SCADA-controlled switches and network monitoring as part of Smart Grid development are expected to improve situational awareness, shorten response time, reduce truck rolls and outage restoration times, thereby mitigating customer outage costs. The anticipated savings are built in to the forecast amounts.

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

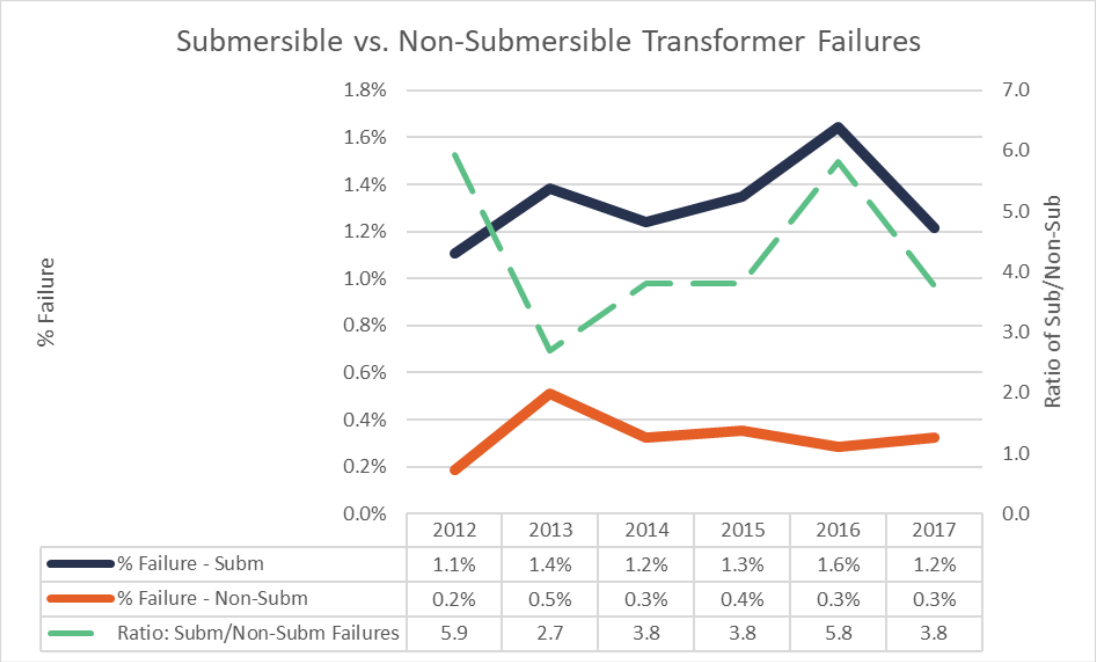
- Over the last seven years, KWHI has implemented a training matrix to provide Design Technologists with the skills and competencies required to perform designs in all three major areas of Overhead (O/H) distribution, Underground (U/G) distribution and Service connection. This has resulted in a shift from specialist designers to designers who are multi-skilled. The engineering department is now able to optimize design effort and resources, because each designer can perform design in each functional area (O/H, U/G, Services). If one area has a higher work volume than others, resources can be shifted as needed. In the past, KWHI would have had to allocate significant overtime for the specialists in the areas where there is high volume of workload. Evidence of cost avoidance resulting from this effort can be seen in the area of capital projects design. KWHI's capital program, for the areas where engineering has responsibility, has increased from $11.6M to $21.8M over the last seven years (2010 – 2016), while the same engineering staff complement with very little outside consulting has been used to implement these designs. Savings are built in to the forecast amounts.

- Voltage conversions in the Wilmot service area (8.32kV to 27.6kV) will ensure long term reliability is maintained at current levels. Conversions will reduce station maintenance needs and lower line losses, provide additional capacity for distributed generation connections and in some cases, improve power quality. Eventual elimination of 8.32kV plant will reduce the need to stock parts/equipment specific to that voltage class, leading to supply chain and inventory efficiencies. Coordination with the pole replacement program is maintained in order to reduce overall installation costs. Poles at the end-of life in a designated conversion area, prior to the conversion being scheduled, will be replaced with new poles and hardware, capable of accommodating higher voltage lines when the conversion takes place. Savings are built in to the forecast amounts.

- KWHI's proposed shift from single phase submersible to single phase pad-mounted transformers in new residential subdivisions will introduce cost savings. KWHI has been using single-phase submersible transformers for servicing residential subdivisions for more than 40 years. While most local distribution utilities have adopted pad-mounted transformers for underground residential distribution service, KWHI continued to use submersible transformers mainly because of aesthetical considerations and the ensuing demand from developers. However, the failure rate of submersible transformers continues to be significantly higher than that of other units (approximately four times higher as seen in Figure 2.8) and the cost of installation is also up to 40% higher for submersible units. Coupled with the higher failure rate is also longer duration to replace a submersible transformer (typically six hours) when

compared to a pad-mounted transformer (typically three hours). Beginning in January 2020, KWHI will begin installing pad-mounted transformers in all new residential subdivisions instead of submersible transformers. Existing in-service submersible transformer locations that fail will be evaluated on a case by case basis and may result in a like-for-like replacement or reconfiguration to a pad-mount transformer. Savings are built in to the forecast amounts.

Figure 2.8: Failure comparison between Submersible & Non-Submersible Transformers



	2012	2013	2014	2015	2016	2017
% Failure - Subm	1.1%	1.4%	1.2%	1.3%	1.6%	1.2%
% Failure - Non-Subm	0.2%	0.5%	0.3%	0.4%	0.3%	0.3%
Ratio: Subm/Non-Subm Failures	5.9	2.7	3.8	3.8	5.8	3.8

- Utilities Standards Forum (USF) Collaboration – USF is an organisation consisting of 52 Ontario LDCs that pool resources and ideas in the areas of Engineering and Operations, Regulatory and IT program management. KWHI became a member of USF in January 2017. Since joining the organisation, KWHI has realised savings in the form of standards development – primarily in the area of cyber security. KWHI has also realised savings through a volume purchase agreement negotiated by USF on behalf of its members with four IT security management service vendors. KWHI anticipates realizing cost savings moving forward with its continued work with USF.

- GridSmartCity Collaboration - KWHI is a proud member of the GridSmartCity Consortium. The Consortium is made up of 30 partner organizations, including local distribution companies, commercial entities, and academia. Thirteen local distribution companies (LDCs) have come together to form the GridSmartCity Cooperative to share resources, insights and systems in several key areas to help the members run smarter companies and advance innovation, reliability, and efficiency across Ontario's electricity grid. Since being established in 2009, the GridSmartCity Cooperative has achieved the following:

    - Established a formal cooperative purchasing function to consolidate volumes and reduce inventories and costs
    - Realized $500,000 in annual savings on poles, cables, wires, and transformers
    - Realized $2M dollars in cost savings from benefits and insurance

Finally, KWHI notes that according to PEG's July 2017 Enhanced Benchmarking Model[5] published by the OEB, KWHI already ranks at 20% better level of efficiency compared to the model's predictions. According to the model, KWHI is an above-average cost performer.

2.1.4 Period Covered by DSP (5.2.1d)

The planning horizon for this DSP covers eleven years with a six-year historical period of 2014 to 2019, where 2019 is the Bridge Year, and a five-year forecast period of 2020 to 2024, where 2020 is the Test Year.

2.1.5 Vintage of the Information (5.2.1e)

All asset inspection/condition assessment data is current per the inspection intervals described in the Asset Management Process.

Unless otherwise noted, all information contained in the DSP is current as of December 31, 2018.

2.1.6 Important Changes to Asset Management Processes (5.2.1f)

This is the first DSP filed by KWHI, and as such, there are no changes from any previously filed plan.

2.1.7 DSP Contingencies (5.2.1g)

There are several ongoing and future activities in the KWHI service areas that may impact on capital project prioritization and spending as outlined in the DSP.

Customer Connections

Customer connection forecasts are based on timing information received from City and Township Planning staff, planning reports (provincial, regional, municipal), developer submissions and inquiries, and historical connection rates. Variances in connection timing/quantity over the period of the DSP will impact on actual connections and related System Access expenses.

Kitchener – Waterloo – Cambridge – Guelph Region Supply Study

KWHI is participating in the Kitchener-Waterloo-Cambridge-Guelph (KWCG) Supply Study. An Integrated Regional Resource Planning (IRRP) Report was published in April of 2015 and a Regional Infrastructure Plan (RIP) was issued in December 2015. The IRRP report indicates that the system supplying the KWCG Region is approaching maximum capacity and that it has limited ability to minimize potential interruptions to customers. The report includes several additional near/medium-term recommendations for areas within the Region but outside KWHI's service area.

At this time, KWHI's DSP as filed assumes that the IRRP medium term needs will not significantly impact the investment levels forecasted in this DSP.

Municipal (Region, City, Township) Road Projects

The Region, City and Township carry out road resurfacing and other types of roadway improvements on an annual basis. Timing and location for these works are subject to short-term planning considerations, and as such, are frequently rescheduled. KWHI will be required to accommodate and react to these road projects as they occur during the period of the DSP.

[5] https://www.oeb.ca/sites/default/files/PEG_Benchmarking_Report_2017.pdf

Waterloo Region LRT

Stage 2 of the LRT is expected to commence within five years of the Stage 1 being put into service. Once the preferred route is finalized, Environmental Assessment (EA) report approved, and funding is finalised, KWHI will likely be required to relocate its existing plant situated along the approved route. An expected time period cannot be provided at this time since the amount of work to be executed will be dependent on the LRT project's finalized scope details and completion schedule.

Municipal Approvals – UG cable replacement

The asset inspection program has identified the need to replace end-of-life underground distribution cable through a multi-year program of spending that has been detailed in this DSP. The timing for annual individual cable replacement projects comprising this program is contingent upon receiving timely municipal approvals for related excavation work. Furthermore, cables will be subjected to testing to identify alternative solutions to underground cable replacement. Projects will be identified and prioritized for execution through the budget process and communicated to the Municipality to ensure optimal coordination of effort between KWHI and the Municipality.

Meter reverification

KWHI is required to have its residential revenue meters tested on a periodic basis, to ensure compliance with Measurement Canada standards. In 2019, approximately 23,500 of KWHI's electronic residential meters will require testing by Measurement Canada compliance sampling methods. If the units pass the sample testing, their seal period would be extended, and they can remain in service for the number of years determined by the statistical sampling process. If the units fail sample testing, they would have to be removed from service and replaced by the end of the year they are sampled in. KWHI's planning assumption is that the meters should pass compliance sampling. However, failure to pass the tests would result in an unbudgeted capital expenditure in the order of $3,750,000. This accounts for only 23,500 meters that would need to be addressed in 2019. The total unbudgeted capital expenditure for the full forecast period would be in the order of $4,858,000.

There will be smaller volumes of meters requiring testing and reverification in the 2020 – 2023 timeframe of the DSP. Meter year of testing, quantity and potential replacement costs are shown in the table below:

Table 2-5: 2019 – 2023 Meter reverification program

Test Year	Quantity of Meters	Approx. Cost to replace
2019	23,500	$3,750,000
2020	1873	$211,000
2021	896	$101,000
2022	4673	$706,000
2023	796	$90,000
Total	**31,738**	**$4,858,000**

The DSP assumes that the meters will successfully pass reverification testing.

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

There are several ongoing and proposed projects that KWHI is undertaking to address grid modernization, DERs integration and climate change adaptation. Addressing these activities will improve service offerings and quality to our customers and aligns with some of the goals and objectives identified in the Ontario's Long-Term Energy Plan 2017: Delivering Fairness and Choice

(LTEP). KWHI's approach to these activities include proactive measures such as rebuild opportunities. The following activities are being undertaken at KWHI:

Installation of automated switches (reclosers) – proactive feeder sectionalizing to address high priority areas with reliability and or access issues. Expected to improve the efficiency of outage restoration work on the parts of the system enabled with this equipment. This activity aligns with the LTEP goal of "*Improving Value and Performance for Consumers*" and the OEB directive to "*Strengthen Utility Accountability to Customers*".

Installation of Line Sensors – KWHI continues to monitor the performance of recently installed line sensors to determine the feasibility of a larger scale implementation. Line sensors are used to provide instantaneous situational awareness of the distribution system (current, voltage, vars, harmonics, etc.) and provide location data to help identify faults. The costs and installation of line sensors is a component of the Innovation and Reliability program. This activity aligns with the LTEP goal of "*Innovating to meet the Future" and the OEB* directive of "*Cost-Effective Modernization*".

Communication Networks – communication networks represent the backbone of all smart grid systems. KWHI continues to build and expand its communication network to facilitate data acquisition from smart meters, line sensors, capacitor banks and automated reclosers. The communication network is a combination of private and public infrastructure. There is a licensed and unlicensed 900 MHz radio network, leased fibre optic network and a leased private cellular network. This activity aligns with the LTEP goal of "*Innovating to Meet the Future*" by deploying communication technology necessary to monitor the grid.

Storm Hardening – KWHI employs proven storm hardening techniques such as installing stainless steel equipment for below grade applications, moving below grade equipment to above grade (where possible) where flooding is a possibility, design to CSA Heavy Loading conditions, and utilize stronger poles in construction. This activity aligns with the LTEP goals of "*Ensuring a Resilient Energy Supply*" and "*Improving Value and Performance for Consumers*".

Voltage Conversion – upgrading of 8.3kV system to 27.6kV to increase load transfer capability and allow higher penetration of DERs. This activity aligns with the LTEP goals of "*Ensuring a Resilient Energy Supply*" and "*Ensuring a Flexible Energy System*".

Replacement of obsolete assets – grid modernization effort to remove assets that no longer meet KWHI's design standards. Removing these assets will support reliability performance, resiliency and operational efficiency, while reducing KWHI's procurement and spare inventory costs through standardization of equipment. This activity aligns with the LTEP goal of "*Ensuring a Resilient Energy Supply*".

Collaboration with Energy Storage Provider – KWHI has worked with Hecate Energy to install a 2MW capacity battery energy storage system at Kitchener No. 5 TS. KWHI's motivation for the project is to understand the impacts of DERs, such as energy storage impact on the grid. Upon complete implementation, further analysis and studies will be done to determine feasibility of adoption of this technology to aid in deferral of equipment capacity upgrades, DG facilitation, grid regulation and power quality support. This activity aligns with the LTEP goal of "*Innovating to Meet the Future*" by using energy storage technology.

2.2 COORDINATED PLANNING WITH THIRD PARTIES (5.2.2)

2.2.1 Summary of Consultations (5.2.2a)

In preparing this DSP, KWHI has considered the Integrated Regional Resources Plan (IRRP) as well as the needs of its customers, the Municipality, HONI and the IESO. This DSP considers the outcomes

of completed consultations, reports and plans and KWHI intends on continuing coordination efforts with third parties. The following sections describe the third-party consultations KWHI participated in.

2.2.1.1 Customer Consultations

KWHI considers the customer as a partner in the development and evolution of the utility and with this concept as a backdrop, KWHI is developing and facilitating a bi-directional conversation with the customer to ensure a mutual understanding that goals, objectives and preferences are met.

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

KWHI has been a valued member of the community for over 100 years. KWHI is proud to give back to its community, where its employees work and many live.

Here are some of the ways KWHI is giving back to its community:

- As Visionary Partners with the Waterloo Region Museum
- As sponsors with the Children's Safety Village
- Through free electrical safety workshops for local students
- Through funding for the Waterloo Region Energy Assistance Program
- Through employee donations to the United Way, Strong Start and other charitable organizations
- Through sponsoring of two academic grants at Conestoga College

RESIDENTIAL CUSTOMERS

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

- Person to person communication;
- Inserts in hydro bills;
- Website interaction;
- Community meetings and events; and
- Surveys.

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

KWHI's customers can access their accounts 24/7 to view energy consumption which is updated nightly via smart meters and check their account balance and payment history.

KWHI participates in several community events throughout the year, raising awareness of conservation and promoting discussion about infrastructure investment.

KWHI conducts customer satisfaction surveys on a regular basis. Surveys show that the customers are very satisfied with KWHI's service. KWHI reviews the survey results to determine if adjustments to corporate programs and strategies are warranted. KWHI last completed a Customer Satisfaction Survey in 2017, and the survey results are discussed in section 2.3.1 and 4.1.3.

COMMERCIAL CUSTOMERS

Planning and consultation are conducted with commercial customers on a regular basis, primarily to engage and promote participation in CDM programs and the IESO FIT/microFIT programs. In addition to this, KWHI uses this opportunity to discuss power quality, other reliability issues and future system planning.

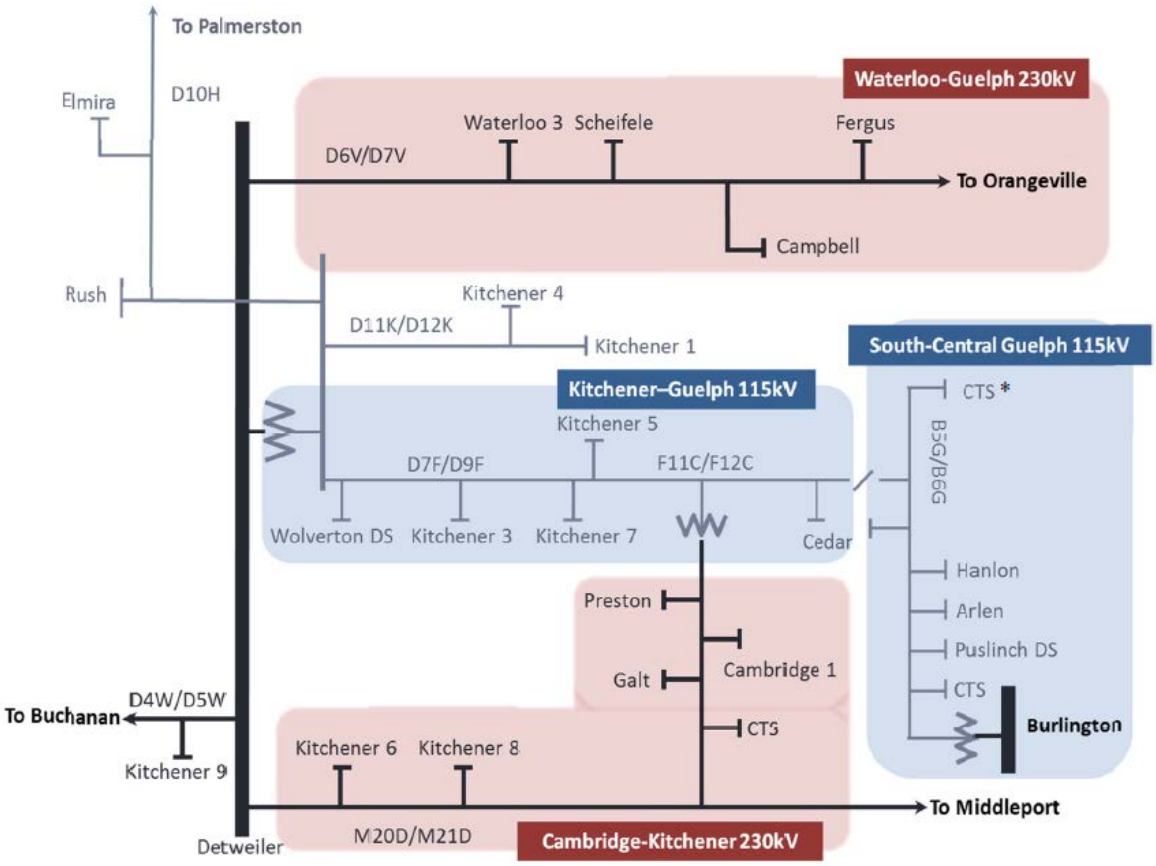
In general, customer engagement supports the DSP's focus of maintaining existing reliability and service levels through prioritized and paced investment plans that smooth and mitigate impact to rates.

2.2.1.2 Transmitter Consultations - Hydro one Networks Inc. (HONI)

KWHI owns and operates its own Transformer Stations (TS) which are connected to HONI's Transmission System. KWHI is considered transmission connected. It is not an embedded utility. It currently has eight TS that provide service to the area, as listed below and shown in Figure 2.9.

- Kitchener No. 1 – D11K, D12K (115 kV)
- Kitchener No. 3 – D7F, D9F (115kV)
- Kitchener No. 4 – D11K, D12K (115 kV)
- Kitchener No. 5 – F11C, F12C (115 kV)
- Kitchener No. 6 – M20D, M21D (230 kV)
- Kitchener No. 7 – D7F, D9F (115 kV)
- Kitchener No. 8 – M20D, M21D (230 kV)
- Kitchener No. 9 – D4W, D5W (230 kV)

Figure 2.9: KWCG Service Area Network



Either KWHI or HONI can initiate the consultations between both entities. KWHI consults regularly with HONI on several issues including:

- Regional Planning
- REG and FIT application screening
- Transmission station outage scheduling and switching
- Joint use on poles
- Mutual assistance during extreme weather events

The Regional Infrastructure Planning (RIP) was completed with HONI in late 2015, with a RIP report issued in December 2015 (Appendix E). KWHI was a member of the working group and was an active participant in the process. The purpose of the RIP process is to develop an electricity infrastructure plan (wires solutions) to address needs identified in previous planning phases of the IRRP, and any additional needs identified based on new and/or updated information provided by the RIP Working Group. The RIP report considered near-term (up to 5 years) and mid-term (5 to 10 years) needs. Three major investments were identified during the RIP process. These are:

- The Guelph Area Transmission Reinforcement (GATR) project;
- The second Preston auto-transformer project; and
- M20/M21D – Install 230 kV In-line Switches.

The anticipated impact of the above projects on KWHI's distribution system is to increase reliability and power transfer capability at the transmission level. The costs associated with these projects do not have any direct implication on KWHI's DSP investments. These costs are borne by HONI and considered as transmission Network Pool costs.

2.2.1.3 Municipality Consultations

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

The City is mature and stable with respect to growth and development, citing a projected growth rate of 0.9% per year for the forecast period. New residential subdivisions are added to the city and township regularly. Commercial growth has been consistent with the growth pace of residential developments. However, the construction of the LRT system has resulted in an upswing in commercial activities along the LRT route.

KWHI consults with the Public Utilities Coordinating Committee (PUCC) for underground plant location led by the City of Kitchener. The PUCC meets and discusses capital plans with all member utilities monthly. PUCC membership consists of local representatives from the municipal, electricity, gas and telecom sectors.

These consultations may provide information that may impact System Access investments in the forecast period. However, the impact that may be seen will only be captured on an annual basis once the municipality has identified potential growth. These investments would be considered non-discretionary as they would be new connections. Information that can be acquired from these consultations would be incorporated into the DSP investment plan an on annual basis.

2.2.1.4 Metrolinx Consultations

Metrolinx plans to electrify core areas of the GO Transit rail network, including a portion of the Toronto-Kitchener line. Present plans call for the line to be electrified from UP Express Spur (at Highway 427) to Bramalea. Currently there are no plans to electrify the remainder of the line to Kitchener. When that occurs, the electrification plans would impact KWHI in several ways, including:

- Any new stations planned in the KWHI territory will have servicing impacts and plant relocation impacts;
- Any rail crossings will likely require rebuilding (bridges or tunnels) resulting in plant relocation/replacement to achieve minimum clearance standards over the proposed 25kV catenary overhead contact system along the rail corridor; and
- Current utility agreements with the rail companies owning the crossings require that the utility pay 100% of their plant relocation costs.

There has been no consultation so far, as no plans have been proposed yet by Metrolinx on road crossing works, new passenger station(s), switching stations, etc. Therefore, the specific future cost impacts to the DSP are unknown.

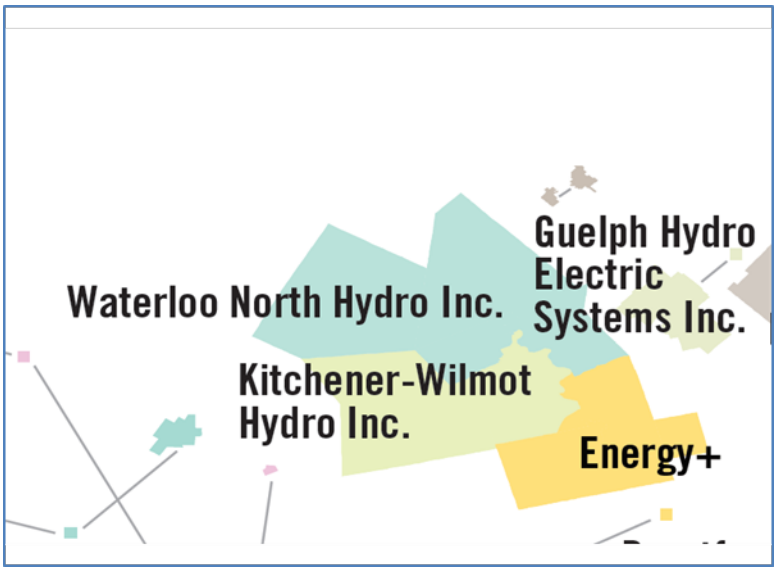
2.2.1.5 Distributor Consultations

KWHI consults with its neighbouring utilities on various matters, such as joint use on poles, mutual assistance during severe weather incidents, sharing of information to resolve common issues (engineering, operations and regulatory), Long Term Load Transfer (LTLT) resolution, etc.

KWHI has the following neighboring utilities:

- Waterloo North Hydro (WNH)
- Energy +
- Guelph Hydro
- HONI

Figure 2.10: KWHI and neighbouring LDCs



KWHI currently participates in a bi-annual engineering and operation regional information sharing session with WNH, Energy+, and Guelph Hydro. Additionally, consultations may be initiated by KWHI or a neighboring utility, depending on the nature of the items to be discussed. As an example, assistance consultation to recover from a severe storm is generally initiated by the utility requiring assistance. Current utility consultations are not expected to have an impact on the DSP investment plan with no final deliverables expected.

2.2.2 Regional Planning Process

KWHI is a member of the Kitchener – Waterloo – Cambridge – Guelph (KWCG) Regional Planning Group which includes the municipalities of Kitchener, Waterloo, Cambridge and Guelph, as well as portions of Perth and Wellington counties and the townships of Wellesley, Woolwich, Wilmot and North Dumfries. From a HONI and IESO perspective, KWCG Region is located within the Group 1 Region.

The IESO recently concluded (April 2015) an Integrated Regional Resource Planning (IRRP) process with the KWCG Working Group. The IRRP process was initiated and led by the IESO to assess the reliability needs within this region and develop an integrated plan for the appropriate mix of investments to address electricity needs over the medium and long-term. KWHI has participated in all KWCG meetings with the other three LDCs as well as HONI and IESO. KWHI actively participated in the study process and provided the following information:

- Input on study Terms of Reference
- Forecast demand data
- Existing, committed and potential DG including FIT and non-FIT uptake
- Information on Green Energy and other relevant community plans
- Conservation and Demand Response programs to be included in the study
- Input to help develop options:

    - Conservation options
    - Local generation options
    - Transmission or distribution options including maximizing existing infrastructure capability
- Input towards the development of implementation plans

A needs assessment was conducted for the region in 2015. The resulting deliverable was an IRRP Report published in April of 2015 and may be found in Appendix F.

The IRRP is a 20-year plan and assesses the regional infrastructure and capacity against the IESO's Ontario Resource and Transmission Assessment Criteria (ORTAC) and identifies the forecasted needs in the near and medium terms, 0-10 years and the long term, 10-20 years. The short-term plan will most directly affect this DSP as it involves the forecast period.

The IRRP report indicates that the system supplying the KWCG Region is approaching maximum capacity and that it has limited ability to minimize potential interruptions to customers. The report tables several recommendations for the near/medium term. The report recommends that the Regional LDCs implement the 2015 – 2020 Conservation programs and continue to support provincial DG programs. Other short/medium term recommendations will be addressed by HONI, Guelph Hydro and Waterloo North Hydro.

The report did not identify any long-term supply and reliability needs within the areas. There is no impact to the DSP.

Furthermore, the first cycle of Regional Planning for KWCG Region was completed in December 2015. The following projects were completed by Hydro One to address near-term needs:

- The Guelph Area Transmission Refurbishment Project (GATR)
- The switching facilities work at Galt Junction to improve supply reliability for the Cambridge-Kitchener 230kV sub-system

The second cycle is in progress and the resulting deliverable Needs Assessment report (Appendix C) was completed in December 2018, which identifies new needs in the KWCG Region. However, it is expected there will be little or no cost implications for KWHI from the transmission projects being undertaken by Hydro One:

- Projects addressing the near-term aging infrastructure needs
- Projects to address the mid-term aging infrastructure needs

Two distribution projects addressing mid-term infrastructure needs for the LDCs, as outlined in the second cycle Needs Assessment Report, are:

- Scheifele MTS – T1 & T2 for Waterloo North Hydro
- Kitchener MTS #5 – T9 & T10 for KWHI

Hydro One's Planning Status letter is attached in Appendix G, which further describes in detail the plans for the KWCG Region.

2.2.3 IESO Comment Letter (5.2.2d)

KWHI has requested and received a comment letter from the IESO with respect to:

1. Status update on Regional Planning initiatives;

2. KWHI REG investment plans.

KWHI's report on REG Investments and the Comment Letter from the IESO are included in Appendix H. KWHI's Renewable Energy Generation Investments Plan 2017 is reasonably consistent with the IESO. Although there is a distribution grid constraint identified on one of the busses at KWHI's No. 3TS and on its secondary network, KWHI has no planned REG investments for the Plan period 2020-2024.

2.3 Performance Measurement for Continuous Improvement (5.2.3)

KWHI's corporate emphasis on continuous improvement is reflected in all areas of its operations. Like most utilities in Ontario, KWHI must replace aging distribution infrastructure to ensure the safe and reliable supply of electricity. In addition to strategic replacement of aging assets, KWHI continues to focus on core maintenance activities, such as transformer station maintenance, distribution station maintenance, and vegetation control, to reduce the disruption of electricity distribution to customers. KWHI focuses on short and long-term planning to ensure sufficient system capacity is available, and contingencies are in place should there be a loss of critical distribution infrastructure.

Monitoring system performance provides KWHI with the information required to appropriately adjust its plans or to identify remedial steps to ensure that distribution assets remain in service for the duration of their design lifespans and can serve under peak demand conditions. KWHI monitors several performance measures, including those mandated by the OEB, that may assist in the utility's continuous improvement activities and in satisfying customer requests. These measures can be divided into three general groups:

1. customer oriented performance;
2. cost efficiency and effectiveness; and
3. asset/system operations performance.

Where applicable, the performance measures included on the scorecard have an established minimum level of performance expected to be achieved. The scorecard is also used to continuously improve KWHI's asset management and capital planning process. KWHI's current performance state is represented by KWHI's official scorecard results as published by OEB. The scorecard is designed to track and show KWHI's performance results over time and helps to clearly benchmark its performance and improvement against other utilities and best practices. The scorecard includes traditional metrics for assessing services, such as frequency of power outages and costs per customer.

Each metric provided in the table and subsections below, influences KWHI's DSP to achieve the best performance for its customers. The following sections address performance metrics as published by the OEB in the performance scorecard and with additional performance metrics identified in OEB's Rate Filing Requirements. Additionally, each performance measure has KWHI's target on delivering the target within this DSP. KWHI's OEB scorecard is shown in Appendix I.

Table 2-6: DSP Performance measures for KWHI

Performance Outcome	Measure	Motivation	Metric	Target
Customer-oriented performance	Service Quality	Regulatory/ Consumer	New Residential/Small Business Services Connected on Time	95%
			Scheduled Appointments Met on Time	95%
			Telephone Calls Answered on Time	85%
	Customer Satisfaction	Customer	First Contact Resolution	95%
			Billing Accuracy	98%
			Bill Impacts	<10%
			Customer Satisfaction Survey	A
	System Reliability	Regulatory/ Customer	SAIDI	5yr Avg < 1.0
			SAIFI	5yr Avg < 1.0
			CAIDI	5yr Avg 0.75 - 1.25
			MAIFI	5yr Avg < 3.0
			Worst Performing Feeder	Monitor
Cost efficiency and effectiveness	Cost Control	Regulatory/ Customer/ Corporate	Total Cost per Customer	Historical Avg ≤+10%
			Total Cost per km of Line	Historical Avg ≤+20%
			Total Cost per MW	Historical Avg ≤+20%
			O&M Cost per Customer	Historical Avg ≤+10%
			O&M Cost per km of Line	Historical Avg ≤+10%
	Distribution System Plan Implementation Progress	Corporate/ Regulatory	Material Project Variance	+/- 20%
			DSP Progress Variance	+/- 10%
Asset/system operations performance	Safety	Regulatory/ Corporate	Level of Public Awareness	80%
			Level of Compliance with Ontario Regulation 22/04	0 NC; 0 NI
			Serious Electrical Incident Index	0
	System Capacity	Corporate	Station Loading	Peak demand ≤ nameplate
			Feeder Loading	Feeder peak load ≤ 400 amps
	Distribution Losses	Corporate	Line Losses	<5%

Annual performance variances that are not within target ranges or meet minimal performance thresholds would result in senior management review of performance cause that may result in changes to immediate or future plans to direct performance back to target levels. KWHI has been and continues to be, focused on maintaining the adequacy, reliability and quality of service to its distribution customers.

2.3.1 Customer-Oriented Performance

2.3.1.1 Service Quality

2.3.1.1.1 Methods and Measures (5.2.3a)

KWHI measures and reports on an annual basis on each of the service quality requirements set out in the Distribution System Code (DSC). Failure to meet minimum service quality targets would result in measures being taken to realign performance with DSC service quality standards. Service Quality measures includes the following major measures: New Residential/Small Business Services Connected on Time, Scheduled Appointments Met on Time and Telephone Calls Answered on Time. Additional sub-measures are tracked as part of the DSC requirements. All these measures are self-explanatory in nature and all relate to KWHI's high quality in providing their connection services as well as their customer services. KWHI is committed to meeting and exceeding all targets found in the Service Quality performance measure group.

2.3.1.1.2 Historical Performance (5.2.3c)

Year over year, KWHI has consistently exceeded the OEB targets for service quality as part of the customer focus section of the OEB scorecard. KWHI's customer service representatives answer a varying number of phone calls per year within the 30 second window prescribed by the OEB. The overall answer rate is well above the industry targets and is indicative of KWHI's dedication to be an organization focused on customer service. Table 2-7 presents the measures and sub-measures for tracking KWHI's performance in the service quality category.

Table 2-7: Performance measures – Service quality

Measure	Sub-Measure	2014	2015	2016	2017	2018 (est.)
New Residential / Small Business Services Connected on Time		90.9%	90.3%	92.5%	98.9%	99.1%
	Low Voltage Connections	91%	90.3%	92.5%	98.9%	
	High Voltage Connections	100%	100%	100%	100%	
	Reconnection Performance Standards	100%	100%	100%	100%	
Telephone Calls Answered on Time		80.4%	78.1%	78.4%	92.8%	91.8%
	Telephone Accessibility	80%	78.1%	78.4%	92.8%	
	Telephone Call Abandon Rate	1.7%	2.30%	4.2%	0.68%	
Scheduled Appointments Met on Time		95.3%	96.2%	97.5%	97.9%	99.2%
	Appointments Met	95%	96.2%	97.5%	97.9%	
	Appointment Scheduling	88.4%	94.1%	96.4%	95.92%	
	Rescheduling Missed Appointments	100%	100%	100%	100%	
Written Response to Enquiries		100%	100%	99.9%	99.9%	
Emergency Urban Response		85%	83.90%	80.8%	94.7%	
Emergency Rural Response		100%	100%	94.7%	100%	

2.3.1.1.3 Performance Trends into the DSP (5.2.3d)

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

2.3.1.2 Customer Satisfaction

2.3.1.2.1 Methods and Measures (5.2.3a)

KWHI measures and reports on customer Satisfaction measures which include: First Contact Resolution, Billing Accuracy and Customer Satisfaction Survey Results. KWHI uses the OEB Targets for these measures and relies on their staff to meet these targets. Additionally, KWHI tracks Bill Impacts on its customers yearly.

Bill Impacts

Over 75% of a customer's bill is due to factors (i.e. generation, transmission, global uplift, etc.) outside the control of the LDC. Notwithstanding that, surveys continue to indicate that it is the overall cost of the bill, not the individual components, that are of concern to the customer.

KWHI considers the short- and long-term customer bill impacts as part of the asset management process, and bill impact mitigation is a consideration in investment planning decisions. Where possible, KWHI's forward looking asset management plans and programs are structured to smooth customer bill impacts over the years. This is especially evident in programs where the utility has a greater degree of control of investment project pacing and prioritization, such as asset refurbishment/replacement, where risk and rate mitigation inputs are considerations to program scheduling. While most of the investment scheduling can be smoothed, certain capital expenditures are lumpy in nature and these may result in expenditure volatility in a specific year.

KWHI's target for this measure is for rate impacts in residential and general service classes to remain within OEB rate mitigation guidelines.

Customer Satisfaction Survey

KWHI undertakes a customer satisfaction survey on a biannual basis to obtain feedback on the overall value of service offered to customers. The latest such survey took place in 2017. Customers (residential and commercial) are engaged to provide high level feedback on their perceptions of KWHI's performance and where they think KWHI could improve service. This information is extremely useful to help guide future investment planning that will maintain or improve customer satisfaction.

KWHI's target is to be within a (+/-) 5% than previous survey scores for the following survey metrics:

- Customer Care
- Company Image
- Management Operations
- Customer Centric Engagement Index
- Customer Experience Performance rating

2.3.1.2.2 Historical Performance (5.2.3c)

Year over year, KWHI has consistently exceeded the OEB targets for customer satisfaction as part of the customer focus section of the scorecard. When corporate and asset management objectives are aligned with OEB performance outcomes and when KWHI involves customers in discussions to understand their preferences and concerns, the result is an increased level of satisfaction.

Table 2-8: Performance Measures – Customer satisfaction

Measure	2014	2015	2016	2017	2018
First Contact Resolution	98.6%	98.9%	99.4%	99.6%	99.03%
Billing Accuracy	100%	100%	100%	99.58%	97.87%
Customer Satisfaction Survey Results	A	A	A	A	A

Bill Impacts

KWHI rebased its 2014 rates through a cost of service application in 2013. In subsequent years, Price Cap IRM applications were filed resulting in the approval of index-based adjustments to distribution rates. The annual distribution rate impacts through the historical period are shown in the table below:

Table 2-9: Performance Measure – Bill impacts (rate adjustment impacts)

Class	2015	2016	2017	2018
	Price Cap IR	Price Cap IR	Price Cap IR	Price Cap IR
Residential	1.45%	1.95%	1.75%	1.05%
GS<50	1.45%	1.95%	1.75%	1.05%
GS>50	1.45%	1.95%	1.75%	1.05%
Large User	1.45%	1.95%	1.75%	1.05%
Street Lighting	1.45%	1.95%	1.75%	1.05%
USL	1.45%	1.95%	1.75%	1.05%

Over the historical period, KWHI residential and GS customers have had an average annual rate increase of 1.72% (2015 – 2017) based on net price cap index adjustment.

Customer survey

The customer survey results over the historical period are shown in Table 2-10 below:

Table 2-10: 2012 - 2017 Customer survey results

Survey Sub-Measures	2012	2015	2017
Customer Care	A	A	B+
Company Image	A	A	A
Management Operations	A+	A	A
Customer Centric Engagement Index (CCEI)	-	85%	84%
Customer Experience Performance rating (CEPr)	-	86%	87%

The survey results indicate KWHI's customer service, care, and experience is good and is consistent annually. There was a slight drop in Customer Care in 2017 primarily due to dissatisfaction over the steep rise in electricity costs through 2016, which primarily reflected increases in charges that are not associated with KWHI's activities. The 2017 UtilityPulse Customer satisfaction survey noted an "*…angry environment towards the electricity industry as a whole, i.e., satisfaction levels and concern over costs…*".

From 2012 through 2018, KWHI scored at or higher than National and Ontario benchmarks in all three performance categories.

The CCEI and CEPr indexes, introduced in 2013, provide specific feedback on customer interaction perceptions and their engagement connection with the KWHI brand. Results have generally been consistently averaging in the mid-eighty percentile region over the historical period. KWHI's performance in this area exceeds both National and Ontario utility performance averages.

2.3.1.2.3 Performance Trends into the DSP (5.2.3d)

Bill impacts

Bill impact considerations are a key driver of KWHI's DSP development. The levelized investment plan reflected in the DSP contributes to smoothing customer bill impacts over the period of the plan and in KWHI's assessment is reasonable (within OEB mitigation guidelines). Furthermore, rate mitigation has been taken into consideration in the development of the DSP and KWHI's capital expenditure planning process through the customer engagement and feedback. The table below shows the proposed 2020 bill impact. The bill impact for 2020 is higher than previous years because of the nature of rate setting whereby during the cost of service year (2020) previous expenditures in capital are "trued-up" to set a new rate base. The next four years (2021-2024) will see bill impacts limited to the rate of inflation less a stretch factor that is approved by the Board for adjusting rates that are set using the Incentive Rate Mechanism (IRM) method.

Table 2-11: Proposed 2020 Bill impacts (rate adjustment impacts)

Customer Class	2020 Bill Impact
Residential	7.23%
GS<50	8.35%
GS>50	2.09%
Large User	7.09%
Street Lighting	-0.39%
USL	7.59%

Customer Survey Results

KWHI conducts customer satisfaction surveys on a biannual basis. Surveys show that the customers are very satisfied with KWHI's performance. KWHI reviews the survey results to determine if adjustments to corporate programs and strategies are warranted. Any significant change to program/strategies would affect the DSP. In general, customer attitudes and preferences (i.e. satisfaction with existing reliability levels) obtained from survey information has been a consideration in the development of the DSP and KWHI's asset management and capital expenditure planning process.

2.3.1.3 System Reliability

2.3.1.3.1 Methods and Measures (5.2.3a)

System reliability is an indicator of quality of electricity supply received by the customer. System reliability and performance is monitored via a variety of weekly, monthly, annual and on demand reports generated by the Supervisory Control and Data Acquisition (SCADA) system and the Outage Management System (OMS). Equipment failures are identified by root cause and reported to the Board of Directors in a bimonthly report prepared by senior managers in the Operations Department.

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

given year by the average number of customers. An interruption is considered sustained if it lasts for at least one minute.

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

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

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

In addition, KWHI calculates and tracks the Customer Average Interruption Duration Index (CAIDI) and the Momentary Average Interruption Frequency Index (MAIFI) indices. The following equations are used to calculate the mentioned indices:

$$CAIDI = \frac{SAIDI}{SAIFI}$$

$$MAIFI = \frac{Total\ number\ of momentary\ interruptions\ for\ all\ customers}{Total\ number\ of\ customers\ served}$$

When a pattern of recurring failures emerges, the Engineering Department is asked to investigate and develop a strategy for improving reliability. Surveys and day to day customer feedback indicate that the existing level of service reliability is not, and has not been, a critical issue raised by the public in the KWHI service area. KWHI continues to work proactively to monitor the power quality to ensure it does not adversely affect the customers in the service area. The previous 5 year rolling average for SAIDI, SAIFI and CAIDI (excluding LOS and MEDs) are used as default targets for reliability performance expectations in the current year.

The top 5 feeders with the highest annual MAIFI are further reviewed to determine if mitigating measures can be implemented such as animal guarding, tree trimming or sectionalizing using automated reclosers. MAIFI is an indicator of the average number of momentary interruptions each customer experienced over a certain period. This index is calculated using all planned and unplanned interruptions of less than one minute in duration. MAIFI is defined as the average number of momentary interruptions in the year.

Lastly, KWHI tracks its Worst Performing Feeders. There are no pre-defined regulatory metrics used to determine Worst Performing Feeders. In assessing feeders that contribute negatively to reliability, KWHI use the following metrics; Customer Hours Interrupted (CHI), and number of Customers Interrupted (CI). These two metrics are directly related to SAIDI and SAIFI respectively. Planned outages, Loss of Supply, and MEDs are excluded from the outage data. Abnormal feeder configurations were not excluded. Abnormal feeder configuration occurs when additional customers are temporarily added to a feeder in order to support construction or maintenance work performed on an adjacent circuit.

Beginning 2020, KWHI plans to utilize additional customer specific measures of reliability. The two measures are:

- Customers Experiencing Multiple Interruptions (CEMI)
- Customers Experiencing Long Duration Interruptions (CELDI)

Per the OEB guidelines, these reliability indices will be calculated for specific customers once a designated threshold is exceeded. CEMI is calculated based on customers experiencing 4 or more interruptions annually. Similarly, CELDI is calculated based on customer interruptions exceeding eight hours or more.

2.3.1.3.2 Historical Performance (5.2.3b)

Reliability Performance Metrics

KWHI's reliability indices for 2014-2018 are shown in the figures below.

Figure 2.11: Performance Measure - SAIDI

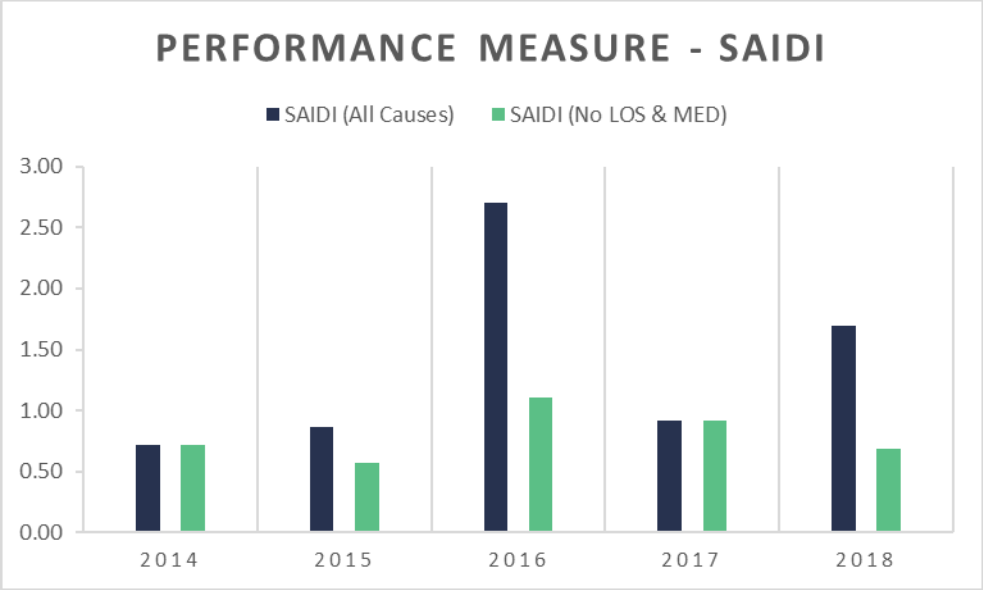


Figure 2.12: Performance Measure - SAIFI

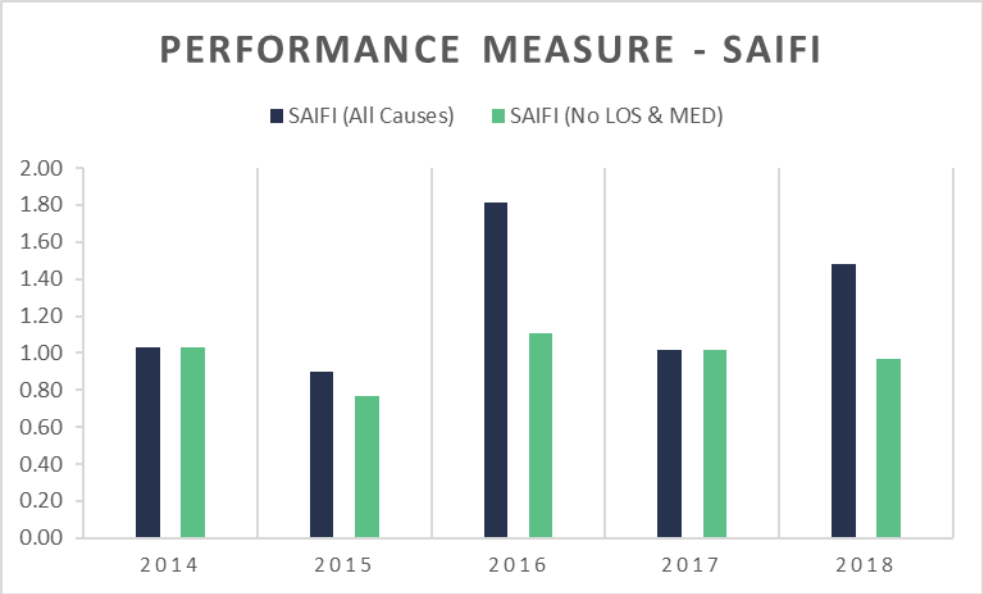


Figure 2.13: Performance Measure - CAIDI

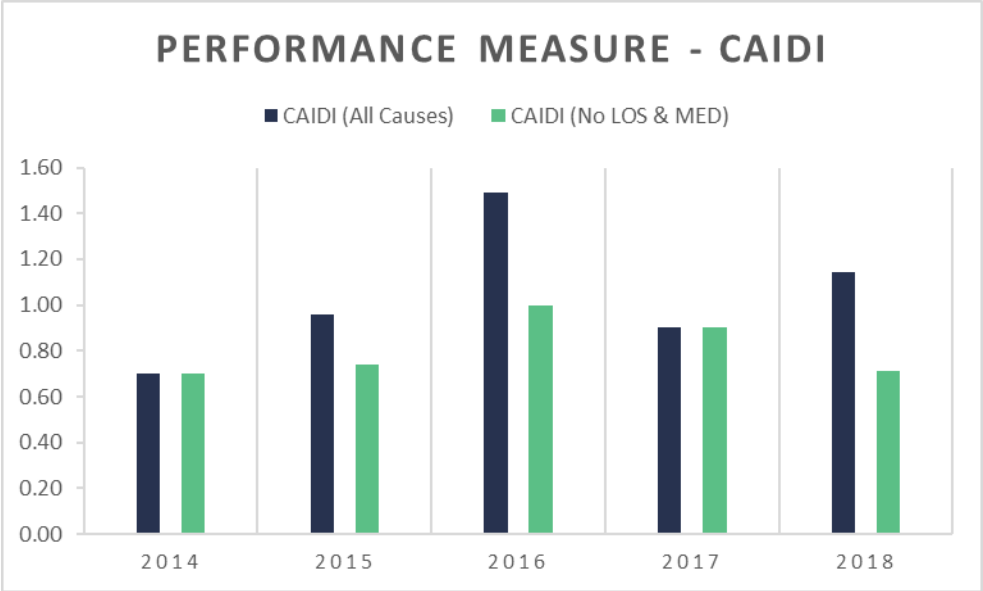
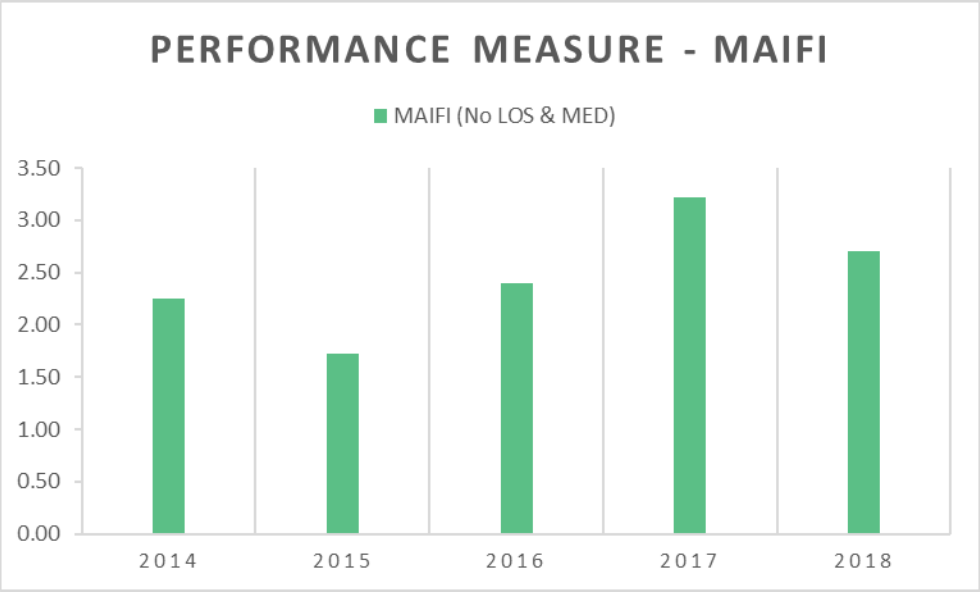


Figure 2.14: Performance Measure - MAIFI



The operational effectiveness portion of the scorecard shows KWHI's continuous improvement in productivity and cost performance, along with reliability and quality objectives. KWHI has exceeded the targets in each category in addition to demonstrating an improvement trend in its reliability statistics. This is attributed to prudent management of the system, its asset management process, and method of capital project prioritization.

KWHI's reliability metric values for the past five years, excluding loss of supply and MEDs, are shown below. For comparison purposes, the table also includes the average for each reliability metric both with and without MEDs and LOS.

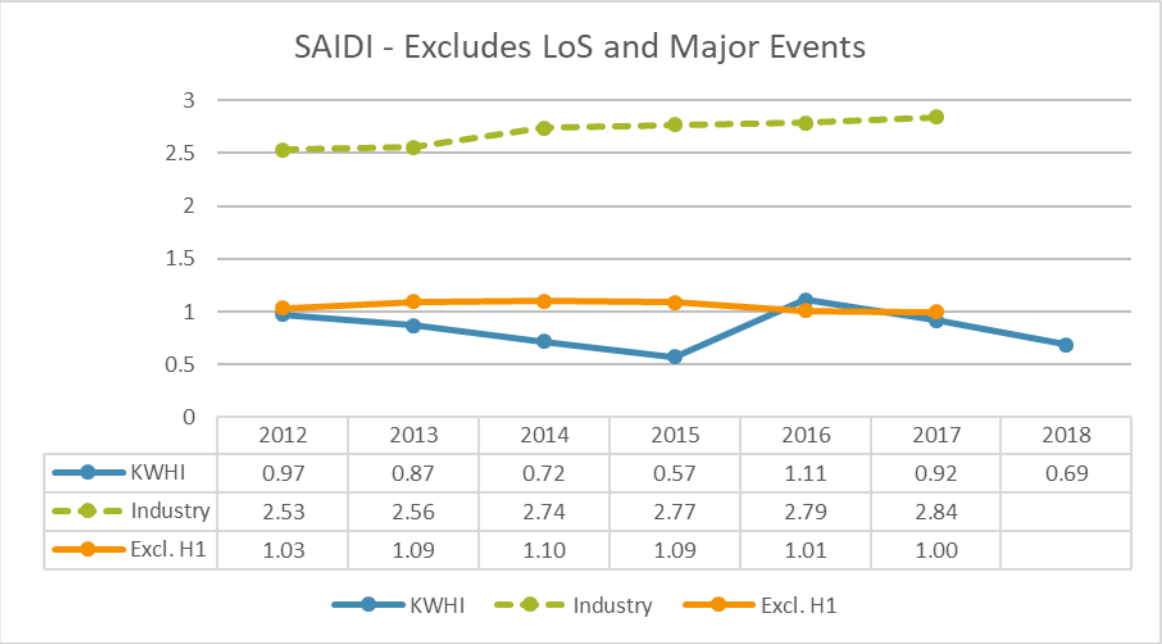
Table 2-12: 2014 – 2018 Reliability Performance Metrics

Metric	2014	2015	2016	2017	2018	Average (Exclude MED & LOS)	Average (Include MED & LOS)
SAIDI	0.72	0.57	1.11	0.92	0.69	0.80	1.38
SAIFI	1.03	0.77	1.11	1.02	0.97	0.98	1.25
CAIDI	0.7	0.74	1.00	0.90	0.71	0.81	1.04
MAIFI	2.25	1.72	2.40	3.22	2.70	2.46	2.46

In 2016, KWHI experienced a severe weather event that had a significant impact on SAIDI and SAIFI statistics. KWHI also commissioned a new Outage Management System (OMS) on April 1, 2016. The OMS leveraged smart meter data to identify outages and a dynamic feeder topology to accurately record all customers impacted by an outage. This method is different than the manual process used in the past to estimate customer impacts.

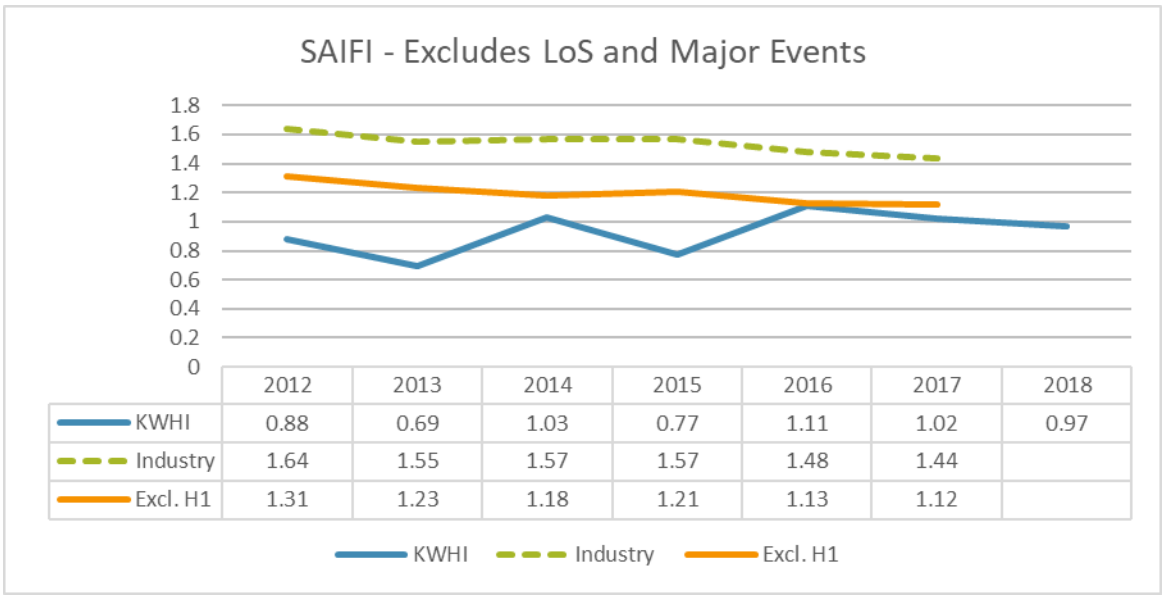
When outage data is adjusted for MED and LOS, SAIFI has been averaging 0.98 over the past five years and SAIDI average 0.80 hours (48 minutes). This equates to a KWHI customer experiencing approximately one outage each year and being without power for 48 minutes. This performance compares very favourably with the OEB published Ontario performance with and without Hydro One Distribution included, shown in Figure 2.15 and Figure 2.16. When major events and LOS are included, the numbers increase to 1.25 for SAIFI and 1.38 hours (83 minutes). This performance compares very favourably with the OEB published Ontario performance.

Figure 2.15: SAIDI comparison (2012-2018) – Excluding LOS & MED



	2012	2013	2014	2015	2016	2017	2018
KWHI	0.97	0.87	0.72	0.57	1.11	0.92	0.69
Industry	2.53	2.56	2.74	2.77	2.79	2.84	
Excl. H1	1.03	1.09	1.10	1.09	1.01	1.00	

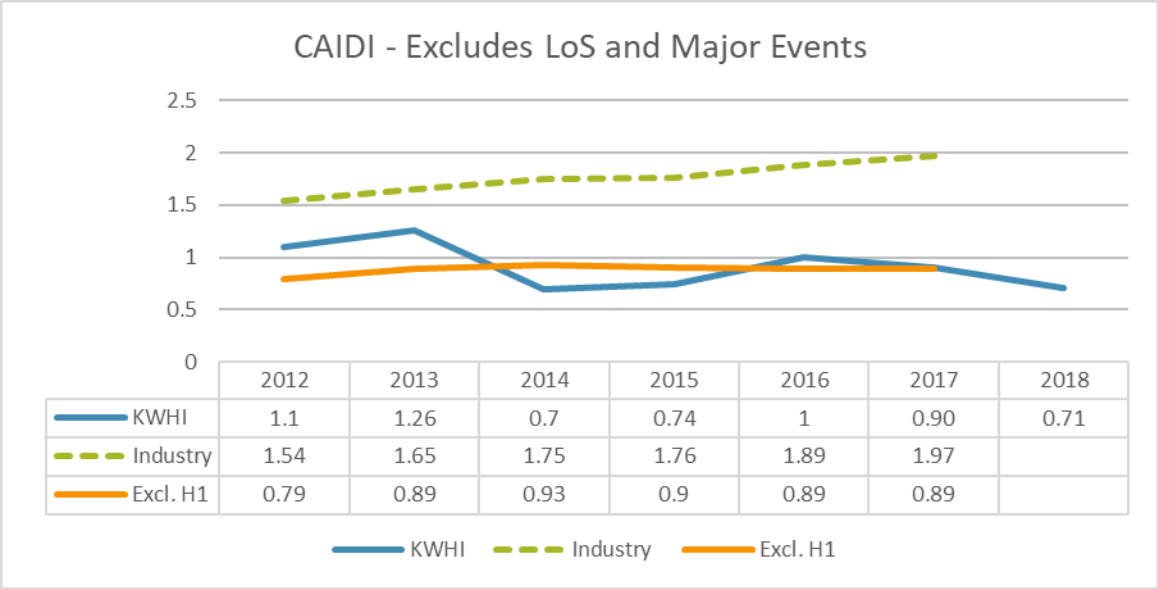
Figure 2.16: SAIFI comparison (2012-2018) – Excluding LOS & MED



	2012	2013	2014	2015	2016	2017	2018
KWHI	0.88	0.69	1.03	0.77	1.11	1.02	0.97
Industry	1.64	1.55	1.57	1.57	1.48	1.44	
Excl. H1	1.31	1.23	1.18	1.21	1.13	1.12	

CAIDI has been averaging approximately 0.81 over the past five years. This translates to 49 minutes in outage duration for those customers who experienced one or more outages. This performance compares very favourably with the OEB Ontario performance, shown in Figure 2.17. However, when compared to all LDCs excluding Hydro One distribution, the performance is average. Failure and replacement of submersible transformers contribute to higher than normal CAIDI for KWHI's customers. This is a result of the work involved in replacing failed submersible transformers which are installed in below grade vault. It takes an average of five (5) hours for a complete replacement. KWHI is in a consultation process with the city of Kitchener and developers to move from submersible to pad-mounted transformers which have lower failure rates and are easier to replace.

Figure 2.17: CAIDI comparison (2012-2018) – Excluding LOS & MED



	2012	2013	2014	2015	2016	2017	2018
KWHI	1.1	1.26	0.7	0.74	1	0.90	0.71
Industry	1.54	1.65	1.75	1.76	1.89	1.97	
Excl. H1	0.79	0.89	0.93	0.9	0.89	0.89	

MAIFI reliability index is similar to SAIFI with the exception that the outages used in calculating the index are momentary outages lasting less than one minute versus sustained outages lasting one minute or more that are used to calculate SAIFI. KWHI's five-year average for MAIFI is 2.46. This is equivalent to each KWHI customer experiencing 2.46 momentary outages per year. The MAIFI index is the same with and without major events because major events will always last longer than one minute in duration. The OEB does not require distributors to report on MAIFI index and therefore there is no industry value to compare to. However, KWHI recognized that its customer are part of a highly digitalized economy and the increase use of computers means that both sustained and momentary power interruptions can lead to significant economic loss. The number of momentary outages is mitigated through activities such as cyclical tree trimming, installation of animal guards on power lines and equipment, and maintaining sufficient clearance between bare conductors. The number of customers impacted by momentary outages is mitigated through the installation of automated reclosers downstream of the main circuit breaker.

Table 2-13 presents a summary of outages that have occurred within KWHI's service territory. The summary provides three different categorizations for accounting of outages. Notwithstanding the positive results from the comparative perspective discussed above, the table highlights an increasing trend of outages experienced within KWHI's service territory, excluding MED and LOS outages. Further breakdown of these outages is provided in the following sections.

Table 2-13: Outage results (2014-2018)

Categorization	2014	2015	2016	2017	2018
All interruptions	751	676	1056	920	878
All interruptions excluding LOS	751	674	1055	919	877
All interruption excluding MED and LOS	751	674	981	919	763

In addition, KWHI experienced MEDs in 2016 and 2018 within the DSP historical period. These outages were attributed to the *Adverse Weather* and *Foreign Interference* cause codes. Table 2-14 presents the total summary of the MED impact by number of interruptions, customer interruptions and customer hours of interruptions.

Table 2-14: Major Event Details (2014-2018)

Major Events Details	2014	2015	2016	2017	2018
Number of Interruptions	-	-	**74**	-	**114**
6-Adverse Weather	-	-	74	-	109
9-Foreign Interference	-	-	-	-	5
Number of Customer Interruptions	-	-	**57,372**	-	**42,573**
6-Adverse Weather	-	-	57,372	-	35,181
9-Foreign Interference	-	-	-	-	7,392
Number of Customer Hours of Interruptions	-	-	**147,908**	-	**96,412**
6-Adverse Weather	-	-	147,908	-	69,040
9-Foreign Interference	-	-	-	-	27,372

In 2016, KWHI experienced one Major Event on March 24th

- On March 24, 2016, a major ice storm impacted KWHI's service territory as a result of freezing rain that occurred over the period March 24-26. The accumulation of ice on overhead power lines and trees resulted in numerous sustained and momentary outages. This event interrupted power to 57,732 customers (many customers saw more than one outage) and caused 147,908 customer-hours of outage time over the three-day period. The storm impacted 24 distribution feeders and it took approximately 10 hours to restore power to over 90% of the customers impacted. By 1:00 pm on the 25th we had 375 customers still without power and it took another day to completely restore power to all the customers who were affected excluding those customers who had damages resulting from tree branches that fell on their service wire.

In 2018, KWHI experienced three Major Events on April 15th, May 4th and June 24th

- The April 15th event was an ice storm with very intense winds gusting at 85 km/h. The accumulation of ice on trees and wires combined with high wind gusts were responsible for a number of fallen trees and broken limbs which took down power lines and caused widespread power outages across KWHI's service territory. The event started at 3:50 p.m. and at the peak of the storm an estimated 20,000 customers were without power. It took approximately four (4) hours to restore power to 90% of the customers impacted.

- The May 4th event was a wind storm with very intense winds gusting at 122 km/h combined with severe thunderstorms. Heavy winds and rain hit Wilmot Township first and moving from West to East battered Kitchener. The impact of lightning and fallen trees created widespread power outages. The event started at 2:50 p.m. and at the peak of the storm (4:00 p.m.) an estimated 11,000 customers were without power. Total number of customers impacted was 14,804. It took approximately seven (7) hours to restore power to 90% of the customers impacted.

- The June 24th event was the result of a motor vehicle accident that knocked down a distribution pole line carrying two three-phase circuits. The distribution system was in a contingency state prior to the accident and the ability to restore power from alternative supply points was lost. The outage started at 12:30 a.m. and impacted 7,392 customers. It took approximately nine and half (9.5) hours to restore power to 90% of the customers impacted.

Outage Details for Years 2014-2018

The following sections and figures provide the breakdown of historical outages for years 2014-2018 regarding to number of outages, number of customers interrupted, and number of customer hours experienced by the outages. Tracking outage performance by cause code provides valuable information on specific outage causes that need to be addressed to improve negative trending. As with the reliability indices, the five-year historical performance range is used as a target and results outside this range indicate positive or negative trending.

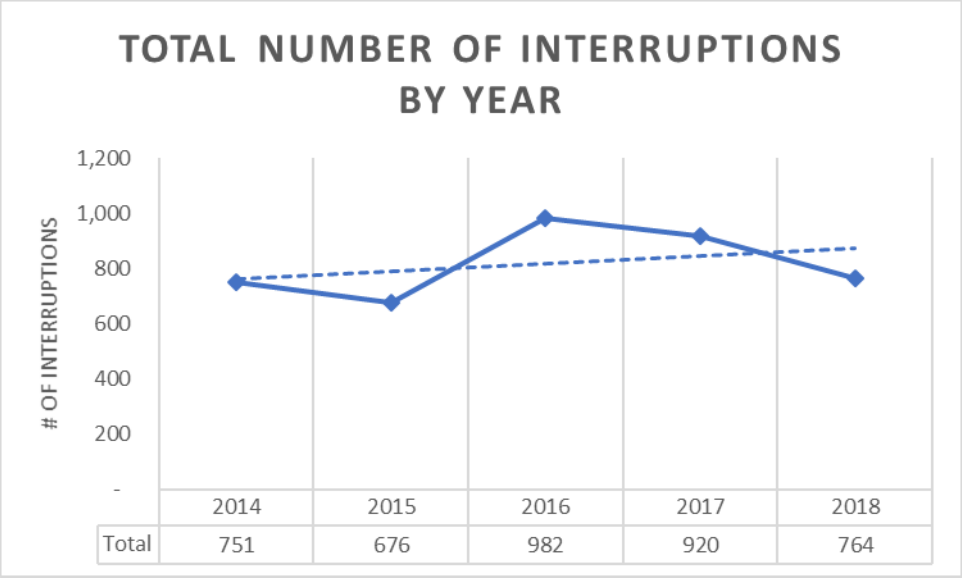
Outages Experienced

Table 2-15 presents the count of outages broken down by cause code. The number of outages is an indication of outage frequency and impact customers differently based on customer class. For example, residential customers may tolerate a larger number of outages with shorter duration while commercial and industrial customers may prefer less outages with longer duration thereby reducing overall impact on production and business disruption. KWHI has implemented several programs to reduce the number of outages that are controllable.

Table 2-15: Number of Outages by cause codes (2014-2018) – Excluding MEDs

Cause Code	2014	2015	2016	2017	2018	Total Outages	Percent Share
0-Unknown/Other	106	42	71	68	72	359	8.77%
1-Scheduled Outage	266	263	377	299	296	1501	36.67%
2-Loss of Supply	0	2	1	1	1	5	0.12%
3-Tree Contacts	33	23	37	50	40	183	4.47%
4-Lightning	35	27	37	21	7	127	3.10%
5-Defective Equipment	138	160	217	218	185	918	22.43%
6-Adverse Weather	36	21	27	66	35	185	4.52%
7-Adverse Environment	0	1	1	2	1	5	0.12%
8-Human Element	5	4	19	19	8	55	1.34%
9-Foreign Interference	132	133	195	176	119	755	18.45%
Total	**751**	**676**	**982**	**920**	**764**	**4093**	**100%**

Figure 2.18: Total Number of outages by year (2014-2018) – Excluding MEDs



The total number of interruptions over the historical period vary from a low of 676 to a high of 982 and shows an increasing trend within the period. This represent an average of 1.7 to 2.7 interruptions per day. There was a marked increase in number of outages from 2015 to 2017 when compared to the previous years. Part of the increase is due to the improvement in data accuracy associated with the launch of a computerised outage management system (OMS) that incorporates outage data from smart meters and records every outage event whether planned or forced, single customer or multiple customers. An increase in planned outages in 2016 to accommodate LRT relocations significantly contributed to the total increase. The performance in 2018 was significantly better than 2016 and 2017 and approached the number of outages seen in the earlier years of 2014 and 2015. The number of

outages by itself does not tell the full story on reliability and should be accompanied by other metrics such as number of customers impacted and the outage duration.

Scheduled outages show an overall increasing trend. This is primarily due to the increase in number of planned outages that were undertaken during 2015 to 2017 to accommodate relocation work due to the Region of Waterloo LRT project. This category consistently accounts for the largest number of interruptions (36.6%). However, as shown in Table 2-16, *Schedule Outages* is not the largest contributor to number of customers interrupted. This is primarily a result of being able to pre-plan outages so that the number of customers impacted is minimal. That is, lines and equipment are taken out of service in a controlled manner and on purpose. Schedule outages are also necessary to reduce safety hazard associated with working around energized circuits.

The number of outages associated with *Loss of Supply* is extremely small due to the N-1 redundancy built into the transmission supply system and the KWHI-owned transformer stations. Most interruptions occur on the downstream 27.6kV, 13.8kV, and 8.3kV feeder systems. However, the number of customers impacted by a *Loss of Supply* outage is always the greatest because of the customer count associated with a transformer station versus a feeder or distribution equipment. In 2018 there was one outage caused by *Loss of Supply*. These outages are mitigated through transformer stations redundant design and coordination with HONI to reduce the occurrences of operating transformer stations in a non-redundant mode.

The number of outages caused by *Tree Contacts* show an overall increasing trend over the historical period. Despite the increasing trend in the number of outages, the customer hours interrupted as shown in Table 2-17 shows a decreasing trend. This is attributed to the sectionalizing of feeders to reduce the number of customers interrupted and the ability to restore customers in a more timely fashion. Tree contact outages are mitigated through effective tree trimming programs to maintain line clearance standards. KWHI operates a six-year tree trimming cycle to clear trees in all nine geographical zones in its service territory. While tree trimming programs help to mitigate outages caused by tree contacts, there are events beyond KWHI's control that normally occur, such as high winds and freezing rain that can result in trees falling and coming in contact with power lines despite being trimmed to acceptable standards.

The number of outages caused by *Defective Equipment* shows an overall increasing trend over the historical period but an improvement in 2018 compared to 2017. This category is also responsible for the second highest number of outages among the cause code categories. Defective equipment outages show an increasing trend in 2016 and 2017. These outages are mitigated through effective maintenance programs and renewal programs for end-of-life assets.

The number of outages caused by *Adverse Weather* shows an increasing trend in 2016. The increase in 2016 is primarily due to an ice storm that impacted the region on the 24th of March 2016. The Region experienced freezing rain over the March 24-26 period resulting in numerous sustained and momentary outages as a result of the accumulation of ice on overhead power lines and trees. This event interrupted power to 93,523 customers (many customers saw more than one outage) and caused 147,908 customer-hours of outage time over the three-day period. In comparison, there were no major storms in the previous two years and weather-related incidents including tree contacts caused significantly fewer power interruptions. These outages are mitigated through efforts to harden the distribution system against adverse weather.

The number of outages caused by *Adverse Environment* are consistently small (less than 5) and typically do not impact KWHI's reliability performance.

Human Element outages show an increasing trend in 2016 and 2017. This is primarily due to the move to a new outage management system (OMS). Closer examination of the events showed that several of the events recorded as outages did not result in actual customer minutes lost but were due to errors associated with the new system as it was being normalized. These errors were recorded as Human Element – Incorrect Maps/Switching Error.

Foreign Interference outages show an increasing trend in 2016. This is primarily due to motor vehicle accidents and animal contacts. In 2016, KWHI experienced three high customer count, long duration outages that were due to motor vehicle accidents. Each outage impacting more than 2,000 customers and lasting 2 hours or more. Some of these outages (such as animal contact) are mitigated through increased use of barriers and environmental design considerations. Other foreign interference outages (e.g. vehicle impacts) are more difficult to mitigate.

Customers Interrupted (CI) and Customers Hours Interrupted (CHI)

The number of customers interrupted is a measure of the extent of outages. Customer Hours Interrupted is a measure of outage duration and the number of customers impacted. The tables and figures below provide the historical values and trends for both CI and CHI.

Table 2-16: Customers Interrupted by cause codes (2014-2018) – Excluding MEDs

Cause Code	2014	2015	2016	2017	2018	Total CI	Percent Share
0-Unknown/Other	10,352	51	14,127	8,180	11,677	44,387	9.10%
1-Scheduled Outage	5,367	5,955	9,177	8,648	6,202	35,349	7.25%
2-Loss of Supply	0	12,350	8,000	-	6,545	26,895	5.51%
3-Tree Contacts	6,967	4,603	7,102	487	5,665	24,824	5.09%
4-Lightning	10,736	1,270	1,588	7,414	8,982	29,990	6.15%
5-Defective Equipment	27,817	36,906	42,299	27,737	32,720	167,479	34.34%
6-Adverse Weather	17,272	1,766	84	7,995	8,656	35,773	7.33%
7-Adverse Environment	0	21	-	60	2,617	2,698	0.55%
8-Human Element	353	7,216	8,475	4,081	90	20,215	4.14%
9-Foreign Interference	14,627	13,082	21,316	33,333	17,777	100,135	20.53%
Total	**93,491**	**83,220**	**112,168**	**97,935**	**100,931**	**487,745**	**100%**

Figure 2.19: Total number of customers interrupted by year (2014-2018) – Excluding MEDs

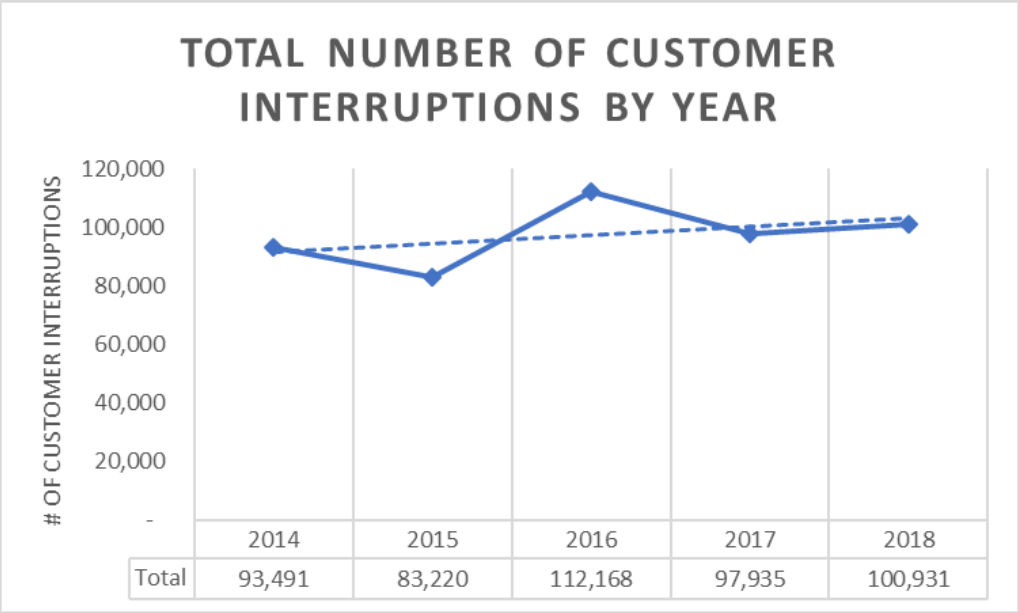
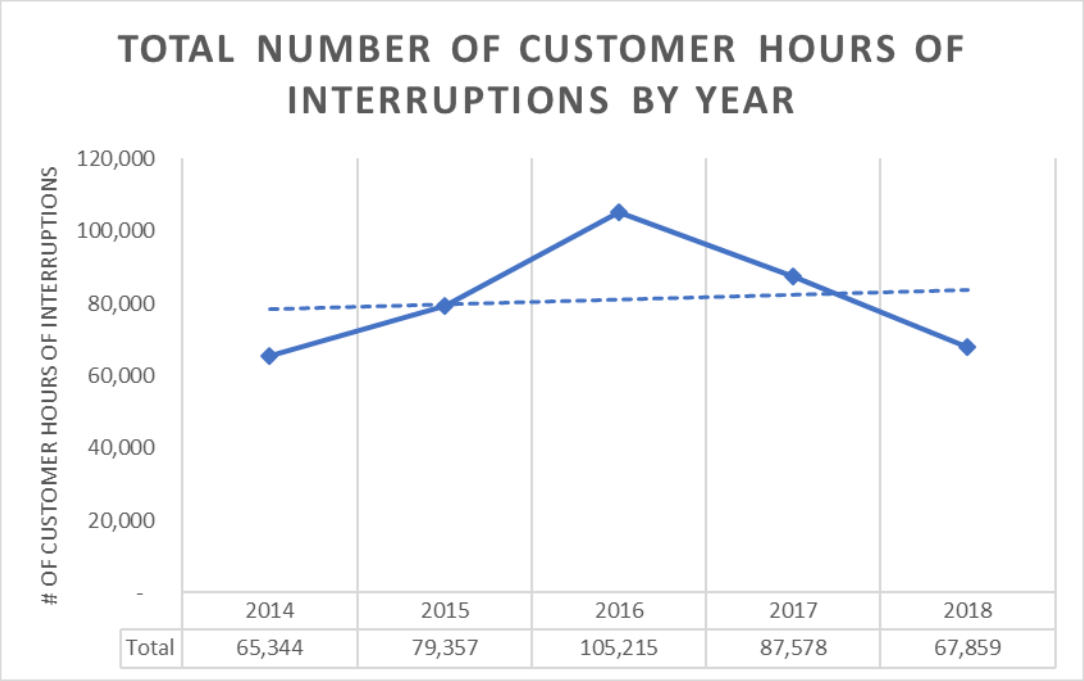


Table 2-17: Customer Hours Interrupted by cause codes (2014-2018) – Excluding MEDs

Cause Code	2014	2015	2016	2017	2018	Total CHI	Percent Share
0-Unknown/Other	956	118	1,708	1,927	2,575	7,285	1.80%
1-Scheduled Outage	6,648	7,624	17,050	9,662	12,131	53,116	13.10%
2-Loss of Supply	-	26,767	800	-	1,105	28,673	7.07%
3-Tree Contacts	8,546	2,904	3,578	1,534	7,513	24,075	5.94%
4-Lightning	12,012	747	320	6,086	2,299	21,464	5.30%
5-Defective Equipment	21,444	28,633	52,242	19,463	25,487	147,269	36.33%
6-Adverse Weather	3,296	2,322	299	16,869	1,389	24,175	5.96%
7-Adverse Environment	-	37	-	188	2,744	2,969	0.73%
8-Human Element	98	297	635	1,255	25	2,309	0.57%
9-Foreign Interference	12,345	9,907	28,583	30,594	12,590	94,019	23.19%
Total	**65,344**	**79,357**	**105,215**	**87,578**	**67,859**	**405,353**	**100%**

Figure 2.20: Total number of customer hours of interruption by year (2014-2018) – Excluding MEDs



The largest contributors to the duration and the number of customer interruptions in the historical period are *Defective Equipment* and *Foreign Interference*.

Defective Equipment is the largest contributor to customers interrupted (CI) and as observed in the table above, it is also the largest contributor to customer hours interrupted (CHI). The customer hours interrupted (CHI) due to defective equipment shows a flat trend over the historical period. However, from 2015 to 2016 there was a significant increase (83%) in CHI. The increase in CHI interrupted in 2016 is primarily due to one large outage that resulted from broken porcelain insulators on a feeder with approximately 3,000 customers lasting 6 hours. The outage occurred early morning before work hours and crews had to be called in to make the necessary repairs. Broken porcelain insulator is a known problem among utilities and KWHI has been taking the necessary cost-effective measures to mitigate against outages and possibly injuries related to this equipment type. These outages are mitigated through effective maintenance programs and renewal programs for assets at end of their useful life.

KWHI replaces defective equipment in the system to ensure a continued reliable supply of electricity to its customers. KWHI's maintenance and inspection program has been an effective means of replacing infrastructure at end of life. KWHI intends to continue to diligently maintain, inspect and service its equipment so that useful life is maximized without compromising the customer's reliability of service.

Foreign Interference is the second largest contributor to CI and CHI over the historical period. Interruptions due to foreign interference such as animals, vehicles, dig-ins, vandalism, sabotage, and foreign objects, are typically beyond the control of KWHI. KWHI has implemented programs such as animal guards to reduce the incidents of animal contacts and actively encourages customers, contractors and residents to participate in its "Call before you Dig" program to identify underground plant.

Analysis of Outages in 2018

In 2018, *Defective Equipment* (38%), *Foreign Interference* (19%) and *Tree Contacts* (11%) were responsible for majority of the customer hours interrupted when MEDs and Planned Outages are excluded. This trend has continued from previous years.

(i) Defective Equipment

In 2018, *Defective Equipment* was responsible for the most customer minutes interrupted when MEDs and Planned Outages are excluded. This trend has continued from previous years. The number of customers impacted by Defective Equipment outages varies from year to year but exhibit a flat trend from 2014 to 2018. The top three contributors to Defective Equipment CHI in 2018 were: underground cable, submersible transformers, and poles, shown in the table below.

Table 2-18: Breakdown of asset classes contributing to Defective Equipment outages

Secondary Cause	CHI	CI	SAIDI	SAIFI	CAIDI	# of Outages
Underground cable	5,395	6,409	0.0554	0.0658	0.8422	7
Submersible transformer	5,027	1,027	0.0518	0.0106	4.8962	54
Pole	4,065	3,437	0.0417	0.0353	1.1827	4
Switch	3,535	11,093	0.0363	0.1139	0.3184	21
Pole fire	1,502	3,598	0.0155	0.0370	0.4199	6
Insulator	1,301	5,589	0.0134	0.0574	0.2335	8
Pad-mounted transformer	733	149	0.0076	0.0015	4.9193	9
Connector / Connections	557	139	0.0057	0.0014	4.0052	22
Underground transformer	347	133	0.0036	0.0014	2.6164	3
Service wire	342	134	0.0035	0.0014	2.5477	16
Overhead transformer	318	469	0.0033	0.0048	0.6800	8
Overhead wire	280	1,139	0.0029	0.0117	0.2462	9
Fuse	71	348	0.0007	0.0036	0.2053	9
Arrestor	66	43	0.0007	0.0004	1.5264	2
Breaker - Transformer	59	30	0.0006	0.0003	1.9816	2

As part of its filing, KWHI intends on addressing assets that are in poor condition through its planned System Renewal programs.

(ii) Foreign Interference

Table 2-19 below shows the secondary cause of outages that attributed to *Foreign Interference*. In 2018, animal contacts and motor vehicle accidents were responsible for the bulk of outages due to *Foreign Interference*. Motor vehicle accidents are mostly unavoidable and KWHI installs its plant as far away from the travelled road portion as practical to mitigate against these outages. Excluded from the data below is a motor vehicle accident that was responsible for a MED and accounted for 21,980 CHI.

Animal contacts, including squirrels and raccoons, were the highest contributor to outages due to *Foreign Interference* in 2018. For tracking purpose, KWHI monitors animal contacts due to specific animals such as squirrels and racoons. Squirrels are responsible for approximately 25% of all animal contacts that occurred in 2018. They are predominantly located in the heavily treed, mature areas of Kitchener. Rarely, does KWHI have squirrel related outages in the Wilmot Township area. Since 2010, KWHI has been investing in installing animal guards on distribution equipment such as transformer bushings and switches (see Figure 2.22). Non-conducting fibreglass materials are also used to replace

switch brackets and transformer drop-leads are replaced with covered conductor. These measures have reduced the incidents of animal contacts at the locations where they are installed. However, a significant reduction in outages is not expected until the majority of the distribution system in and around where squirrels congregate is replaced. This is because the animals typically move from one area to another and if they did not cause a flashover at a guarded location, they inevitably caused flashover at other locations not retrofitted with animal guards.

Table 2-19: Breakdown of secondary causes contributing to Foreign Interference outages

Secondary Cause	CHI	CI	SAIDI	SAIFI	CAIDI	# of Outages
Animal Contact	8,158	11,336	0.0839	0.1167	0.7188	11
Squirrel	2,953	1,495	0.0304	0.0154	1.9755	30
Other	912	940	0.0094	0.0097	0.9697	6
Motor Vehicle Accident	409	2,059	0.0042	0.0213	0.1976	15
Underground Primary Contact	118	62	0.0012	0.0006	1.9066	2
Raccoon	59	27	0.0006	0.0003	2.1826	2
Underground Secondary Contact	27	11	0.0003	0.0001	2.4701	4
Overhead Secondary Contact (Not Animal)	14	2	0.0001	0.0000	7.0000	1
Overhead Primary Contact (Not Animal)	5	2	0.0001	0.0000	2.4358	2
Unknown	2	1	0.0000	0.0000	1.9333	1

Figure 2.21 shows a geographical location of all animal contact in KWHI's service territory for 2018. Not shown is Wilmot Township which had one animal contact in 2018. The north-east section of the city tends to suffer the most from animal-caused outages and efforts have been directed towards this area over the last five years.

Figure 2.21: Geographical location of all recorded animal contact outages in 2018

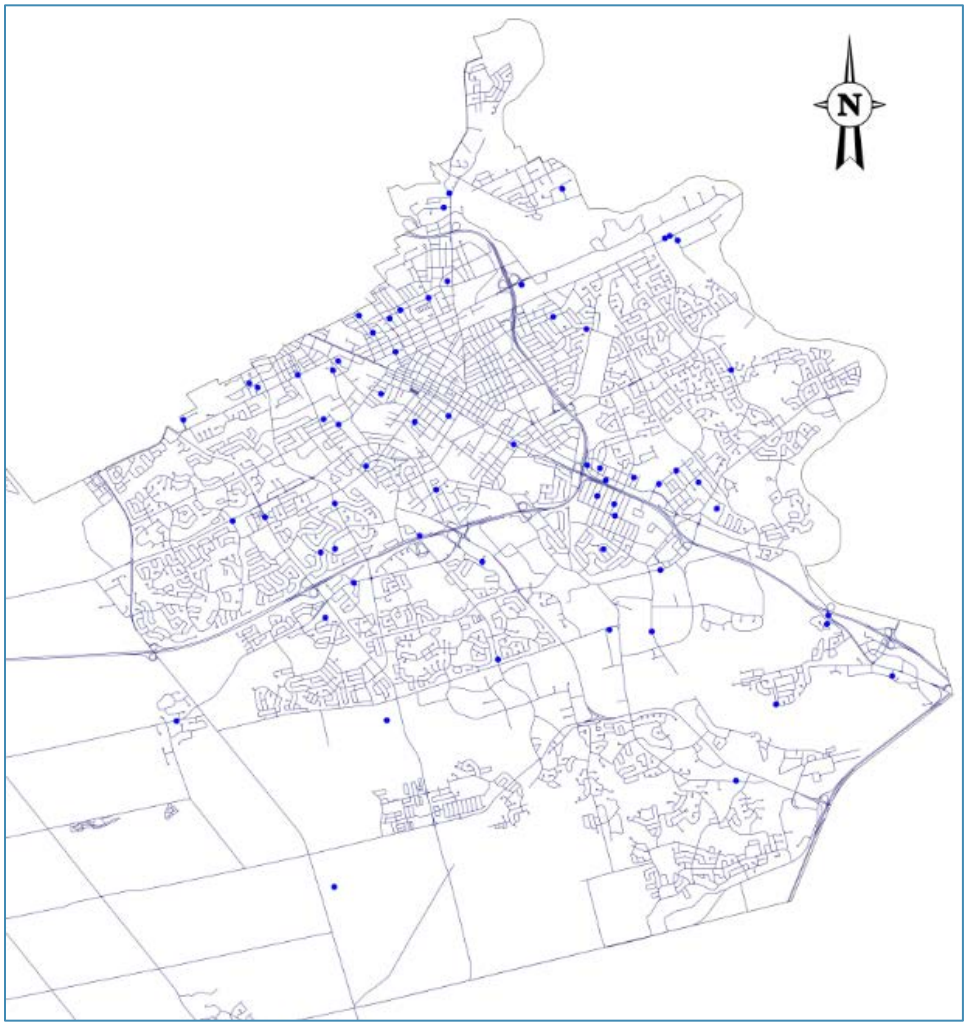


Figure 2.22: (a) Typ. Transformer without animal proofing (b) Typ. Transformer with animal proofing

(a) 

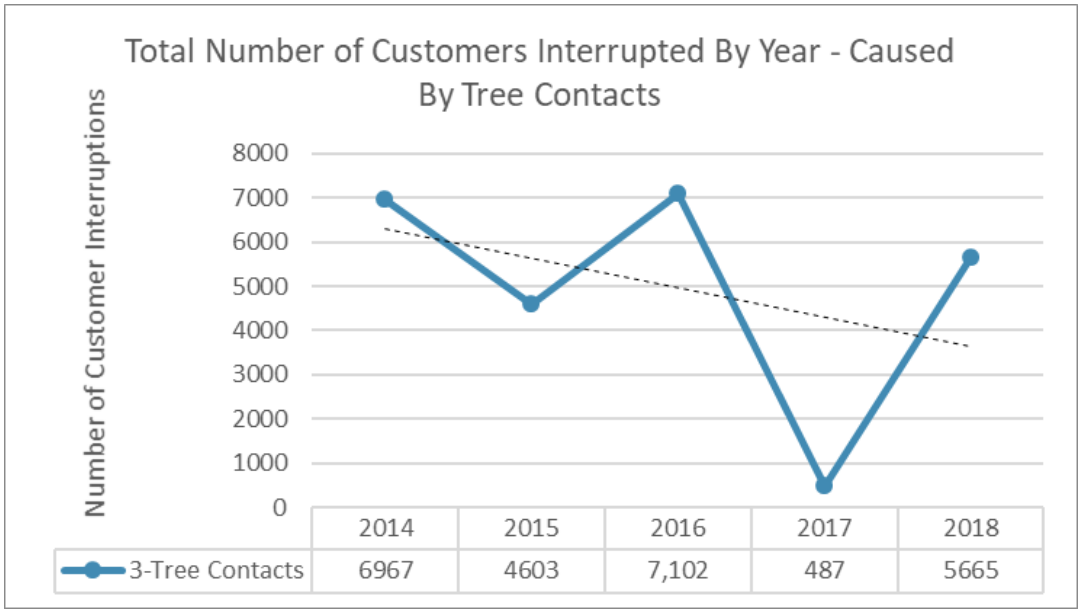
(b) 

As part of its 2020 maintenance programs, KWHI continues to invest in retrofitting distribution equipment, in areas prone to animal contact, with animal guard equipment.

(iii) Tree Contacts

In 2018, *Tree Contacts* was responsible for the third highest customer minutes interrupted when MEDs and Planned Outages are excluded. This trend has continued from previous years. The number of customers impacted by *Tree Contact* related outages varies from year to year but exhibits an overall declining trend from 2014 to 2018, seen in Figure 2.23. KWHI has two full time crews who are responsible for tree trimming and vegetation management. Trees are trimmed on a six-year cycle and more frequent for areas with known high vegetation growth rates or where trees cannot be trimmed to their required setback.

Figure 2.23: Historical trend of Tree Contact related outages



Worst Performing Feeder

KWHI uses two years of outage data (2017-2018) to develop the Worst Performing Feeders (WPF) list. Since it typically takes two years to design and implement measures to improve reliability on feeders that perform poorly in the prior years, the number of years for outage data should not be too long. That is, if there are too many years the list may contain feeders that have been previously addressed. Hence, the choice of two years of outage data.

KWHI's focus on developing the Worst Performing Feeders is based on the feeders' contribution to overall system reliability as opposed to the reliability experienced by an average customer on the feeder.

Table 2-20: Worst Performing Feeder analysis (2017-2018)

Ten Worst Performing Feeders Based on CHI - 2017-2018						
Feeder	Customers on Feeder (Typ.)	SAIDI	SAIFI	CHI	CI	# of Outages
5M16	2500	0.1610	0.0848	15,488	8,218	6
6M17	1470	0.0936	0.0814	9,011	7,852	23
3M26	2500	0.0806	0.1339	7,730	12,869	15
9M4	4000	0.0798	0.1556	7,686	15,046	10
7M9	1500	0.0687	0.0934	6,594	9,007	16
4M26	2100	0.0570	0.0665	5,550	6,471	11
5M13	1500	0.0570	0.1054	5,524	10,126	12
5M27	2600	0.0526	0.0606	5,038	5,804	26
6M27	2200	0.0524	0.0793	5,002	7,589	25
5M23	1950	0.0496	0.0413	4,788	3,997	10
Total	**22320**	**0.7522**	**0.9021**	**72,411**	**86,979**	**154**
Ten Worst Performing Feeders Based on CI - 2017-2018						
Feeder	Customers on Feeder (Typ.)	SAIDI	SAIFI	CHI	CI	# of Outages
9M4	4000	0.0798	0.1556	7,686	15,046	10
3M26	2500	0.0806	0.1339	7,730	12,869	15
5M13	1500	0.0570	0.1054	5,524	10,126	12
7M8	1500	0.0396	0.1015	3,802	9,777	24
7M9	1500	0.0687	0.0934	6,594	9,007	16
4M11	2400	0.0198	0.0858	1,896	8,221	28
5M16	2500	0.1610	0.0848	15,488	8,218	6
6M17	1470	0.0936	0.0814	9,011	7,852	23
6M27	2200	0.0524	0.0793	5,002	7,589	25
6M11	1535	0.0430	0.0770	4,160	7,474	24
Total	**21105**	**0.6954**	**0.9981**	**66,895**	**96,179**	**183**

There are seven feeders, highlighted in red, that appear on each list created to evaluate the WPF. Feeders 5M16, 6M17, 3M26, 9M4, 7M9, 5M13 and 6M27. Appendix J provides more details on the cause of outages that impact the worst performing feeders.

There are 105 active feeders (83 – 13.8 kV, 4 – 27.6 kV, 18 – 8.32 kV) supplying KWHI's service territory of approximately 96,000 customers. The ten worst performing feeders (10% of total feeder count and 20% of total customers) are responsible for approximately 50% of the total customer minutes interrupted during 2017 and 2018. Therefore, by focusing on these feeders, there is the potential to positively impact reliability performance for KWHI's customers. KWHI notes that not all outage causes are controllable, such as motor vehicle accidents and severe weather. However, measures can be implemented to reduce the impact of outages caused by these events.

Outages that occurred on worst performing feeders are analyzed to determine the nature and root causes of the outages, the condition of assets involved in the outages, and the capabilities for load transfer including outage restoration time. Based on the causes that are responsible for the poor performance of a feeder, the typical work performed to mitigate poor reliability performance includes; installing new automated line reclosers, replacing overhead and underground conductors, installing new fault indicators, reframing poles to increase phase separation, installing animal/bird guards, repairing or replacing deteriorated equipment, installing surge arresters on distribution lines, and proactive tree trimming.

2.3.1.3.3 Performance Trends into the DSP (5.2.3d)

KWHI uses the CAIDI, SAIDI and SAIFI reliability indexes to gauge the system reliability performance and maintain a tight control over capital and maintenance spending. KWHI will also use the WPF analysis to provide more targeted mitigation measures. Looking forward, DSP investment priorities are expected to result in outcomes that maintain existing reliability performance. Historical reliability performance of KWHI's system provides insight as to how the system is performing. KWHI's intention is to continuously improve the reliability of the system with incremental investments such as installing SCADA switches. Furthermore, with the recent introduction of tracking WPF, KWHI will be able to specifically target feeders that are contributing the most in terms of total CHI and CI. The expectation is a reduction of impact of the identified feeders on the WPF list would improve the overall reliability performance. Additionally, tracking system performance by major cause codes aides KWHI in identifying the required investments needed to be prioritized. For example, tree contact related outages might infer that KWHI may need to revisit its tree trimming program. Additional analysis would further confirm the appropriate approach.

Furthermore, KWHI has implemented several programs to reduce the number of outages that are controllable. These programs include:

- Planned renewal of end-of-life assets such as poles and cables;
- Proactive vegetation management;
- Inspection of plant to identify potential problems;
- Testing of wood poles; and
- Design and construction of distribution circuits to meet CSA-Heavy standards.

2.3.2 Cost Efficiency and Effectiveness

2.3.2.1 Cost Control (5.2.3b)

2.3.2.1.1 Methods and Measures (5.2.3a)

Efficiency Assessment

The OEB has ranked all Ontario LDCs in one of five efficiency groups (1 – 5) with Group 1 being deemed the most efficient and Group 5 being deemed the least efficient.

Cost Metrics

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

$$Total\ Cost\ per\ Customer\ = \frac{\sum Capital\ \&\ O\&M\ costs}{Number\ of\ customer\ served}$$

KWHI as well collects the trend data on total cost per kilometer of line and total cost per MW. The total cost is calculated as the sum of KWHI's capital and operating costs divided by the total kilometers of line in service at KWHI or by the peak MW for each measure respectively:

$$Total\ Cost\ per\ Kilometer\ of\ Line\ = \frac{\sum Capital\ \&\ O\&M\ costs}{Kilometers\ of\ line}$$

$$Total\ Cost\ per\ MW\ = \frac{\sum Capital\ \&\ O\&M\ costs}{Peak\ MW}$$

Additionally, KWHI tracks the additional metrics introduced in OEB's Chapter 5 update; the O&M Cost per customer and O&M Cost per kilometer of line. The metrics are calculated with the total O&M costs divided by the respective number for each metric, defined as follows:

$$O\&M\ \ per\ Customer\ = \frac{\sum O\&M\ Cost}{Number\ of\ customer\ served}$$

$$O\&M\ Cost\ per\ Kilometer\ of\ Line\ = \frac{\sum O\&M\ Cost}{Kilometers\ of\ line}$$

In compliance with the Filing Requirements, KWHI attaches the OEB Appendix 5-A as part of this filing found in Appendix Q which identifies the total CAPEX cost metrics.

2.3.2.1.2 Historical Performance (5.2.3c)

Efficiency Assessment

KWHI is currently ranked in Group 2 with respect to Efficiency Assessment (stretch factor = 0.15%). Group 2 is defined as having actual costs within 0% to 10% of predicted costs. KWHI's goal is to continue remaining in this efficiency cohort.

Cost Metrics

KWHI's capital cost metrics have been generally consistent in the past, experiencing higher than normal fluctuation in recent years. Specifically, the total cost per customer experienced and the total cost per kilometer of line experienced a 12% increase. This is a direct result of the increase in capital expenditures that occurred in 2016 when KWHI ramped up relocation work for the LRT project. Furthermore, the total cost per peak MW fluctuates from year to year but shows a general declining trend. This may be attributable to the varying weather patterns as well as customers being more aware and efficient with power usage combined with the variation in capital expenditures.

KWHI's operation and maintenance (O&M) cost metrics have experienced a minor increase. Specifically, the total O&M cost per customer experienced a 12% increase and total O&M cost per kilometer of line experienced a 11% increase between 2018 and 2017. This increase is a result of O&M costs getting back to its normal level after years of being reduced to accommodate the higher than normal capital expenditures associated with the LRT relocation project. This trend is expected to continue over the forecast years, as additional assets being installed require incremental O&M spending, and programs that were deferred or scaled back in recent years ramp up to their desired level.

Figure 2.24: Performance Measure - Total cost per customer

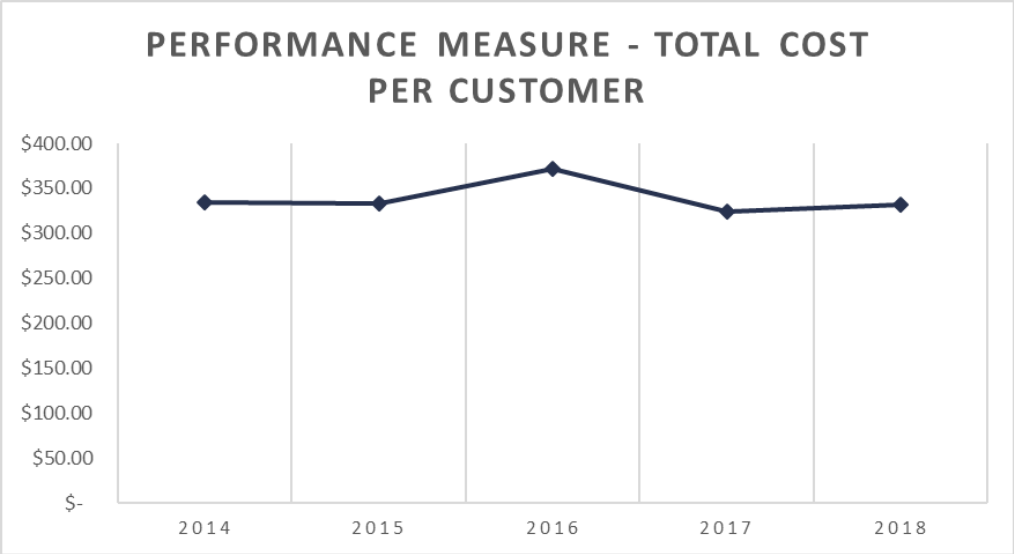


Figure 2.25: Performance Measure - Total cost per kilometer of line

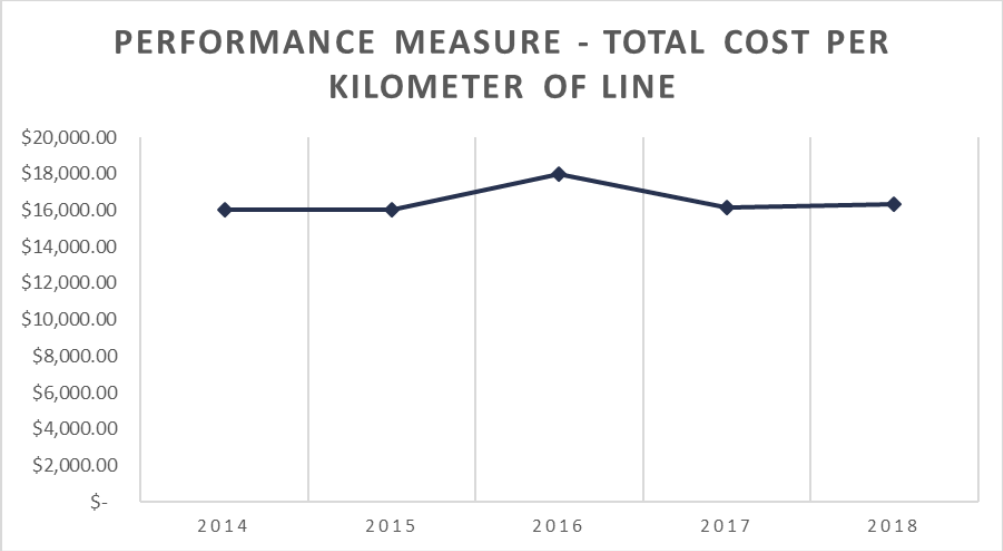


Figure 2.26: Performance Measure – Total cost per MW

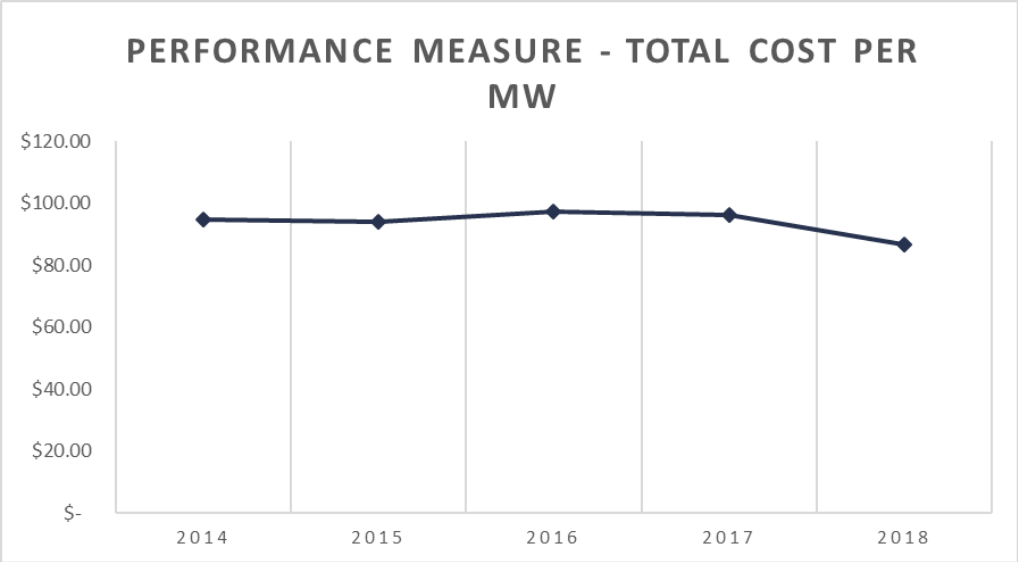


Figure 2.27: Performance Measure - O&M cost per customer

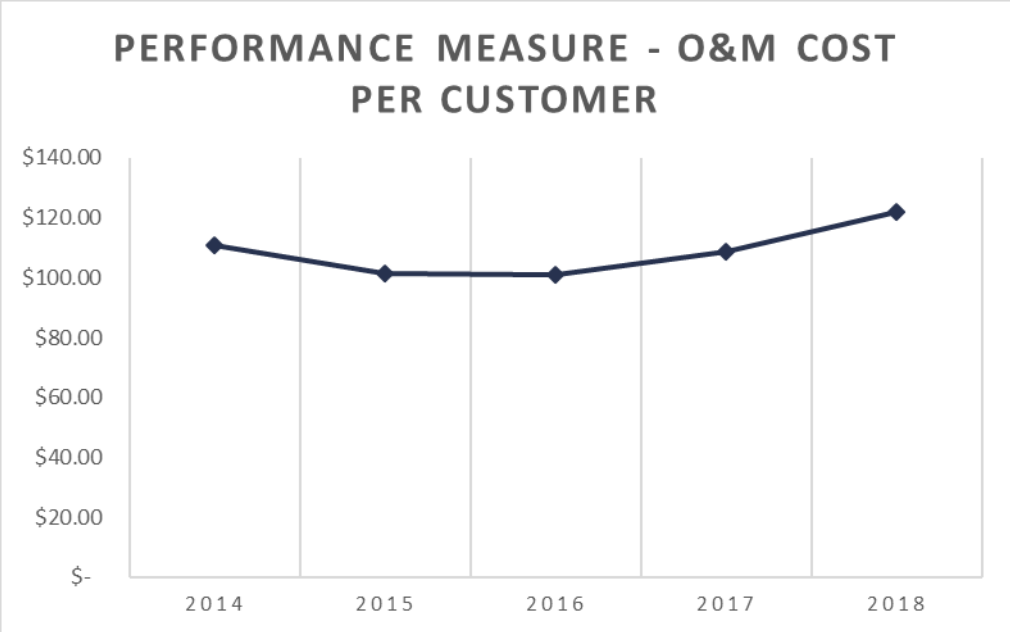
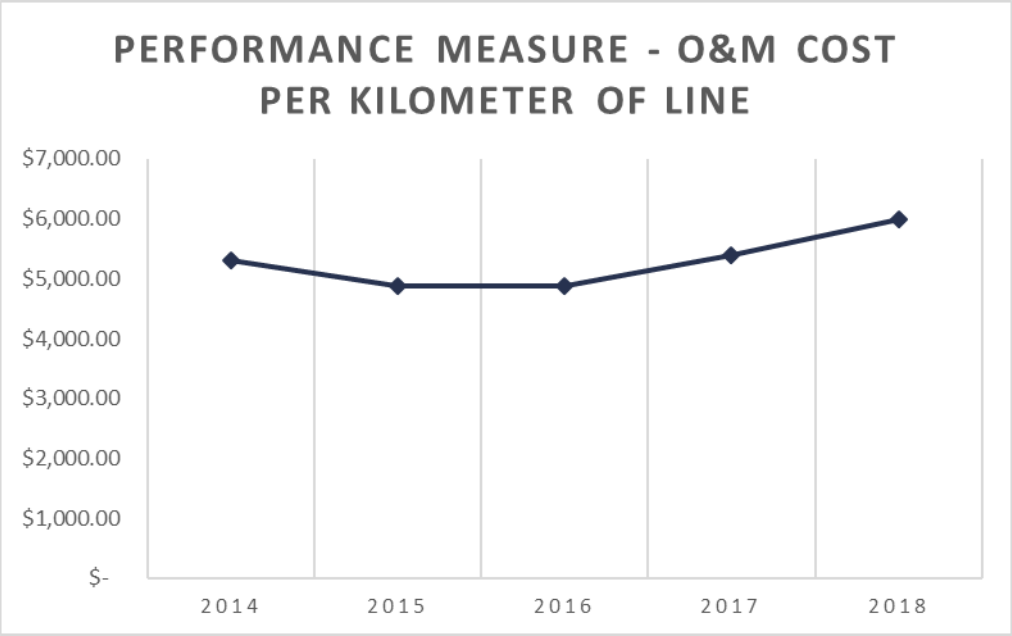


Figure 2.28: Performance Measure - O&M cost per kilometer of line



2.3.2.1.3 Performance Trends into the DSP (5.2.3d)

Efficiency Assessment

Going forward, KWHI intends to continue to implement productivity and efficiency improvements to help offset some of the costs associated with distribution system enhancements, while maintaining the reliability and quality of its distribution system.

Cost Metrics

With an expected growth within KWHI's service area, the cost metrics are expected to increase slightly over the DSP period to similar historical levels. KWHI considers the projects that would have a minimal cost impact on customers but return a benefit to the quality of the service. These trade-offs are considered and communicated with customers to understand their preference. The projects and programs considered within this DSP period take a proactive approach so that KWHI would be able to maintain its distribution system while minimizing the cost per customer as much as possible. KWHI's intended action for these measures is to manage costs such that the annual increase does not exceed the percentage values listed in Table 2-6.

2.3.2.2 Distribution System Plan Implementation Progress

2.3.2.2.1 Methods and Measures (5.2.3a)

Project/program variance analysis

KWHI monitors capital projects and maintenance program spending. Going forward, for material capital projects, actual costs are to be compared to estimates and variances exceeding designated thresholds will require detailed explanation by operations staff that executed the project and engineering staff that planned the project. The performance measure is that these projects and programs are completed within +/-20% of budget and are executed within the budget year unless carryover spending has been specifically identified.

For all billable work (Offer to Connect), KWHI conducts a reconciliation and a variance analysis. If the actual cost is greater than 10% of the estimated cost an explanation is sought from the operations and engineering staff responsible for the job.

Planned maintenance programs are expected to be completed within the budget and calendar year. KWHI's target for this measure is that actual variances are within 10% of estimate.

DSP Spending Progress Report

KWHI will be monitoring its execution of the projects and programs included in the DSP. On a semi-annual basis, KWHI will review actual capital expenditures to date and will forecast total expenditures to year end. Where forecast to year end is materially greater than the budget, KWHI will review projects and determine if they can be deferred to a later date or reduce their scope. Mandatory projects for a given year are typically not subjected to deferral.

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

2.3.2.2.2 Historical Performance (5.2.3c)

Project/program variance analysis

KWHI budget to actual spending has been impacted by significant amounts of mandatory work during the historical period. KWHI has limited ability to affect mandatory work schedules. Mandatory budget spending schedule prepared at the beginning of the year have been subject to substantial actual spending schedule change due to alignment with external schedules (i.e. Waterloo Region LRT).

Since there has been no historical DSP filed by KWHI, there is no historical performance to report. KWHI will monitor and track the project and program variances moving forward with the current DSP.

DSP Spending Progress Report

As this is the first DSP filing, there are no historical statistics for benchmarking.

2.3.2.2.3 Performance Trends into the DSP (5.2.3d)

Project/program variance analysis

Projects and programs have been prepared in consideration that spending must be achievable with the resources that are available (i.e. suppliers (material), design services, municipal approvals, contract labour, vehicles, etc.) in a timely manner. Programs are to be completed in the year they are budgeted, unless; carryover spending has been specifically planned for, project scope changed and is approved, or unforeseen higher priority projects had to be undertaken. Material projects exceeding a designated threshold of +/- 20% will require a detailed variance explanation. DSP investment planning has been set up to design, issue, and construct reasonable amounts of works that can be achieved within the forecast period.

DSP Spending Progress Report

The DSP has been prepared in consideration that program spending must be achievable with the resources that are available (i.e. suppliers (material), design services, municipal approvals, contract labour, vehicles, etc.) in a timely manner. Programs are expected to be completed in the period(s) they are budgeted. Annual DSP spending exceeding a designated threshold of +/- 10% will require a detailed variance explanation. DSP investment planning has been set up to design, issue and construct reasonable amount of work that can be achieved within the forecast period.

2.3.3 Asset/ System Operations Performance

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

2.3.3.1 Safety

2.3.3.1.1 Methods and Measures (5.2.3a)

Maintaining a high level of employee safety, health & wellness and public safety are key corporate objectives. Safety is monitored on an ongoing basis. Reports on all incidents and accidents are provided to the President & CEO and relevant Senior Executive Team members. The KWHI Board is verbally advised of any safety-related issues arising since the previous verbal report to the Board, as well as receiving bimonthly reports on Worker Health, Safety & Wellness and Public Safety initiatives. KWHI provides electrical awareness training to school children and First Responders. KWHI has adopted the WSIB Rate Group 835 historical profile as an external performance benchmark for occupational safety incidents. KWHI has adopted the ESA Serious Electrical Incident Index as a performance benchmark for non-occupational safety incidents involving KWHI plant. The safety measure is generated by the ESA and includes three components:

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

Reg. 22/04

As with every other Ontario distributor, KWHI's design, construction, inspection, maintenance practices are audited on a yearly basis as required by Ontario Regulation 22/04. The utility can be deemed to be in one of three performance categories:

1. In compliance
2. Needs Improvement
3. Not in compliance

KWHI's target is to remain in compliance in all categories being audited.

2.3.3.1.2 Historical Performance (5.2.3c)

KWHI continues to strive in maintaining its employee safety, health & wellness, and public safety measures and in compliance with Ontario Regulation 22/04. The table below highlights KWHI's historical performance for each of the three components. 2018 values are estimates only and have not been finalized as of the DSP writing.

Table 2-21: Performance measures - Safety

Measure	2014	2015	2016	2017	2018 (est.)
Level of Public Awareness		83%	83%	83%	83%
Level of Compliance with Ontario Regulation 22/04	C	C	C	C	not available
Serious Electrical Incident Index	1	0	0	0	3

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

Measuring incidents is a lagging indicator used for comparing company to company. There have been four lost time injuries to date over the historical period of the DSP. All safety-related issues encountered (i.e. slips in adverse weather) are considered controllable through continued education,

awareness and application of safe work practices. A leading initiative is the external audit of KWHI by a world class auditor in 2016, providing guidance on areas of the utility's safety program that need attention, and those that should be praised. The KWHI and WSIB Rate Group 835 historical profiles for Lost Time Injury (LTI) and Non-Lost Time Injury (NLTI) are as follows.

Table 2-22: Lost Time injury profiles

Year	2014	2015	2016	2017
KWHI LTI	3	1	0	0
Group 835 LTI (avg.)	0.48	0.45	0.57	0.59
KWHI NLTI	7	9	10	6

Reg. 22/04

KWHI has achieved compliance in this portion of the audit each year since the regulation came into effect in 2004. Issues noted as "Needs Improvement" are addressed to ensure that they are "In Compliance" for the following year's audit. Exceptions to "In Compliance" audit findings are shown in the table below. At the time of preparing this document, 2018 results were not available.

Table 2-23: ESA Audit Results

Audit Year	2014	2015	2016	2017
Not in Compliance	0	0	0	0
Needs Improvement	0	0	0	0

KWHI has adopted a target of "zero" non-compliance and "zero" needs improvement as a performance benchmark for the period of the DSP.

Serious Electrical Incidents

KWHI has been averaging less than 1 SEI per year over the historical period. The estimated increase in the number of serious electrical incidents (3) for the 2018 reporting period is a result of changes to the guideline for reporting SEI which came into effect in late 2017 and includes a broader selection of incidents that now qualify for reporting. Example, whether a protective device operates or not to clear a wire down fault, the incident is now defined as a SEI. In the 2018 reporting period, KWHI had two broken wire incidents resulting from the age and size of the conductor coupled with metal fatigue. This contributed to the higher than usual number of SEI. The pole line as since been rebuilt.

2.3.3.1.3 Performance Trends into the DSP (5.2.3d)

KWHI continues to promote continued education, awareness and application of safe work practices and as such safety continues to play a key role in project prioritization. Ensuring a safe environment for workers and the public has been taken into consideration in the development of the DSP and KWHI's asset management and capital expenditure planning process.

Reg. 22/04

KWHI continues to demonstrate prudent compliance with O. Reg. 22/04 and as such ESA compliance continues to play a key role in project prioritization. Ensuring Reg. 22/04 compliance is maintained has been taken into consideration in the development of the DSP and KWHI's asset management and capital expenditure planning process.

Serious Electrical Incidents

KWHI continues to put measures in place to reduce/eliminate SEI that are within its control and has identified a number of pole line rebuild projects that will eliminate some of the hazards such as small conductors that are at end of life.

2.3.3.2 System Capacity

2.3.3.2.1 Methods and Measures (5.2.3a)

Station Loading

KWHI's transformer stations have been identified as being the single most critical asset category within its distribution system. KWHI looks to maintain station normal loading at or below 100% of the Oil Natural Air Forced MVA capacity of one of the two station transformers. KWHI deems this a reasonable operating philosophy in that the use of the asset is optimized, and overload capacity to 120% exists for contingency situations. Station loading information is collected and reviewed continuously via the SCADA system. The station loading indicates the effectiveness of KWHI's asset utilization planning. KWHI's target for this measure is that station peak demand is not to exceed transformer maximum nameplate rating under normal conditions (all elements in service).

Feeder Loading

As part of KWHI design and operating philosophy, 13.8kV and 27.6kV feeders are loaded to 50% of capacity to ensure that contingency situations can be addressed with the minimal amount of service interruption to the customer. Feeder loading is collected and reviewed on an ongoing basis via the SCADA system. The feeder loading indicates the effectiveness of KWHI's asset utilization planning and contingency capability.

KWHI feeders have a thermal capacity of 600A. The loading of feeders is monitored monthly and a target of 400A is set to trigger a system planning study to determine if additional feeder capacity is required or reconfiguration of the feeder. The rationale for the 400A is to allow each feeder to have the capability of carrying additional load from another feeder during contingencies.

KWHI's target for this measure is that feeder peak demand is not to exceed 600A under contingency conditions.

2.3.3.2.2 Historical Performance (5.2.3c)

Station Loading

Both the Kitchener and Wilmot service areas are summer peaking. All transformer and distribution stations loading shown in the chart below reflect the coincident peak data.

Table 2-24: KWHI 2014 – 2018 Station loading

TS/DS Name	Capacity (MVA)	2014 Peak Load (MVA)	2015 Peak Load (MVA)	2016 Peak Load (MVA)	2017 Peak Load (MVA)	2018 Peak Load (MVA)	Avg % Utilization
Transformer Stations							
1TS	50	22.3	26.5	29.9	33.2	34.0	58.4%
3TS	100	36.8	33.3	37.1	41.1	46.3	38.9%
4TS	83.3	55.7	32.5	42.6	49.3	57.5	57.0%
5TS	83.3	72.2	76.2	81.1	58.6	69.9	85.9%
6TS	83.3	57.6	76.7	80.5	63	65.5	82.4%
7TS	50	33.5	36	31.9	35.8	39.0	70.5%
8TS	50	25.7	32.9	38.3	28.5	31.1	62.6%
9TS	83.3	32.9	31.9	35.0	30.5	34.0	39.5%
Total	**583.2**	**336.7**	**346.0**	**376.4**	**340.0**	**377.3**	**60.9%**
Distribution Stations							
1DS	5	4.25	4.36	4.49	4.11	4.77	87.9%
2DS	5	4.12	4.61	5.07	4.48	4.89	92.7%
3DS	5	2.1	2.42	2.58	2.45	2.46	48.0%
5DS	5	3.96	2.24	0.73	0.48	0.60	32.1%
6DS	6.66	3.67	4.8	5.09	3.74	4.53	65.5%
7DS	5	3.01	3.14	3.38	3.15	3.19	63.5%
8DS	6.66	3.77	2.83	3.14	3.73	3.11	49.8%
Total	**38.32**	**24.88**	**24.4**	**24.48**	**22.14**	**23.55**	**62.3%**

Loading demonstrates the extent to which TS and DS interconnections are utilized to provide contingency for short term operational purposes.

The Wilmot service area loading demonstrates the relatively stable nature of a low load growth area, impact of voltage conversion (8.32kV to 27.6kV) and that any substantial increase in area development will be serviced from the 27.6kV system. Loading on 5DS will continue to decline to below nameplate rating over the forecast period of the DSP due to active voltage conversion taking place in the areas served by this distribution station.

Feeder Loading

27.6kV, 13.8kV and 8.32kV feeders loading is shown in Section 3.2.4. 27.6kV feeder loadings average 38.9% of capacity. 13.8kV feeder loadings average 46% of capacity. 8.32kV feeder loadings average 37% of capacity. In most cases there is considerable capacity on the 27.6kV and 13.8kV feeder system to accommodate incremental load growth (i.e. electric vehicles).

2.3.3.2.3 Performance Trends into the DSP (5.2.3d)

Station Loading

The station loading pattern in the KWHI service area indicates that existing load is effectively serviced. There is no need for additional station facilities during the period of the DSP under present conditions. For the period of the DSP, KWHI has adopted a performance target of transformer peak demand to be less than or equal to nameplate rating.

Feeder Loading

Existing performance is within planning capacity thresholds. However, the feeders to downtown Kitchener are expected to exceed their normal operating loading limit of 400A within the next 3-5 years

due to the increase in demand associated with the influx of mix-use developments (3,000-4,000 new residential units) occurring in the downtown core. For the period of the DSP, KWHI has adopted a performance target of peak feeder load less than or equal to 400 amps. Additional feeder capacity or non-wire alternatives will be installed when existing feeder capacity is exceeded, or new load is being proposed that will result in overload situation.

2.3.3.3 System Losses

2.3.3.3.1 Methods and Measures (5.2.3a)

KWHI system losses are monitored annually. System design and operation is managed such that system losses are maintained within OEB thresholds, as defined in the *OEB Practices Relating to Management of System Losses*. Losses are monitored to ensure that the OEB 5% threshold is not exceeded.

2.3.3.3.2 Historical Performance (5.2.3c)

KWHI system losses over the historical period are shown below.

Table 2-25: KWHI System Losses

Year	2014	2015	2016	2017	2018
System Losses	2.7%	3.7%	2.8%	3.1%	2.7%

Losses are trending in the 2.5 – 4.0% range over the historical DSP period and within the OEB 5% threshold. According to data from the 2017 OEB Yearbook of Ontario Electricity Distributors[6], the average annual loss factor in Ontario was 3.82% in that year. KWHI's loss factor in 2017 was 3.1%, a loss factor below the provincial average. The visible green bar in Figure 2.29 is KWHI's line loss percentage in comparison to Ontario LDCs. It is evident KWHI is performing well in this performance measure.

Figure 2.29: 2017 OEB Yearbook of Ontario Electricity Distributors Average Annual Line Loss



2.3.3.3.3 Performance Trends into the DSP (5.2.3d)

Existing performance is within performance targets and as such there is no specific impact on the DSP. For the period of the DSP, KWHI has adopted a performance target of maximum 5% system loss.

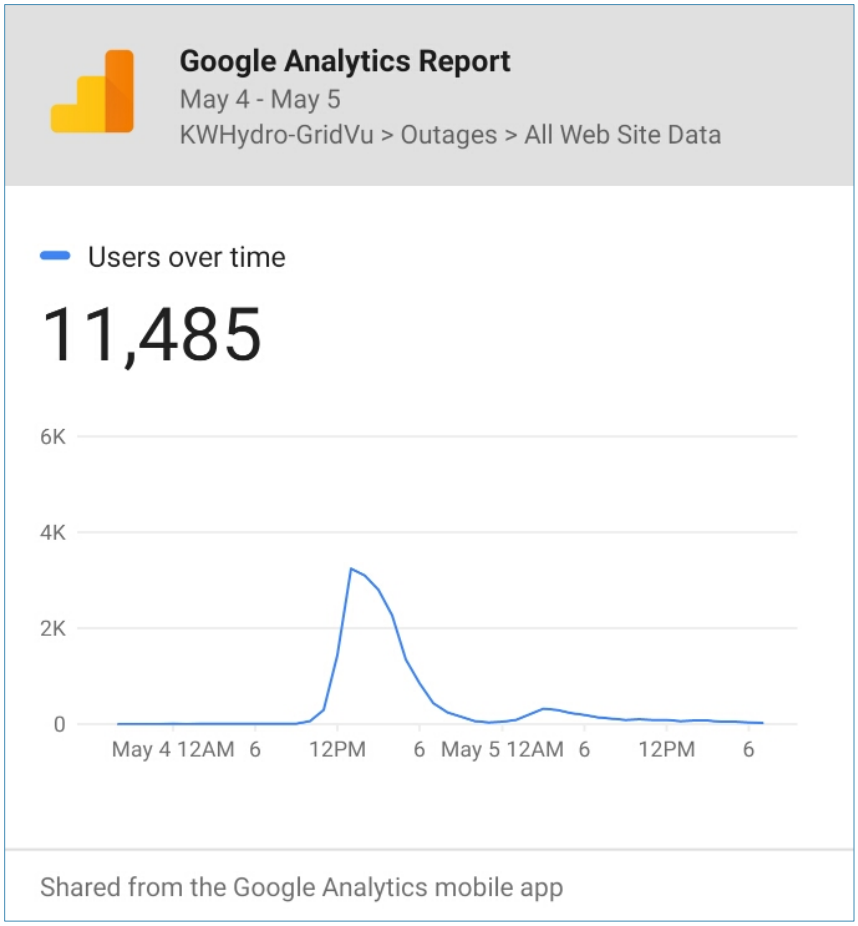
[6] http://www.ontarioenergyboard.ca/

2.4 REALIZED EFFICIENCIES DUE TO SMART METERS (5.2.4)

The installation of smart meters provides KWHI and its customers an operational advantage in maintaining its service while simultaneously improving upon it. These operational advantages include:

- "Last Gasp" functionality of the meters is utilized in OMS to identify extent of outages and devices that operated. This permits KWHI to have faster outage detection and restoration of service. It also allows for graphical identification of outage range which is displayed on a public outage map. This reduces the amount of trouble calls and line stress to the call center allowing KWHI call center and control room to identify the higher concerning issues. An example of this is evident on May 4, 2018 when over 11,000 users visited KWHI's outage website during the windstorm; see Figure 2.30:.

Figure 2.30: Google Analytics stats for May 4, 2018



- AMI data in ODS is used to monitor transformer loading. This allows for KWHI to plan appropriately which areas require an upgrade prior to the transformer failing due to accelerated degradation or aging. Effective planning reduces the overall cost impact experienced by customers. Transformer loading data is also used in designs to effectively size transformers for new and upgraded services.
- Smart meters provide more detailed energy use for customers throughout the day. This enables customers to proactively manage their energy consumption.

- Smart meters are used for remote examination of meters (via pinging) to diagnose power related issues without deploying a crew.
- KWHI's power quality data collected from smart meters allows for KWHI's engineers to observe voltage sags/swells which translate to identifiable power quality issues. Issues are corrected through appropriate planning to limit the cost impact.

3 ASSET MANAGEMENT PROCESS (5.3)

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

3.1 ASSET MANAGEMENT PROCESS OVERVIEW (5.3.1)

3.1.1 Asset Management Objectives (5.3.1a)

KWHI's asset management objectives align with KWHI's strategic goals, and are implicitly summarized in KWHI's corporate overview statement:

> *"We are committed to ensuring that we are financially viable to continue to make necessary investments to continue to provide a safe, reliable, quality service to our customers. Our objective is to meet that commitment while maintaining fair and reasonable local charges"*

The key outcome is maintaining the desired level of customer service at the best appropriate cost accepted by KWHI's customers.

KWHI's strategic corporate objectives form the foundation for KWHI's asset management objectives which are:

- Construct, maintain and operate all assets in a safe manner;
- Monitor and address asset condition issues in a timely manner to ensure the continued reliable supply of electricity delivery;
- Ensure asset management plans align with customer expectations;
- Manage investment planning to mitigate rate impacts while maintaining corporate financial stability and long-term sustainable performance; and
- Ensure that environmental considerations are considered in the design and management of the distribution system.

The corporate goals and asset management objectives form the high-level philosophy framework for KWHI's investment program and are implicitly embedded in KWHI's Asset Management Strategy and capital investment planning process and maintenance program.

The table below shows the linkages between RRFE Outcomes, Corporate Objectives and Asset Management objectives. Additional information is provided in Section 0 that highlights the ranking and prioritization of projects using the objectives.

Table 3-1: RRFE Outcomes - Corporate Objectives - Asset Management linkage

RRFE Outcomes	Strategic Corporate Goals	Asset Management Objectives	AM Objective Measure	AM Objective Target
Operational Effectiveness	Health & Safety	Construct, maintain and operate all assets in a safe manner	1. Lost/non-lost time 2. ESA Non-Compliance 3. ESA SEII	1. WSIB rate class 10-year benchmarks 2. Zero (Max 1 N) 3. 3. SEII = 0
	Asset Management	Monitor and address asset condition issues in a timely manner to ensure the continued reliable supply of electricity delivery	1. SAIDI 2. SAIFI	1. SAIDI within range of past 5-year performance 2. SAIFI within range of past 5-year performance
Customer Focus	Customer Satisfaction	Ensure asset management plans align with customer expectations	Customer Survey	a. Customer Care > 80% b. Company Image > 80% c. Mgmt. Operations > 80%
Financial Performance	Corporate Management	Manage investment planning to mitigate rate impacts while maintaining corporate financial stability and long-term sustainable performance.	1. Investment spending 2. DSP implementation	1. Material Capital expenditure +/- 20% to estimate 2. DSP annual investment category spending +/- 10% of plan
Public Policy Responsiveness	Growth & Sustainability	Ensure that environmental considerations are considered in the design and management of the distribution system.	Reportable spills to the Ministry of Environment	Zero reportable spills to Ministry of Environment from Code 5 events

For investment benefit and risk assessment, it is necessary to identify the relative priority of each asset management objective with respect to others. Different investments will have different benefits and risks with respect to the Asset Management Objectives. The Asset Management Objectives identify investments that are best aligned from an overall benefit and risk management perspective.

An integral part of achieving the Asset Management Objectives are inspection, maintenance and replacement programs, to ensure system performance is sustained during the entire asset service life. KWHI has inspection, maintenance and replacement programs in place to achieve this.

To provide consistency with its Strategic Goals, KWHI has adopted an Asset Management Strategy that provides direction for the management of assets while recognizing realistic service and

performance goals. The Asset Management Strategy ensures a continual and consistent focus on delivering services in a way that balances risk and long-term costs. In addition to the Asset Management Strategy, KWHI developed an Asset Management Policy that provides the high-level overview of the strategy (Appendix K).

3.1.2 Components of the Asset Management Process (5.3.1b)

Asset Management Lifecycle

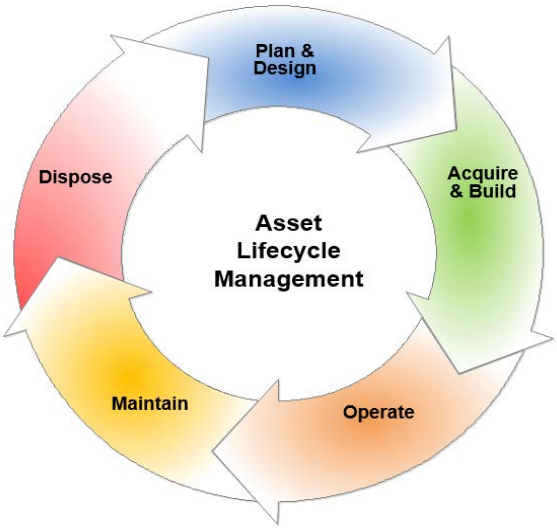
KWHI's asset management process is a systematic approach used to plan and optimize ongoing capital and operating and maintenance expenditures on the distribution system and general plant. Electricity power distribution is a capital intensive operation, and prudent capital investments and maintenance plans are essential to ensure the sustainability of the distribution network.

Asset Management is the management of physical infrastructure throughout its life cycle with the goal of optimizing life cycle costs and performance. KWHI's approach is to perform routine inspections and conduct preventative maintenance on a regular basis, balancing the costs and threats against the desired level of performance of assets to obtain the greatest return on investment and to attain the main objectives of the organization. Major assets such as pole lines are replaced as they approach the end of their useful life. End of life criteria are made based on age, deteriorating condition, deteriorating performance, accelerating maintenance costs or some combination of the listed criteria.

The key to achieving an optimal asset lifecycle is the Asset Management Plan (AMP). KWHI's AMP is comprised of an Asset Management Strategy and a 5-year (10-year for transformer station work) capital expenditures program.

The Asset Management Lifecycle is a process designed to achieve KWHI's Asset Management Objectives. Figure 3.1 depicts the typical process used by KWHI to manage its physical assets.

Figure 3.1: Asset Management Lifecycle



A. <u>Plan / Design</u>

The Asset Management Lifecycle is cyclical in nature and begins with a review of system performance and whether current performance meets KWHI's Asset Management Objectives and service delivery needs. During the planning phase the sufficiency of existing assets is assessed, resources are

determined and evaluated and options for acquiring assets are analysed. The output of asset condition assessment (ACA) studies are used to determine asset replacement timeline and priority.

B. Acquire & Build

After the planning and design phase is completed, the asset is built/acquired and placed into service. Asset performance information and annual asset data collection is used to update KWHI's asset register for the investment planning part of the cycle. Performance data normally reflects the previous year's data. Data collection is ongoing as new/replaced assets are added to the system. Load forecasts provide insights on anticipated growth, which allows the planners to identify assets at risk that may constrain the system from delivering on performance expectations. As such, the Asset Management Plan is impacted by and impacts all the capital investment categories covered in the DSP.

C. Operate and Maintain

The operation and maintenance stages involve the utilization and management of the asset, including maintenance. These two stages are critical to delivering the level of service that customers expect. Most of the assets that make up KWHI's distribution system have long typical useful life (25 years and above) and therefore require a strong emphasis on maintenance and monitoring during their life cycle to ensure that value is being delivered and the asset is operating safely.

D. Dispose / Decommission

After an asset reaches the end of its useful life based on a combination of factors such as age, condition, risk and obsolescence, it is treated as an underperforming asset or surplus, and is disposed of or decommissioned. Assets that are removed from service are disposed of in a manner compliant with statutory and regulatory requirements.

Capital Investment Plan Process

While the AMP looks at the broad asset categories, the capital investment plan looks at the details of programs and projects required to achieve the AMP objectives. In other words, the capital investment plan is governed by the outputs of the AMP.

The relationship between the components of the asset management process used to prepare a capital investment plan is shown in Figure 3.2. The inputs and outputs of this process are as follow.

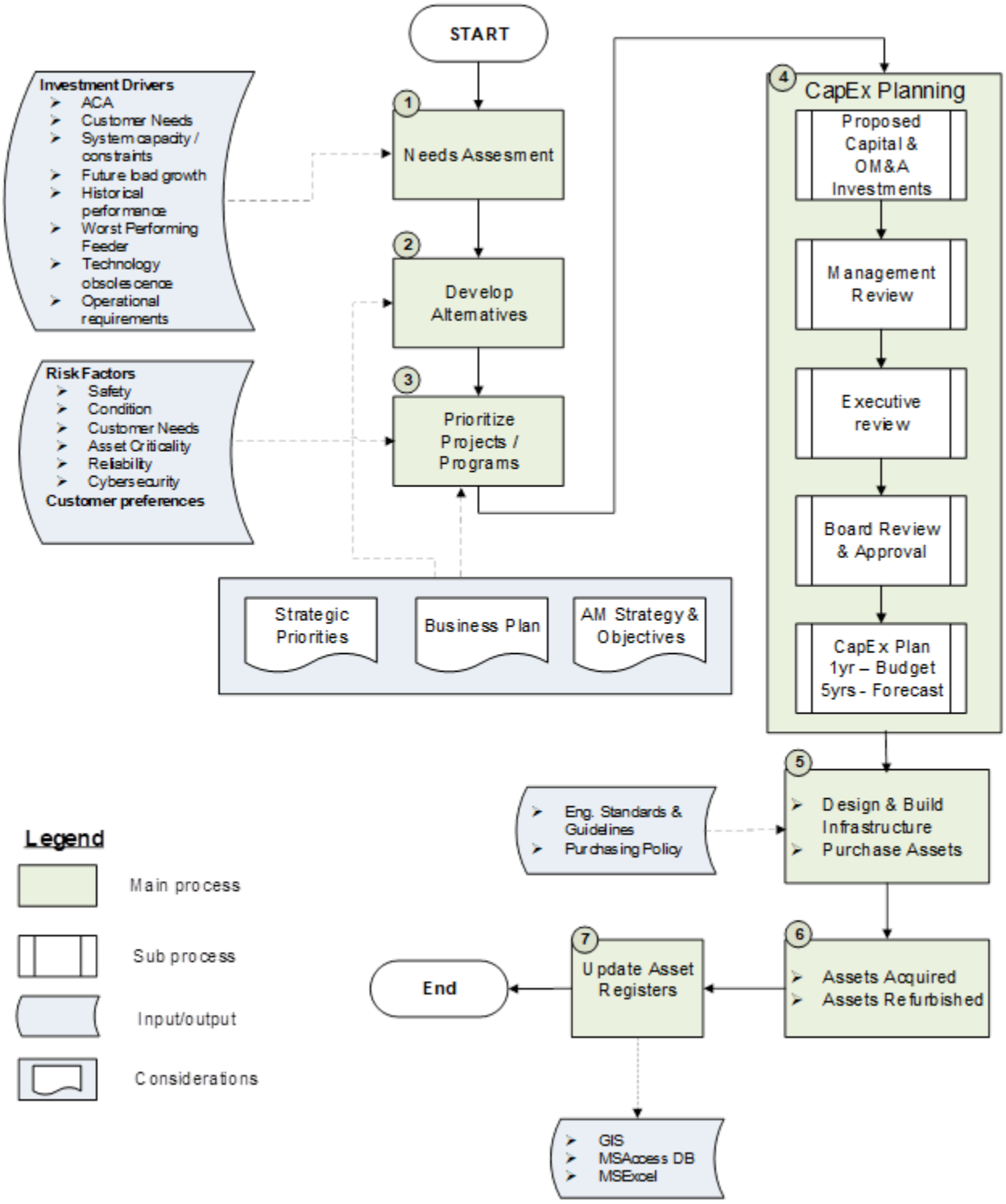
Inputs

- Asset condition assessment results – asset health and condition
- Asset register – age, location, demographics, physical characteristics
- Typical useful life of asset
- Customer Needs and Preferences
- System capacity utilization and constraints
- Risk factors
- Historical performance data – equipment failures and outages (reliability)
- Worst performing feeder analysis (reliability)

Outputs

- Prioritized one-year capital investment plan (budget)
- Five-year capital investment plan for distribution assets and general plant investments
- Ten-year capital investment plan for transformer station assets

Figure 3.2: Asset Management Process used to prepare the Capital Investment Plan



Needs Assessment (1)

The annual investment process begins with a *Needs Assessment*. Asset performance information, reflecting the previous investment cycle activities is collected and used to update the asset register. This performance information, along with other investment drivers, will determine initial investment

category needs (System Access, System Renewal, System Service and General Plant). The investment drivers vary by investment category and include the following:

1. Asset condition assessment results
2. Customer Needs and Preferences
3. System capacity utilization and constraints
4. Historical performance data – equipment failures and outages (reliability data)
5. Worst performing feeder analysis
6. Future load growth
7. Technology obsolescence
8. Operational requirements such as fleet and tools
9. Regulatory/government directives/policy

Investment needs are constrained with a proposed budget envelope. The proposed budget envelope consists of total capital and operating funds determined by financial/capability considerations, mandatory directives, and bill impacts. The proposed budget envelope provides the required information on organizational financial capability for ranking, prioritizing and pacing of investment projects aligned with the four RRFE performance outcomes.

A preliminary portfolio of capital investments is produced as the output of this step. Investment justification is compiled for projects in the portfolio along with more detailed business cases for the larger material project proposals.

Develop Alternatives (2)

In this phase, alternatives to the portfolio based on the *Needs Assessment* are developed that can range from "do nothing" to partial need fulfillment, to proceeding with full need fulfillment. Repair vs replacement is also considered and is governed by KWHI's asset management strategy and the asset lifecycle cost-benefit of capital vs O&M. Where needs are mandatory (e.g. System Access), alternatives are not considered except for the timing of implementation.

Mandatory capital projects are automatically included as per the scheduled need. There is normally little flexibility to defer these projects for more than several months. In general, mandatory projects are defined as:

- New/modified customer service connections *(System Access)*
- Road authority required plant relocation projects *(System Access)*
- Mandated service obligations *(System Access)*
- Renewable energy projects *(System Access)*
- Emergency plant replacement *(System Renewal)*
- Safety related projects *(System Renewal / System Service)*

In developing alternatives, a number of considerations are taken into account. These considerations include; KWHI's strategic priorities, business plan, asset management strategy and objectives, and costs. Additional considerations include; bill impacts (rate mitigation), resource availability and capability, and financial stability.

Prioritize Projects (3)

In this phase, projects are prioritized by risk and value to achieving the Asset Management Objectives and achieving the Corporate Strategic goals and the RRFE objectives. KWHI utilizes a project prioritization tool to aid in capital project selection for each budget year. The prioritization tool assesses

each project based on the estimated benefits it may provide or the potential risks mitigated and calculates an overall benefit score.

Risk management is a fundamental activity in any business and in the electrical distribution industry it requires a systematic approach to assess the following attributes of each asset:

- Safety impact
- Condition and health
- Age and life expectancy
- Location
- Operational and maintenance data
- Reliability performance
- Asset criticality
- Cyber security

It is the systematic approach of inspections, condition assessment, data analysis and maintenance that allow KWHI to identify and mitigate risk to its assets and distribution system.

In identifying the final priority of each capital project, one of the following methods is used:

(i) Fixed Order – mandatory projects (typically system access investments and projects driven by regulatory requirements) followed by needs for replacement (age, condition, safety), needs for enhancement (capacity upgrades) and operational restrictions (reliability). This method is normally used to prioritize projects at the program level (System Access, System Renewal, System Service and General Plant).

(ii) Risk Evaluation – although KWHI currently does not have a formal risk evaluation process to evaluate and document the risk associated with each proposed investment, risk factors as described earlier are considered when prioritizing capital projects. The inputs to these decisions include consequence of failure, likelihood and frequency of occurrence. This method is normally used to prioritize individual projects within a program.

(iii) Health Index – Health Index is an indicator of an asset's remaining life given as a percentage. It is the first step towards implementation of a risk-based asset management program. It is used as a measure and benchmark of health and condition of in-service assets. It is calculated based on analyzing several factors such as age, historical failure, impact of failure and nature of load served (critical loads, large load, load density, etc.).

<u>Develop Capital Investment Plan (4)</u>

After completing the prioritization process, the portfolio of selected projects is compared to the budget envelope and prioritized investments are paced/scheduled to optimize system performance, costs and risks relevant to service delivery. Risk and value assessments provide an initial triage to determine projects that can be deferred to future budget periods and those that need closer review for potential inclusion in the immediate planning period. Assessments may also indicate that to optimize system performance the capital envelope may require funding adjustment. Reasons for adjustment consider factors such as:

- Project interdependencies
- Resource (labour, material, etc.) availability
- Cost and benefit uncertainties/risks
- Capital availability
- Bill impact
- Portfolio effectiveness (corporate goals)
- Portfolio effectiveness (customer value)

In the case the above adjustment factors exist, a revised capital budget envelope may be considered, and the capital investment portfolio would be re-evaluated to optimize system performance.

The capital plan and annual maintenance plan are prepared simultaneously. The maintenance plan reduces unplanned and emergency repairs, as it emphasizes preventative and predictive maintenance. It determines which assets are maintained to maximize asset life-cycle benefit and which assets are simply run to failure.

The final proposed budget envelope and project selection is determined through KWHI senior management discussion and review. Final approval of budget envelope and investment mix is determined by KWHI Executive in consultation with the Board of Directors. The output of this stage is a one-year capital budget with project detail and a five-year capital expenditure plan (ten-year for transformer station assets) with allocation of funds to each major budget and investment category.

Plan Implementation - Acquire Assets/Install Assets (5,6)

Following final investment plan approval, the asset management process would then proceed to the plan implementation stages. During these stages, the distribution plant is designed and constructed or purchased in the case of vehicles, tools, and other general plant. Some assets are refurbished where practical, such as hard-to-access below-grade transformer vaults and pull boxes (cable chambers).

Update Asset Register (7)

After acquiring new assets or refurbishing existing assets, the relevant asset registers are updated and used to track performance of the assets. System performance outcomes are collected and reviewed, starting the asset management planning cycle over again.

KWHI utilises several asset registers. The main asset register utilised is a GIS which manages all distribution assets (poles, wires, transformers, etc.). Other asset registers are in the form of MS Access database (e.g. IT infrastructure) and MS Excel spreadsheets (e.g. vehicles and transformer station equipment).

3.2 Overview of Assets Managed (5.3.2)

3.2.1 Description of the Service Area (5.3.2a)

KWHI is a medium sized LDC in the Province of Ontario, serving the City of Kitchener and the Township of Wilmot. See Figure 3.3 for map of service area. As of December 31, 2018, KWHI served 96,826 customers in two communities with a combined service area of 425 square kilometers that is 1/3 urban and 2/3 rural. KWHI's system has an almost even split of overhead to underground systems, with the current distribution at 52% overhead system and 48% underground system.

For more than 100 years, KWHI and its predecessors have proudly served the residents of its communities. On January 1, 1978, Bill 55 came into force "*An Act to establish Electrical Service Areas in The Regional Municipality of Waterloo*" that merged four electrical distribution utilities and the surrounding rural area (served by Ontario Hydro) in the City of Kitchener and the Township of Wilmot into a new entity now known as KWHI.

Kitchener is located in Southwestern Ontario, in the Saint Lawrence Lowlands. This geological and climatic region has wet-climate soils and deciduous forests. Located in the Grand River Valley, the area is generally above 300m (1000') in elevation.

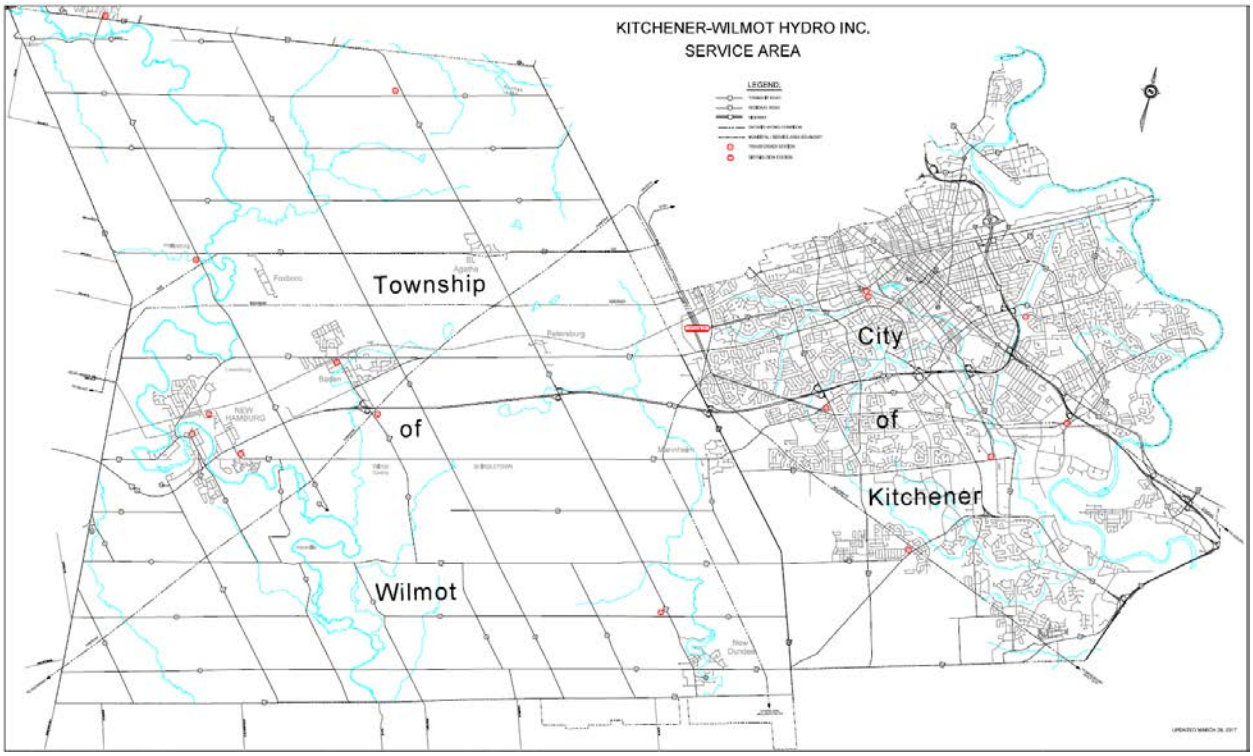
Kitchener is the largest city situated within the Grand River watershed, and the largest city on the Haldimand Tract. Just to the west of the city is Baden Hill, in Wilmot Township. This glacial kame remnant formation is the highest elevation for many miles around. The other dominant glacial feature is the Waterloo Moraine, which snakes its way through the region and holds a significant quantity of artesian wells, from which the city derives most of its drinking water. The settlement's first name, Sandhills, is an accurate description of the higher points of the moraine.

Kitchener has a humid continental climate of the warm summer subtype. There are large seasonal differences, usually warm and humid summers and cold to occasionally very cold winters. Winter-like conditions generally last from the mid-December until mid-March, while summer temperatures generally occur between mid-May to close to the end of September. Temperatures during the year can exceed 30°C in the summer and drop below −20°C in the winter several times a year, but prolonged periods of extreme temperatures are rare. The frost-free period for Kitchener averages about 147 frost-free days a year, a much more limited number than cities on the Great Lakes due its inland location and higher elevation. Snowfall averages 160 centimetres (63in) per year, high but not nearly as high as areas more directly affected by lake effect snow.

KWHI is the largest of the electrical distribution companies within the Regional Municipality of Waterloo. KWHI has the following neighboring utilities:

- Waterloo North Hydro
- Energy +
- Guelph Hydro
- HONI

Figure 3.3: Map of KWHI's Service Area



3.2.2 Summary of System Configuration (5.3.2b)

KWHI was the first and is one of only a few distribution companies in Ontario that designs, owns and operates its own Transformer Stations. KWHI purchased its first Transformer Station from Ontario Hydro in 1954 and has owned and operated transformer stations since that time. Currently, KWHI owns and operates eight transformer stations that are connected to the 115 kV or 230 kV transmission grid. KWHI is considered transmission connected and as such is an IESO Market Participant. Since KWHI supplies all its customers from these transformer stations, KWHI's customers benefit from lower pass-through charges as there are no transformation connection charges incurred by KWHI. The transformer stations are strategically located throughout the City of Kitchener and the Township of Wilmot. Power is transformed from 115 kV or 230 kV to 13.8 kV (in Kitchener) and 27.6 kV (in Wilmot). KWHI also has seven 27.6/8.3kV rural Distribution Stations in the Township of Wilmot.

KWHI's distribution system distributes power at 13.8 kV in Kitchener and at 27.6 kV and 8.3 kV in Wilmot. See Figure 3.4 and Figure 3.5 below for schematic layout. Table 3-2 provides additional breakdown of linear assets by voltage and system classes.

Figure 3.4: KWHI 13.8kV System Map

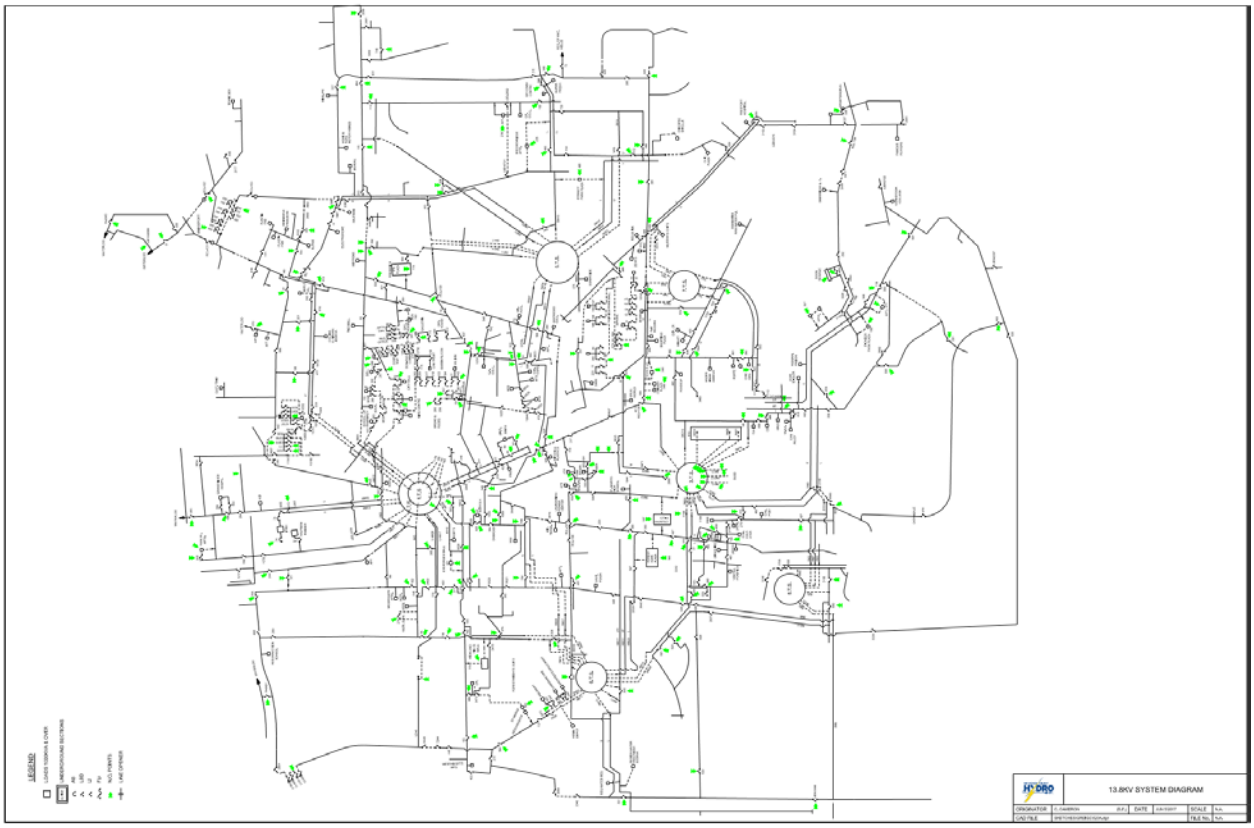


Figure 3.5: KWHI 27.6kV System Map

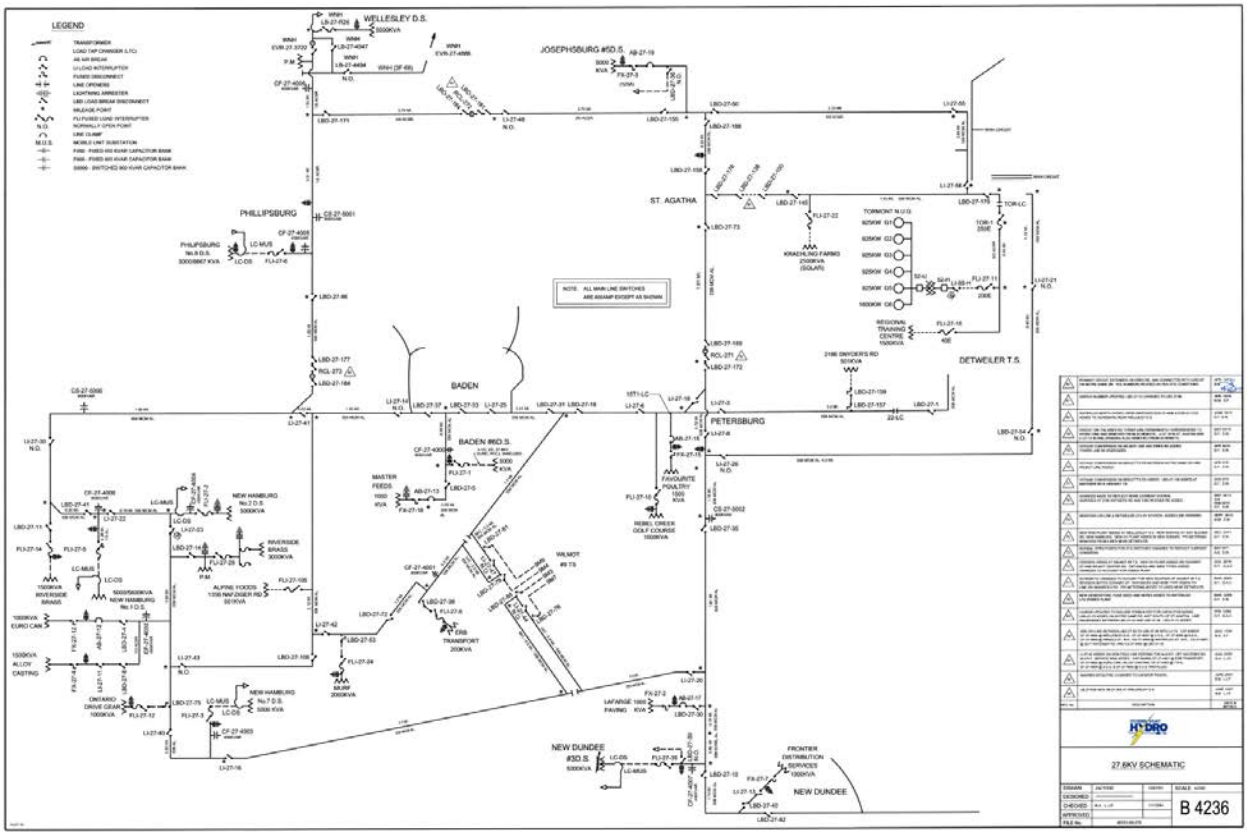


Table 3-2: KWHI Linear asset length by voltage and system class

Voltage Class	Overhead System (m)	Underground System (m)
8.32 kV	345,100	68,648
13.8 kV	541,820	777,607
27.6 kV	126,017	17,340
Total	**1,012,937**	**863,595**

The Rural Service Area comprises approximately 300 sq. km. The Urban Service Area comprises approximately 125 sq. km. As of December 2018, there is a total of 1,013 km of primary overhead line, 864 km of primary underground line, 23,107 poles and 11,047 distribution transformers. There are eight transformer stations and seven distribution substations in KWHI service territory, presented in the tables below.

Table 3-3: KWHI TS summary

TS Name	Details	Transformer Sizes	Normal TS Capacity	Contingency TS Capacity
Kitchener 1	Primary 115kV; Secondary 13.8kV	T1 30/50 MVA T2 30/50 MVA	50 MVA	60 MVA
Kitchener 3	Primary 115kV; Secondary 13.8kV	T1 60/100 MVA T2 60/100 MVA	100 MVA	120 MVA
Kitchener 4	Primary 115kV; Secondary 13.8kV	T1 50/83 MVA T2 50/83 MVA	83 MVA	99.6 MVA
Kitchener 5	Primary 115kV; Secondary 13.8kV	T1 50/83 MVA T2 50/83 MVA	83 MVA	88.5 MVA
Kitchener 6	Primary 230kV; Secondary 27.6kV	T1 50/83 MVA	83 MVA	99.6 MVA

		T2 50/83 MVA		
Kitchener 7	Primary 230kV; Secondary 13.8kV	T1 30/50 MVA T2 30/50 MVA	50 MVA	60 MVA
Kitchener 8	Primary 230kV; Secondary 13.8kV	T1 30/50 MVA T2 30/50 MVA	50 MVA	60 MVA
Kitchener 9	Primary 230kV; Secondary 27.6kV	T1 50/83 MVA T2 50/83 MVA	83 MVA	99.6 MVA

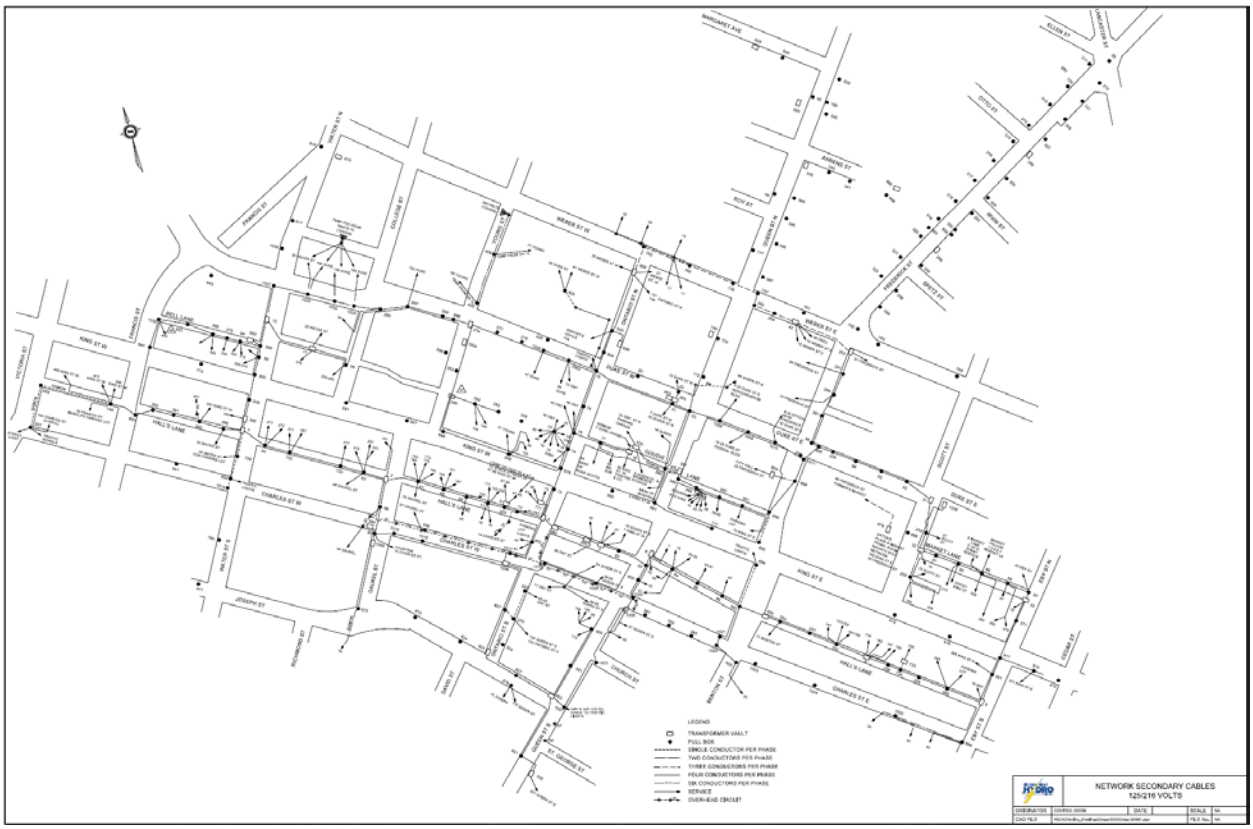
Table 3-4: KWHI DS summary

DS Name	Details	Transformer Sizes	Normal DS Capacity
1DS	Primary 27.6kV; Secondary 8.32kV	5 MVA ONAN	5 MVA
2DS	Primary 27.6kV; Secondary 8.32kV	5 MVA ONAN	5 MVA
3DS	Primary 27.6kV; Secondary 8.32kV	5 MVA ONAN	5 MVA
5DS	Primary 27.6kV; Secondary 8.32kV	5 MVA ONAN	5 MVA
6DS	Primary 27.6kV; Secondary 8.32kV	5/6.66 MVA ONAN/ONAF	6.66 MVA
7DS	Primary 27.6kV; Secondary 8.32kV	5 MVA ONAN	5 MVA
8DS	Primary 27.6kV; Secondary 8.32kV	5/6.66 MVA ONAN/ONAF	6.66 MVA

In Kitchener, a network of 13.8kV feeders (83) is used to move the power to residential and small commercial neighbourhoods where it is again transformed down, through local overhead, pad mount, submersible and vault transformation facilities to user utilization levels of 600/347V, 120/208V and 120/240V.

Parts of downtown Kitchener are supplied by a secondary grid network that is a 125/216V three-phase secondary grid fed by four 13.8kV parallel feeders from Kitchener #1 MTS, consisting of forty-one (41) distribution transformers with interconnected secondaries. See Figure 3.6 for a typical secondary network configuration. This secondary network covers a small 0.5 square kilometer area between Francis Street and Eby Street from west to east, and between Weber Street and Charles Street from north to south. It supplies the load customers with less than 500kW peak demand. Customers larger than 500kW in the same area are supplied by two 13.8kV underground loop feeders from Kitchener #1 MTS.

Figure 3.6: Secondary Network Configuration Map



In Wilmot, 27.6kV feeders from Kitchener No. 9 TS are used to supply seven distribution stations. From the distribution stations, a network of 8.32kV feeders moves the power to residential and small commercial neighbourhoods where it is again transformed down, through local overhead and pad mount transformation facilities to user utilization levels of 600/347V, 120/208V and 120/240V.

3.2.3 Asset Condition Assessment (5.3.2c)

The Asset Condition Assessment (ACA) study was carried out by METSCO for KWHI with the objective of establishing the health and condition of station and distribution assets in-service. The ACA is based on data compiled to the end of June 2018. Figure 3.7 and Table 3-5 present the summary results of the ACA, which was completed in October 2018. Additionally, Table 3-6 compiles the known age demographics of in-service assets. Data collection of asset's conditions was completed through KWHI's current maintenance practice, such as visual inspections, pole testing, and power equipment oil sampling.

Figure 3.7: KWHI Health Index Distribution for Major Assets

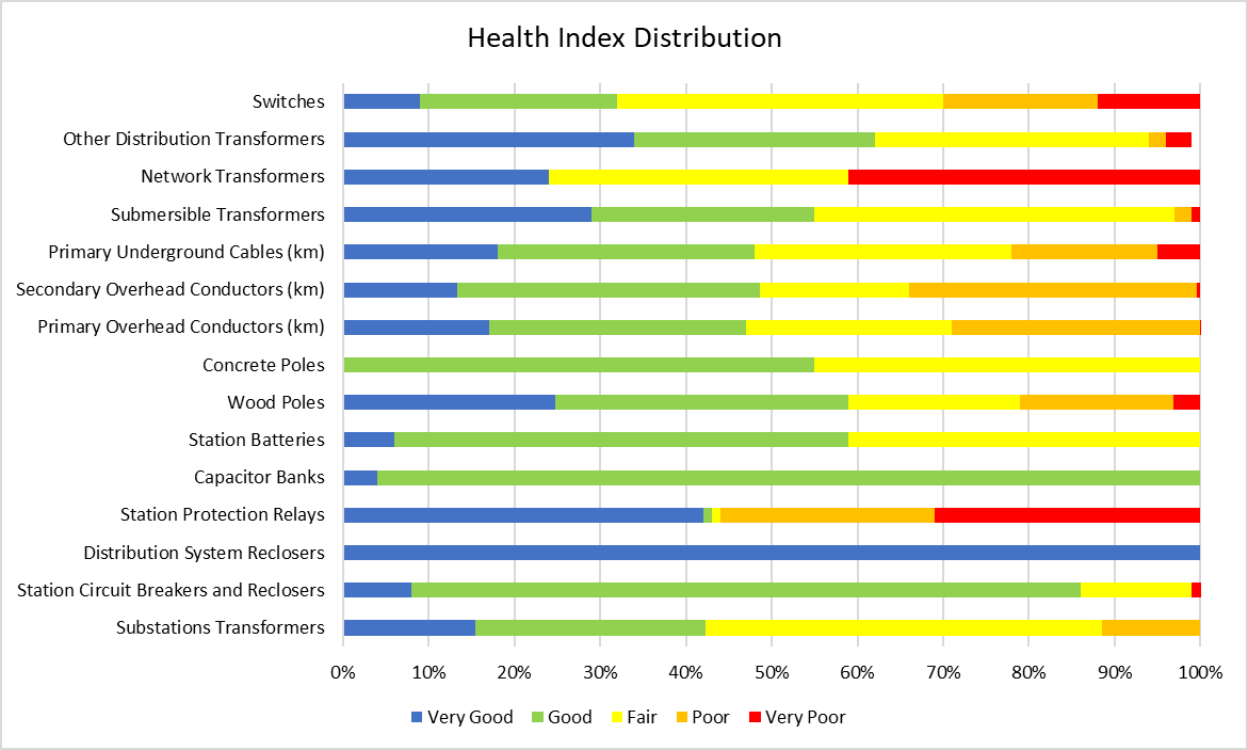


Table 3-5: Health Index Distribution Count Results

Asset Category	Count	Health Index Distribution (%)				
		Very Good	Good	Fair	Poor	Very Poor
Substation Transformers	26	15%	27%	46%	12%	0%
Station Circuit Breakers & Reclosers	169	8%	78%	13%	0%	2%
Distribution System Reclosers	28	100%	0%	0%	0%	0%
Station Protection Relays	281	42%	1%	1%	25%	31%
Capacitor Banks	73	4%	96%	0%	0%	0%
Station Batteries	16	6%	53%	41%	0%	0%
Wood Poles	15977	25%	34%	20%	18%	3%
Concrete Poles	7130	0%	55%	45%	0%	0%
Secondary OH Conductors (km)	327	13%	35%	17%	34%	0.4%
Primary Overhead Conductors (km)	1040	17%	30%	24%	29%	1%
Primary Underground Cables (km)	957	18%	30%	30%	17%	5%
Submersible Transformers	3704	29%	26%	42%	2%	1%
Network Transformers	34	24%	0%	35%	0%	41%
Other Distribution Transformers	7309	34%	28%	32%	2%	3%
Switches	4263	9%	23%	38%	18%	12%

Table 3-6: Age Distribution Count Results

Asset Category	Count	Age Demographics					
		0-10 Years	11-20 Years	21-30 Years	31-40 Years	41-50 Years	51+ Years
Substation Transformers	26	4	4	9	4	4	1
Station Circuit Breakers & Reclosers	169	13	107	38	11	0	0
Distribution System Reclosers	28						
Station Protection Relays	281	111	78	81	11	0	0

Capacitor Banks	73	3	70	0	0	0	0
Station Batteries	16	9	7	0	0	0	0
Wood Poles	15977	3931	2162	2775	1274	1282	4552
Concrete Poles	7130	555	1868	2676	1110	870	51
Secondary OH Conductors (km)	327	43.1	43.4	71.2	32.4	23.9	110.2
Primary Overhead Conductors (km)	1040	173.1	124.5	181.0	112.6	135.4	307.5
Primary Underground Cables (km)	957	167.9	277.0	282.1	159.3	39.8	2.2
Submersible Transformers	3704	100	1275	978	449	1	0
Network Transformers	34	14	1	0	2	15	2
Other Distribution Transformers	7309	1611	1602	2940	810	196	46
Switches	4263	376	977	1598	736	278	216

It is evident that network transformers, station protection relays and switches are asset classes that have a larger portion of the asset's condition being Very Poor. The remaining assets exhibit a condition degradation pattern that can be expected of a mature utility and require periodic system renewal to mitigate additional failure risks of assets. The ACA report, found in Appendix L, also provides a recommended replacement plan. The replacement plan is used as a preliminary baseline for KWHI on how many assets should be replaced to maintain the overall system health. The baseline does not consider external factors such as load growth, customer preference, external stakeholders or improvement in reliability measures. The baseline is primarily used as an initial approximation analysis for KWHI to understand the level of investment needed to maintain the current level of asset condition.

Station Transformers

The key role of station transformers is to step down transmission or sub-transmission voltage to distribution voltage. KWHI has 19 TS transformers of which three are spare power transformers and seven Distribution Station (DS) transformers. Figure 3.8 presents the age distribution of TS and DS transformers. Of 19 TS transformers 15 are less than 30 years old and 4 are between 31-50 years. One of the DS transformers is in-service for more than 50 years. 12% of the station transformers are in Poor condition, 46% are in Fair condition and remaining 42% are in Good or Very Good condition, shown in Figure 3.9.

Figure 3.8: Station Transformer Age Demographic

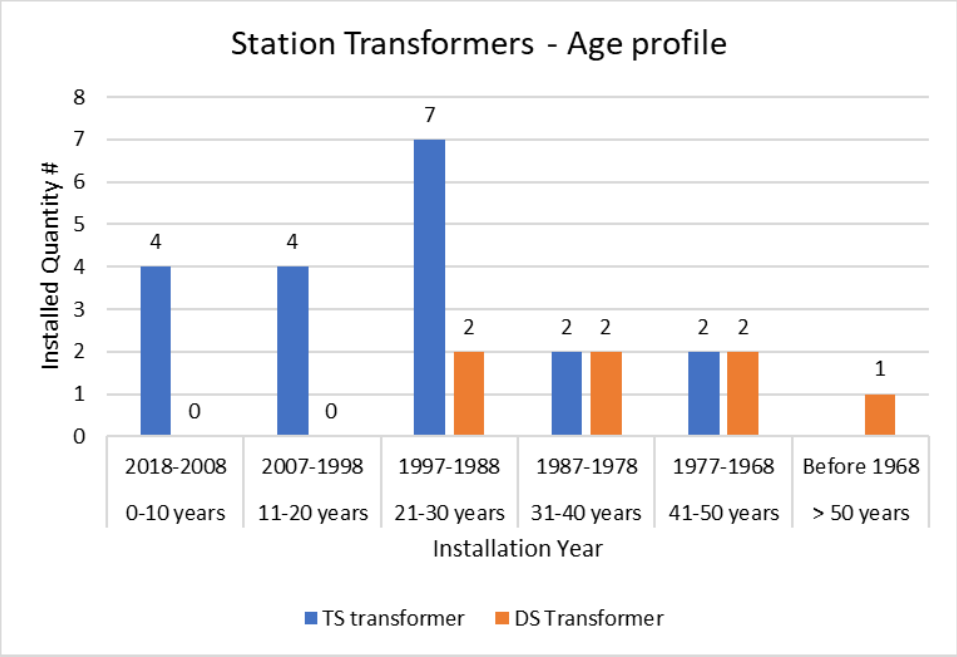
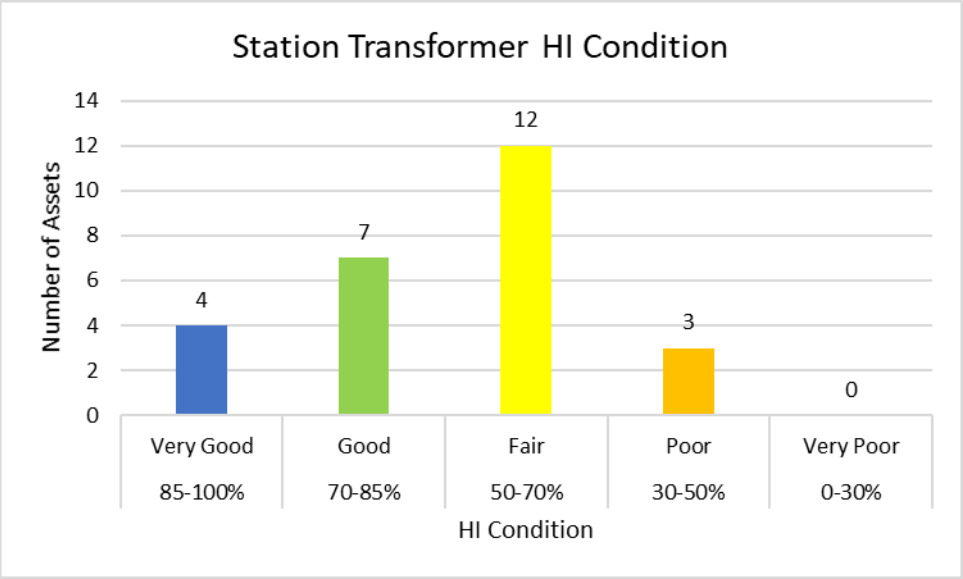


Figure 3.9: Station Transformer Health Index Demographic



Station Circuit Breakers and Reclosers

KWHI's distribution system employs a total of 168 Circuit Breakers (CBs), of which 149 are either vacuum type or SF6 type in the TS and 20 are reclosers or air breakers in the DS. Age distributions of these breakers and reclosers are presented in Figure 3.10. All the Vacuum CBs at the TS of KWHI are in-service for less than 20 years. SF6 CBs are between 21-40 years old. There are three air breakers in-service at 6 DS for about 36 years and 17 Reclosers between the age of 21 to 30 years at other DS. 2% of the circuit breakers are in Very Poor condition mainly due to service age parameter, nearly 13% are in Fair condition and remaining 85% are in Good or Very Good condition, shown in Figure 3.11.

KWHI owns a total of 28 distribution reclosers installed in their distribution system at 27.6 or 13.8 kV level. All the reclosers are quite new with less than 5 years in service. All the reclosers in the distribution system are new and hence assumed to be in Very Good condition.

Figure 3.10: Circuit Breaker Age Demographic

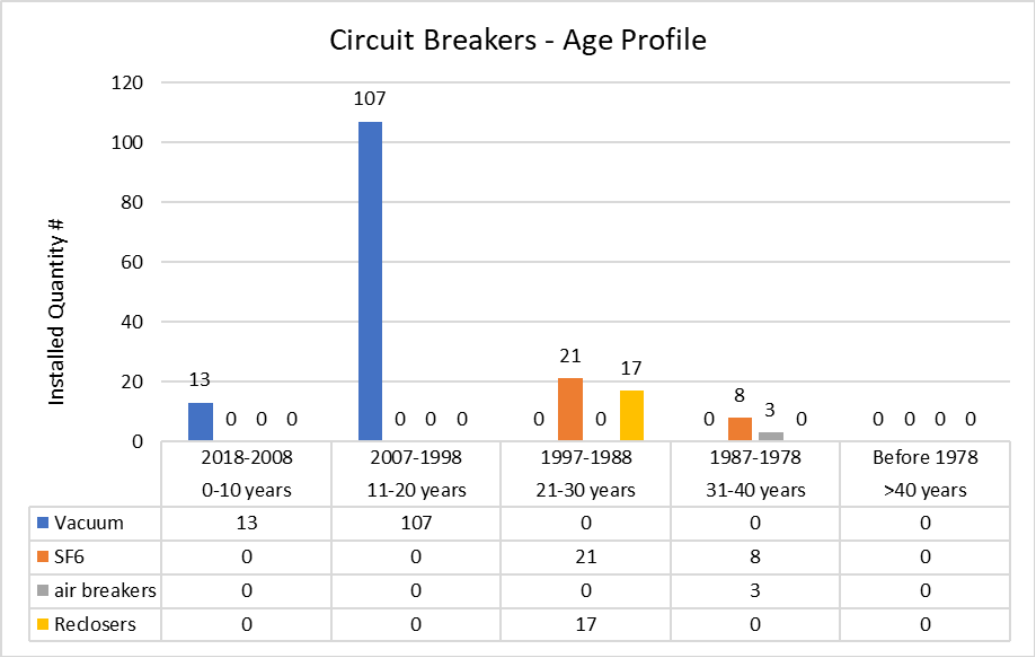
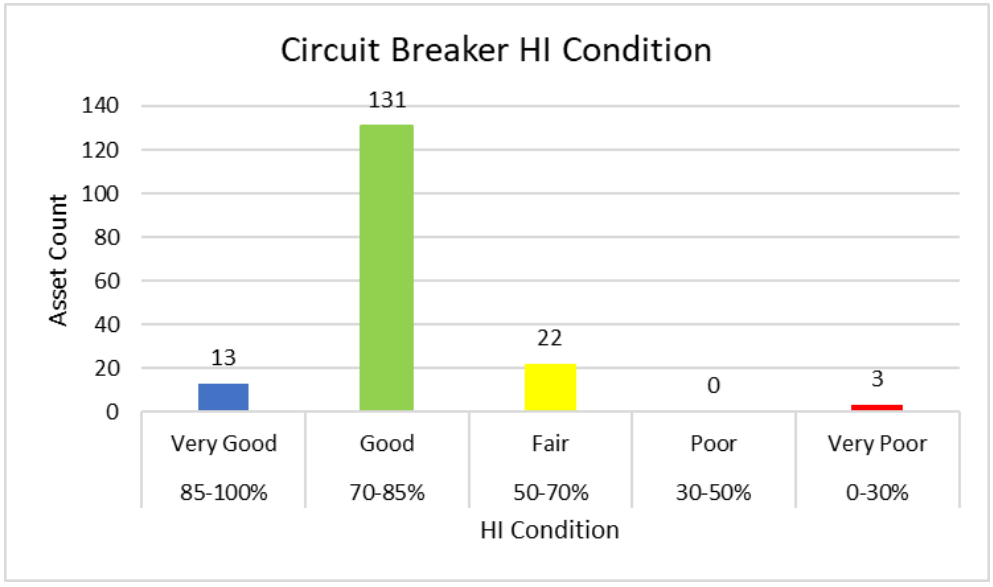


Figure 3.11: Circuit Breaker Health Index Demographic



Station Protection Relays

The function of protection relays on distribution systems is to detect and annunciate abnormal operating conditions and initiate circuit breaker or recloser trip to isolate faulty circuits from healthy circuits. Protection relays obtain their input from instrument transformers, process the information and automatically take corrective action with adequate speed and selectivity.

KWHI employs a total of 281 protection relays in its transformer and distribution stations. Figure 3.12 presents the age demographics of these relays by their types, digital, electronic, and electromechanical. Eleven protection relays are in-service for 31-40 years. Oldest relays in-service

are 2 electromechanical relays of 38 years old. Most digital relays have been installed in the last 10 years. 31% of the relays are in Very Poor condition. The main factors driving these relays into Very Poor condition are non-discretionary obsolescence considerations. KWHI has identified several of the oldest relays to be obsolete. About 25% of the protection relays are in Poor condition, and 1% are in Fair condition. Remaining 43% are in Good or Very Good condition, shown in Figure 3.13.

Figure 3.12: Protection Relay Age Demographic

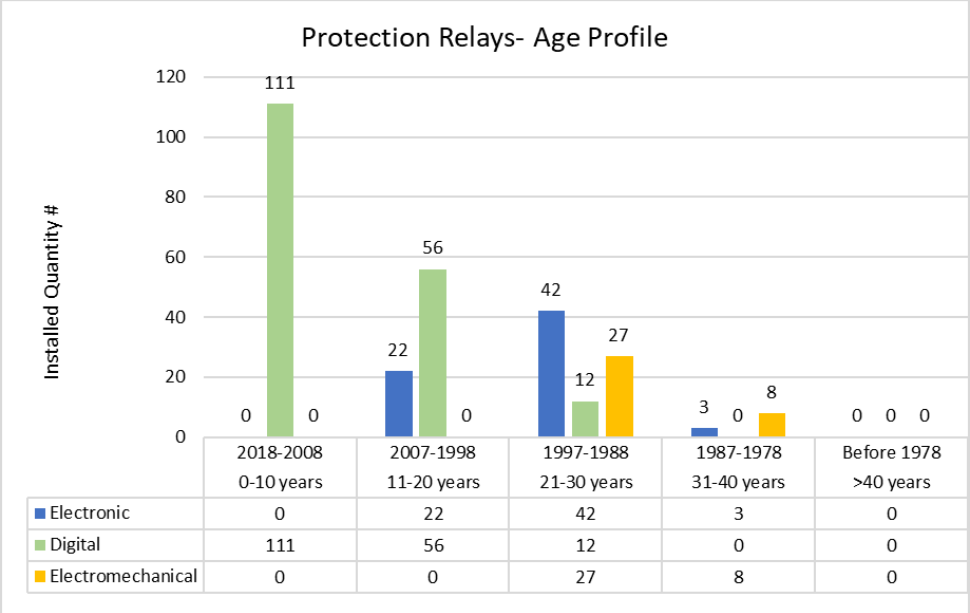
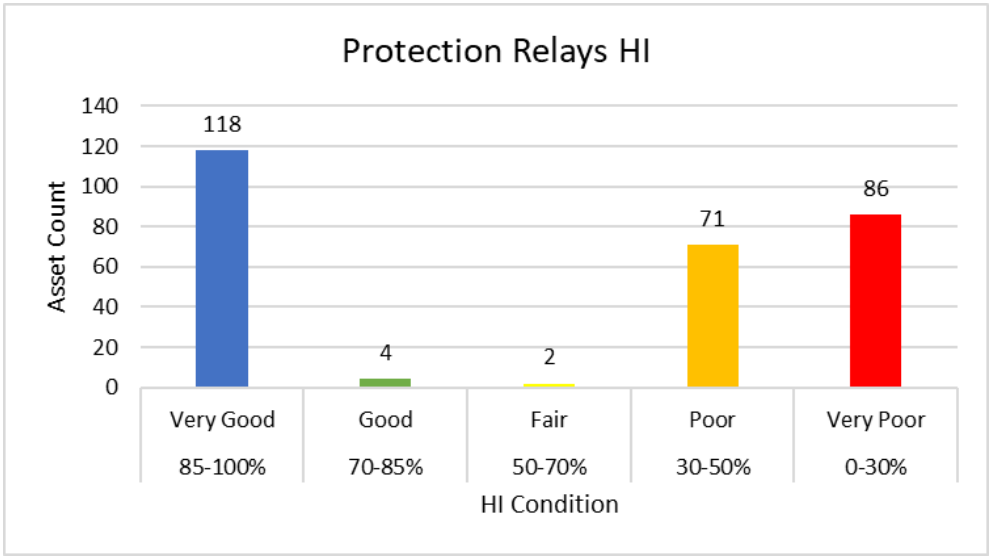


Figure 3.13: Protection Relay Health Index Demographic



Capacitor Banks

Shunt capacitors, connected in parallel to the line load, are employed to provide VAR compensation for power factor improvement and they provide the benefits of improved voltage, reduced kVA demand, reduced line current and reduced system loss. KWHI employs 73 OH capacitor banks in ground wye configuration. Approximately 92% of the population are fixed type banks and the remaining

8% are switched types. Figure 3.14 presents the age profile of capacitor banks. All the capacitors are less than 20 years of age. All the capacitors are in either Good or Very Good Health Index condition shown in Figure 3.15.

Figure 3.14: Capacitor Bank Age Demographic

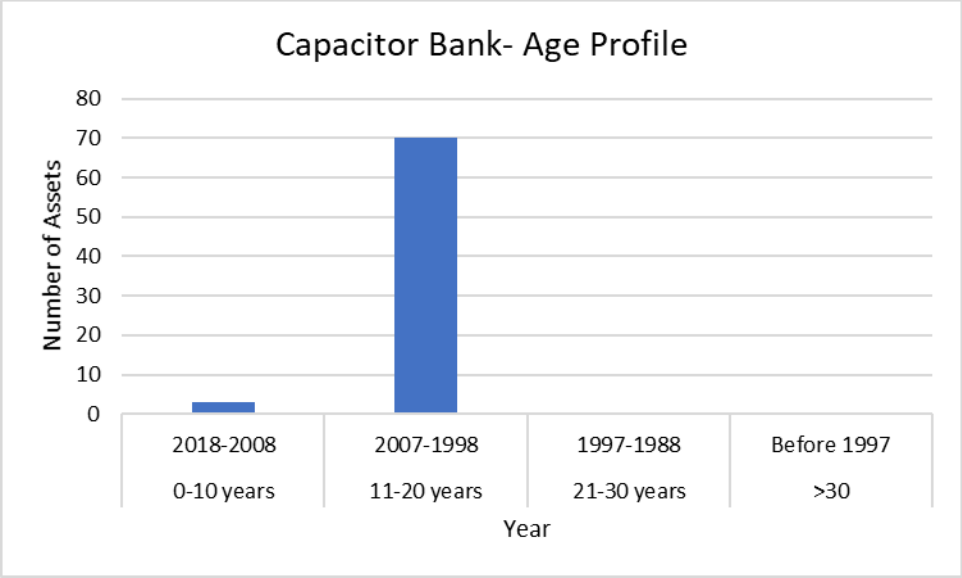
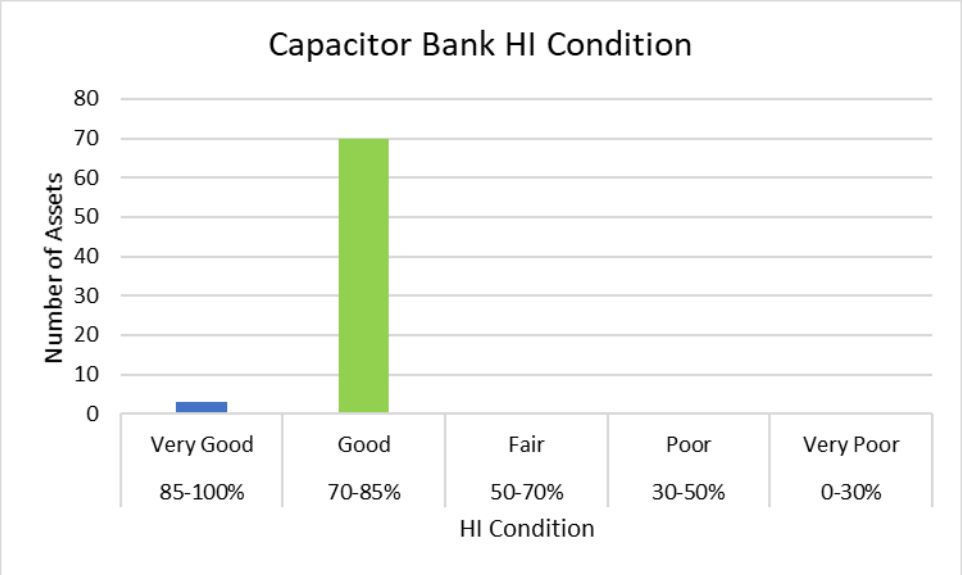


Figure 3.15: Capacitor Bank Health Index Demographic



Station Batteries

The purpose of substation control batteries is to provide power for critical control functions such as trip coils of circuit breakers. KWHI's distribution system commonly uses lead acid batteries. Batteries are carefully sized to store adequate energy for system operation during an AC power failure.

Figure 3.16 shows the age demographics of station batteries. Majority of the batteries are less than 10 years old. Majority of the batteries are Good condition followed by Fair condition, shown in Figure 3.17.

Figure 3.16: Station Battery Age Demographic

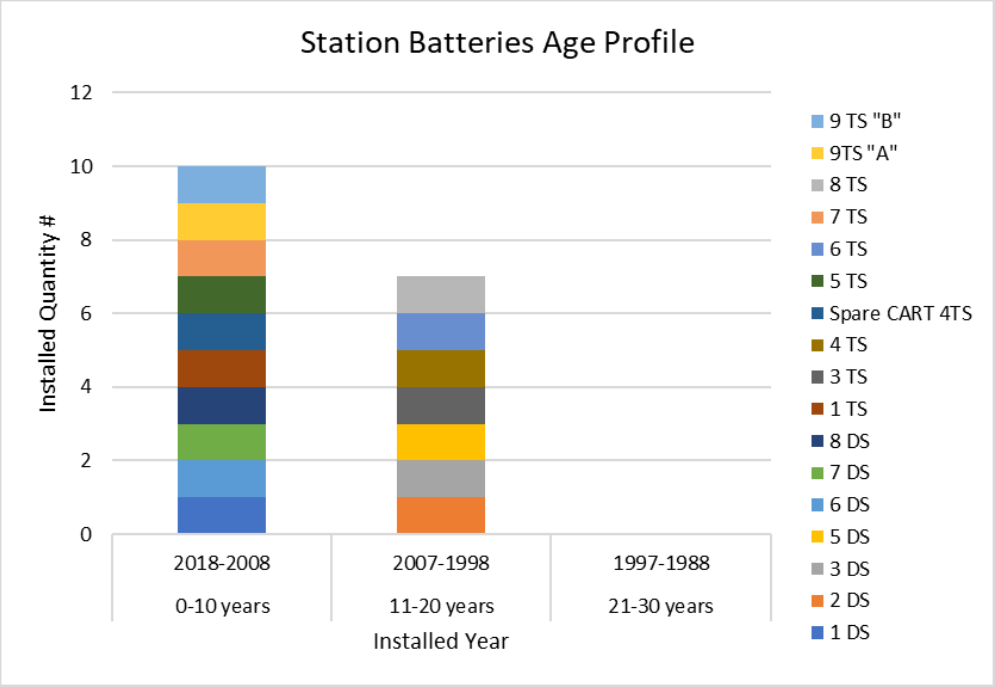
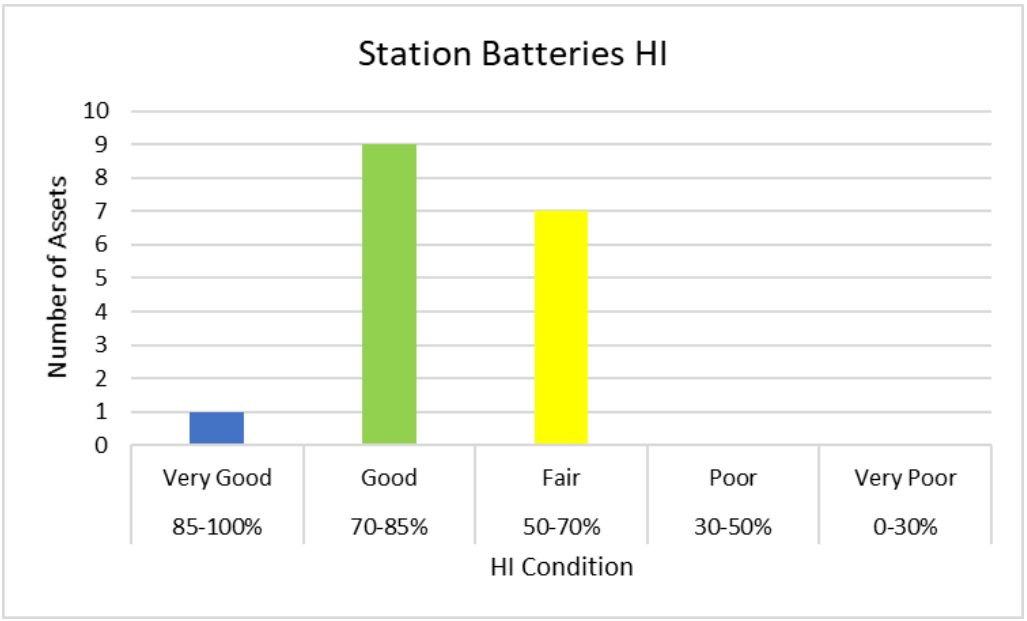


Figure 3.17: Station Battery Health Index Demographic



Wood Poles

KWHI owns 15977 wood poles. Figure 3.18 presents the age demographics of wood poles Figure 3.19 shows the age demographics of wood pole by pole type. Of the 5802 single-phase poles, 39% are

above 50 years old, 18% are between 31 to 50 years, and 43% are in-service for less than 30 years. Of the 5081 three-phase poles, 18% are above 50 years old, 13% are between 31 to 50 years, and 69% are less than 30 years old. KWHI owns about 2275 secondary poles, of which, 46% are in-service for more than 50 years, 15% are in-service between 31 to 50 years and 39% are in-service for less than 30 years. As seen in Figure 3.20, about 3% of the poles are found to be in Very Poor condition.

Figure 3.18: Wood Pole Age Demographic

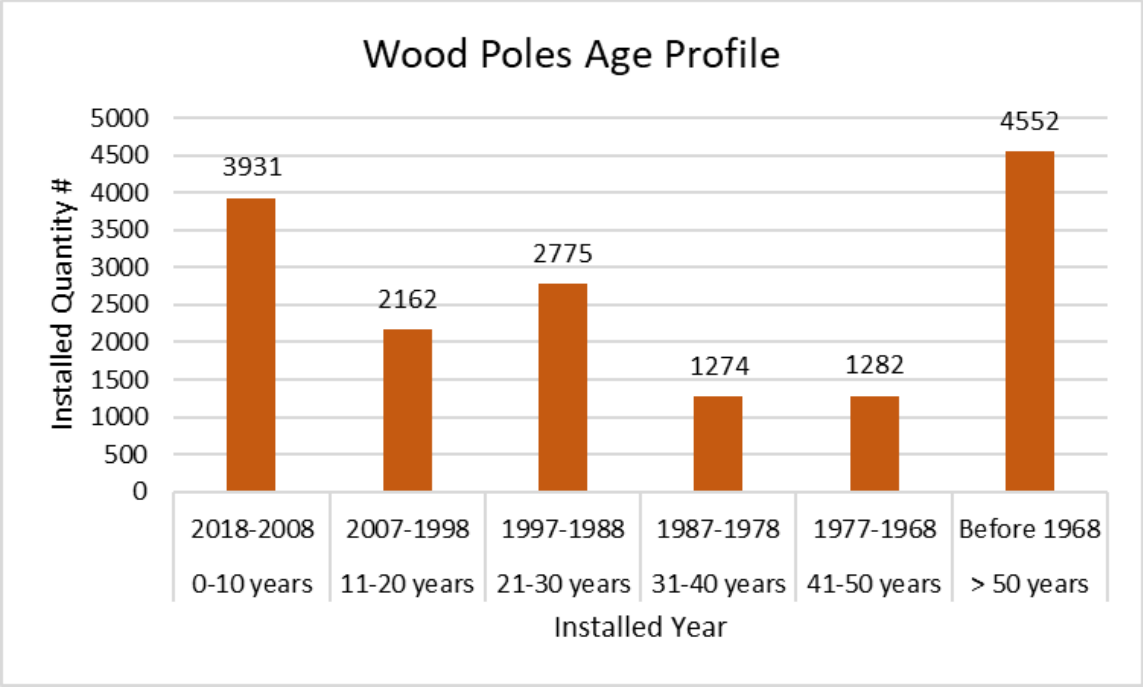


Figure 3.19: Wood Pole Age Demographic by Pole Type

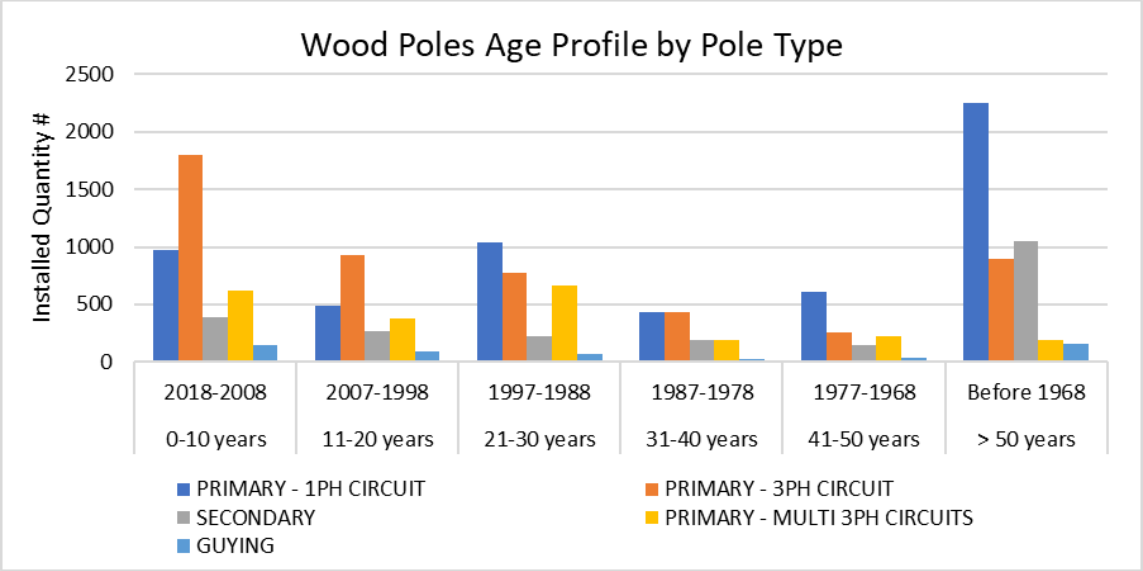
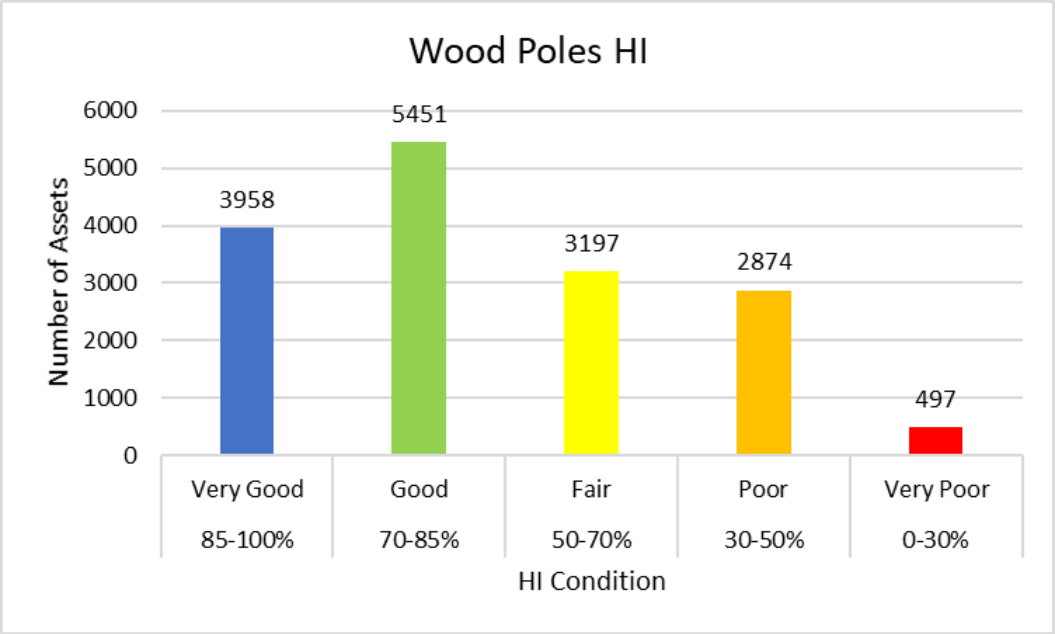


Figure 3.20: Wood Pole Health Index Demographic



Concrete Poles

KWHI owns 7130 concrete poles. Figure 3.21 presents the age demographics of concrete poles and Figure 3.22 present the age demographics of concrete poles by pole types. Of the 717 single-phase poles, 1% are above 50 years old, 24% are between 31 to 50 years, and 75% are in-service for less than 30 years. Of the 4487 three-phase poles, 1% are above 50 years old, 31% are between 31 to 50 years, and 68% are less than 30 years old. KWHI owns about 764 secondary concrete poles, of which, 2% are in-service for more 50 years, 18% are in-service between 31 to 50 years and 80% are in-service for less than 30 years. All 785 primary-multi 3-phase poles are in-service for less than 50 years, of which, 24% are in-service between 31 to 50 years, and remaining 76% are in-service for less than 30 years. As seen in Figure 3.23, concrete poles are either in Good or Fair condition.

Figure 3.21: Concrete Pole Age Demographic

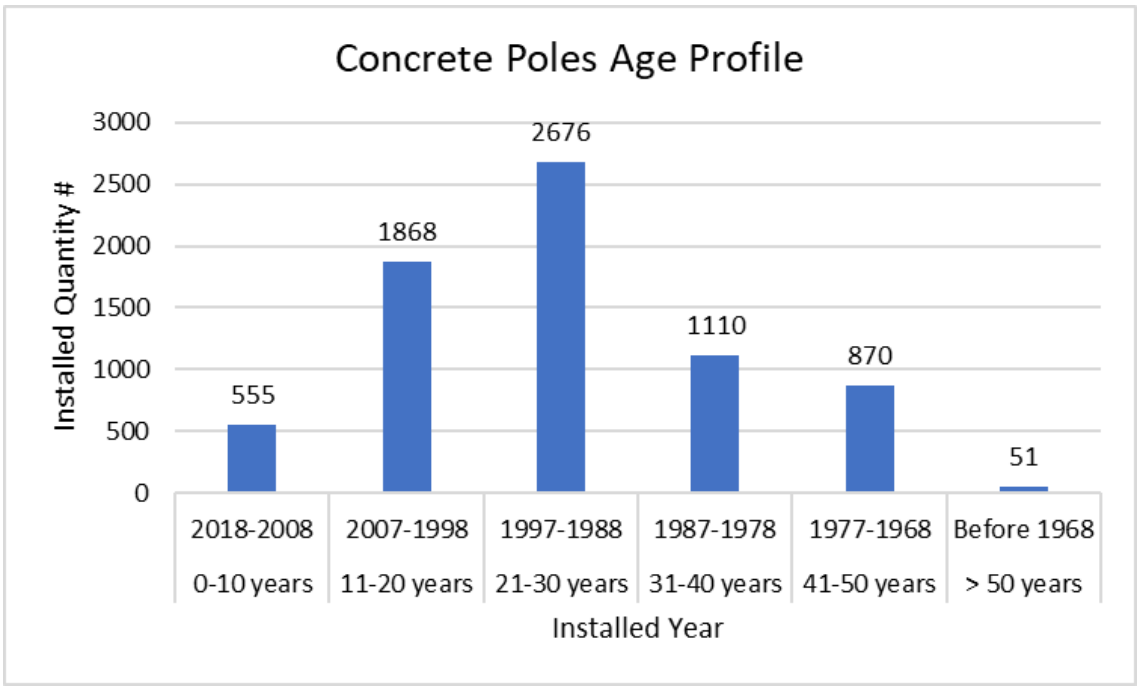


Figure 3.22: Concrete Pole Age Demographic by Pole Type

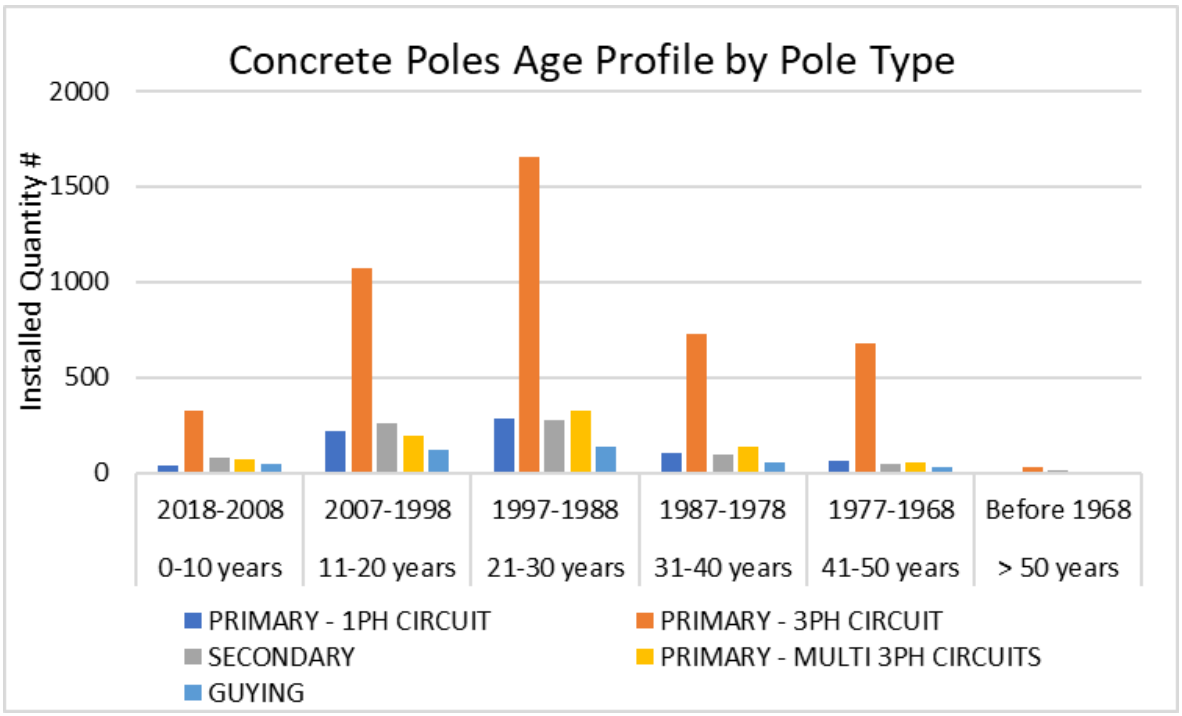
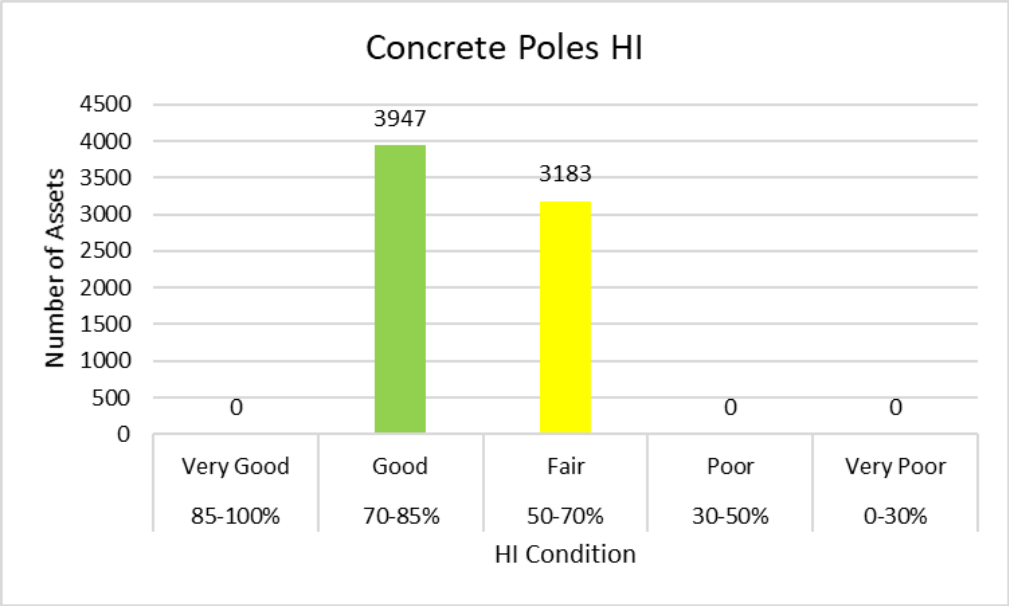


Figure 3.23: Concrete Pole Health Index Demographic



Overhead Conductors

Overhead conductor length is measured in kilometres of circuit, where a 1-km run of three-phase cable is measured as 1 km rather than 3 km. KWHI owns 1040 km of primary overhead conductors across its distribution system. The installation year is known for 1034 km of conductors – or 99% of the population. Figure 3.24 presents the overhead primary conductor age profile. 30% of the conductor length is more than 50 years old, 24% are in-service for about 31 to 50 years and 46% conductor length is in-service for less than 30 years. Figure 3.26 presents the Health Index condition for Overhead Primary Conductors. About 1% of the population are in Very Poor condition, 29% are in Poor condition, 24% are in Fair condition, and 46% are in Good or Very Good condition.

Figure 3.24: Overhead Primary Conductor Age Demographic

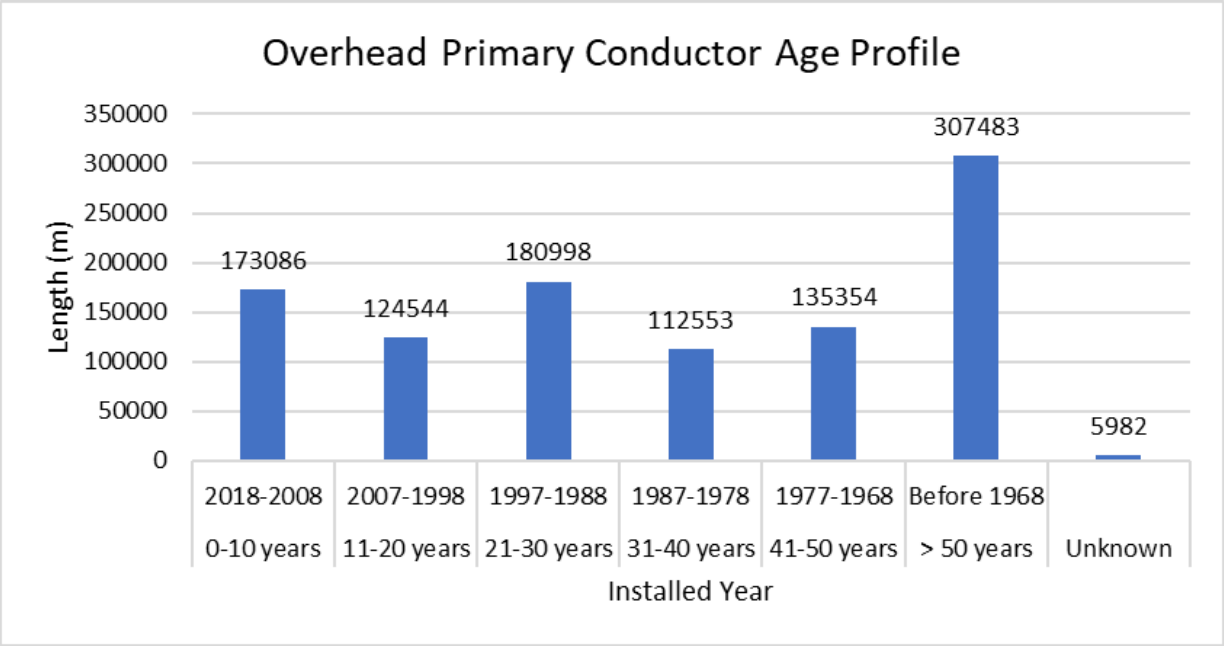
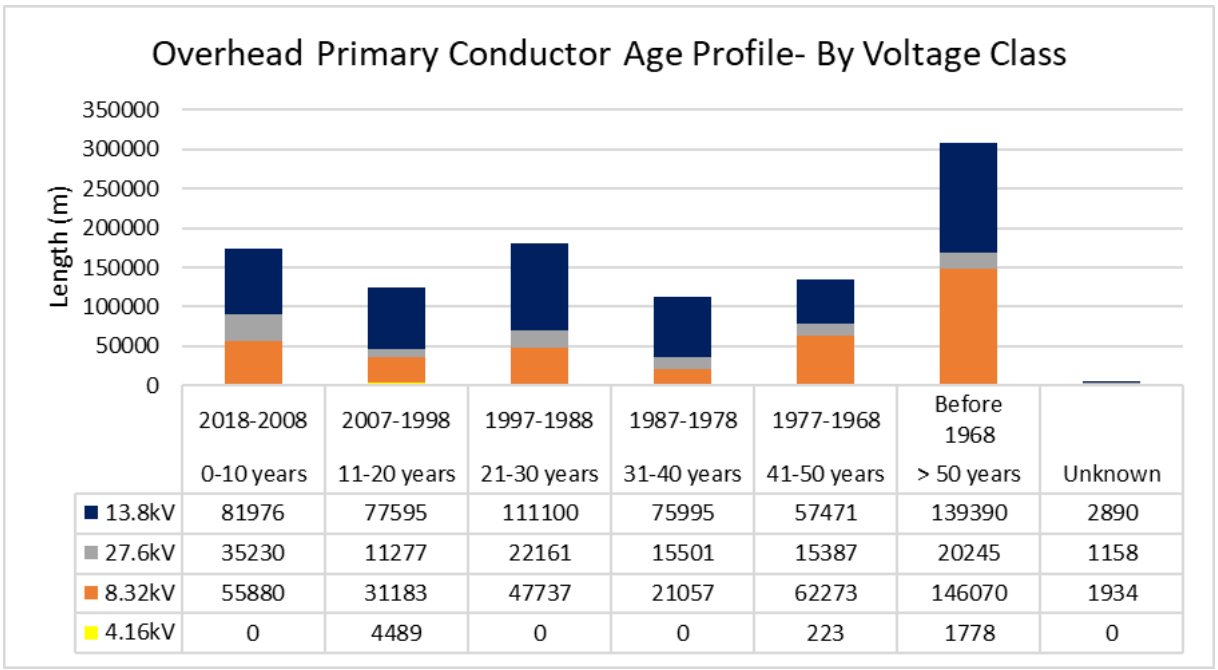
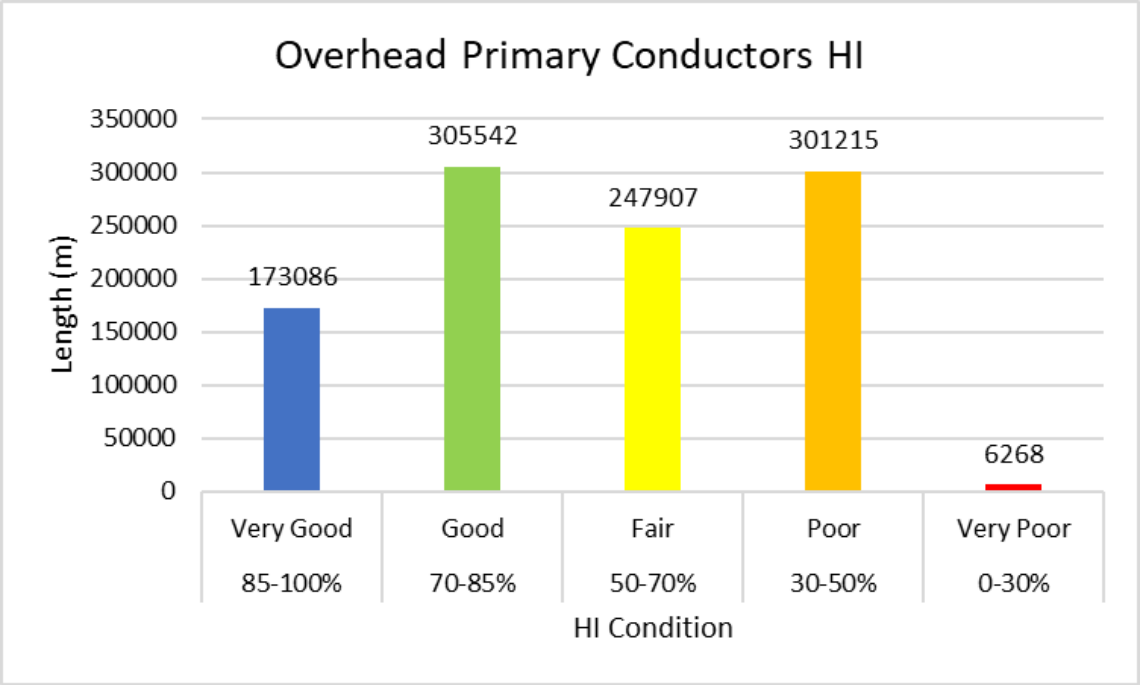


Figure 3.25: Overhead Primary Conductor Age Demographic by Voltage Class



	2018-2008 0-10 years	2007-1998 11-20 years	1997-1988 21-30 years	1987-1978 31-40 years	1977-1968 41-50 years	Before 1968 > 50 years	Unknown
13.8kV	81976	77595	111100	75995	57471	139390	2890
27.6kV	35230	11277	22161	15501	15387	20245	1158
8.32kV	55880	31183	47737	21057	62273	146070	1934
4.16kV	0	4489	0	0	223	1778	0

Figure 3.26: Overhead Primary Conductor Health Index Demographic



KWHI's distribution system employs 327 km of secondary conductors. The age information is known for 99% of the populations which was populated using the age of connected pole. Figure 3.27 presents the age distribution of these conductors by length (m). About 34% of the population is in-service for more than 50 years. Figure 3.28 presents the Health Index condition for Overhead Secondary Conductors. About 0.4% of the population are in Very Poor condition, 34% are in Poor condition, 17% are in Fair condition, and 49% are in Good or Very Good condition.

Figure 3.27: Overhead Secondary Conductor Age Demographic

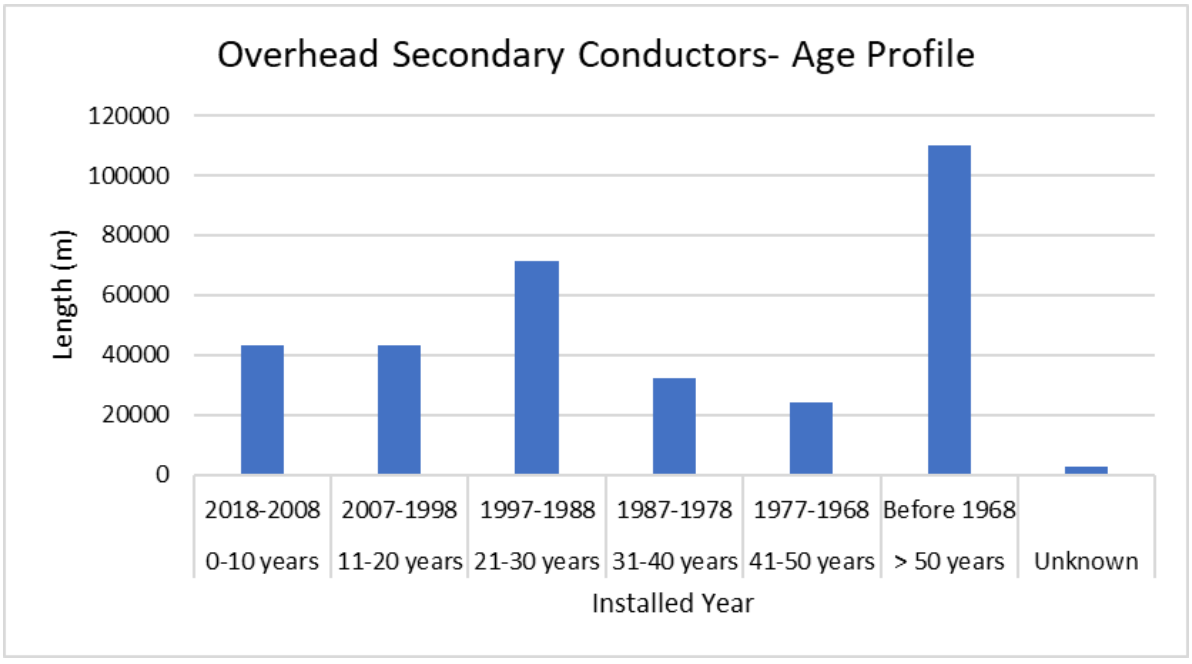
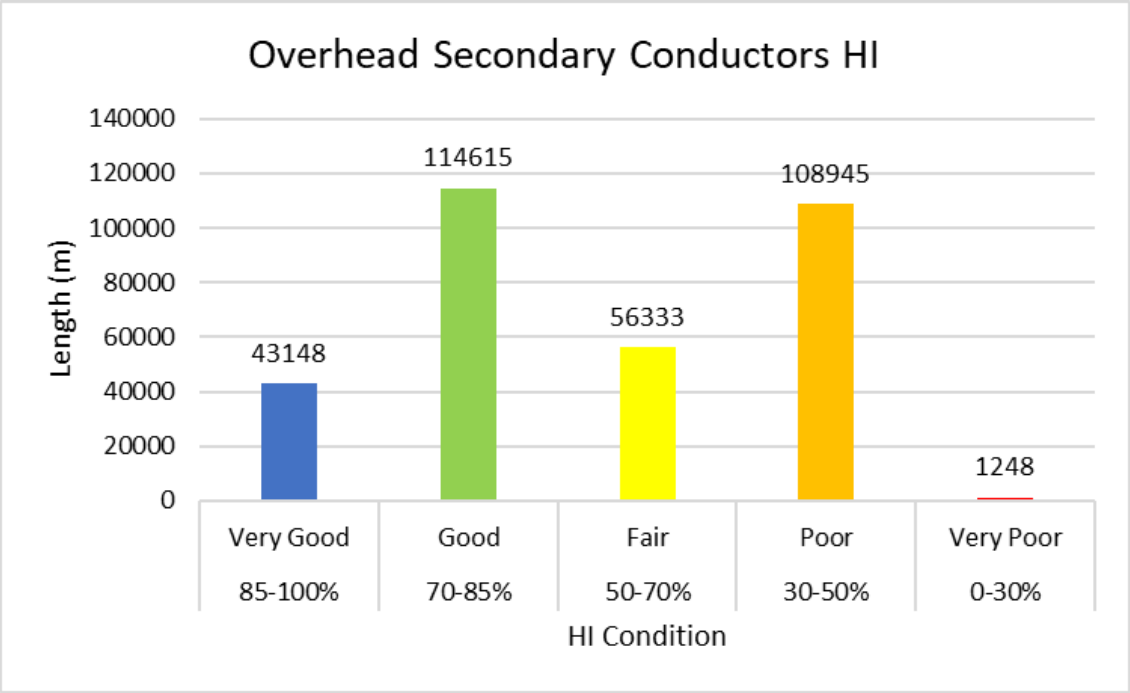


Figure 3.28: Overhead Secondary Conductor Health Index Demographic



Underground Cables

Underground cable length is measured in kilometres of circuit, where a 1-km run of three-phase cable is measured as 1 km rather than 3 km. KWHI owns 957 km of primary underground cables across its distribution system. The installation year is known for about 928 km of cables – or 97% of the length. Figure 3.29 presents the underground primary cables age profile. Majority of the cables were installed within the last 50 years, 21% are in-service for about 31 to 50 years and 76% cable length is in-service for less than 30 years. Figure 3.30 presents the underground primary cable age distribution by voltage class. Majority of the cables are rated 13.8 kV. Figure 3.31 presents the Health Index condition for Underground Primary Cables. About 5% of the population are in Very Poor condition, 17% are in Poor condition, 30% are in Fair condition, and 48% are in Good or Very Good condition.

Figure 3.29: Underground Primary Cable Age Demographic

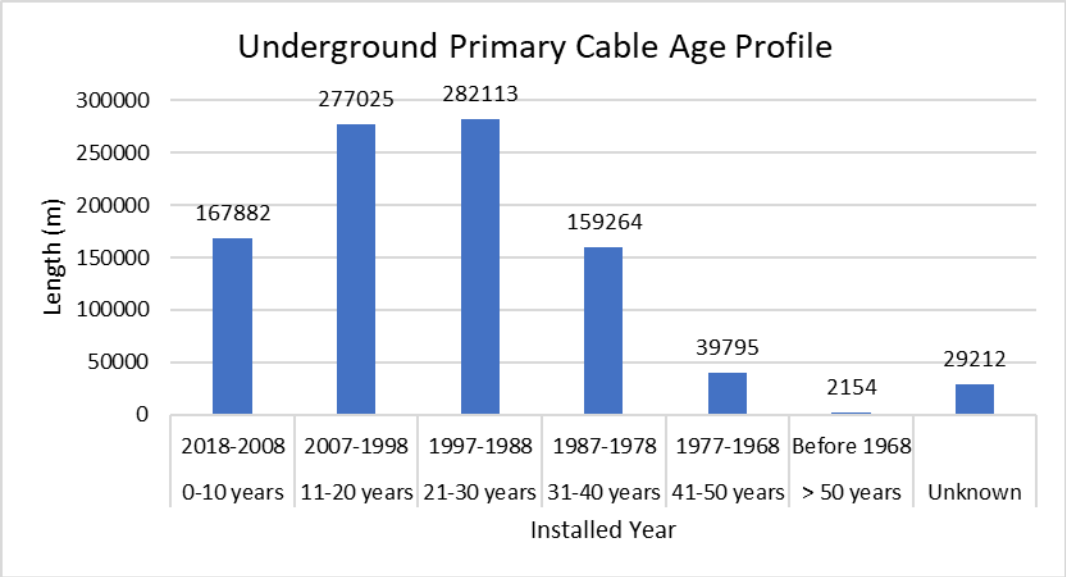
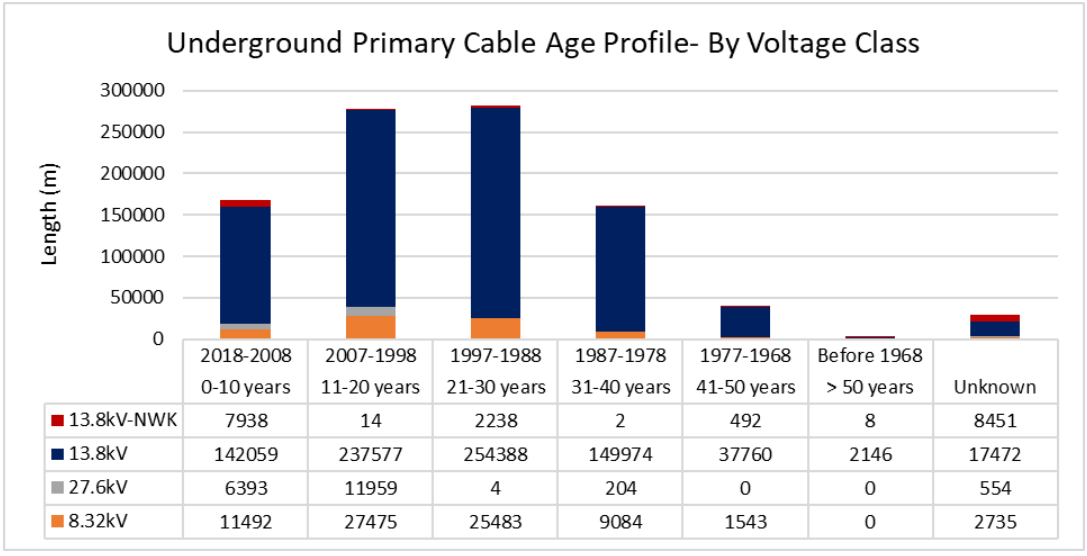
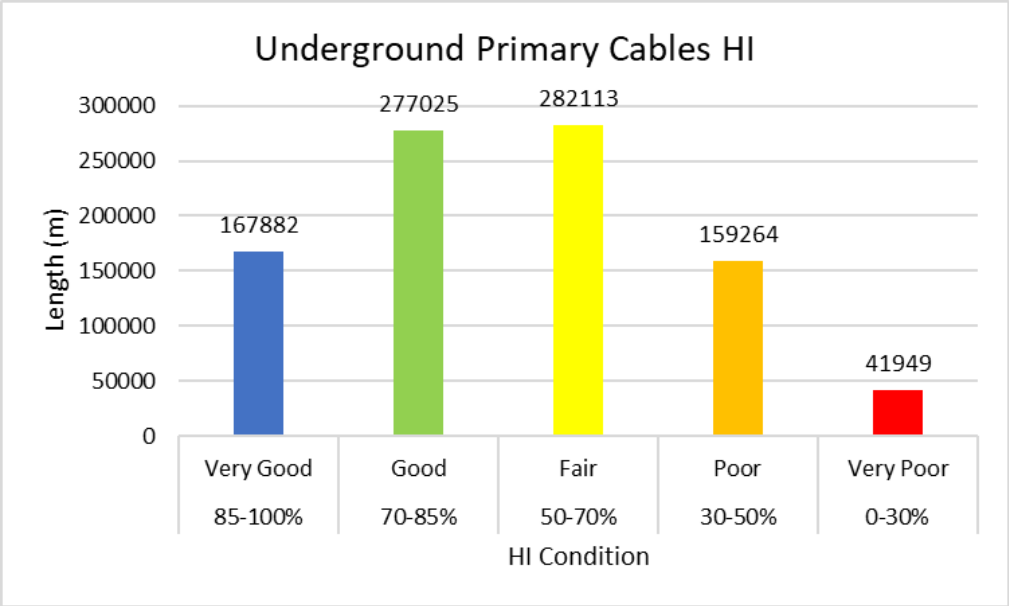


Figure 3.30: Underground Primary Cable Age Demographic by Voltage Class



	2018-2008 0-10 years	2007-1998 11-20 years	1997-1988 21-30 years	1987-1978 31-40 years	1977-1968 41-50 years	Before 1968 > 50 years	Unknown
13.8kV-NWK	7938	14	2238	2	492	8	8451
13.8kV	142059	237577	254388	149974	37760	2146	17472
27.6kV	6393	11959	4	204	0	0	554
8.32kV	11492	27475	25483	9084	1543	0	2735

Figure 3.31: Underground Primary Cable Health Index Demographic



Submersible Transformers

As previously stated, KWHI have been using single-phase submersible transformers for servicing residential subdivisions for more than 40 years. Local distribution utilities have adopted pad-mounted transformers for underground residential distribution service, whereas KWHI continued to use submersible transformers.

The observed failure rate of submersible transformers continues to be significantly higher than other transformers (approximately 4 times higher as seen in Figure 2.8). Coupled with the higher failure rate is also the longer duration to replace a submersible transformer (typically six hours) when compared to a pad-mounted transformer (typically three hours) and the cost of installation is also higher by up to 40%.

Commencing January 2019, KWHI will begin installing pad-mounted transformers in all new residential subdivisions instead of submersible transformers. Existing in-service submersible transformer locations that fail will be evaluated on a case by case basis and may result in a like-for-like replacement or reconfigured to a pad-mount transformer. For comparison, Figure 3.32: and Figure 3.33: present the age and condition comparison between submersible and pad-mount transformers. The ratio of submersible transformers to pad-mount transformers is almost 3:1. Reducing the ratio will reduce the observed failures which in turn will reduce the cost and duration impact for replacement.

Figure 3.32: Transformer Age Comparison

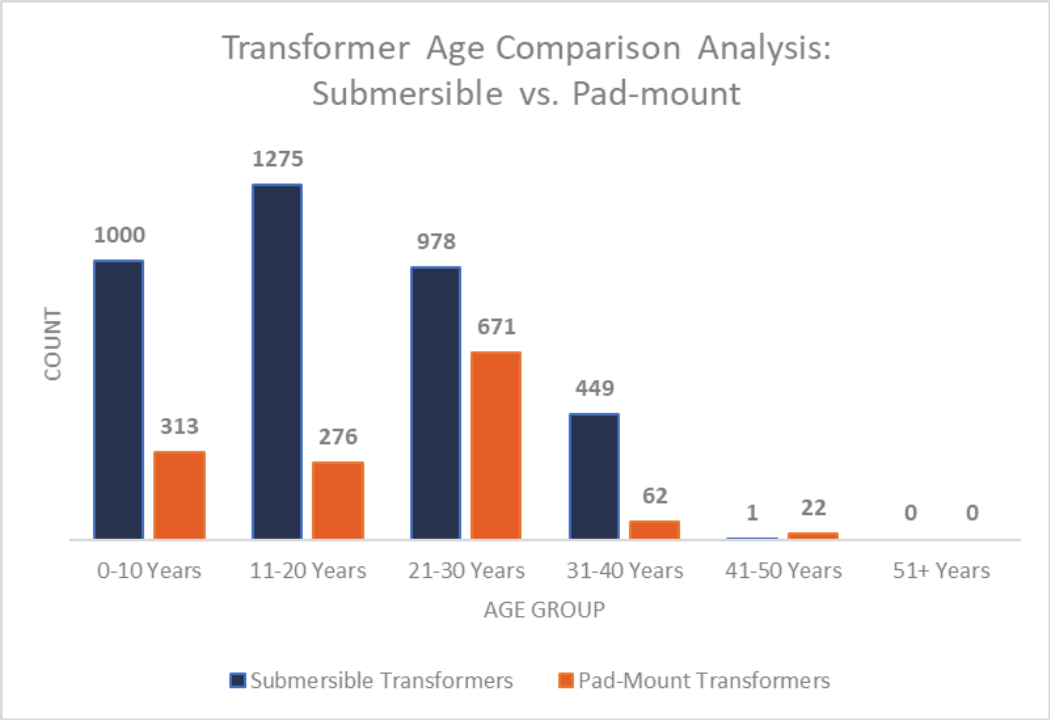
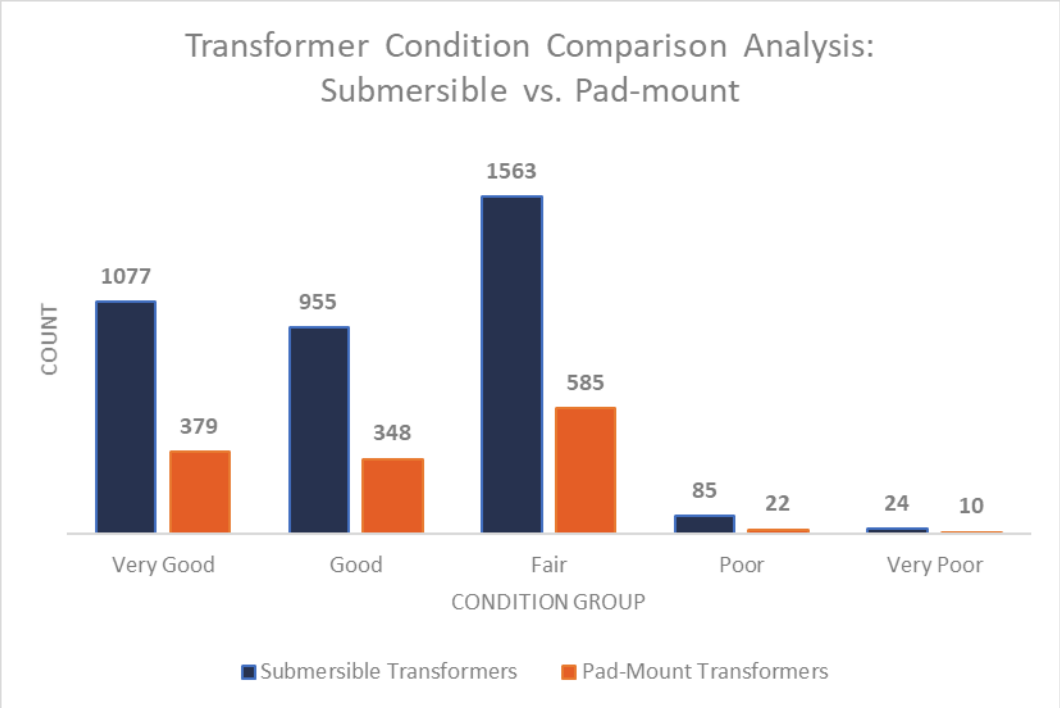


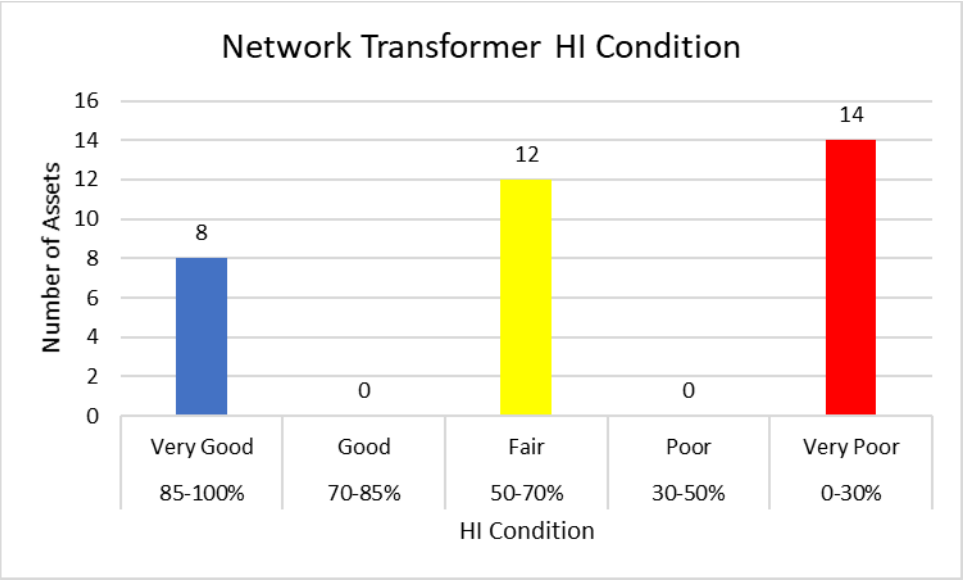
Figure 3.33: Transformer Condition Comparison



Network Transformer

Figure 3.34 presents the Health Index condition for network transformers. About 41% of the population are in Very Poor condition mainly due to service age and the failed visual examination. Nearly 35% are in Fair condition, and the remaining 24% are in Very Good condition.

Figure 3.34: Network Transformer Health Index Demographic



Supplementary Transformers

Health Index for the remaining distribution transformers is calculated using both age and the peak loading information and Figure 3.35 presents the Health Index condition. About 3% of the population are in Very Poor condition, another 2% are in Poor condition, nearly 32% are in Fair condition, and the remaining 62% are in Good or Very Good condition. Table 3-7 presents the breakdown of Health Index condition by transformer types.

Figure 3.35: Distribution Transformer Health Index Demographic

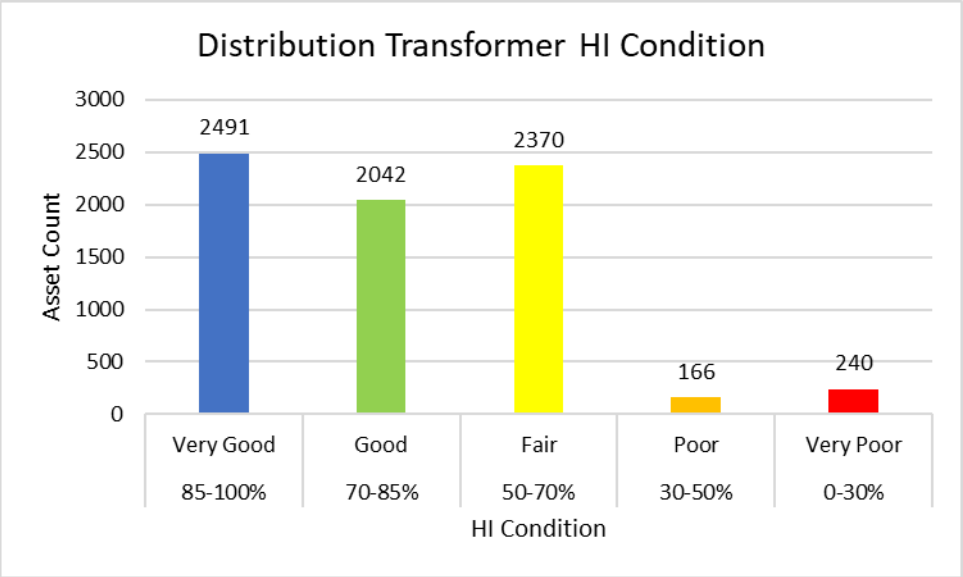


Table 3-7: Distribution Transformer Health Index Demographic

Transformer Type	Health Index Condition				
	Very Poor	Poor	Fair	Good	Very Good
Pad-mounted	10	22	585	348	379
Overhead	130	137	1403	1088	1642
Customer Owned	9	0	10	30	150
Network	14	0	12	0	8
Overhead Bank	7	2	51	37	25
Submersible	24	85	1563	955	1077
Underground	6	5	102	111	51
Underground Bank	78	0	219	428	244

Switches

KWHI's distribution system has a total of 4263 various types of overhead and underground switches including load break, load interrupters, fused load interrupters, etc. operating at voltages 8.32 kV, 13.8 kV, and 27.6 kV. The installation age data is available for 98% of the assets. Figure 3.36 presents the age demographics of KWHI's distribution switches. Approximately 12% of the population are in-service for more than 40 years which are mainly overhead switches. Switches with service age range of 30 to 40 years accounts for about 17% of the population of which 15% are overhead. The remaining 69% of the population are less than 30 years of age. Figure 3.37 presents the Health Index demographic for distribution switches.

Figure 3.36: Distribution Switch Age Demographic

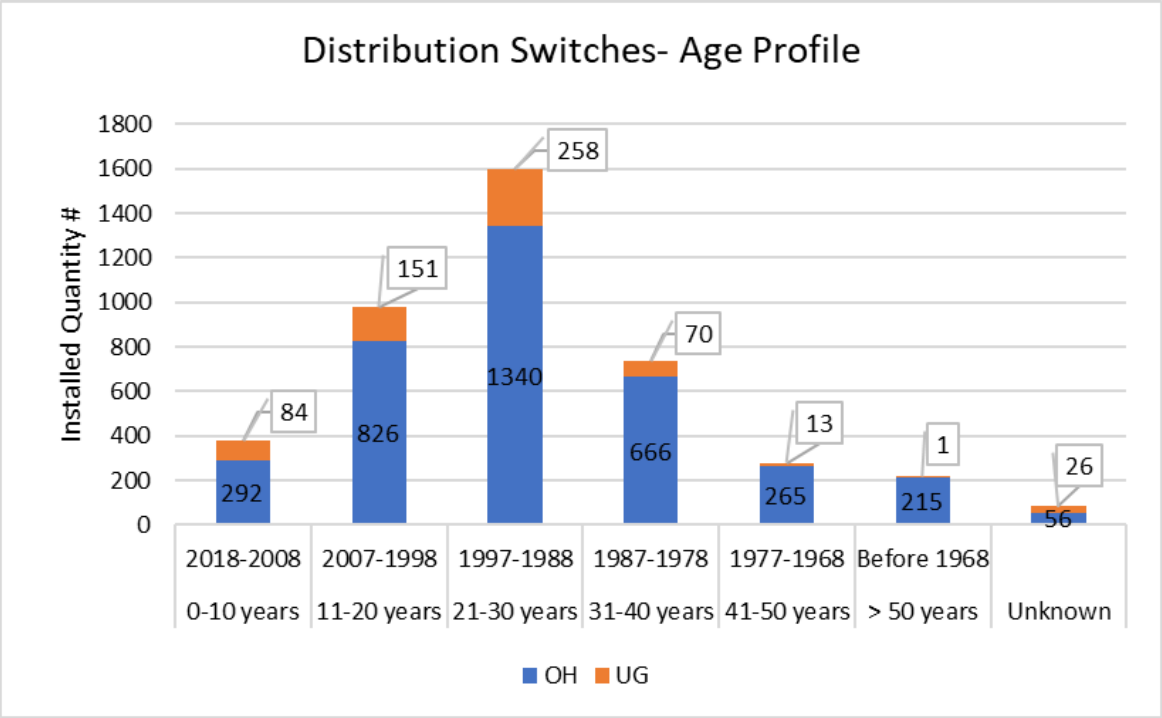


Figure 3.37: Distribution Switch Health Index Demographic

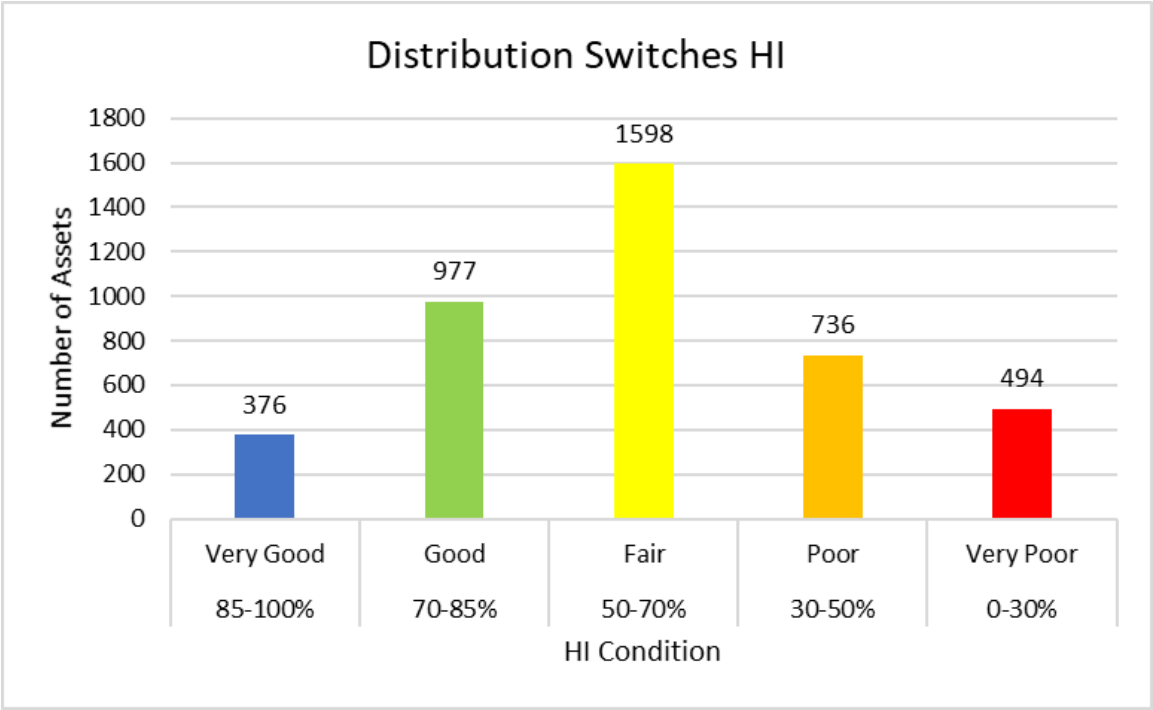


Table 3-8 highlights the baseline recommended asset replacement over the forecast period to maintain the system's health and to effectively continue managing the system's risk and performance. KWHI's intention is to follow the recommended approach with adjustments made where identified as the

forecast capital plans are developed. Ranges are proposed to provide flexibility in KWHI's asset management processes.

Table 3-8: Asset Replacement Recommendation based on the ACA

Asset Category	Age Demographics					
	2018	2019	2020	2021	2022	2023
Substation Transformers	0	0-1	0-1	0-1	0-1	0
Station Circuit Breakers & Reclosers	0-1	1-2	0-1	0	0-1	0-1
Distribution System Reclosers	0	0	0	0	0	0
Station Protection Relays	0-2	5-7	30-35	0-9	25-29	20-25
Capacitor Banks	0	0	0	0	0	0
Station Batteries	0	0	0	0	0	0
Wood Poles	425-450	425-450	425-450	425-450	425-450	425-450
Primary Underground Cables (km)	10-12	10-12	10-12	10-12	15-17	15-17
Submersible Transformers	10-20	4-14	20-22	20-22	20-22	20-22
Network Transformers	4-6	8-10	0	0	0	1-2
Other Distribution Transformers	80-85	80-85	80-85	40-45	40-45	40-45
Switches	100-108	100-108	130-140	130-140	150-160	150-160

3.2.4 System Utilization (5.3.2d)

Station Capacity

For planning purposes, Transformer Stations (TS) can be loaded up to 100% of nameplate of a single transformer. For contingency purposes, there is a 60-day overload capacity of approximately 120% for at least two hours a day. This will allow enough time for a worst-case transformer failure requiring the replacement of the transformer.

Distribution Stations (DS) are planned, configured and loaded to 100% normal rating. There are sufficient 8.32kV feeder interconnections that allow for an entire DS to be backed up from one or more adjacent DS. A distribution station transformer should not be loaded above its normal rating during non-contingency situations. Operating above normal rating will result in a shortening of the transformer service life. Under contingency situations load is to be transferred to other distribution stations, without exceeding the normal rating of the distribution station transformers or circuits receiving the load, as soon as possible.

The table below indicates an average utilization rate of 61% of total capacity for the transformer stations and 62% of total capacity for the distribution stations over the historical period 2014-2018. It should be noted that the peak load at each transformer station is calculated as the coincident peak on the day when KWHI experience an overall system peak. Also, from time-to-time loads are transferred from one station to anther to facilitate planned and emergency work and may impact the individual station peak load.

Table 3-9: KWHI 2014 – 2018 Station loading

TS/DS Name	Capacity (MVA)	2014 Peak Load (MVA)	2015 Peak Load (MVA)	2016 Peak Load (MVA)	2017 Peak Load (MVA)	2018 Peak Load (MVA)	Avg % Utilization
Transformer Stations							
1TS	50	22.3	26.5	29.9	33.2	34.0	58.4%
3TS	100	36.8	33.3	37.1	41.1	46.3	38.9%
4TS	83.3	55.7	32.5	42.6	49.3	57.5	57.0%
5TS	83.3	72.2	76.2	81.1	58.6	69.9	85.9%
6TS	83.3	57.6	76.7	80.5	63	65.5	82.4%
7TS	50	33.5	36	31.9	35.8	39.0	70.5%
8TS	50	25.7	32.9	38.3	28.5	31.1	62.6%
9TS	83.3	32.9	31.9	35.0	30.5	34.0	39.5%
Total	**583.2**	**336.7**	**346.0**	**376.4**	**340.0**	**377.3**	**60.9%**
Distribution Stations							
1DS	5	4.25	4.36	4.49	4.11	4.77	87.9%
2DS	5	4.12	4.61	5.07	4.48	4.89	92.7%
3DS	5	2.1	2.42	2.58	2.45	2.46	48.0%
5DS	5	3.96	2.24	0.73	0.48	0.60	32.1%
6DS	6.66	3.67	4.8	5.09	3.74	4.53	65.5%
7DS	5	3.01	3.14	3.38	3.15	3.19	63.5%
8DS	6.66	3.77	2.83	3.14	3.73	3.11	49.8%
Total	**38.32**	**24.88**	**24.4**	**24.48**	**22.14**	**23.55**	**62.3%**

Feeder Capacity

The majority of load is supplied through the 27.6kV and 13.8kV feeder systems. The 2017 feeder utilization statistics (non-coincident peak loading day) are shown below. From time-to-time loads are transferred from one feeder to another to facilitate planned and emergency work and may impact the individual feeder peak load that is recorded on the day of the system peak.

Table 3-10: KWHI 27.6kV and 13.8kV Feeder utilization

Feeder	Planning Capacity (Amps)	2018 Peak Load (Amps)	2018 % Utilization
1TS			
1M1	400	0	0
1M3	400	349	87
1M4	400	78	19
1M5	400	74	18
1M6	400	56	14
1M7	400	66	17
1M8	400	0	0
1M9	400	453	**113**
3TS			
3M11	400	209	52

Feeder	Planning Capacity (Amps)	2018 Peak Load (Amps)	2018 % Utilization
3M13	400	0	0
3M14	400	44	11
3M15	400	0	0
3M16	400	130	33
3M18	400	103	26
3M20	400	146	36
3M21	400	351	88
3M22	400	272	68
3M23	400	48	12
3M24	400	0	0
3M25	400	0	0
3M26	400	436	**109**
3M27	400	38	10
3M28	400	0	0
3M29	400	0	0
3M210	400	128	32
3M211	400	0	0
3M212	400	0	0
4TS			
4M11	400	0	0
4M12	400	318	79
4M13	400	182	46
4M14	400	77	19
4M15	400	0	0
4M16	400	100	25
4M17	400	142	36
4M18	400	0	0
4M21	400	185	46
4M22	400	0	0
4M23	400	0	0
4M24	400	238	60
4M25	400	151	38
4M26	400	256	64
4M27	400	462	116
4M28	400	196	49
5TS			
5M11	400	547	137
5M12	400	0	0

Feeder	Planning Capacity (Amps)	2018 Peak Load (Amps)	2018 % Utilization
5M13	400	306	77
5M14	400	291	73
5M15	400	496	124
5M16	400	361	90
5M17	400	432	108
5M18	400	0	0
5M21	400	0	0
5M22	400	0	0
5M23	400	0	0
5M24	400	0	0
5M25	400	0	0
5M26	400	0	0
5M27	400	0	0
5M28	400	0	0
6TS			
6M11	400	177	44
6M12	400	0	0
6M13	400	199	50
6M14	400	210	52
6M15	400	148	37
6M16	400	0	0
6M17	400	21	5
6M18	400	468	117
6M21	400	225	56
6M22	400	57	14
6M23	400	253	63
6M24	400	100	25
6M25	400	237	59
6M26	400	304	76
6M27	400	258	64
6M28	400	0	0
7TS			
7M1	400	0	0
7M2	400	207	52
7M3	400	160	40
7M4	400	0	0
7M5	400	260	65
7M6	400	0	0

Feeder	Planning Capacity (Amps)	2018 Peak Load (Amps)	2018 % Utilization
7M7	400	0	0
7M8	400	217	54
7M9	400	466	116
7M10	400	266	67
8TS			
8M1	400	0	0
8M2	400	80	20
8M3	400	0	0
8M4	400	203	51
8M5	400	68	17
8M6	400	0	0
8M7	400	341	85
8M8	400	0	0
8M9	400	433	108
8M10	400	131	33
9TS (27.6kV)			
9M3	400	93	23
9M4	400	397	99
9M7	400	58	15
9M9	400	125	31

The 27.6kV and 13.8kV peak feeder loading is well within the normal planning loading limits. At the time of system peak in 2018, work was being done at KWHI's No. 5 TS on the no.2 bus resulting in load being transferred from feeders 5M21 – 5M28 to adjacent feeders. This load transfer resulted in a number of feeders (5M11, 5M15, 5M17, 4M27, and 7M9) operating above their planning capacity of 400A. However, the feeders design capacity of 600A was never exceeded. There is currently a limitation in providing backup for the load supplied by some of the feeders from No. 5TS. This limitation arises from insufficient capacity from adjacent feeders. In 2021 a new 7M4 feeder is planned to provide load relief for 5TS feeders during contingency.

Feeders 1M9, 3M26, 6M18, and 8M9 exceeded their planning capacity because of load transfers from adjacent feeders that were being rebuilt as part of planned capital projects. In all cases, the feeder design capacity of 600A was not exceeded.

The 2017 utilization statistics for 8.32kV feeder supplied from the Wilmot area DS are shown below. Feeder loading is generally within planning guidelines. The feeders from No. 5DS are currently being converted from 8.3 kV to 27.6 kV feeders supplied directly from No. 9TS. When this conversion is completed, the No. 5DS station will be decommissioned.

Table 3-11: KWHI 8.32kV Feeder utilization

Feeder	Planning Capacity (Amps)	2017 Peak Load (Amps)	% Utilization
1DS			
1DS1	200	192	96
1DS2	200	29	14
1DS3	200	92	46
2DS			
2DS1	200	204	102
2DS2	200	0	0
2DS3	200	119	60
3DS			
3DS1	200	90	46
3DS2	200	0	0
3DS3	200	72	36
5DS			
5DS1	200	0	0
5DS2	200	41	20
5DS3	200	0	0
6DS			
6DS1	200	95	48
6DS2	200	132	66
6DS3	200	68	34
7DS			
7DS1	200	32	16
7DS2	200	70	36
7DS3	200	104	52
8DS			
8DS1	200	29	14
8DS2	200	91	46
8DS3	200	88	44

3.3 Asset Lifecycle Optimization Policies and Practices (5.3.3)

The asset lifecycle practices and policies employed by KWHI are specific to the asset and can include simple measures such as visual inspections or can include more in-depth examinations such as asset testing and 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.

The DSP has been prepared with a vision of sustaining the assets such that they continue to perform at the present level or better in regard to safety and reliability performance while improving cost effectiveness. For each asset type, sustainment options such as increased maintenance, proactive and reactive replacement, and elimination/substitution are considered and evaluated. The option selected for each asset type reflects the assessment of risk and total lifecycle cost. The condition and performance of the assets are carefully monitored so that adjustments can be made to the sustainment plan to ensure safety, reliability and cost effectiveness are not compromised.

3.3.1 Asset Lifecycle Optimization Policies and Practices (5.3.3a)

3.3.1.1 Asset Replacement Policies

Management of assets is specific to the asset with respect to its operating context and which refurbishment approach can be employed. In general, asset management practices and policies address the KWHI's asset management replacement factors to determine and mitigate the risk of operating aged assets.

If 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 the need for further attention, KWHI employs its refurbishment policies to address the asset and take corrective actions. The output of asset condition assessments forms a part of the annual capital budget and prioritizing capital renewal expenditures for rehabilitation or replacement. The result is a prioritized list of detailed capital projects for the next year and a five-year capital plan that will preserve and/or enhance the value of service to the customer.

The timing of the System Renewal investments with respect to assets is often considered from a combination of a condition-based assessment, safety issues, probability and consequence of failure and the asset approaching its economic useful life. KWHI strives to achieve an optimal renewal investment by addressing those assets that have a much larger impact of failure or pose a safety concern to its surrounding operating context. In order to pace investments and to prevent a vicious cycle of deferring System Renewal investments, KWHI includes assets in its renewal plan that are within 1 – 5 years of needing to be replaced. Investments that need to be deferred from the System Renewal category will be re-evaluated based on the KWHI's internal assessment of the operating asset based on safety, condition, and failure impact. Certain assets can remain in service until they fail, however, KWHI uses its risk management processes in determining which assets can be operated in such a manner without compromising public safety and service reliability. Typically, there are two main approaches to replacing assets.

Run to Failure

Essentially, every asset can be run to failure. This is usually 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 entail a 'like for like' replacement rather than upgrading technology, which may not always provide opportunities for upgrade of the utility's capabilities.

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

Proactive Replacement

Another approach is to proactively replace a cluster of like assets based on the results of an asset condition assessment or at the time that the first asset begins to fail. This is more expensive in the short term but allows for technological upgrades, completing all work in the area at once and causing a single disruption for customers while conducting the work.

This DSP balances both approaches using variables like age, condition and financial value to ensure that the distribution system operates safely and reliably for customers.

As can be seen in this DSP and the Asset Management Strategy, approaches to management of assets are specific to individual assets or asset types. Such an approach to asset management ensures that expenditures for asset condition assessment follow standards, optimize and benefit the distribution system. This results in effective asset management and managing the risk, safety and performance of the system. As such, KWHI employs both a proactive and reactive approach to asset management, depending on the needs of specific assets.

Proactive asset management involves periodic condition assessments and includes the following assets:

- Poles
- Substation Transformers
- Network Transformers
- Substation Breakers
- Protection and Control equipment
- Substation On-Load Tap Changers
- Oil Circuit Reclosers.
- Load Break Switches/ Switchgear
- Underground cable – feeder cables and cables within high density areas such as downtown Kitchener

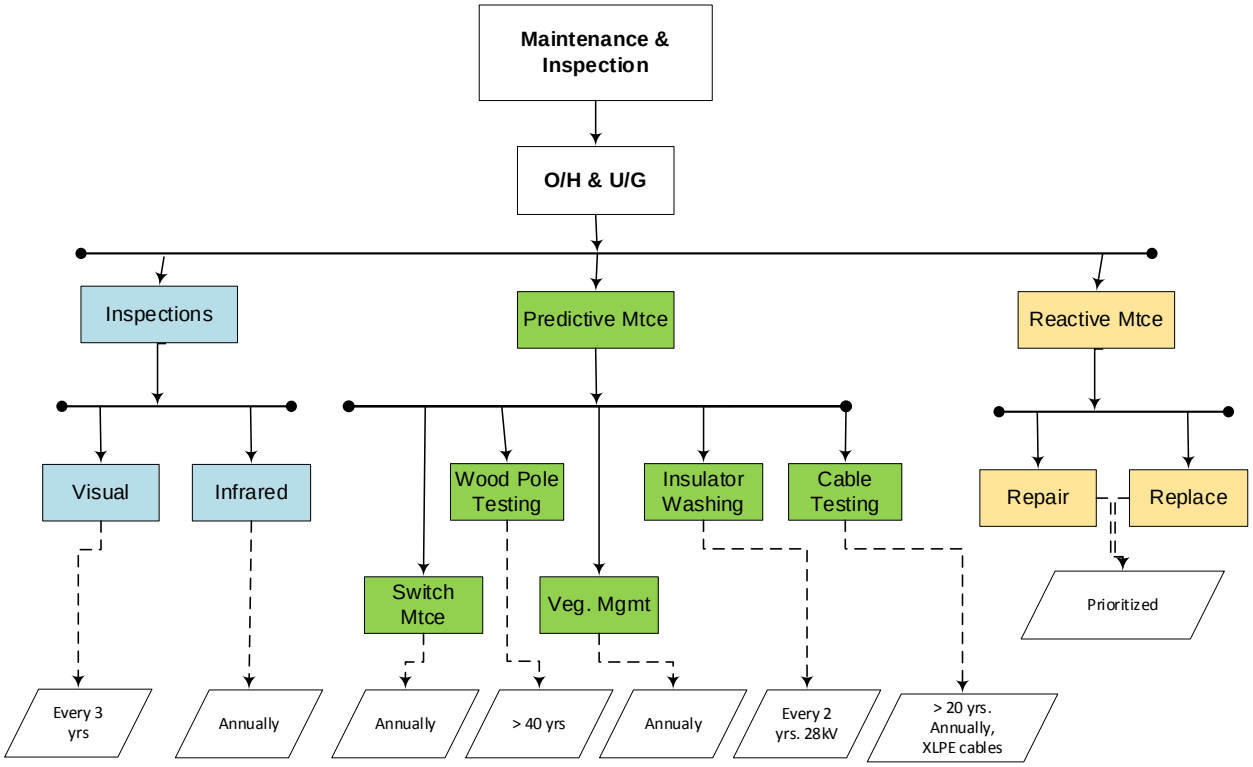
KWHI employs preventative maintenance practices and policies relating to specific assets to ensure the assets are operating as intended and the risk of failure is minimized, or otherwise identified and monitored. An evidence-based maintenance program is essential to the safe and reliable delivery of electricity to customers. The preventative maintenance programs employed by KWHI are performed to regulated requirements, include staff and/ or qualified contractors, and may include specific industry standards and manufacturer specifications.

- Pole Testing & Inspection Procedure 2010 – Appendix M
- Cable Testing & Inspection Procedure 2017 – Appendix N

3.3.1.2 Lifecycle Optimization through Maintenance Planning – Criteria and Assumptions

Maintenance is essential to minimizing risk and maintaining the functional integrity of a distribution system. Furthermore, such maintenance reduces overall costs, service disruptions and the need for immediate or emergency expenditures. KWHI recognizes these benefits and has implemented two types of maintenance programs: reactive maintenance and preventative/predictive maintenance. Deficiencies identified during routine system inspections are recorded on a *Patrol Deficiency Record Report*. 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. Figure 3.38 below shows an overview of the maintenance activities that are undertaken by KWHI to maintain the integrity of the distribution system.

Figure 3.38: KWHI Asset Maintenance & Inspection Overview



Overhead Systems – Reactive Maintenance General Practice

Generally, maintenance activities are initiated after the inspection process through the creation and issuance of a Maintenance Work Order (MWO). The MWO identifies the equipment and location, follow-up action to address defects or concerns, the time frame for completion, an estimate of man-hours required to complete the maintenance activity and a work order number to which time and materials are charged. The activities are then scheduled based on priorities:

- Health and/or safety concerns
- External demands (e.g. customers, City of Kitchener or Township of Wilmot)
- Reactive maintenance (identified during visual patrols)
- Preventative maintenance
- Asset Management Strategy and planning through the annual budget

The reactive maintenance program serves to address and remedy any deficiencies found during inspections, and as noted on the *System Inspection Work Log Sheet*, *Overhead System Defect Report* and *Overhead Line Maintenance Sheet*. Reactive maintenance is further prioritized into 3 categories (A, B and C) based on severity of the defects. ‘A’ priority are defects or concerns requiring immediate attention, where any critical issues are identified and addressed immediately. Due to the urgency of these concerns, a separate MWO is not issued as described above. Instead, the work is executed without delay and the associated costs are charged to a standing work order that is then reviewed at a later date. ‘B’ and ‘C’ priorities, as determined by experience or a site review, are less urgent. Items of this priority level are subsequently channeled into a maintenance schedule for completion within 1 month to 3 years, that is, prior to the next inspection period. External demands and/or customer impact

are also considered when scheduling ‘B’ and ‘C’ priority remediation. For example, deficiencies that negatively impact service reliability would be corrected more quickly. Costs are charged to the work order numbers, as identified on the MWO. Once reactive maintenance is completed, the MWO is returned with further comment on action taken and the date of completion. The MWO is subsequently utilized for further system defect reporting and monthly reporting. Alternatively, through data analysis, these deficiencies may be channeled into a capital program for asset replacement.

Overhead Systems – Preventative Maintenance General Practice

The preventative maintenance program is a more structured and comprehensive program for scheduling and completion of routine maintenance of the distribution facilities. The frequency of maintenance varies, but generally considers the available technology to perform maintenance (such as infrared thermography), manufacturer specifications and relative importance of the equipment to the overall system reliability. Furthermore, preventative maintenance activities such as insulator washing serve as a secondary visual inspection of the condition of the assets. The program encompasses all the activities that are industry standard and good utility practice, including switch maintenance, infrared thermography of overhead plant, insulator washing and vegetation management. These combined inspection and maintenance activities provide adequate warning of asset deterioration and major problems. Like inspection and reactive maintenance activities, data from preventative maintenance programs are compiled and used for reporting. Corrective action to address deficiencies is initiated after analysis of reports and data.

Underground Systems – Reactive Maintenance General Practice

Reactive maintenance of KWHI’s underground distribution system assets follows the same practice as noted for overhead systems, addressing and resolving any deficiencies found during inspections and documented on the *Underground System Defect Report*, *Underground System Pad-Mounted Transformer Survey Sheet* and *Underground System Submersible Survey Sheet*. Data from these documents is reviewed and subsequently utilized for reporting. As with overhead, associated costs for underground reactive maintenance are charged to the appropriate work order number.

Civil Infrastructure

There are three options to correct deficiencies in civil infrastructure. The deteriorated structure may be repaired (minor defects only), rebuilt to the original design or replaced with a new design. All three types of work are normally performed internally by KWHI staff. Depending on the severity of the deficiency, the repair/rebuild/replace activities are generally completed within 3 months to 3 years from the initial inspection.

Underground Systems – Preventative Maintenance General Practice

The preventative maintenance program for the underground distribution system also forms a more structured and comprehensive program for scheduling and completion of routine maintenance of the underground distribution facilities. The frequency of maintenance varies, but again considers the available technology to perform maintenance (such as infrared thermography, oil testing and cable testing), manufacturer specifications and relative importance to the overall system reliability of the equipment. Furthermore, the preventative maintenance activities serve as a secondary visual inspection of assets, as the condition is further noted. The program encompasses activities that are industry standard and good utility practice, including infrared thermography of some underground plant. These combined inspection and maintenance activities provide adequate warning of asset deterioration and major problems. As with inspection and reactive maintenance activities, data from preventative maintenance programs are compiled and used for reporting. Corrective action to address

deficiencies is initiated after analysis of reports and data. Associated costs for underground preventative maintenance are charged to the appropriate work order number.

3.3.1.3 Description of Maintenance and Inspection Practices

3.3.1.3.1 Distribution Equipment

KWHI currently abides by the OEB requirements of performing system inspections every 3 years for its Urban area and exceeds the requirements by inspecting its 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. Table 3-12 list the frequency for common maintenance and inspection activities for the distribution system.

Table 3-12: KWHI maintenance and inspection activities for distribution equipment

System	Category	Activity	Frequency
Overhead System	Predictive maintenance	Visual Inspections	3-year cycle
		Infrared Thermography	Annually
		Wood Pole testing	5-year cycle Threshold: 40 years +
	Preventative maintenance	Vegetation management	6-year cycle
		Insulator Washing	2-year cycle – 27.6 kV 1-year cycle – 13.8 kV
		Switch Maintenance	10-year cycle
	Reactive maintenance	Field repairs	As required
Underground System	Predictive maintenance	Visual Inspections	3-year cycle
		Infrared Thermography	As required
		Cable testing	Pilot project
	Reactive maintenance	Field repairs	As required

The OEB's DSC establishes Minimum Inspection Requirements which document in detail the inspection standards and cycles required. Table C-1 within OEB's Minimum Inspection Requirements identifies the maximum intervals for the inspection cycle patrols, which for most urban facilities is 3 years. A definition of Patrol Inspection is included on the first page of the document.

KWHI's service area is served by an urban distribution system serving the City of Kitchener and a rural distribution system serving the Township of Wilmot. The utility's service area is structured into geographical zones for implementation of systematic and routine visual patrols to comply with the OEB inspection requirements, at a minimum. The visual inspections of the major distribution facilities, noted below, are comprehensive and the level of detail is beyond the Patrol Inspection Definition. In addition to fulfilling the requirements of the DSC, the inspections allow for deficiencies and the general condition of system components and related peripheral equipment and hardware, including vegetation growth, to be realized and documented with enough lead time and for subsequent analysis in support of maintenance and capital planning activities concerning the following assets:

- Poles/Supports/Hardware
- Conductors
- Switches and Protective Devices
- Transformers
- Stations
- Civil Infrastructure

The following O&M programs are completed to extend the life of distribution assets, obtain a condition assessment, and improve the safety and reliability of the distribution system.

Visual Inspection

The purpose of visual inspections is to identify potential safety and reliability problems to plan mitigation actions to reduce the safety risk to the public and the risk of asset failure. Furthermore, the visual inspections are used to capture condition attributes of equipment to support KWHI's on-going renewal efforts with the use of current asset condition assessments.

KWHI currently inspects the distribution system in each geographic zone, completing approximately one-third of its distribution system each year, as per the DSC. The visual patrol serves as an inspection to assess the condition of overhead and underground assets, including poles, distribution transformers, overhead switches, underground switchgears, overhead conductors, civil structures, insulators and additional hardware and accessories like pole attachments, sensors and surrounding vegetation.

The visual inspection maintenance program is driven by OEB compliance requirements, ESA compliance requirements, utility best practices and the need to mitigate equipment failures reducing the risk to public safety, employee safety and maintaining reliability. Though not defined in official regulatory requirements, utility best practices as captured in various industry publications provide a benchmark for KWHI to adhere to.

Visual inspections allow KWHI to extract valuable information about the state of its system's repair. The condition-based assessment allows KWHI to monitor and identify defects concerning the integrity of the asset or identify issues concerning the condition of the asset. Deficiencies related to the asset are noted and subsequently addressed through either maintenance programs or planned programs.

Wood Pole Testing

Wood pole testing is a predictive maintenance action that checks the integrity of the wood pole prior to experiencing a failure and avoiding the consequences of the failure. A non-destructive testing technique is used by a third-party to test the wood poles that are 40 years and older. Selected poles are further tested using the Resistograph method to determine the extent of degradation. Resistograph testing gives an indication of the severity of internal pole defects. Internal defects such as decay and cavities are displayed in graphs along with the location and size of defects. The third-party provides KWHI threshold recommendations on what pole is at risk of failing and should have an immediate action planned. Results from the wood pole testing are used to prioritize and support immediate and short-term remediation efforts to address the pole at risk of failure.

KWHI notes recent analysis of the asset records maintained in KWHI's GIS reveals that the poles supporting three-phase trunk feeders have an average age approximately 10 years younger than the poles supporting single-phase distribution circuits. This is consistent with past capital investments, as KWHI has focused its construction efforts in rebuilding pole lines carrying trunk feeders.

Infrared Thermography

Infrared thermography is a predictive maintenance action that checks for temperature variances or anomalies caused by excessive heat. The excessive heat may be attributed to connections in poor condition, overloading, or defective equipment.

Infrared thermography of overhead plant is completed once per year on all overhead 3-phase feeders by a third party. Infrared thermography for the underground distribution system is completed as needed in known problem areas, specifically where outages most commonly occur, and at underground trunk

feeders from substations. This practice is performed once every two years. In the intermediate years, infrared thermography is completed at expressway crossings and on portions of KWHI's secondary network system, again in known problem areas where hot spots most commonly occur.

During these activities, all equipment installed on the same structure is checked for hot spots and general deficiencies of the facilities, including primary conductors for all voltages, overhead transformers, secondary dip cable, et cetera. These hot spots are recorded, and a summary report is submitted to KWHI, documenting all defect locations and severity of the defects. Maintenance to address defects, as noted in the report, is subsequently scheduled based on defect severity. Generally, hot spots categorized as severe are addressed and repaired within 2 weeks, intermediate hot spots within 1 month and minor hot spots within 2 to 3 months.

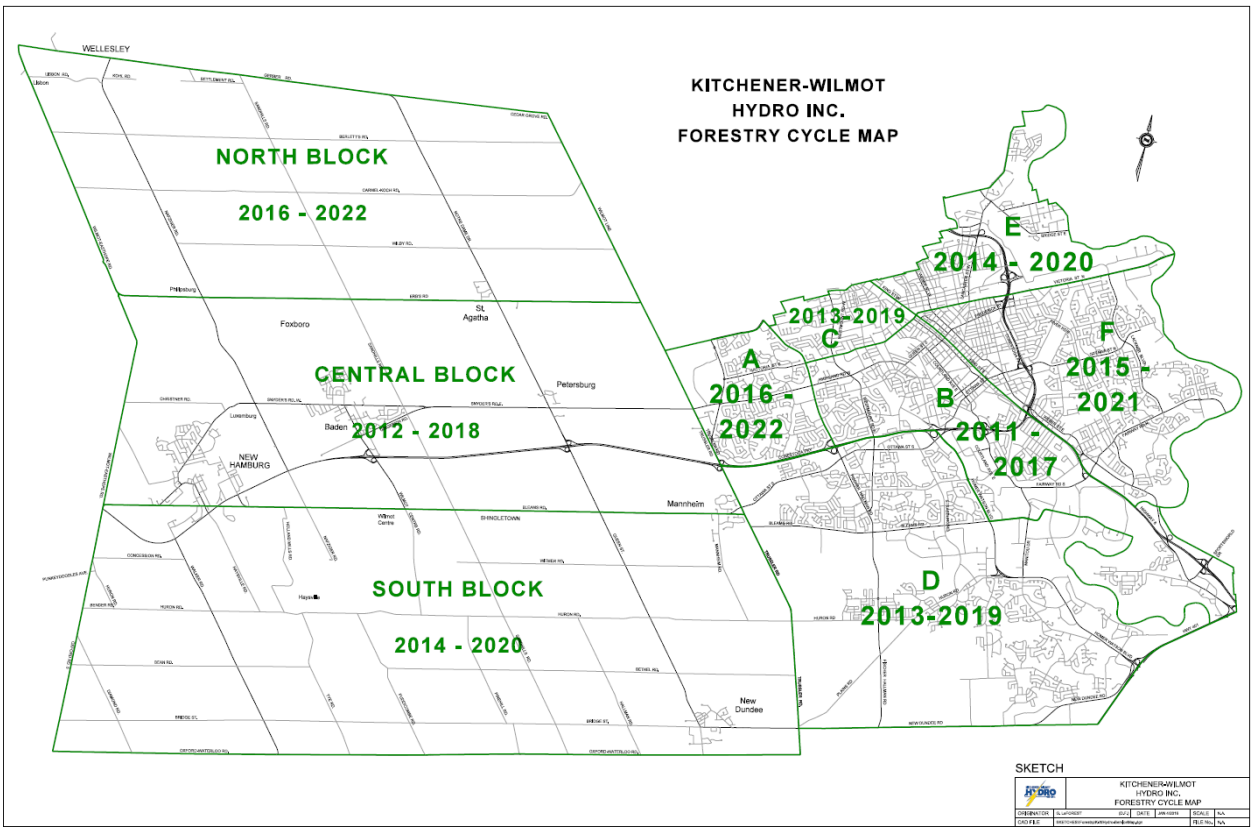
Vegetation Management

Vegetation management, or tree trimming, is a preventative maintenance program scheduled on a 6-year cycle. This accounts for roughly two of the nine segmented zones of the distribution system. The objective is to maintain operating clearances between tree limbs and the overhead equipment as per regulation. Additionally, vegetation management identifies and removes hazardous trees at risk of falling and overhangs that can be energized. Vegetation management is required to reduce the amount of tree contact outages but additionally animal contact and wind-related disturbances. The practice of routine tree trimming contributes to safety and improves system reliability.

Vegetation management is executed by in-house utility arborists. Using their specialized knowledge of growth rates of various vegetation, arborists may either trim more frequently in a zone or trim back more growth to account for the different growth rates. This would deviate from the standard 6-year trim cycle applied for the whole system. A reduction in cycle frequency would result in cost savings and an increase would result in extra costs. However, the cost difference would not be significant at year-end. KWHI takes additional preventative maintenance initiatives in their vegetation management program including tree-trimming during the implementation of capital build/rebuild projects as well as weed-spraying around transformer stations, rural distribution stations and transformer enclosures. Additionally, a substantial amount of reactive maintenance is performed in response to requests from the public to trim or remove trees in proximity to power lines.

KWHI service territory is divided into nine zones for vegetation management, identified in Figure 3.39. Each zone is inspected in the year following the tree trimming for that zone. This way, any quality issues pertaining to vegetation can be identified.

Figure 3.39: Map of KWHI vegetation management zones and cycles



Insulator Washing

Insulator washing is a preventative maintenance program to prevent high voltage insulator tracking and flashover events by removing contaminants such as salt and dust from insulator surfaces. If contaminated insulators are not addressed they can cause pole fires, flashovers and power interruptions. The combination of contaminated insulators and a moist environment forms a conductive layer enabling current flow. This is known as leakage current.

Insulator washing is performed on a 2-year cycle for all 27.6kV polymer and porcelain insulators; that is, half of the total number of insulators are washed in year one while the other half are washed in year two. Additionally, insulator washing on the 13.8kV system is performed annually for insulators in areas known to have high salt contamination, as identified through previous washings and general reporting. An Insulator Cleaning Report summarizes washing activities and identifies insulator concerns such as broken insulators and other visible issues observed with existing overhead equipment. In response to the insulator washing report, KWHI engineers prepare MWO's to resolve the concerns and issues.

Switch Maintenance

Preventative maintenance on switches is scheduled to be performed on a 10-year cycle. A list of Load Interrupter and Fused Load Interrupter switches are inspected to identify potential safety and reliability issues with the intent of extending the asset's service life. Inspection and maintenance activities are documented which identifies switch properties, such as manufacturer, and switch condition. A check list for the switch condition allows personnel to note the condition and further comment on maintenance performed. Any outstanding switch activities are carried over as inspection/maintenance activities for the subsequent year.

Dry Ice Cleaning

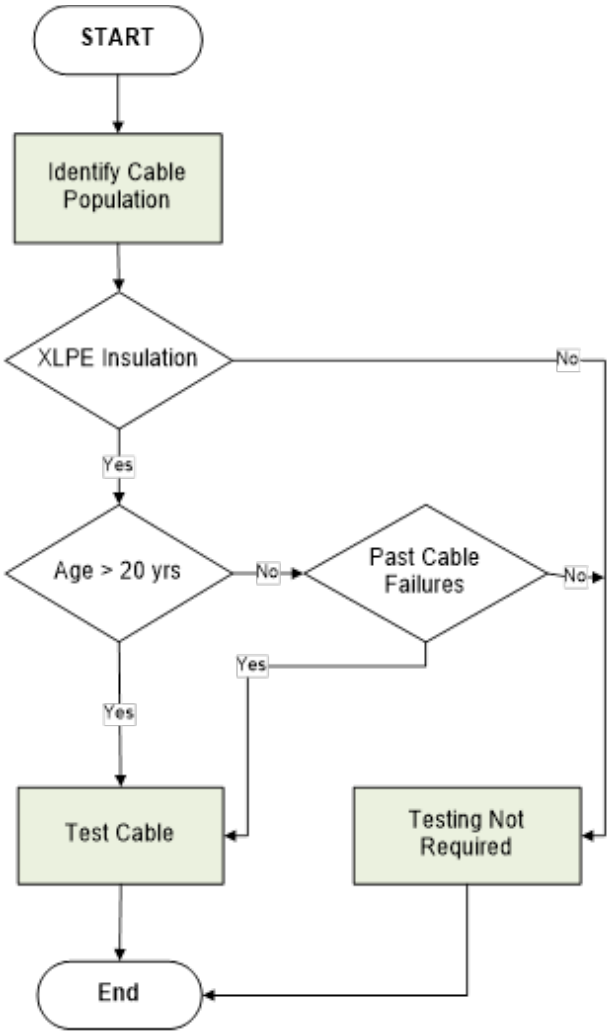
Dry ice cleaning is a preventative maintenance activity performed on KWHI-owned Load Interrupter switches. Dry ice cleaning is performed to prevent flashovers from occurring. Dry ice cleaning is proven to be effective at removing contamination such as salt to prevent favourable conditions for leakage current. Dry ice cleaning reduces downtime because the process can be performed without having to de-energize the assets, ultimately maintaining service for customers.

Dry-ice cleaning is performed on the KWHI-owned Load Interrupter switches and power fuses installed in customer-owned substations on a 3-year cycle.

Cable Testing

KWHI tracks the location of high voltage cable faults within its GIS to help identify patterns of failures that require attention. Cables with multiple failures within the same segment will be scheduled for replacement. As of September 2017, KWHI is currently evaluating a non-destructive testing technique for XLPE cables to aid in determining and prioritizing which cables need replacement. This technology was developed by National Research Council Canada (NRCC) and is licensed to Energy Ottawa. The technique detects the effect that water trees have on XLPE cables and a diagnostic criterion is used for determining the insulation's condition. Cables are given a health index score ranging from 1 – 100 based on the results. These health indices are further categorised into health index descriptions (poor, fair, good) to assist in making recommendations on whether to replace, refurbish, or maintain the cable in service. The health indices are described as follows:

Figure 3.40: Cable Selection Process for Testing



Poor – Failure probability due to water treeing is high and any repair to the cable would be short-lived. The cables in this category should be scheduled for early replacement.

Fair – Failure probability due to water treeing is moderate and could increase and result in insulation failure if voltage transients due to switching operation or lightening surges are not properly controlled. The cable could be repaired and returned to service after failure. However, the cable should be retested every three to five years to keep track of the ongoing water-tree deterioration.

Good – Failure probability due to water treeing is low, but it could increase and result in insulation failure if voltage transients due to switching operation or lightening surges are not correctly controlled. If cable failure occurs, it could be due to other causes such as local defects, mechanical damage or termination failure. The cable should be repaired and returned to service.

The cable segments that are selected for testing are based on age, past failures, criticality (e.g. feeder cable vs service cables) and installation type (direct buried vs in conduit). It is KWHI's intent to only test cables that are 20 years and older unless there have been previous failures in a younger cable population. Figure 3.40 below describes the process flow used to select cables for testing.

3.3.1.3.2 Station Equipment

KWHI-Owned Stations

All power transformers are owned by KWHI, with 23 in service and 1 spare at the various Transformer Stations and Distribution Stations within the City of Kitchener and the Township of Wilmot. Preventative maintenance of these power transformers includes tap changer maintenance, oil testing and general maintenance to name a few. Generally, when deficiencies are identified by inspection, 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. Conditional data collected is used as an input to KWHI's ACA which calculates the Health Index of the asset. The Health Index provides a good indication as to what steps KWHI can take to maintain the asset or if it should be replaced.

KWHI-Owned Transformer Stations

As with the overhead and underground distribution system, KWHI performs comprehensive inspections and condition assessments of both KWHI-owned stations and customer-owned

substations. KWHI-owned Transformer Stations (TSs) operate at 115kV to 13.8 kV or 230kV to 13.8kV or 230kV to 27.6kV. Inspection of the TSs and associated equipment is performed on a pre-determined inspection cycle and follows the general KWHI practice of reporting deficiencies and subsequent scheduling of maintenance. Inspection and preventative maintenance of the 115kV and 230kV circuit switchers is performed annually or after 750 open/close operations. SF6, vacuum and air circuit breakers are located at each of the TSs and at one DS and are maintained once every 5 years (or if 50 operations have occurred before maintenance is due). Transformer Station inspections incorporate several maintenance activities as seen in the table below.

Table 3-13: KWHI maintenance and inspection activities for Transformer Station equipment

Maintenance Activity	Cycle				
	Daily	Weekly	Monthly	Annual	Other
Transformer Inspections	X				
Switchgear Building Inspection	X				
General Inspections		X			
Tap Changer Counter Reading & Assessment of Station Service Transformers			X		
Emergency Equipment Inspections			X		
Battery Inspection			X		
Transformer Oil Sample Testing				X	
Infrared Survey				X	
Tap Changer Maintenance				X	
Circuit Switcher Maintenance				X	
Repainting					Upon inspection
Voltage Regulator Maintenance					3-year
Protection Verification (including SCADA)					4-year
Doble Testing					5-year
Circuit Breaker Maintenance					5-year

KWHI-Owned Distribution Stations

KWHI-owned Distribution Stations (DS) operate at 27.6kV to 8.32kV. Inspection of the DS is performed on a pre-determined inspection cycle and follows the general KWHI practice of reporting deficiencies and subsequent scheduling of maintenance. Six of the seven DSs incorporate three-phase reclosers for protection and control that are maintained once every 3 years. DS inspections incorporate several maintenance activities as seen in the table below.

Table 3-14: KWHI maintenance and inspection activities for Distribution Station equipment

Maintenance Activity	Cycle				
	Daily	Weekly	Monthly	Annual	Other
Transformer and Building Inspections		X			
Recloser/Circuit Breaker Operations Assessment and Readings		X			
Voltage Regulator Inspection and Readings			X		

Emergency Equipment Inspections			X		
Battery Inspection			X		
Infrared Survey				X	
Tap Changer Maintenance				X	
Circuit Switcher Maintenance				X	
Repainting					Upon inspection
Voltage Regulator Maintenance					3-year
Protection Verification					4-year cycle
Doble Testing					5-year
Circuit Breaker Maintenance					5-year

Customer-Owned Substations

There are 764 customer-owned substations, of which 609 house transformers owned by KWHI while the remaining house customer-owned transformers. Both substation enclosures and KWHI-owned transformers are inspected by KWHI crew on a three-year cycle.

In addition to inspection and reporting of the substation enclosure, the transformers are inspected for leaks, oil level and oil temperature; if necessary, oil temperature is reset and recorded again after resetting. Deficiencies are noted which are submitted for review by Operations management. Subsequent follow-up reactive maintenance, if necessary, is prioritized and performed for KWHI-owned transformers. If deficiencies are found in customer-owned transformers, transformer vaults or transformer rooms, the owner is notified indicating the time-frame in which repairs are to be made, based on the severity of the deficiency.

If deficiencies are not repaired in a timely manner, a second letter is issued to the owner and the Electrical Safety Authority (ESA) is notified. In addition to the above inspection activities, maintenance is performed at the substations. For most of these activities, inspection and maintenance are performed together.

Dry-ice cleaning is performed on the KWHI-owned load interrupter switches and power fuses installed in customer-owned substations on a 3-year cycle. This preventative maintenance activity can be implemented without having to de-energize the transformers, ultimately improving reliability.

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

Risk management is a fundamental activity in any business and in the electrical distribution industry it requires a systematic approach to assess the following attributes of each asset:

- Condition data analysis
- Age and life expectancy
- Location
- Operational and maintenance data
- Reactive maintenance
- Preventative maintenance
- Asset replacement based on condition/age to minimize failures

It is the systematic approach of inspections, condition and age assessment, data analysis and maintenance that allow KWHI to identify and mitigate risk to its assets and distribution system. KWHI's asset lifecycle risk management philosophy is based on the need to minimise risks, extend asset lifetimes, optimize maintenance costs and utilize proven management processes. By conducting

detailed inspections and testing where applicable, the risk associated with each asset can be identified and the pacing and prioritization of investments optimized to spread OM&A and capital costs evenly over a long period of time.

Asset performance during an investment cycle is collected and utilized in the next investment planning period. Mandatory investments are automatically included in the investment plan regardless of risk. Additional asset investments are valued and scored using KWHI's project prioritization tool and methodology. The scoring process considers the implicit risk of not investing in the upcoming investment cycle. For example, critical asset investments such as station transformers score relatively high on risk compared to distribution transformer investment due to the higher widespread impact that a failure of a critical asset has. This has also led to the development of proactive replacement strategies for specific higher risk high cost critical assets (i.e. station transformers, poles) and bulk reactive replacement strategies for lower risk low cost assets (distribution transformers).

The 2020 – 2024 DSP focuses on several proactive and reactive distribution asset replacement investments. KWHI's inspection, testing and maintenance programs, described earlier, support the need for these programs. The investment strategy is designed to smooth out the impact of these programs on rates. Programs are structured to remain within OEB rate mitigation guidelines. There is an increased amount of risk for those high value assets in Very Poor and Poor condition that await replacement towards the later years of the replacement program. In this sense, risk is balanced against the reality of unsustainable rate increases that would be needed to eliminate all asset risk in a short period of time. Other assets in better condition are deferred to future investment periods. Individual asset priority position in the programs will be managed as more asset information is obtained through ongoing annual inspection, testing and maintenance to optimize replacement risk decisions. Remaining assets in Very Poor and Poor condition will be dealt with on a reactive basis through bulk program funding. Program funds in these categories reflect the historical cost and effort to replace these failed assets reactively.

3.4 FLEET ASSET MANAGEMENT STRATEGY

KWHI's fleet assets play a critical role in keeping the organization working efficiently and safely. These assets are required to be reliable and maintained. Fleet assets consist of 116 vehicles, trailers and specialty-power operated equipment. The vehicle and equipment inventories, as of the end of 2018, are presented in the table below:

Table 3-15: KWHI fleet inventory

Vehicle/Equipment Type	# in Fleet
Air Compressor	2
Backhoe/Loader	2
Brush Chipper	2
Bucket Truck (Distribution)	14
Bucket Truck (Forestry)	2
Car/Compact SUV	6
Cable Puller Truck	1
Dump Truck	3
Flat Deck Crane Truck	1
Forklift	2
Mini Excavator	1
Pick-up Trucks	21
Service Truck (Construction)	3
Service Truck (Forestry)	1
Service Truck (Underground)	4
RBD	4
Sweeper	1
Tension Stringers	2
Tractor/Mower	1
Trailers	23
Van (Cargo)	12
Van (Passenger)	8

The same principles used to manage the distribution network are also used in the management of KWHI's Fleet assets. That is:

- plan appropriate resources to meet the needs of the corporation and its customers;
- replace or refurbish aging assets; and
- reduce or eliminate the length and severity of outages by having well maintained fleet assets.

Fleet asset lifecycle follows the same approach used with distribution assets which is:

- Plan
- Acquire
- Operate
- Maintain
- Dispose

KWHI maintains the Vehicle and Equipment Fleet with a combination of internal staff (two Mechanics and one Supervisor) and external contractors. KWHI has found that operating the Vehicle Maintenance department in this way allows us to maintain the fleet, provide emergency service and specialized repairs or maintenance as required, and control costs.

In general, large vehicles (Bucket Trucks, RBD's, Service Trucks, etc.) and smaller work vehicles (pick-up trucks, vans, cars, etc.) are budgeted on a 10 to 12-year replacement schedule. Trailers and other power operated equipment are kept for longer periods of time and are scheduled for replacement when annual maintenance and repair costs escalate. Heavy use power operated equipment, such as backhoes, are budgeted to be replaced on a 7 to 8-year interval.

A 5-year Vehicle and Equipment replacement schedule is completed/reviewed on annual basis for large vehicles and equipment. Smaller vehicles and equipment replacements are determined on a year to year basis. When finalizing budgets/replacements for a particular year, an overall assessment of the vehicle's mileage, engine hours, age, repair history, vehicle condition and future intended use is considered. This assessment may result in the vehicle replacement being deferred to the next budget year when the vehicle would be assessed again. The table below lists the Large Vehicles and Equipment scheduled for replacement on the current 5-year replacement schedule from 2019 to 2024.

Table 3-16: Fleet replacement schedule 2019-2024

Budgeted Replacement	Unit #	Acquired Year	Description	Department
2019	73	2005	International, Terex RBD Flat Deck	Construction
2019	25	2006	Sterling Dump Truck	Distribution
2019	22	2005	Construction Service Truck with Crane	Construction
2019	28	2005	International, Stations Service Truck	Distribution
2020	35	2007	Freightliner, 50' Posi-Plus Single Bucket	Distribution
2020	80	2009	Sterling, 70" Hi Ranger Single Bucket	Forestry
2020	56	2007	Sterling Dump Truck	Construction
2021	70	2008	Sterling, Terex RBD	Distribution
2021	72	2008	Sterling, Hiab Flat Deck	Distribution
2022	75	2008	Sterling, 55' Posi-Plus Double Bucket	Distribution
2022	9	2006	Freightliner, 50' Posi-Plus Single Bucket	Distribution
2023	34	2010	Freightliner, 50' Posi-Plus Single Bucket	Distribution
2023	66	2010	Sterling, Underground Service Truck	Distribution
2023	64	2009	Sterling, 42' Reach All Single Bucket	Distribution

3.5 Information Technology Asset Management Strategy

KWHI's information systems and technology (IST) assets play a critical role in keeping the organization connected and working efficiently. These assets are required to be reliable and current. IST assets include all elements of computer software and hardware that are found in the business environment at KWHI that supports both information technology (IT) and operation technology (OT). IT and IST are used interchangeably throughout this document and includes OT unless stated otherwise.

Asset Management

The same principles used to manage the distribution network are also used in the management of KWHI's Information Technology assets. That is:

- plan information system expansions to meet the needs of the corporation and its customers;
- replace or refurbish aging hardware and software; and
- reduce or eliminate the length and severity of information system outages.

IT asset lifecycle follows the same approach used with distribution assets which is:

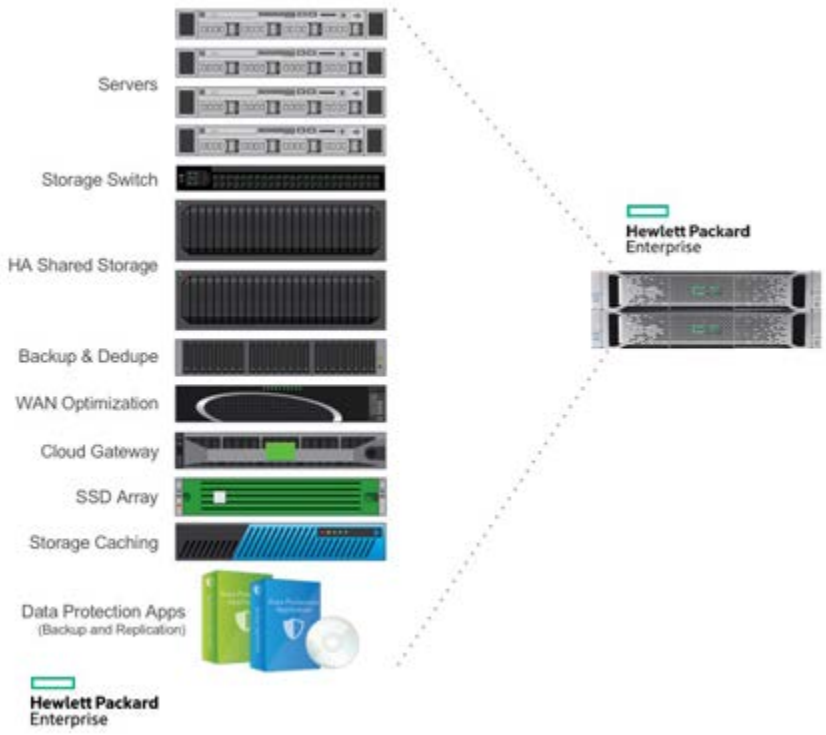
- Plan & Design

- Acquire/Build
- Operate
- Maintain
- Dispose

Plan & Design

The ever-changing regulatory environment within the electricity sector will continue to influence the expansion plans within the area of IST. Disk storage requirements which have increased dramatically since the introduction of the retail electricity market in 2002 will continue to grow at an exponential rate with smart metering and time-of-use pricing and smart grid activities. Centralized shared disk storage capacity has been installed to meet this demand. The new Storage Area Network (SAN) facilities which have been implemented over the last several years can be scaled as required to accommodate the escalating demand for on-line disk storage resources. This technology uses arrays of multiple physical disk drives connected by fibre optic cables to achieve the optimum balance between system performance and data protection through hardware redundancy. KWHI is investigating the use of hyper converged IT infrastructure with built-in data deduplication to reduce the requirements for physical storage and significantly improve data recovery during disasters. Hyper converged infrastructure provides compute, storage, networking, virtualization, backup and disaster recovery resources that are all managed by software instead of being separate entities shown in the figure below.

Figure 3.41 Hyper converged IT infrastructure



KWHI monitors its IT infrastructure to ensure that it is always sufficient and effectively allocated so that benefits to the business can be maximised. When infrastructure is required, evaluation of current technologies is undertaken to select the most cost-effective approach that will meet the business needs now and in the future.

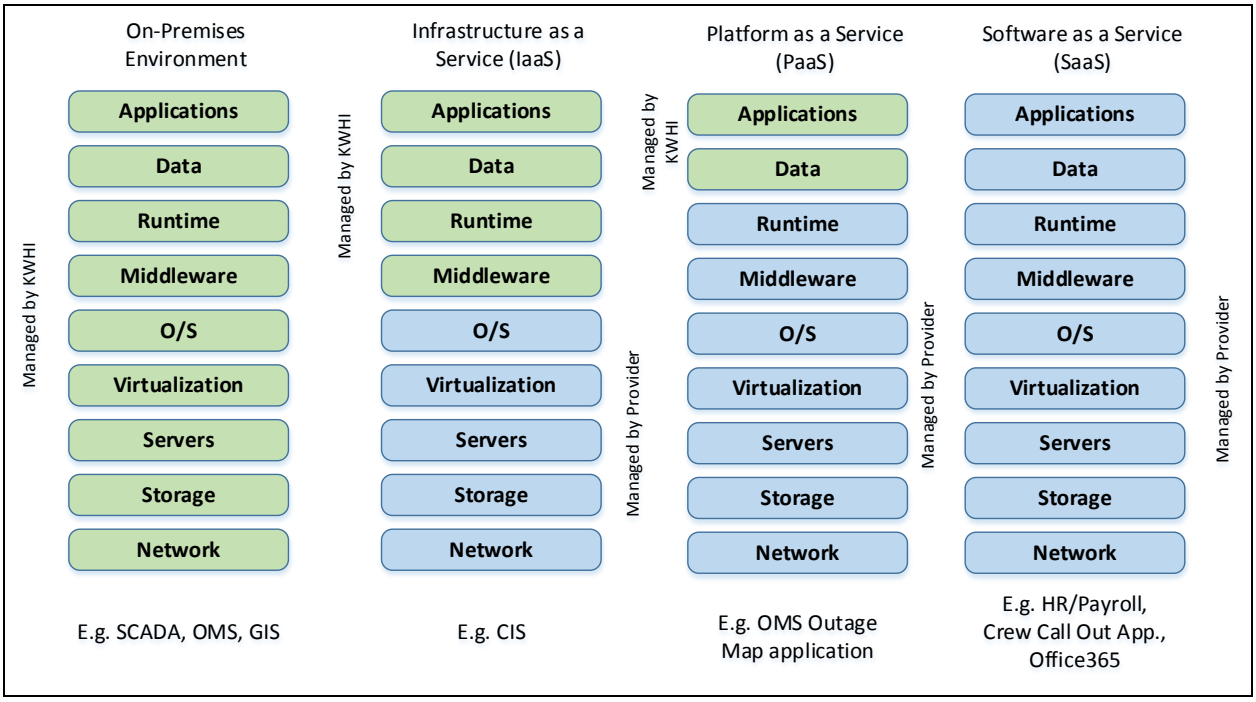
With regards to IT applications, the need for software systems is driven by business needs and technology obsolescence. Due to the complexity and potential business impact of upgraded/new core applications, KWHI takes a long-term planning view and enlist end user requirements for the planning and designing of these applications. With the shift from in-house developed applications to commercial off the shelf systems (COTS), detailed design for application systems is typically done after a preferred vendor is selected.

Acquire/Build

IT infrastructure is traditionally acquired as commercial off the shelf hardware and software and will continue this way going forward. On the contrary, application systems were traditionally developed in-house utilizing KWHI's resources and if acquired were often customized to suit KWHI's business processes. While this has served the organization well in the past, the rapid pace of technology changes and advancements prohibit KWHI from maintaining enough resources in-house to stay current. This has led to aging and obsolete applications, such as the CIS, that lack sufficient resources to provide maintenance and/or upgrade. Recognizing this challenge, KWHI made a paradigm shift from developing applications in-house to acquiring affordable best in class commercial off the shelf systems. This is one of KWHI's IT strategic objectives.

Another IT strategic objective is to utilize cloud computing technology, when necessary, to reduce capital and maintenance costs associated with IT infrastructure and software applications while enhancing data recovery, security, and application scalability. The figure below shows the different cloud computing service models and example of existing and future applications that KWHI has for each service.

Figure 3.42: Cloud Computing Service Models



Operate and Maintain

After acquiring IT assets, KWHI operate and maintain these assets based on industry best practices. The typical useful life (TUL) for IST assets has been determined in accordance with industry best practice and KWHI's local experience. Other factors such as technology obsolescence and availability of subject matter experts contributes to IST asset management decisions. Table 3-17 and Table 3-18 summarise the useful life of KWHI's information system core hardware and software systems.

Table 3-17: Useful Life of KWHI IST Software Applications

Enterprise Application	Description	Age (2018)	Last Major Update	Life Cycle	Future Direction
CIS	In-house billing application based on COBOL	30+	Continuous	7-10	Replace legacy CIS with commercial off the shelf system. 2019-2020
ERP	JD Edwards (JDE) is a suite of enterprise resource planning software that supports finance, procurement, maintenance and capital works.	20	2012	7-10	Evaluate upgrade vs replacement in 2020.
Payroll	In-house application based on Oracle DB	5	2014	5-7	Replace with HR/Payroll commercial off the shelf system. 2019
HRM	Part of In-house Payroll application and Sprigg software	2	Software-as-a-Service	N/A	To be included as part of HR/Payroll system. 2019
MSOffice	MSOffice 2013 Productivity suite	6	Routine Upgrades	3-5	Migrate to Office 365. 2019
SharePoint	Collaborative web-based platform that integrates with MSOffice and serves as the corporate intranet	1	2017	7-10	Maintain
MS Exchange	Email message system	6	Routine Upgrades	3-5	Migrate to Office 365. 2019
MyAccount	Online web presentment of customer consumption data	6	N/A	N/A	Integrate into new CIS as customer portal. 2021
File Nexus	File archiving and document management system	12	2016	7-10	Maintain
PLSCADD	Pole line design software	10	Routine Upgrades	7-10	Maintain
CYMDIST	Distribution analysis software	7	Routine Upgrades	7-10	Maintain
DESS	Distribution analysis software	13	2007	7-10	To be replace with CYMDIST
Avaya	Telephony system	2	2016	7-10	Maintain
Insight	Operational Reporting and Business Intelligence Tool	6	2011	7-10	Maintain
Spiceworks	IT Helpdesk Software	1	New	N/A	SaaS
Mobile Device Management (MDM)	IBM MaaS360	1	New	N/A	To be replaced with cloud-based application (SaaS) in 2018
CAD Software	MicroStation	18	Routine Upgrades	7-10	Periodic upgrades/updates
SCADA	Survalent SCADA system	30+	2015	7-10	Evaluate replace/keep when acquiring Distribution Management System
GIS	Hexagon (Intergraph) Geographic Information System	15	2017	7-10	Maintain
OMS	ACS outage Management System	3	2015	7-10	Maintain
AMI	Sensus Advanced Metering Infrastructure (AMI)	9	2014	3-5	Maintain

Table 3-18: Useful Life of KWHI IST Infrastructure Assets

Hardware	Qty	Description	Age Distribution			Life Cycle (years)
			(0 – 3 years)	(3 – 5 years)	(> 5 years)	
Servers - Physical	10	Computer infrastructure with its own hardware: Memory, network, processing and storage resources	4	4	2	3 - 5
Servers – Virtual (On Premises)	125	Virtual servers hosted on premises and run on physical servers using VMWare.	N/A	N/A	N/A	5 (based on OS and application lifecycle)
Servers – Virtual (Cloud)	3	Virtual servers hosted in a public cloud	N/A	N/A	N/A	5 (based on OS and application lifecycle)
Firewalls	2	Security devices at the edge of the network.	2	0	0	3-5
Storage Devices	3	SANs and Enclosures	1	0	3	5-7
Network Switches	23	Devices that provides connectivity between network devices on a Local Area Network (LAN)	0	0	23	7-10
Cybersecurity Monitoring	1	Variety of services from Managed Security Provider	1	N/A	N/A	Managed detection and response service
Wireless Access Points	15	Devices that permit wireless access to network resources	0	0	15	3-5
Routers	3	Devices that allow different LAN's to talk to each other	2	1	0	3-5
Workstations (PC)	110	Desktop computers	45	31	34	3-5
Laptops	67	Mobile computing devices	0	27	24	3-5
Network Printers	10	Leased multi-function printers	N/A	N/A	N/A	3-5
Plotters	2	Large format printers	1	0	1	5-7
Tablets	4	Mobile computing devices	6	0	0	3-5
Handhelds	4	e.g. barcode scanners	0	0	4	5-7
Smartphones	67	Cellphones	67	0	0	2-3

KWHI's IST infrastructure assets are stored and tracked in a MS Access database. The database is an inventory of servers, desktop computers, laptops, and all peripheral devices. IST software and applications are inventoried and kept in a MS Excel database. KWHI uses automation tools to manage the discovery of IST assets. The information from these tools gives insight into what assets are connected to the network and provides an inventory that can be compared to license entitlements.

The inspection cycle for IST assets is based on online monitoring for hardware equipment and user feedback for software and application systems. Maintenance of an IST asset is performed after degradation of service for hardware equipment and typically annually for software by vendors.

Dispose

After an IT asset reaches the end of its useful life based on a combination of factors such as age, condition, risk and obsolescence, it is treated as an underperforming asset or surplus and is disposed of or decommissioned. Assets are disposed of according to legal and statutory requirements, and per KWHI's policies. IT hardware assets that are removed from service are disposed of by first removing all data from the asset then having an asset disposition vendor destroy the hardware.

3.6 System Capability Assessment for Renewable Energy Generation (5.3.4)

3.6.1 Applications Over 10 kW (5.3.4a)

As of October 2, 2017, KWHI has connected 619 Distributed Generation projects for a total capacity of 22.248 MW, including 617 renewable energy generation projects for a total capacity of 17.99 MW. Among the renewable energy generation projects, there are 39 Feed-In Tariff (FIT) projects (6.69 MW), 640 microFIT projects (5.21 MW), one Renewable Energy Standard Offer Program (RESOP) project (6.63 MW), and 13 Net Metering projects (0.35MW), as shown in Table 3-19.

Table 3-19: List of FIT connections

	Connected FIT		Connected MicroFIT		Connected RESOP		Connected Net Metering	
Station	#	Total Capacity (kW)	#	Total Capacity (kW)	#	Total Capacity (kW)	#	Total Capacity (kW)
1TS	2	300	31	239.4	0	0	1	1.2
3TS Bus B51B61	2	325	2	20.0	0	0	0	0
3TS Bus B52B62	7	1226	38	304.6	0	0	0	0
4TS Bus B71B81	1	250	19	146.1	0	0	1	7.6
4TS Bus B72B82	3	542.8	36	292.9	0	0	0	0
5TS Bus B91B101	3	410	56	422.0	0	0	1	2.2
5TS Bus B92B102	5	756	44	361.6	0	0	1	10
6TS Bus B111B121	6	980	52	441.9	0	0	1	250
6TS Bus B112B122	1	250	69	546.9	0	0	0	0
7TS	5	1125	27	224.8	0	0	1	10
8TS	2	210	75	624.6	0	0	0	0
9TS (direct)	0	0	30	262.2	1	6225	0	0
9TS (indirect,8kV)	2	320	141	1323.5	0	0	7	64.8
Total:	**39**	**6694.8**	**620**	**5210.6**	**1**	**6225**	**13**	**345.8**

There is a total of 53 FIT, RESOP and Net Metering distributed generation connections over 10 kW. This amount to approximately 13.5 MW of distributed generation over 10 kW.

3.6.2 Forecast of REG Connections (5.3.4b)

Based on Kitchener-Wilmot Hydro's FIT/microFIT data and the future assumptions, it is estimated that the connection of Renewable Energy projects under FIT and microFIT programs will remain steady beyond 2018. This estimate assumes that the IESO will not significantly change the program rules and rate calculation methodology. The following table outlines the expected FIT/microFIT connections between 2020 and 2024. KWHI notes the values in the below table have been reforecast with current information and vary from the table submitted to the IESO.

Table 3-20: Anticipated DGs 2020 – 2024

Year	FIT projects	MicroFIT projects
2020	5-10 (1-2MW)	50-100 (0.4-1MW)
2021	5-10 (1-2MW)	50-100 (0.4-1MW)
2022	5-10 (1-2MW)	50-100 (0.4-1MW)
2023	5-10 (1-2MW)	50-100 (0.4-1MW)
2024	5-10 (1-2MW)	50-100 (0.4-1MW)

3.6.3 Capacity Available (5.3.4c)

The estimated remaining station capacity at each transformer station is shown in Table 3-21 below. Most transformer stations have sufficient short-circuit capacity to accommodate the typical distributed generations. The only exception is Kitchener 3TS Bus B52B62. As of drafting this DSP, most of the renewable energy projects proposed in Kitchener-Wilmot Hydro service area are inverter-based with insignificant fault contribution to KWHI's distribution system. It is unlikely that the fault contribution from the renewable distributed generation will cause the transformer stations to reach the short-circuit capacity limits. For all other KWHI transformer stations, the station capacity is limited by the thermal capacity of the station transformers. Dual-winding transformers are installed at Kitchener 3TS, 4TS, 5TS and 6TS. These dual-winding transformers cannot sustain reverse flow; thus the station thermal capacity is determined by the minimum station load.

All KWHI DS are limited to 500 kVA maximum size of DG connected capacity.

Table 3-21: KWHI TS Station capacity for REGs

Station Name	Bus Name	Feeder Name	Nominal Voltage (kV)	Max. Allowable DG SC Capacity (MVA)	Max. Allowable DG Thermal Capacity (kW)	Existing DG Non-Renewable (kW)	Existing DG Renewable (kW)	Existing Remaining Capacity (kW)	Proposed Applications FIT 3.X and 4.0 (KW)**
Kitchener #1 MTS	B1B2	1M1, 1M3, 1M4, 1M5, 1M6, 1M7, 1M8, 1M9	13.8	OK	32,000	0	540.6	31,480	0
Kitchener #3 MTS	B51B61	3M11, 3M13, 3M14,3M15, 3M16, 3M18	13.8	OK	3,400	0	345	3,075	0
	B52B62	3M20, 3M21, 3M22, 3M23, 3M24, 3M26, 3M27, 3M28, 3M29, 3M210, 3M211, 3M212	13.8	0 MVA	4,400	4,080*	1530.6	0	250
Kitchener #4 MTS	B71B81	4M11, 4M12, 4M13, 4M14, 4M15, 4M16, 4M17, 4M18	13.8	OK	10,400	0	403.7	9,996	0
	B72B82	4M21, 4M22, 4M23, 4M24, 4M25, 4M26, 4M27, 4M28	13.8	OK	4,400	0	835.7	3,568	0
Kitchener #5 MTS	B91B101	5M11, 5M12, 5M13, 5M14, 5M15, 5M16, 5M17, 5M18	13.8	OK	7,500	0	834.2	6,752	385
	B92B102	5M21, 5M22, 5M23, 5M24, 5M25, 5M26, 5M27, 5M28	13.8	OK	7,200	180	1127.6	6,142	570
Kitchener #6 MTS	B111B121	6M11, 6M12, 6M13, 6M14, 6M15, 6M16, 6M17, 6M18	13.8	OK	8,100	0	1671.9	6,492	0
	B112B122	6M21, 6M22, 6M23, 6M24, 6M25, 6M26, 6M27, 6M28	13.8	OK	9,200	0	796.9	8,475	100
Kitchener #7 MTS	B13B14	7M1, 7M2, 7M3, 7M4, 7M5, 7M6, 7M7, 7M8, 7M9, 7M10	13.8	OK	3,3400	0	1359.8	32,020	0
Kitchener #8 MTS	B15B16	8M1, 8M2, 8M3, 8M4, 8M5, 8M6, 8M7, 8M8, 8M9, 8M10	13.8	OK	32,600	0	834.6	31,868	0
Kitchener Wilmot #9 TS	B17B18	9M1, 9M2, 9M3, 9M4, 9M5, 9M6,9M7, 9M8, 9M9, 9M10	27.6	OK	50,000	0	8195.5	41,846	1,877

3.6.4 Constraints – Distribution and Upstream (5.3.4d)

HONI constraints

There are no upstream HONI transmission system constraints.

Transformer Station constraints

One KWHI transformer station has reached the short-circuit capacity limit at Kitchener 3TS Bus B52B62, due to the replacement of the power transformer T5 and HONI's transmission system upgrade as part of the GATR (Guelph Area Transmission Reinforcement) project. Considering the fault contribution from the existing DG (non-renewable, 4075kW), the current short-circuit capacity at feeder breakers (474MVA) has exceeded the short-circuit capacity of the bus (15kV, 18kA, 467MVA). No additional distributed generation can be connected to this bus.

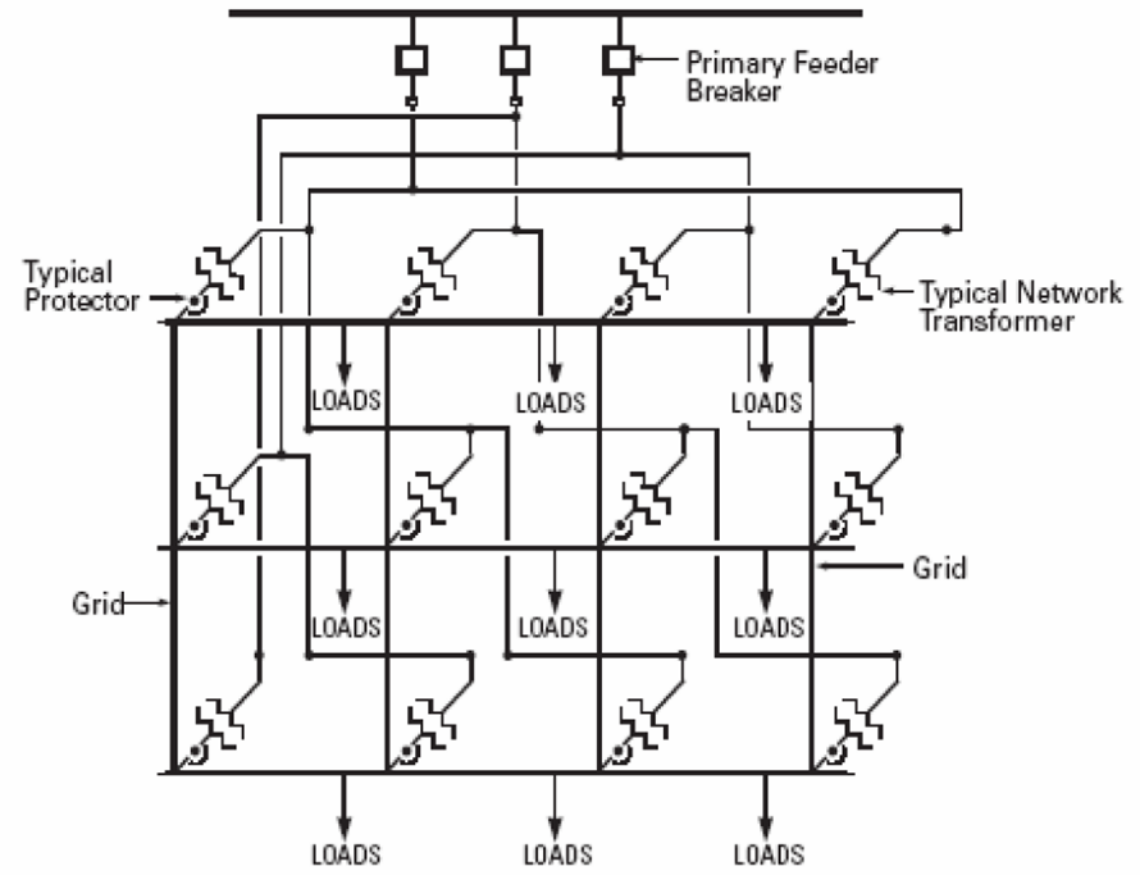
Distribution Station constraints

The seven Distribution Stations in the Township of Wilmot are directly supplied from Kitchener No.9 TS. All KHWI DS are limited to 500KVA maximum size of DG connected capacity.

Feeder constraints

Part of the City of Kitchener's downtown is supplied by a secondary grid network, i.e. a 125/216V 3-phase secondary network fed by four 13.8kV parallel feeders from Kitchener #1 MTS, consisting of 41 transformers with interconnected secondaries. See Figure 3.43 for a typical secondary network configuration. This secondary network covers a small 0.5 square kilometer area between Francis Street and Eby Street from west to east, and between Weber Street and Charles Street from north to south. It supplies the load customers less than 500kW. The customers larger than 500kW in the same area are supplied by another 13.8kV underground loop feeder from Kitchener #1 MTS.

Figure 3.43: Schematic of a typical grid secondary network



It is technically challenging to integrate the distributed generators into the secondary grid networks due to the protection mechanism and philosophy used to protect the network transformer by design. A secondary network is a complex power grid with a web of multiple parallel sources of power to each customer. The design of a secondary network does not allow customers to export power to the grid due to safety and technical reasons (the change of power flow direction may cause the secondary network protector to malfunction resulting in inadvertent loss of load). To prevent export into KWHI's secondary network system, a customer's protection and control (P&C) system must be designed to sense the power flow at the customers' main service Point of Common Coupling and trip out the generator's main breaker, or trip out the customer's main breaker at a pre-determined minimum import level or during P&C alarm conditions. Like most other utilities, KWHI's current practice is to disallow any distributed generation connection to the secondary downtown grid network, including all FIT and microFIT projects, unless the DG proponents are willing to install special protective devices at their end to prevent the reversed power flow into the secondary grid network. KWHI will keep this policy until more technical research is complete.

For the proposed FIT and behind the meter generation projects in this area, KWHI also offers the option to connect the distributed generation project to the 13.8kV underground loop feeder.

3.6.5 Constraints – Embedded Distributor (5.3.4e)

KWHI has one Embedded Distributor, Waterloo North Hydro Inc. (WNHI). Prior to market opening on May 1, 2002, HONI had the obligation to supply WNHI's Wellesley DS in the Town of Wellesley.

Following market opening, KWHI became the host distributor to WNHI. Wellesley DS is supplied from KWHI No. 9 TS. KWHI have no capacity constraints for the connection of REG load to Wellesley DS.

4 CAPITAL EXPENDITURE PLAN (5.4)

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

4.1 SUMMARY

KWHI's DSP details the programme of system investment decisions developed based on information derived from KWHI's asset management and capital expenditure planning process. Investments, whether identified by category or by specific project, are justified in whole or in part by reference to specific aspects of KWHI's asset management and capital expenditure planning process.

KWHI's DSP includes information on prospective investments over a five-year forward-looking period (2020 – 2024) as well as planned and actual information on investments over the historical period (2014 – 2019).

4.1.1 Capital Expenditures over the Forecast Period

The following table summarizes the planned capital expenditures, by investment category, over the period of the DSP:

Table 4-1: Planned Capital Expenditures per investment category

Category	2020($)	2021($)	2022($)	2023($)	2024($)	Avg. ($)
System Access	7,664,500	7,767,000	7,817,000	7,717,000	7,767,000	**7,746,500**
System Renewal	9,415,000	10,350,000	10,650,000	11,400,000	11,500,000	**10,663,000**
System Service	3,200,000	3,200,000	2,800,000	2,300,000	2,300,000	**2,760,000**
General Plant	4,295,000	3,275,000	3,565,000	3,500,000	3,480,000	**3,623,000**
Gross Capital Expenses	**24,574,500**	**24,592,000**	**24,832,000**	**24,917,000**	**25,047,000**	**24,792,300**

Figure 4.1: 2020-2024 capital expenditures



	2020	2021	2022	2023	2024
General Plant (Gross)	4,295,000	3,275,000	3,565,000	3,500,000	3,480,000
System Service (Gross)	3,200,000	3,200,000	2,800,000	2,300,000	2,300,000
System Renewal (Gross)	9,415,000	10,350,000	10,650,000	11,400,000	11,500,000
System Access (Gross)	7,664,500	7,767,000	7,817,000	7,717,000	7,767,000

The figures and table above demonstrate that over the forecast period of the DSP, KWHI plans to pace and prioritize capital expenditures so as to produce a predictable impact on rates and prevent spikes in spending. KWHI plans to invest an average of $24.79M in capital expenditures per year across all four investment categories.

4.1.2 Capital Planning for 2020-2024

The asset management and capital investment process identify System Access, System Renewal, System Service and General Plant requirements. These requirements result in a list of mandatory and added value investments to be executed over the investment period. Mandatory capital investment needs are documented, costed and scheduled according to timeline needs. Added value investments that provide benefits to the system are documented, costed and prioritized according to risk of deferral and the benefit each investment has towards achieving corporate Asset Management Objectives, regardless of which investment category they reside in. In general, investments with a high safety risk and benefit projections will take precedence over other investments. The capital budget is allocated among the categories according to the mandatory and prioritized investments in the final capital investment portfolio. The final investment portfolio considers the balance between achieving KWHI's Asset Management Objectives and impact on customer rates.

The combination of KWHI's asset management and capital expenditure planning process leads to a capital expenditure plan consisting of a five-year capital expenditure forecast which includes a one-year detailed capital budget.

4.1.2.1 System Access

Expenditures in this category are driven by external requirements such as servicing new customer load, relocating distribution plant to suit road authorities, etc. Timing of investment is driven by the

needs of the external parties. These expenditures are mandatory. Specific project scopes are rarely known at the time that the budget is set, and total expenditures can vary from year to year. Most of the forecasted investments in this category are based on historical requirements. Specific projects such as relocations due to LRT development which are planned as multi-year projects are budgeted for based on KWHI's estimates, in conjunction with information from external agencies (such as the City of Kitchener, Township of Wilmot and Region of Waterloo) of the work required over the project life cycle.

KWHI 2020 – 2024 capital programs that form part of System Access investments are found in the table below.

Table 4-2: 2020-2024 System Access Expenditure Plan ($ Thousands)

Programs	2020	2021	2022	2023	2024
Miscellaneous Underground Distribution	450	450	450	450	450
Relocation Due to Roadway Modifications	1,700	1,700	1,750	1,750	1,800
Underground Residential Distribution	3,708	3,800	3,800	3,800	3,800
Commercial, Industrial & Apartment Services	1,209	1,220	1,220	1,120	1,120
Revenue Meters	597	597	597	597	597
System Access Total	**7,664**	**7,767**	**7,817**	**7,717**	**7,767**

4.1.2.1.1 Miscellaneous Underground Distribution

This program allows funding to be budgeted for new or upgraded underground services that are required to supply individual residential customers (not part of a subdivision or townhouse development), small commercial customers and unmetered scattered load customers. The projects in this program are non-discretionary (mandatory) and individual project costs are typically small. Specific projects are not known at the time that the budget is set, and total expenditures can vary from year to year. This program also allows funding to be budgeted for the completion of System Access projects that are underway at the end of the previous budget year.

4.1.2.1.2 Relocation Due to Roadway Modifications

This program includes expenditures to relocate/replace pole line and underground assets that conflict with roadway construction activities. The spending is driven by the road authorities (region of Waterloo, City of Kitchener, Wilmot Township, and MTO) and is mandatory. Reimbursement is normally limited to 50% of labour and labour-saving devices only in accordance with the *Public Service Works on Highways Act*. Specific projects are rarely known at the time that the budget is set, and total expenditures can vary from year to year. Relocations usually mean replacement with little recovery of material for reuse. Experience has shown however, that the labour cost to recover used materials often approaches or exceeds the cost to purchase new materials.

4.1.2.1.3 Underground Residential Distribution

Underground Residential Distribution (URD) consist of several individually budgeted project activities such as; Installation of Underground Residential Distribution, Installation of Residential Underground Services, and Purchase and Installation of URD transformers. These activities form a subset of System Expansion to Supply New Developments that are customer driven. Investments in URD is in response to requests from developer to supply new infrastructure to serve residential subdivisions. KWHI is budgeting to supply and install 1,200 residential services for the 2020 Test Year. The forecasted number of units is based on historical trends and anticipated future single family and townhouse developments. The same level of activity is anticipated for the forecast years of 2021-2024.

The following sections describe the sub-programs that contribute to this program.

4.1.2.1.3.1 Installation of Residential Underground Services

The costs to connect the meter at each new home to the URD system that was installed when the subdivision was serviced are captured in this category. These costs tend to be mostly labour and per unit costs are relatively consistent. Total expenditures are proportional to the number of new homes constructed. This spending is customer driven and is mandatory.

4.1.2.1.3.2 Installation of New Underground Residential Distribution

The costs to install URD systems in new residential subdivisions are captured here. The distribution assets installed during this activity are; conduits and cables. Total expenditures tend to vary with the level of economic activity in the Region. This spending is customer driven and is mandatory.

4.1.2.1.3.3 Installation of New URD Transformers

The labour and materials to install distribution transformers (submersible and mini-pad) in URD systems in new residential subdivisions are captured here. Also captured here are the costs to complete the vault collars for submersible transformers installed in previous years, work which must be deferred until final landscaping has been completed. Total expenditures tend to vary with the level of economic activity in the Region. These expenditures are customer driven and are mandatory.

4.1.2.1.3.4 URD Transformer Purchases

This program includes the purchasing of transformers for new URD developments and the replacement of existing URD transformers that have failed and are at end of life. For investment categorization purpose, this project is classified as System Access since approximately 70% of the cost is typically associated with transformers purchased for new developments. The transformers purchased in this category are single-phase submersible and pad-mounted transformers.

4.1.2.1.4 Installation of Commercial, Industrial & Apartment Services

This is a component of System Expansion to Supply New Developments. The costs to install ducts and cables to service new large 3-phase commercial and industrial customers are captured here. The purchasing of transformers that are used for new and upgraded commercial, industrial and apartment services are also included in this program. The transformers purchased in this category are three-phase vault type (above grade) and pad-mounted transformers. Also captured here are the costs to upgrade the capacity of existing commercial, industrial and apartment services. The cost per service can vary widely with the nature and capacity of each service. Total expenditures tend to vary with the level of economic activity in the Region. KWHI is anticipating an increase in development activities along the recently completed LRT route which will require underground servicing. This spending is customer-driven and KWHI is obligated to complete the associated work.

4.1.2.1.5 Revenue Meters

This program includes expenditures related to the supply and installation of revenue meters that are installed at each customer service point for retail settlement and billing purposes for each customer connected to KWHI's distribution system. The budget for revenue meters includes installation of single-phase residential meters (both load and generation customers), polyphase meters for small commercial customers (General Service less than 50 KW), Meters Inside the Settlement Timeframe ("MIST") meters for General Service customers with a monthly demand greater than 50 kW, and primary metering equipment (instrument transformers and potential transformers). Revenue meters have four primary drivers; new meters for new customers, replacement of failed units, reliability (elimination of meter types that have history of poor reliability) and standardization (elimination of meter types for which KWHI has only a few in service e.g. 600V Delta).

KWHI is forecasting approximately 1,400 revenue meters for installation in each of the forecast years. The number of revenue meters forecasted for installation in each year is based on historical trends and the expected customer growth.

These investments are required by the Distribution System Code, are customer driven and are mandatory.

4.1.2.2 System Renewal

Expenditures within the System Renewal category are largely driven by the condition of distribution system assets and play a crucial role in the overall reliability, safety and sustainability of the distribution system. KWHI's ACA recommends assets for renewal based on condition data from tests and inspections and other factors unique to specific asset class. The asset management process outlines the strategy used to determine the criteria for asset replacement. The output of the asset management plan drives the development of the capital expenditure plan and prioritisation for System Renewal. For the Test Year, System Renewal related expenditures account for approximately 40% of the total expenditures. This is a shift from the past 5 years in which System Access was the highest annual expenditures, primarily driven by relocations due to road works and LRT. During the historical period, KWHI deferred several System Renewal projects in order to accommodate the higher than usual expenditures for System Access. This was necessary to provide appropriate pacing of expenditures resulting in non-lumpy capital spending.

KWHI 2020 – 2024 capital programs that form part of System Renewal investments are found in the table below.

Table 4-3: 2020-2024 System Renewal Expenditure Plan ($ Thousands)

Programs	2020	2021	2022	2023	2024
Transformer and Distribution Stations Renewal	2,004	2,800	2,800	3,500	3,500
Replacement of Pole Line Assets	3,404	3,500	3,500	3,500	3,500
Replacement of Primary Cables and Conduits	850	850	1,000	1,000	1,000
Voltage Conversion	1,375	1,400	1,550	1,600	1,700
Rebuild Transformer Vaults & Pull Boxes	240	250	250	250	250
Network Transformer Replacement	192	200	200	200	200
Distribution Transformer Installation and Replacement	1,350	1,350	1,350	1,350	1,350
System Renewal Total	**9,415**	**10,350**	**10,650**	**11,400**	**11,500**

4.1.2.2.1 Transformer and Distribution Stations Renewal

This program includes a collection of projects in which power transformers, protection and control devices and switchgear equipment at existing transformer stations are replaced or upgraded due to age, deteriorating condition or functional obsolescence. These equipment types are usually replaced with upgraded or new technologies available at the time of renewal.

KWHI is one of only a few local distribution companies in the Province which receives power at the transmission voltage and transforms it down to distribution voltage by way of its own transformation assets. The utility owns eight high voltage transformer stations, strategically located throughout the City of Kitchener and the Township of Wilmot. Distributed generation combined with a very successful Conservation and Demand Management program have combined to slow KWHI's load growth considerably. Adding the material and permanent loss of load resulting from plant closures during the economic downturn in the late 2000's, KWHI anticipates that it can defer the next expansion of its transformer station capacity for 5-10 years. In the absence of any immediate need to expand transformer station capacity, capital investments in transformer station assets will be limited to a series

of end of life replacements over the forecasted period. A work plan summarizing the anticipated expansion and refurbishment of the utility's transformation stations over the next 10 years may be found in Appendix O. Below is a high-level summary of these initiatives.

Planned Initiatives	Proposal Year
The protection and control equipment at #6 Transformer Station is approaching end of life and will be replaced	2020
The protection and control equipment at #3 Transformer Station is approaching end of life and will be replaced	2022/2023
Retrofit the switchgear at #5 Transformer Station with arc resistant features to enhance worker safety and minimize the extent of damage should a fault occur	2020
Retrofit the switchgear at #3 TS Transformer Station with arc resistant features and replace 14 circuit breakers	2021
Replace circuit switcher and acoustic enclosure at #4 Transformer Station	2021 - 2022
Replace 2 x 83 MVA power transformers at end of life with 2 x 100 MVA standard size units. Between 2022 and 2024, two power transformers at #5 Transformer Station that are at end of life and were flagged for replacement in the ACA are budgeted to be replaced with standard size equipment. The transformers at #5 Transformer Station is configured with two power transformers (2 x 83 MVA – 1976 vintage). By 2021, these transformers will be 45 years old and approaching end of life. Two new 100 MVA transformers will be purchased to replace the existing units. The existing 83 MVA units will be scrapped.	2022 - 2024

The Township of Wilmot is currently supplied via twenty 8.3kV feeders originating from seven distribution substations. Each distribution station receives power from one of the 27.6 kV feeders and transforms it to 8.3 kV. The most recent of these stations was constructed in the early 1990's at a cost of approximately $500,000. No additional capital expenditures for distribution stations are planned. Capital expenditures to expand these facilities as the load grows or to refurbish/replace existing facilities as they age will be avoided by converting the distribution feeders from 8.3 kV to 27.6 kV operation within the forecast planning period.

Voltage conversion will eventually see the elimination of these stations. This plan would follow the same methodology as used in Kitchener between 1982 – 1998 that eliminated 26 4-kV substations

4.1.2.2.2 Replacement of Pole Line Assets Due to Age/Condition

This program consists of a number of overhead rebuild projects that are planned for based on the results of KWHI's ACA and other unplanned asset replacement that occurred throughout the budget year. For budgeting purpose, KWHI used the following budget categories: Miscellaneous Overhead Distribution, Single Phase Rebuilds, and individual budget categories for large three-phase pole line rebuilds with expenditures greater than $100,000. Over the DSP period, 425-450 poles per year are planned for replacement. KWHI had strong customer support for this program and in some cases, customers were willing to pay more to accelerate the program based on results from the 2018 Customer Engagement Survey.

The following sections describe the sub-programs that contribute to this program.

4.1.2.2.2.1 Miscellaneous Overhead Distribution

This program includes minor replacements of assets. These are typically pertinent to some other larger project e.g. during the installation of an underground cable, it becomes necessary to replace a pole, install an additional pole or install additional guying. On occasion, the costs of unanticipated rebuild projects are attributed to this program. Spot replacement of rotted poles are captured under this program. These poles are identified as being in Very Poor condition from pole surveys and are often not feasible to wait until a larger rebuild project is planned for the particular area. Carryovers from

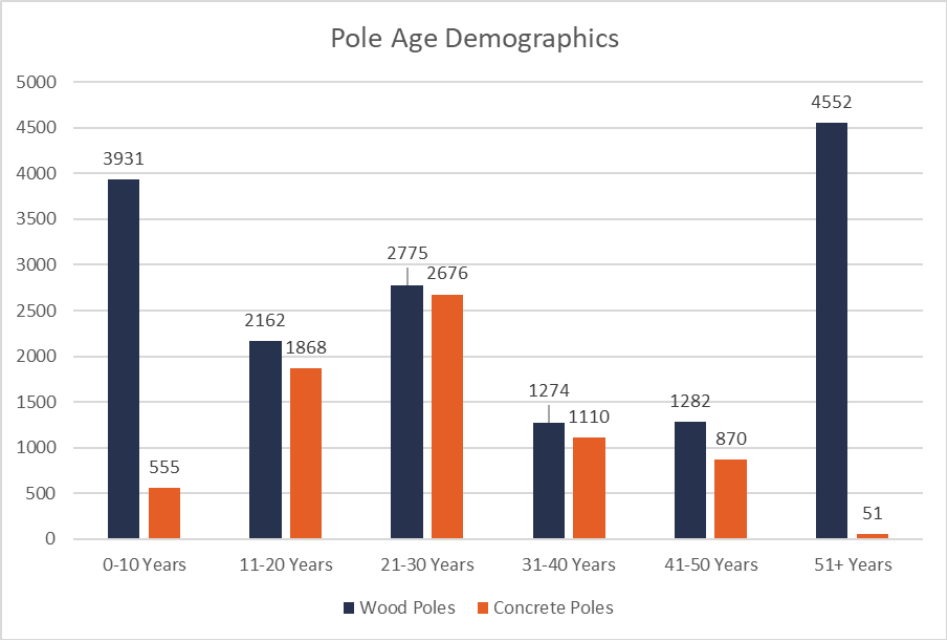
System Renewal projects that are substantially completed in a prior year are normally budgeted for in this category. Specific projects are not known at the time that the budget is set, and total expenditures can vary from year to year. Individual project costs are typically small.

4.1.2.2.2.2 Single-Phase Pole Line Rebuilds

This program includes a collection of single-phase pole lines that are determined to have reached the end of life and are targeted for a rebuild. Assessing pole line rebuild projects based on KWHI's planning criteria allows KWHI to prioritize projects and adjust throughout the budget year depending on the requirements for other unforeseen jobs. Single-phase pole lines have a lower probability of structural failure due to the nature of the mechanical load that they typically support.

As of 2018, there were 23,107 distribution poles catalogued in KWHI's GIS. The distribution of ages is summarized in the following figure.

Figure 4.2: KWHI Pole Age Demographics (reported within ACA)



While the figure illustrates KWHI's commitment to replacing old poles (37% of the population has been installed in the last 20 years), it also demonstrates the need to continue investing in pole replacements (approximately 20% older than 50 years). All poles that currently exceed the age of fifty years are expected to be replaced within the next ten years. In all, the capital program should allow for the replacement of approximately 4,500 poles due to age/condition over the next 10 years.

To assist in prioritizing pole replacements, in 2011, KWHI commenced a program to test the condition of all poles more than 40 years old to identify the most critical poles. The data from these pole tests is used in the ACA to calculate a health index for each pole which in turn is used to categorise the overall pole condition and flag poles for replacement. See table below for wood poles summary from ACA.

Table 4-4: Recommended Wood Pole Replacement

Number of Wood Poles Recommended for Replacement						
Year	2018	2019	2020	2021	2022	2023
Quantity	425-450	425-450	425-450	425-450	425-450	425-450

4.1.2.2.3 Replacement of Primary Cables and Conduits Due to Age/Condition

This program includes the replacement of primary cables and conduits due to age, condition and risk of failure. During pole line rebuilds, all underground cable associated with poles that are being replaced are captured under this program. In other words, during the reconstruction of a pole line, it becomes necessary to replace the riser ducts, replace a cable or transfer an underground service. Individual project costs are typically small and significant variability is expected between each project. Moreover, any feeder cable or URD cable that fails during the budget year and requires replacement as opposed to repairs are captured under this program.

There is also an ongoing program, conduit replacement, that involves the installation of conduit in anticipation of replacing direct buried primary cable in residential subdivisions that are approaching end of life and to drain submersible transformer vaults that contain transformers which exhibits high failure rate.

On December 31, 2017, there was 84.7 circuit-kilometres of trunk feeder primary cable and 778.9 circuit-kilometres of URD cable catalogued in KWHI's GIS. The distribution of ages is summarized in the following tables.

Table 4-5: Trunk Feeder Cable Statistics

Age	Range	Totals (cct-km)
40+ Yrs	Pre 1976	9.2
30-39 Yrs	1977 - 1986	1.7
20-29 Yrs	1987 - 1996	13.2
10-19 Yrs	1997 - 2006	15.4
< 10 Yrs	2007 - 2016	26.2
	Null	19.0
	Totals	**84.7**

Table 4-6: URD Cable Statistics

		Voltage System			Totals (cct-km)
Age	Range	27.6kv	13.8kv	8.3kv	
40+ Yrs	Pre - 1976	0.0	22.2	2.4	24.5
30-39 Yrs	1977 - 1986	0.0	140.1	8.6	148.6
20-29 Yrs	1987 - 1996	0.0	252.2	23.8	276.5
10-19 Yrs	1997 - 2006	13.1	168.9	25.5	207.5
< 10 Yrs	2007 - 2016	2.4	111.2	7.9	121.5
	Null	0.1	0.0	0.1	0.2
	Totals	**16.2**	**694.6**	**68.2**	**778.9**

Currently, the trunk feeder primary cables have a very low failure rate. The typical useful life for these types of cables (XLPE mostly) is a life expectancy of 25-30 years. KWHI believes its practice of using exclusively copper cables and a PVC jacket will result in cable life that exceeds the industry norms. KWHI estimates a life expectancy of approximately 40 years based on its past experience.

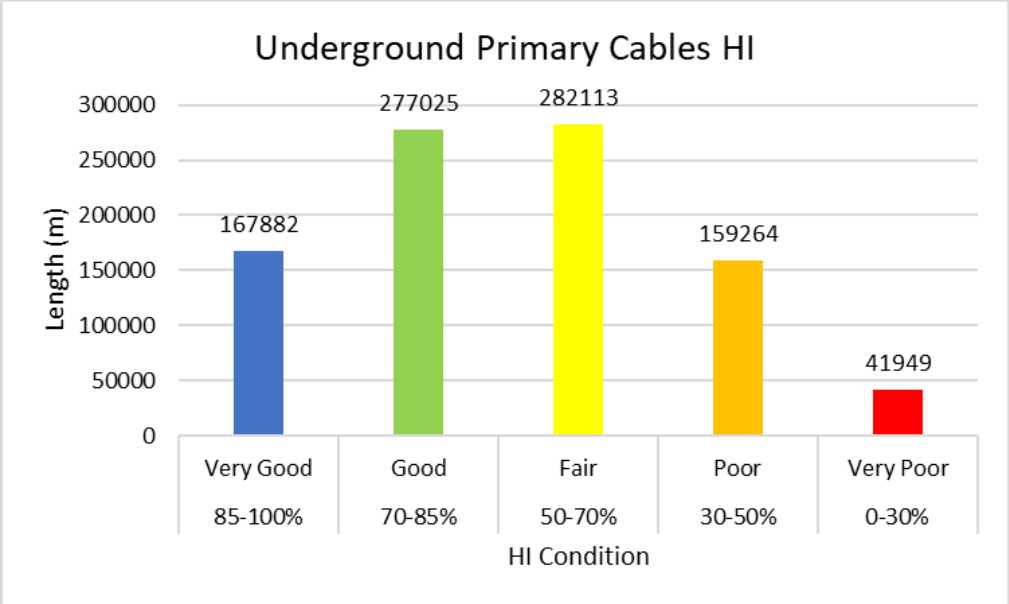
KWHI's trunk feeder primary cables are installed in duct. These cables can be replaced by pulling out the old cable and pulling in the new. KWHI does not expect to begin replacing these cables until they begin to exhibit a pattern of failures or test results show fair to poor health indices. KWHI allocated funds in this category based on historical performance.

All URD primary cables installed after 1994 are installed in duct. These cables can be replaced by pulling out the old cable and pulling in the new. URD primary cables installed before 1994 are direct buried. Cable replacement will involve burying a new duct in a trench or bore hole opened by tunnelling, and then pulling a cable into it. This will be a very expensive exercise.

KWHI does not expect to begin replacing these cables until they begin to exhibit a pattern of failures or test results show fair to poor health indices.

Results of the ACA show that approximately 42 km of underground primary cable is in Very Poor condition (see figure below). However, the ACA analysis was primarily based on age data.

Figure 4.3: Underground Primary Cables Health Index Demographic



In 2018 KWHI conducted detailed testing (using CableQ non-destructive testing methods) of 20 samples of underground primary cable that are 40 years and older and found that of the 20 samples only 1 sample was listed as Fair condition. The other samples were ranked as being in Good condition. Recognizing that the currently available testing sample set is too small to extrapolate to the larger cable population KWHI will continue to perform more tests and develop more long-term trends.

Although KWHI can approximate the survival of primary cables using the typical useful life and continue to monitor the performance to mitigate and control failures, KWHI notes that 11.5 kilometres of URD primary cables are more than 30 years old. It is reasonable to expect that KWHI will begin to see more failures as cable continues to age. KWHI plans to allocate funds toward cable replacement on an annual basis. KWHI has also begun a program to install conduits in URD areas older than 1994.

These conduits serve two main purposes; the first being to provide an interconnected path to drain submersible transformer vaults and keep them dry and secondly to install replacement cable at some time in the future when the cable fails. KWHI attempts to strike a balance between cable replacement and conduit replacement each year. That is, if there are more cables that need replacing than budgeted for, the amount of conduit installed is reduced. This strategy paces expenditures for cable replacement.

4.1.2.2.4 Voltage Conversion - 8.3 to 27.6 kV

This program includes projects that are undertaken for the purpose of voltage conversion from 8.32kV to 27.6kV. Voltage conversion is driven by the need to improve system efficiency (by reducing line losses), improve voltage profile (regulation), improve ability to connect distributed generation and increase system capacity for load growth. However, the trigger for voltage conversion projects is normally the need to replace end of life pole line assets. Hence, the categorisation of the program as System Renewal. If voltage conversion projects are triggered by the need to increase system capacity for load growth, then those projects will be classified as System Service or System Access.

KWHI began the conversion to 27.6 kV in 1995. The conversion strategy leverages the need to rebuild pole lines due to age/condition. If voltage conversion for any given section of line is deferred until the pole line is rebuilt, the cost of conversion is essentially the marginal cost of the insulation and is therefore included as part of the project's overall cost instead of the voltage conversion cost. The majority of voltage conversion will happen through the rebuild process. All lines constructed in Wilmot Township since 1995 have been constructed with 27.6 kV insulation and operated at 8.3 kV. However, since KWHI No.9 Transformer Station is now in-service (as of December 2010); plans have been put in place to strategically operate some of the previously constructed lines and lines currently being constructed at 27.6 kV. The labour and materials required to make this happen (replacement of surge arresters, insulators, poles and conversion of customer-owned primary services) are captured under the category of Voltage Conversion.

4.1.2.2.5 Rebuild Transformer Vaults & Pull Boxes

The structural elements of KWHI's network transformer vaults deteriorate over time. KWHI surveys the condition of these vaults on a regular basis as per OEB guidelines. Structural elements that are found to be in poor condition are replaced/rebuilt. This program captures the cost associated with major repairs that extends the useful life of the vault/pull box rebuilding. The expenditures required will vary with the results of the surveys. KWHI is budgeting to rebuild two transformer vaults per year for the forecasted period.

Figure 4.4: Portion of a deteriorated transformer vault being prepared for rebuilding

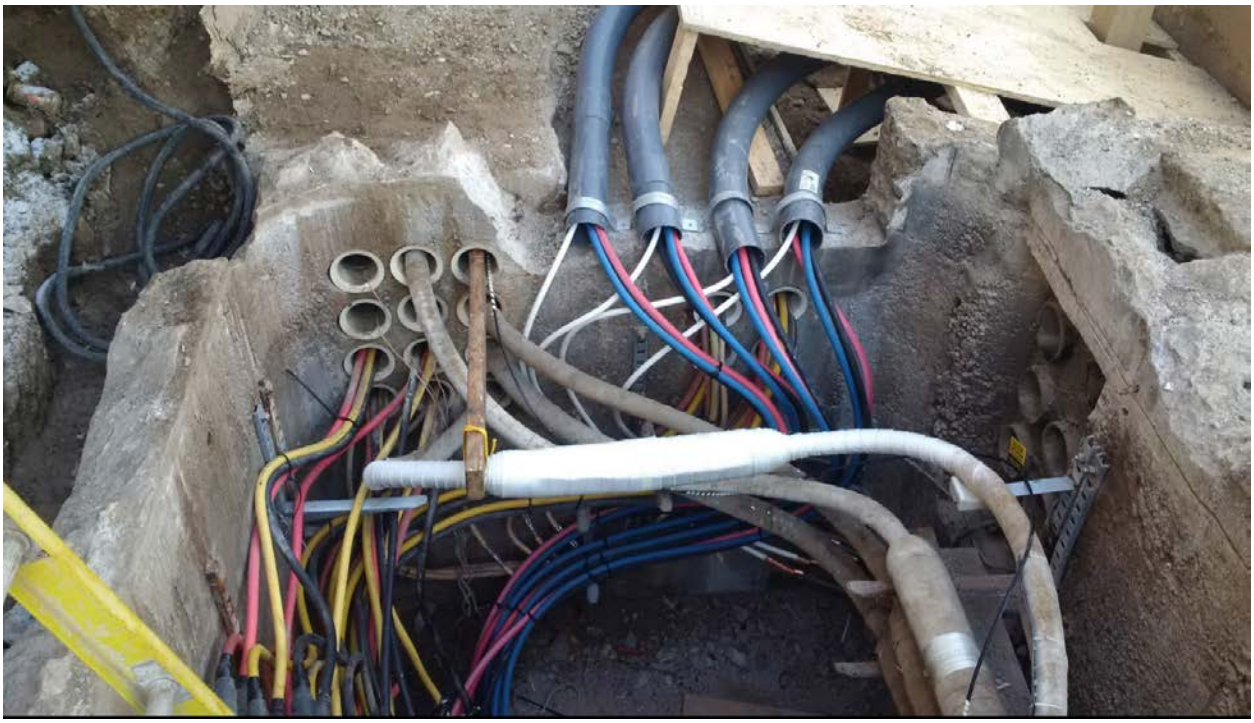


Figure 4.5: Network transformer vault under construction



4.1.2.2.6 Network Transformer Replacement

This program includes the replacement of network transformers complete with network protectors. These assets are specialized in their use, costly to replace and should not be run to failure because of the risk of a catastrophic failure in areas with high pedestrian traffic. Network transformers are

installed in below grade vaults in Kitchener's downtown core and are used to supply high density loads with demand below 500kW.

Network transformers are maintained on a regular basis. Routine maintenance includes:

I. Testing the oil
II. Testing and calibrating the network protector
III. Servicing the primary switch
IV. Repainting when rusted

Figure 4.6: Deteriorated network transformer with protector



Figure 4.7: New network transformer with protector

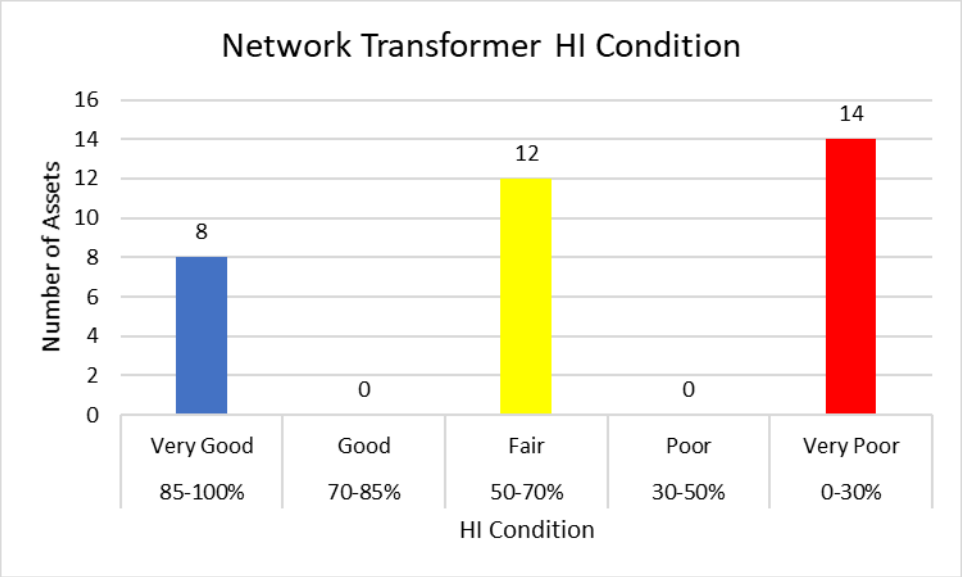


Transformers found to be in poor condition are replaced with one of the spare units. With this level of maintenance, the life expectancy is 45-50 years. KWHI plans to allocate funds to replace two units per year. However, the recently concluded ACA identified 14 network transformers as being in Very Poor condition which may require KWHI to ramp up this program (see figure below). There were 34 network transformers in service catalogued in KWHI's GIS. The distribution of ages is summarized in the following table.

Table 4-7: Network Transformers Age Profile

Age by Decade (December 2018)	Network Transformers
>50 yrs	3
41-50 yrs	14
31-40 yrs	2
21-30 yrs	0
<20 yrs	15
Total	**34**

Figure 4.8: Network Transformers Health Index Demographic



4.1.2.2.7 Distribution Transformer Installation and Replacement

This program includes purchasing and installation of overhead and underground distribution transformers that are a part of the scope (installing new services, rebuilding pole lines, replacing faulted units, etc.). Projects can be significantly variable that affect costs and deliverance, however individual project costs are typically small. The program is divided between two budget categories, namely Installation and Replacement of Distribution Transformers and Overhead Transformer Purchases. While most projects that get executed under this program are categorised as System Renewal, there are projects that effectively fall under other investment categories as well. However, for the purpose of multi-year planning and based on historical allocations, these projects are identified as System Renewal until the time of their execution, when they can be categorised based on their main investment driver.

4.1.2.3 System Service

Expenditures in this category are driven by the need to ensure that the distribution system continues to meet operational objectives (such as reliability, grid flexibility and DER integration) while addressing anticipated future customer electricity service requirements (i.e. station capacity increases, feeder extension, etc.).

KWHI 2020 – 2024 capital programs that form the System Service investments are found in the table below.

Table 4-8: 2020-2024 System Service Expenditure Plan ($ Thousands)

Programs	2020	2021	2022	2023	2024
System Expansion to Supply New Developments & Load Growth	2,400	2,400	2,000	1,500	1,500
Innovation and Reliability	800	800	800	800	800
System Service Total	**3,200**	**3,200**	**2,800**	**2,300**	**2,300**

4.1.2.3.1 System Expansion to Supply New Developments & Load Growth

Expenditures in this category include the addition of feeders to provide service to new developments. Additional circuits may be constructed to provide service to new customers in areas not previously serviced. Additional circuits may also be constructed in previously serviced areas to increase capacity where load density increases. Investments in this sub-category can be categorized as System Access or System Service depending on the trigger. If the trigger is based on the need of a specific customer or group of customers, then the investment is categorised as System Access. If the trigger is based on KWHI's medium to long term planning to increase system capacity, then the investment is categorized as System Service. The latter is mostly the case for projects in this category since KWHI often conducts system planning studies to determine medium and long-term needs.

Projects within this program have variable costs associated with the work though effectively managed by KWHI. A specific project that has a high project cost (>$100,000) and is known at the time that the budget is prepared may be allocated funding under a separate budget item number. New feeders constructed from Transformer Stations and dedicated feeders for large customers are allocated funding in this manner.

In 2020, 2021 and 2022 KWHI will continue with the construction of a new underground distribution system (duct banks, cables and switchgear) to supply the increasing demand to Kitchener's downtown core driven by significant increase in commercial and residential development activities.

4.1.2.3.2 Innovation and Reliability

KWHI is constantly looking for ways to cost effectively improve system reliability and efficiency. Implementation of projects that specifically target reduction in outage duration, number of outages and frequency of outages are included in this category. Some specific projects in this category include:

- Installation of automated reclosers and switches - investments related to the installation of remotely operated and control (SCADA) reclosers and switches. Work in this project covers the installation of automated reclosers in new locations during new construction and the replacement of existing manually operated switches with automated reclosers. The installation of automated reclosers supports reliability improvement, operational flexibility and operational efficiency. KWHI's long-term goal for recloser installation is to install 2.5 reclosers per 13.8kV feeder and 3.5 reclosers per 27.6kV feeder. This goal takes into consideration that each 13.8kV feeder is sectionalized into two and typically has interconnection with 2-3 other distribution feeders while each 27.6kV feeder is sectionalized into three and typically has interconnection with 2-3 other distribution feeders. The 5-year expenditures forecast includes cost to install approximately seven reclosers in each budget year. Projects that are budgeted for individually and have the need to install automated switching devices will have the expenditure allocated in the project budget accordingly.

- Installation of Line Sensors - investments related to the installation of wireless line sensors used to detect fault current and identify the location of faults. These line sensors have built-in communication modules that allow for remote communication via a distribution SCADA system. Information obtain from automated line sensors is used to identify the location of faults quicker than the traditional method and allows for faster response to outages.

- O/H to U/G Conversion for Reliability Improvement and Accessibility – investments in this category are a result of past poor performance associated with certain overhead line sections that are typically installed in hard to reach areas, areas with significant tree coverage and areas with frequent animal contacts.

4.1.2.4 General Plant

Expenditures in this category are driven by the need to modify, replace or add to assets that are not part of the distribution system but support the utility's everyday operations (i.e. land, buildings, tools and equipment; rolling stock and electronic devices and software used to support day to day business and operations activities). While being important to safe and reliable operation, General Plant investment levels and timing are generally subject to a greater degree of discretion than other investment categories. Material investments in computer software and building improvements are required in the DSP forecast period. Fleet Management has determined that material fleet investments can be smoothed over the 2020-2024 investment period.

KWHI 2020 – 2024 capital programs that form part of General Plant investments are found in the table below.

Table 4-9: 2020-2024 General Plant Expenditure Plan ($ Thousands)

Programs	2020	2021	2022	2023	2024
Land & Buildings	750	750	750	750	750
Office Equipment	70	70	70	70	70
Information Systems and Technology	2,335	1,315	1,605	1,540	1,520
Vehicles	1,000	1,000	1,000	1,000	1,000
Tools & Equipment	140	140	140	140	140
General Plant total	**4,295**	**3,275**	**3,565**	**3,500**	**3,480**

4.1.2.4.1 Land & Buildings

Expenditures in this program are driven by the need to modify, replace or acquire new land and buildings. KWHI has one main office and service centre located at 301 Victoria Street South. There are also two transformer stations located on this property. There are six other sites that host transformer stations and eight sites that host the distribution stations. Expenditures associated with building renovations are ongoing and are allocated over several years to the reduce cost impact. Some of the activities to be undertaken over the DSP period include renovation of KWHI's control room, replacing backup generator and re-surfacing of the parking areas.

4.1.2.4.2 Office Equipment

KWHI purchases additional office furniture and equipment and replaces existing office furniture and equipment on an incremental basis to address needs as they arise. Expenditures greater than $1,000 are included in this category.

4.1.2.4.3 Information Systems and Technology

Expenditures in this program are driven by the need to acquire, enhance and upgrade computer hardware and software used in information technology (IT) and operation technology (OT) applications. These hardware and software tools are crucial to the day-to-day running of the organization and must be protected and secured to reduce the likelihood of cyber security breaches. IT Infrastructure represents the foundation on which the rest of the IT and OT environments operate and includes core backend infrastructure (network, storage, and server assets), endpoints (desktops, laptops and tablets), and printer and plotters. These assets are planned for replacement based on the asset life cycle described in Section 3.5. IT Applications captures costs associated with the acquisition of new systems to meet business needs, upgrading existing systems to stay current and maintain secure and reliable systems, and enhancement of existing applications to add new functionalities or integrate two or more systems to meet ongoing business and regulatory needs. Table 4-10 below shows breakdown of IT/OT capital expenditures forecasted for the DSP period 2020-2024.

Table 4-10: 2020-2024 Information Technology Expenditure Plan ($ Thousands)

Expenditure Category	2020	2021	2022	2023	2024
IT Infrastructure (Hardware)	285	205	255	290	270
IT Applications (Software) - New Systems, Upgrades & Enhancements	1,960	1,010	1,250	1,100	1,100
Computer Hardware/Software - Miscellaneous	90	100	100	150	150
IT total	**2,335**	**1,315**	**1,605**	**1,540**	**1,520**

The 2020 forecasted expenditures is heavily influenced by the costs to replace the 35+ years old legacy Customer Information System (CIS) with a next generation commercial off the shelf product. This is a multi year project with investments budgeted for in 2019 and 2020. More details can be found in the Material Projects justification in Appendix A. Also included in the IT capital expenditures is the acquisition of cyber security related hardware and software required to monitor, detect, and protect the organizations' network, data and information.

Other investments in IT/OT includes:

- Distribution Management System (DMS) software [2022-2023] – the Distribution Management System (DMS) is a decision support system to assist the control room and field operating personnel with the monitoring and control of the electric distribution system in an optimal manner while improving safety and asset protection. The DMS will leverage all of the real time operational data available from Smart Meters, OMS and SCADA. It will facilitate the implementation of a self-healing grid and provide the Control Room Operators with alternatives to restore power to customers in a safe, timely and efficient manner.
- Asset Management Software [2022] – KWHI is planning to invest in a risk-based Asset Management System (AMS) that will be used to monitor and track the performance of all distribution and transformer station assets. The AMS will also be used to prioritize system renewal investments according to needs, condition and risk factors.
- Enterprise Resource Planning Upgrade [2022-2023] – KWHI has been utilising JD Edwards as its ERP system since 2009 and strives to keep it current to avoid outdated versions that do not have vendor support. The software has a 3-5 year cycle for major version release, and it is anticipated that an upgrade will be required in 2022. In 2019, KWHI will be upgrading to version 9.2 which will have Oracle's Premier support until 2030 through their continuous delivery model.
- SCADA/OMS Upgrade and Enhancements [2021-2024] – upgrade the existing SCADA/OMS to latest versions and add enhancements and integrations such as mobile workforce

management, automated vehicle location (AVL) system, and interactive voice response system (IVR).

4.1.2.4.4 Vehicles

This program captures the purchase of new and replacement vehicles and equipment, as well as expenditures for major rebuilds that extend the useful service life of vehicles and equipment. These expenditures are required to ensure that KWHI's equipment and fleet remains in excellent condition for serving the need of its customers and to allow the fleet to be expanded to provide service to a growing customer base.

4.1.2.4.5 Tools & Equipment

This program includes tools and communication equipment. KWHI purchases the tools and equipment required to support its construction, operation and maintenance activities. Broken and worn out equipment must be replaced to ensure operational effectiveness and worker safety. Individual items that have a high purchase cost (> $1,000) are capitalized.

A necessary first step for implementing a Smart Grid is developing the infrastructure and acquiring the necessary equipment for Smart Grid operation. This includes the evaluation and selection of the communications system necessary to implement distribution automation. KWHI has been building out a 900MHz radio network in the City to allow for communication between field devices and the Control Room. A private Access Point Network (APN) has also been established with a wireless carrier to communicate with field devices in the Township and the Control Room.

4.1.3 Customer Engagement and Preferences (5.4a)

4.1.3.1 Customer Engagement

Customer engagement is considered essential to achieving KWHI's Customer Focus outcomes. KWHI believes that customer engagement with respect to DSP outcomes should provide useful information, be cost-effective, and be able to engage as many customers as reasonably possible. The goal is to capture preferences with respect to the underlying principle of the DSP to maintain existing service levels over the period of the plan. KWHI undertakes several ongoing customer engagement activities daily, including:

I. Direct Engagement
   - Telephone calls, emails, written notices, in-person interactions at offices
   - Community meetings
   - Information displays
   - Employee volunteerism and corporate donations
   - Electrical Safety Program for the public
   - Bill inserts and rate brochures
   - Media releases and alerts

II. Online Engagement
   - Corporate website
   - My Account online bill portal for residential and commercial customers
   - Online outage map
   - Social Media (Twitter, Instagram, LinkedIn, YouTube)

III. Customer Survey Program
   - Customer Satisfaction Surveys
   - Public Safety Awareness Surveys
   - Customer Feedback surveys (recently completed in 2016 and 2018)

KWHI conducted two customer engagement sessions in preparation of this Plan – the first in 2016 engaging UtilityPULSE, and the second in 2018 engaging INNOVATIVE Research Group (INNOVATIVE). KWHI has been conducting customer surveys since 2012.

In 2016, KWHI engaged UtilityPULSE to conduct a survey of its customers. Customer surveys provide a high-level assessment of customer preferences with respect to service reliability and operational effectiveness. For accuracy purposes, survey samples should be representative of the service territory population. UtilityPULSE uses standard public opinion research methods to obtain survey results. Survey results indicate satisfaction with current service performance levels which indicates that plan efforts to maintain historical levels are reasonable thereby supporting system renewable efforts and prudent smart grid development. Concerns regarding the overall cost of electricity supports the need to consider rate mitigation efforts while managing risk and smoothing spending over time for prioritized investments. It is understood that KWHI's rate mitigation efforts will only impact less than 20% of the customer's bill, the other 80% being out of KWHI's control. Survey results are implicitly considered in the development of the asset management strategy, objectives and plans.

In 2018, KWHI engaged INNOVATIVE to design and execute a multi-faceted engagement program that aligns with both OEB expectations and provides meaningful input for the utility's business planning. INNOVATIVE developed a workbook in consultation with KWHI and additional feedback from OEB and intervenor stakeholders as well as a series of focus groups with low volume customers. Spanning the timeframe from September 19 to November 14, 2018 KWHI conducted four dedicated customer engagement sub-initiatives, covering every type of customer across the service territory – from residential to large business. Table 4-11 summarizes the scope of customer engagement activities employed by INNOVATIVE.

Table 4-11: Summary of customer engagement activities (2018 INNOVATIVE)

Customer Engagement Activity	Methodology	Customers Engaged
Low-volume focus groups	In-person	**14**
Mid-Market and Large Business Workshops	In-person	**37**
Low-volume online workbook	Online	**1,749**
Low-volume telephone surveys	Telephone	**715**
Total number of customers who participated in the engagement:		**2,515**

Customer needs and preferences with respect to CDM and DG programs are determined at a customer project level in discussions with program participants. A CDM information session is held annually to update consumers on programs and opportunities and to solicit program performance feedback from the consumers.

In carrying out distribution activities to support the Corporate Objectives, stakeholder interests must be considered and factored into the short- and long-range planning processes. Stakeholder interests vary and at times can be either complementary or conflicting. As a part of the planning process, some basic assumptions are made about the stakeholder interests. The assumptions represent high level utility assessments of key stakeholder class attributes that the utility has observed from many years of historical interaction with each respective stakeholder group. The assumptions and related stakeholder interests are shown in Table 4-12.

Table 4-12: Stakeholder needs, interests and perceptions

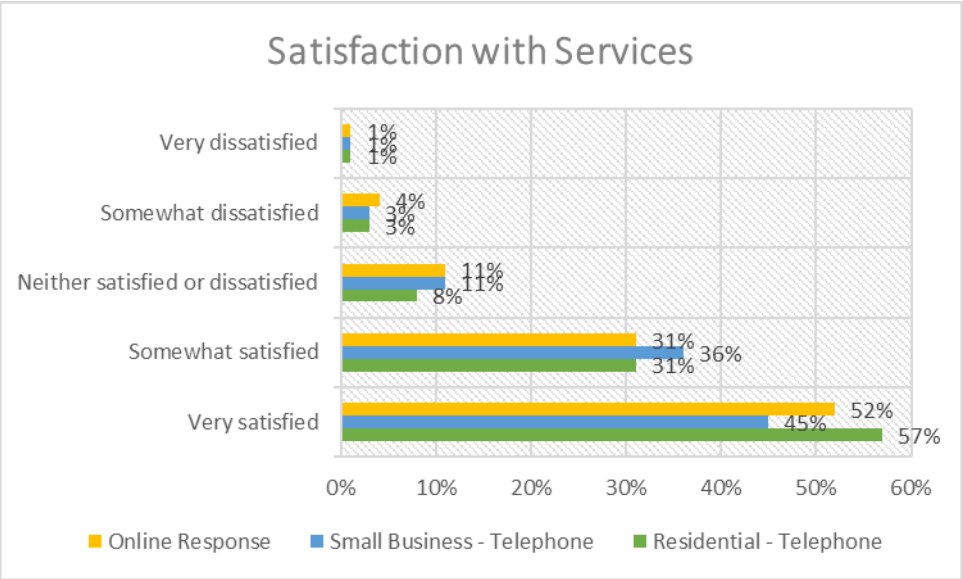
Stakeholders	Stakeholder Needs	Stakeholder Interests	Stakeholder Perception of Planning Risks
KWHI Corporation	Accurate external/internal information to set policy	Achieve mission vision and corporate objectives	Financial loss due to sub-optimization of operations; brand value deterioration
KWHI Employees	Safe and stable work environment; skills development	Long term productive relationship with employer	Employment instability; unsafe work environment
Shareholders	Stable rate of return	Safe long-term investment	Financial and political pitfalls
IESO	Accurate load forecasting; meeting CDM targets for LTEP; accurate real-time information and market rule compliance by market participants	Comprehensive utility forecasting process; LDC delivery of CDM programs; LDC adherence to technical and communication protocols	Inaccurate information contribution to Regional planning processes; CDM targets not met; inaccurate or untimely information for market operations
HONI	Information to determine short, medium and long term local and regional infrastructure needs.	Coordination of transmission and distribution growth needs; LDC participation in Regional Planning	Inaccurate forecasts affecting resource commitments; Inaccurate information contribution to Regional planning processes
Generators	Stable market and ability to connect to distribution system	Clear rules and processes for connection	Distribution congestion affecting plant location and costs
Retailers	Reliable supply to customers; efficient business processes	Maximize contract revenues; customer relationship	Loss of revenue; loss of customers
Provincial Government	Efficient, low cost and reliable market	Reliable supply to stimulate growth and political goodwill	Localized negative political impact
OEB	Efficient, low cost and reliable market; regulatory compliance	Minimization of regulatory intervention	Regulatory intervention and political impact risks
ESA	Public electrical safety	Utility construction built to Reg. 22/04	Public safety risk if plant not built/maintained to code(s)
Municipalities(non-shareholders)	Reliable supply to customers	Consultations on activities within municipal boundaries; visual aesthetics	Supply/reliability shortfalls affecting their constituents
Residential Customer	Reliable supply and low rates	Aesthetics	Supply/reliability shortfalls; price concerns
Small Commercial	Reliable supply and low rates	Rate stabilization or reduction	Supply/reliability shortfalls; price concerns affecting business plans
Large Commercial/ Industrial	Reliable supply and low rates	Rate stabilization or reduction	Supply/reliability shortfalls; price concerns affecting business plans

4.1.3.2 Customer Preference

The following sections summarize the various feedback gathered through KWHI's customer engagement. Appendix D contains the survey result reports provided by INNOVATION for a detailed analysis.

Customer Satisfaction

Figure 4.9: Customer engagement results - Satisfaction with services (detailed)



As shown in Figure 4.9, majority of respondents indicated they are "Very satisfied" or "Somewhat satisfied" with KWHI services. 11% online respondents and 8% phone respondents are neutral and 6% online respondents and 5% phone respondents are "Somewhat dissatisfied", "Very dissatisfied" or "Don't know". Table 4-13 provides the high-level summary of percentage of respondents being satisfied with KWHI's services. Through the online survey, the top suggestion for improved services is to lower the rates/delivery fees (27%), followed by no suggestion at 19%. This is aligned with the responses from the phone survey where the top two suggestions for improved services is "No improvements" (25% of participants), followed by "Lower the rates" (22% of participants).

Table 4-13: Customer engagement results - Satisfaction with services (summary)

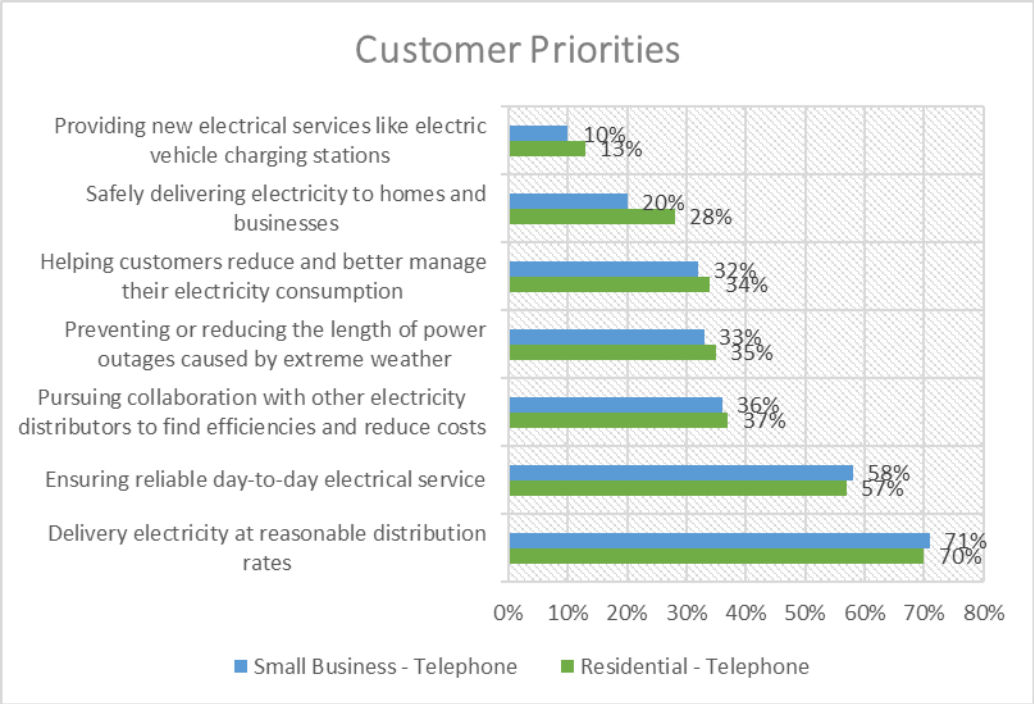
Customer Engagement Activity	% Satisfied with KW Hydro
Low-volume online workbook	**84%**
Residential telephone survey	**88%**
Small business telephone survey	**81%**

In summary, there does not appear to be a gap between the services KWHI is currently providing, and the services that customers expect. KWHI intends to continue meeting customer expectations to maintain the current level of satisfaction moving forward. Annual customer satisfaction surveys will continue to provide the insight KWHI will need to better inform themselves on customer satisfaction levels.

Customer Priorities

From the 2018 surveys conducted by INNOVATIVE, the results can be divided into two major sub-groups: low-volume/small business customers and mid-market/large business customers. At 37% of residential customers and 42% of small business customers, delivering electricity at reasonable rates is the number one priority they believe KWHI should focus on. Moreover, distribution rates top the priority list for mid-market and large business customers. This is followed by 20% of both residential and small business customers wanting KWHI to focus on reliable day-to-day electrical service. The third most important outcome is related to pursuing collaboration with other LDCs, in order to find efficiencies and reduce costs. Figure 4.10 provides the detailed breakdown from least priority to most desired priority for customers.

Figure 4.10: Customer engagement results – Customer priorities (detailed)

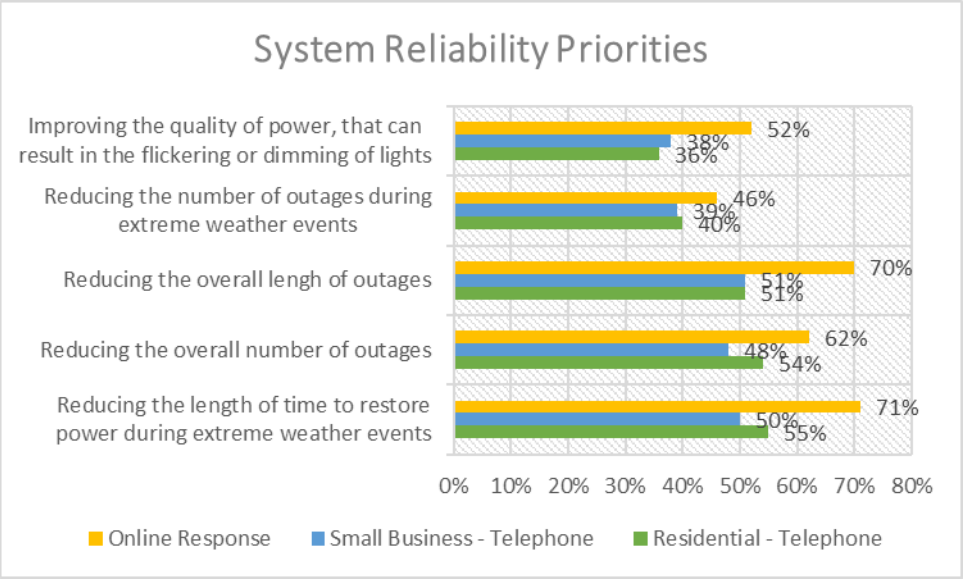


In summary, distribution rates are the top priority for low-volume customers, and an important priority for larger business customers. Furthermore, ensuring reliable day-to-day electrical service remains an important priority, especially for business customers who are negatively impacted by outages and power quality issues. As a result, KWHI will monitor cost increases yearly and will strive to maintain cost increases throughout the DSP period.

Customer Reliability Preference

As shown in Figure 4.11, 71% of online respondents and 55% of phone respondents indicated the most important system reliability priority is “Reducing the length of time to restore power during extreme weather events”. 70% of online respondents and 51% of phone respondents indicated the second most important system reliability priority is “Reducing the overall length of outages”. 62% of online respondents and 54% phone respondents indicated the third most important reliability system priority is “Reducing the overall number of outages”.

Figure 4.11: Customer engagement results – System reliability priorities (detailed)

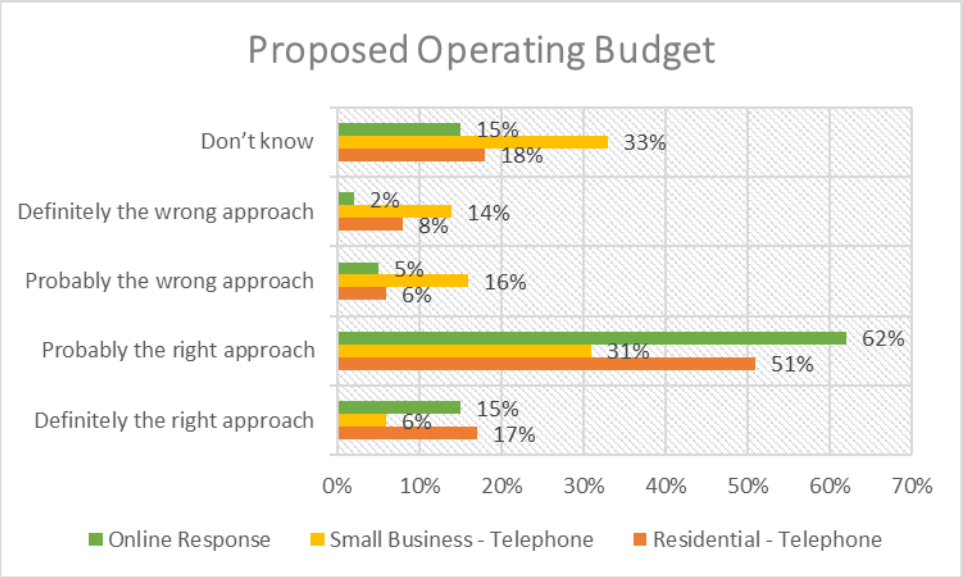


In summary, low-volume customers are consistent on priorities related to reliability – reducing the number and length of outages and improving restoration times during extreme weather. Midmarket and large business customers appear to prioritize reliability over price, with a focus on power quality and communications during outages in order to assist with operational planning. As a result, KWHI will track and monitor reliability performance indices and select investments that would aide in maintaining the reliability as well as targeting the top customer reliability preferences. KWHI is proposing a specialized Innovation and Reliability program that will focus on providing faster outage response and restoration using smart switches. Additionally, KWHI is investing in a crew call out application which will reduce the time and effort required to have crews on-site when there is an outage after-hours. Further details on the Innovation and Reliability program can be found in the respective section of Appendix A – Material Investments.

Customer Feedback on Planning Principles for the proposed 5-year plan

77% of online respondents and 68% of phone respondents indicated they believe KWHI's approach for its operating budget is "Definitely the right approach" or is "Probably the right approach". 15% of online respondents and 18% of phone respondents did not know, where the remaining believe it is "Probably the wrong approach" or "Definitely the wrong approach". Figure 4.12 provides the detailed results from each customer engagement group.

Figure 4.12: Customer engagement results – Proposed operating budget (detailed)



Furthermore, 53% of online respondents and 62% of phone respondents believe that "[KWHI] should keep spending levels consistent year-over-year, even if that means deferring investments to other years to lesson the impact of any bill increase". 29% of online respondents and 27% of phone respondents believe "[KWHI] should not defer investments, even if that means larger bill increase in some years". 18% of online respondents and 9% of phone respondents do not know.

Overall, residential and small business customers are generally split on KWHI's approach to planning for the next five years, however, are consistent in supporting the utility's approach to pacing investments, including keeping spending consistent year-over-year to lessen bill impacts.

However, there is strong support for KW Hydro's proposed plan, or even one that exceeds current spending levels in order to improve service further. A larger proportion of residential customers feel that the utility should be spending more, rather than spending less. Small business customers are generally less supportive of a plan that spends beyond what's currently proposed, and more think that the utility should spend less compared to spend more. Mid-market and large business customers generally trust KW Hydro, however, expect to understand how this plan specifically impacts them, especially provided they feel the rate impact is significant.

As a result, KWHI will focus on maintaining the spending levels consistent year-over-year but will modify the spending levels with the additional feedback obtained through the remaining results of the 2018 survey. KWHI will progress with its current approach on its operating budget and engage with customers for continued feedback.

System Access Investment Preferences

Pertaining to KWHI's approach to mandatory and prioritized investments, 43% of respondents believe "[KWHI] should not cap spending in non-mandatory investments when additional mandatory spending is required, even if that means my bill could increase more beyond 2024". 34% of respondents indicated "[KWHI] should stick with its spending cap by deferring investments, even if that could result in longer and more frequent power outages". 23% of respondents indicated that they do not know.

As a result, KWHI plans to take an optimized approach in selecting investments to be completed without compromising the reliability of the system that would result in longer or more frequent power outages.

System Renewal Investment Preferences

Pertaining to KWHI renewing its pole at an accelerated rate, 52% of online respondents and 50% of phone respondents indicated, "I am willing to pay an additional $0.12 [$0.67] per month annually so [KWHI] can accelerate its pole replacement plan and replace 1,500 more at-risk poles by 2024". This is in contrast with small businesses where only 35% were willing to support such an increase. Whereas 31% of online respondents and 30% of phone respondents indicated "[KWHI] should stick with the proposed pace of investment in pole replacement, which would see 400 poles per year replaced over the next five years". Additionally, 40% of small business selected the previously stated option. 11% of online respondents and 14% of phone respondents indicated "I would like [KWHI] to slow down this program so the proposed rate increase can be reduced" whereas small businesses accounted for 20%. 5% of online respondents and 4% of phone respondents selected the "do not know" option. Table 4-14 provides the summary results from each customer engagement group.

Table 4-14: Customer engagement results – Pole replacement investment (summary)

Customer Engagement Activity	% who support proposed approach to pole replacement or accelerated approach
Low-volume online workbook	**84%**
Residential telephone survey	**81%**
Small business telephone survey	**75%**

Overall, support for investments in KWHI's pole replacement program is strong, especially amongst residential customers, where a majority believe that the utility's investment pace should be accelerated. With the responses received in favor of an increase in pole replacement, KWHI has increased its pole replacement plan to replace more at-risk poles by 2024. KWHI believes this will improve the system's condition health and can effectively reduce the safety risk that poor condition poles carry.

Pertaining to KWHI renewing its power transformers at an accelerated rate, 50% of online respondents and 43% of phone respondents indicated, "I am willing to pay an additional $0.20 [$1.08] per month annually so [KWHI] can accelerate its power transformer replacement plan and replace these end of life transformers by 2022". Once again, this is in contrast to small businesses, where only 31% were willing to support an increase. Whereas 37% of online respondents and 41% of phone respondents indicated "[KWHI] should stick with the proposed pace of investment in power transformer replacement, which would see two end of life assets replaced over the next five years, small businesses came up to be 49%. 7% of online respondents and 11% phone respondents indicated "I would like [KWHI] to defer this replacement to the next five-year plan, even if that increases the risk that these power transformers fail, affecting supply of electricity to entire neighbourhoods", whereas 14% of small business customers selected this option. 6% of online respondents and 4% of phone respondents selected the "do not know" option. Table 4-15 provides the summary results from each customer engagement group.

Table 4-15: Customer engagement results – Transformer replacement investment (summary)

Customer Engagement Activity	% who support proposed approach to transformer replacement or accelerated approach
Low-volume online workbook	**87%**
Residential telephone survey	**84%**
Small business telephone survey	**79%**

Overall, about eight-in-ten low-volume customers support KWHI's transformer replacement plan, with a plurality of small business customers favouring the current approach, and residential customers supporting an approach that would accelerate replacement by three years. Residential customers in Wilmot Township are most supportive of these types of investments. KWHI believes its customers understands the functionality and benefit of maintaining the system's power transformers. With the positive feedback received from customers on the proposed increase on power transformer replacement, KWHI is proposing to increase its expenditures within this area. The two transformers identified in the 5-year plan are proposed for replacement and are identified as high priority. The priority placement will allow KWHI to avoid further deferring this investment.

System Service Investment Preferences

Pertaining to KWHI modernizing the distribution system to create a more robust system and maintain the reliability customers experience currently, 45% of respondents answered "[KWHI] should invest in the benefits of modernization now, even if that means customers will have to pay bit more on their distribution rates in the near future". Whereas 46% of respondents answered "[KWHI] should keep rate increase down by modernizing as part of the normal replacement of aging equipment, even though that means delaying the potential benefits of modernization for decades". 10% of respondents do not know.

As a result, KWHI will continue with its proposed increase in spending in modernizing the distribution system within the current DSP period.

Pertaining to KWHI spending on automated switches and software design to remotely detect an outage with the goal of reducing outages, 58% of online respondents and 43% of phone respondents replied, "I am willing to pay an additional 6 cents per month for [KWHI] to install more automated switches and software that will help detect outages and 'auto-reset' to reduce the length of outages". 31% of online respondents and 45% of phone respondents replied "[KWHI] should stick with the proposed pace of investment in installing automated switches and software as planned within its existing budget proposed budget". 6% of online respondents and 8% of phone respondents indicated "I would like [KWHI] to reduce its planned investments in automated switches and software, even if that means longer outage restoration times". 5% of online respondents and 3% of phone respondents do not know. Table 4-16 provides the summary results from each customer engagement group.

Table 4-16: Customer engagement results – Automated switches investments (summary)

Customer Engagement Activity	% who support proposed approach to spending on automated switches or an accelerated approach
Low-volume online workbook	**89%**
Residential telephone survey	**88%**
Small business telephone survey	**84%**

Overall, when not tied to specific program benefits, low-volume customers are split on investments in grid modernization. In the context of reducing outage lengths through automated switches, low-volume customers are supportive of KWHI's proposed approach, and in many cases, one that focuses on spending more. As a result, KWHI will continue with its proposed increase in spending on automated switches within the current DSP period.

General Plant Investment Preferences

Pertaining to KWHI investing in vehicles and equipment to maintain its distribution system and IT systems to manage the system and customer information, 67% of respondents answered "[KWHI] should make the investments necessary to ensure its staff have the equipment they need to manage the system efficiently and reliably". Whereas 25% of respondents answered "[KWHI] should find ways to make do with the business equipment it already has". 8% of respondents do not know.

As a result, KWHI will continue with its proposed investment plan for vehicles and equipment for the current DSP period.

Pertaining to KWHI investing in a new Customer Information System (CIS) with enhance capabilities that would provide the additional benefit to customers of email or text alerts, insight into electricity consumption, a self-service customer portal and an interactive voice response system, 56% of online respondents, 70% of phone respondents and 75% of small business respondents replied "[KWHI] should stick with the basic CIS solution that will ensure customers continue to receive a bill on time". 35% of online respondents, 24% of phone respondents and 20% of small business respondents replied "[KWHI] should invest in the enhanced CIS solution for an additional $0.46 [$2.57] per month which offers customers self-serve account management options, greater insight into how they are using electricity and streamlined processing". 8% of online respondents and 5% of phone respondents do not know. Table 4-17 provides the summary results from each customer engagement group.

Table 4-17: Customer engagement results – CIS implementation (summary)

Customer Engagement Activity	% who selected basic CIS solution
Low-volume online workbook	**56%**
Residential telephone survey	**70%**
Small business telephone survey	**75%**

KWHI believes implementing the CIS with enhanced capabilities would provide a greater cost-saving benefit for its business and for its customers over an extended period. However, based on feedback from the customer engagement survey, KWHI will defer investing in the additional functionalities as part of the core CIS. Investment in the additional functionalities will be revisited after implementation of the core CIS and if found to be prudent, will be paced and prioritised to reduce customer bill impact. KWHI has developed a business case for supporting its decision on implementing the CIS and is filed under Appendix P.

4.1.3.3 Projects in Response to Customer Preference, Technology and Innovation

Planned 2020 capital investments related to:

1. customer preferences (CP);
2. technology-based opportunities (TBO) and
3. innovative processes, service, business models or technologies (IP/T)

are summarized in Table 4-18. The identified projects were already within KWHI's proposed 2020 budget but have been readjusted to reflect the collected responses from the customer engagements.

Table 4-18: Customer preference, technology and innovation capital projects

Category	Investment Name	2020 Cost	Description
CP, IP/T	Information Systems & Technology – CIS Replacement	$ 1,675,000	Phase 2 of a multi-year project to replace legacy in-house CIS with commercial application including customer-facing app.
CP	Replacement of Pole Line Assets Due to Age/Condition	$ 3,404,000	Replace pole line assets that are at end of life to prevent failures and unplanned outages.
CP	Replacement of Primary Cables and Conduits Due to Age/Condition	$ 850,000	Replace underground cable and conduits that are at end of life to prevent failures and unplanned outages.
CP	Installation of New Underground Residential Distribution	$ 3,168,000	Installation of underground distribution system (cables, duct work, transformers and services) to supply new residential subdivisions
CP	Installation of New Residential UG Services	$ 540,000	Installation and connection of new residential services.
CP	Installation of Commercial, Industrial & Apartment Services	$ 1,209,000	Installation of 3-ph underground services to supply commercial, industrial & multi-tenant developments including transformers.
CP	Relocations Due to Roadway Modifications	$ 1,700,000	Relocation of poles, wires cables and ducts to suit modifications of roadways as requested by the road authority.
CP	System Expansion to supply new developments and distributed generation	$ 2,400,000	Expansion of the distribution system (overhead and underground) to connect new customers and to facilitate distributed energy resource projects.
TBO	Innovation and Reliability (underground)	$ 250,000	Commence installation of fibre optic cable in downtown Kitchener for secondary grid network monitoring and retrofitting of underground switchgear for remote monitoring and control.
TBO	Innovation and Reliability (overhead)	$ 550,000	Automated switch/recloser installations in City of Kitchener and Wilmot Township for reliability improvement and reduction in truck rolls.
IP/T	Mobile Computing	$50,000	Commenced installation of laptops/tablets in service trucks to allow crews to interact with IT/OT systems and applications installed at the central office without having to drive back to the office.
IP/T	Cybersecurity	$85,000	Continue to implement cybersecurity measures to monitor, detect, respond and contain cyber threats.

KWHI believes that it has incorporated customer preferences through the feedback it has received from the communication channels that it maintains. KWHI has successfully engaged customers and promoted their participation in CDM and DG programs. The CDM 2017 Annual Report submitted to the OEB demonstrated KWHI's efforts in delivering the IESO-Contracted Province-Wide CDM Programs to the residential and commercial customer sectors.

4.1.4 System Development over the Forecast Period (5.4b)

4.1.4.1 Ability to Connect New Load/Generation

There is sufficient capacity at the TS, DS and feeder levels to connect new load over the forecast period. Adjustments to feeder configuration and interties may be required to accommodate load connections at a specific location.

There are two constraints to connecting new generation. The Kitchener 3TS Bus B52B62 has no capacity for DG connections and the downtown network cannot accept DG connections without customer installed special protective devices at their end to prevent reversed power flow into the secondary grid network.

Notwithstanding the constraints noted above, based on the applications to connect new renewable energy generation, KWHI has determined that there are no KWHI limitations to the connections for the 2020 – 2024 forecast period.

KWHI notes that generation connection capacity may be severely impacted by even a modest penetration of natural gas generation behind the meter. Interest in this type of generation has increased due to government subsidy programs. Capacity constraints may change over periods if the connection to gas generation becomes an increasing activity. Capacity constraints are impacted because natural gas generation has 5-7 times the impact on system capacity as renewable inverter-based generation.

4.1.4.2 Load and Customer Growth

It is expected that the operational and service requirements driving KWHI's capital expenditures, and found within its DSP, will generally remain consistent through the 2020 to 2024 planning window. KWHI expects low peak demand growth (0.9% annually) in line with development plans that directly impact KWHI's service territory:

1. Ontario Places to Grow Act (May 2017)
2. Region of Waterloo Official Plan
3. City of Kitchener Official Plan
4. Wilmot Township Official Plan

Downtown Kitchener has been designated as an Urban Growth Centre under the province of Ontario's Places to Grow Act. By 2031 or earlier Downtown Kitchener will achieve a minimum density target of 200 residents and jobs combined per hectare. The City of Kitchener Official Plan indicates forecast population and employment numbers of 319,500 residents and 132,500 jobs by 2031.

System Renewal investments (end of life replacement) will ensure that customer service levels with respect to reliability are maintained. Condition monitoring and performance analytics help direct preventive maintenance to specific at-risk equipment and extend further the safe reliable useful life of all equipment.

System Access investments will provide for overhead and underground plant relocation due to road widening, new connections and revenue metering to service increased development densities.

System Service innovation and reliability investments will be pursued where prudent and prioritized (i.e. automation of overhead distribution system and secondary network monitoring). Investments in system expansion to supply load growth are planned for and scheduled to come online in time for the realisation of the increased demand in certain parts of the service territory such as Downtown Kitchener.

4.1.4.3 Grid Modernization

KWHI is a member of the GridSmartCity Consortium. The Consortium is made up of 30 partner organizations, including local distribution companies, commercial entities, and academia. 13 local distribution companies (LDCs) have come together to form the GridSmartCity Cooperative who share resources, insights and systems in several key areas to help us run smarter companies and advance innovation, reliability, and efficiency across Ontario's electricity grid.

KWHI continues to invest in activities such as communication infrastructure, line monitoring, feeder hardening and installation of automated switches and reclosers to meet expectations of reliability performance. Investments in distribution automation such as SCADA controlled switches and network monitoring are part of KWHI's grid modernization efforts and will continue over the period of the DSP.

4.1.4.4 REG Accommodation

The accommodation of renewable energy generation projects is not expected to drive any significant system developments over the next five years. During implementation of investments in System Access, System Renewal, System Service, and General Plant initiatives, considerations for REG will be undertaken.

4.1.4.5 Climate Change Adaptation

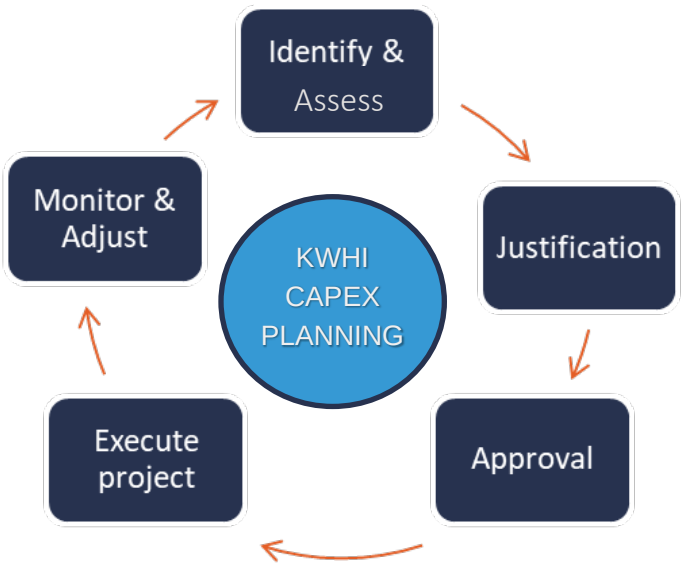
Recent years have seen more severe and more frequent storms as a result of climate change. The impacts on a power distribution system include high electrical demand and unusual operating conditions resulting from extreme temperatures, flooding of below-grade transformers and switchgear equipment due to prolonged rainfall, and ice and wind damages to overhead lines and poles due to wind and ice storms. These abnormal activities normally result or have the potential to cause significant customer outages. To respond to these changes, KWHI is undertaking a number of initiatives to harden the distribution system and make it more resilient to extreme weather events. Initiatives include adhering to higher design standards, utilising stronger materials, reducing the number of equipment installed below grade and utilising stainless-steel equipment when required, improving grid flexibility using automated reclosers, proactive tree trimming, and proactive inspection and maintenance. These activities will continue and be enhanced in some areas over the period of the DSP.

4.2 CAPITAL EXPENDITURE PLANNING PROCESS OVERVIEW (5.4.1)

This section of the DSP provides a high-level overview of KWHI's capital investment planning process. The capital investment planning process is embedded within KWHI's Asset Management process and focuses on determination of which investments are included in the current budget year.

The annual Asset Management capital planning investment cycle consists of five general steps as seen in Figure 4.13.

Figure 4.13: Capital Expenditure Planning Process for All Projects



A detailed breakdown of the planning process for capital expenditures is shown in Figure 4.14 below.

Capital expenditures are selected and prioritized for implementation once all mandatory expenditures (i.e. System Access) have been accommodated in the budget plan. The basic process is as follows:

1. Determine Capital Investment Needs

   Capital investment needs are determined based on several key drivers. These key drivers represent the input to the process. The drivers used are; customer feedback, reliability data, Asset Condition Assessment, results of system studies, Regional Plans, DG forecasts, business needs and technology needs.
2. Forecast Capital Expenditures - Planning

   Once the need for capital investments are identified, the next step is to forecast these needs in terms of activity volume, resources, timing and cost. The projects are prioritized and paced. Projects not prioritized for the current budget year are held over to future years. The output of this process is a project plan typically in the form of an annual budget.
3. Investment Plan Review by Manager

   The investment plan is reviewed by the manager with responsibility for each work area and evaluated against Corporate Objectives and the Asset Management Strategy. Review may result in adjustment of the investment portfolio.
4. Senior Management reviews and approves the plan accordingly provided that funding is available, and it meets corporate goals and objectives.

5. The capital budget for the current year is prepared. This budget is incorporated with the mandatory capital expenditure budget to form one overall corporate capital budget plan. Projects are provided with detailed cost estimates and justification documentation.
6. Project estimates are submitted for individual approval and implementation. These projects are typically identified in the overall planning stage but without detail cost estimates.
7. Projects are reviewed and receive Senior Management approval to proceed subject to overall budget spending constraints.
8. Implementation Scheduled

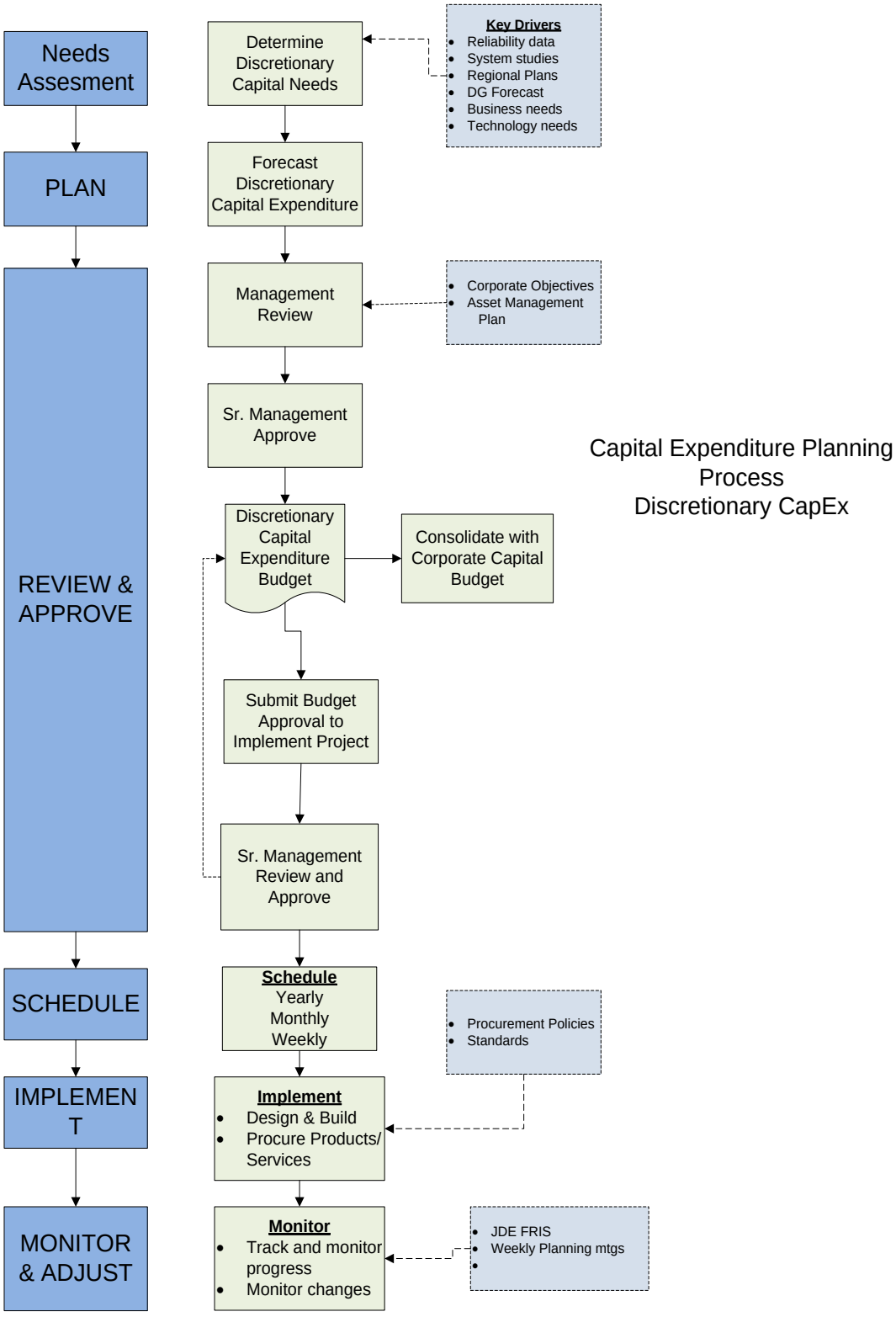
   Resources and materials are assigned to the projects taking into consideration the requirements of mandatory projects. Scheduling occurs at three different stages:

   I. Yearly schedule which involves a large cross-functional team from the organisation that reviews the entire capital project plan and schedule projects on a quarterly basis.
   II. Monthly schedule which involves a subset of the participants from the yearly schedule making decision on the details of which projects are on track and which are at risk of being removed due to constraints.
   III. Weekly schedule which involves engineering and operations personnel making tactical decisions on the day to day project schedules and adjustments where necessary to align with current conditions.
9. Implementation

   The investment is implemented (design, procure, build, commission, etc.). KWHI's procurement policies and design standards are applied to ensure compliance with internal and external requirements.
10. Monitoring

    Investment spending and timing is monitored during the implementation stage. Adjustments are made to investment scope, timing, spending, etc. as required. Weekly planning meetings are used as a forum to review project progress and scope. On demand reports are used to review project costs.

Figure 4.14: Capital expenditure planning process



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

Currently, KWHI does not have any formal analytical tools and methods used for risk management. KWHI is planning to investigate within the forecast period in developing a more structured and formal tool to aggregate existing and new planning methods associated with risk management. However, the below sections identify the current state of KWHI's planning methods and how to best address the risks identified and associated within its distribution system.

4.2.1.1 Planning Objectives

KWHI planning objectives are governed by the following principles:

- focus on the customer;
- sustain operational efficiency (increased functionality, visibility, and control of the distribution system to allow for improved operation, efficiency, reliability, and increased DG interconnection); and
- comply with codes, standards and regulations.

KWHI's planning objective can be summarized as determining the optimum level of investment and configuration of distribution capacity while having due regard to:

- alignment with corporate objectives and asset management strategy;
- meeting safety and regulatory requirements;
- meeting customer demand and expectations;
- minimizing rate impacts;
- coordination with road authorities, local developers and municipalities;
- planning for future growth;
- investing in programs to maintain system reliability;
- modernising the distribution grid; and
- upgrading and refreshing general plant assets.

4.2.1.2 Planning Assumptions

The following key assumptions form the basis of the development of this DSP:

- historical trends will continue unless information is available otherwise;
- level of activity in Distributed Generation will continue; and
- external assumptions such as growth input from regions, municipalities and developers are held constant and up to date.

4.2.1.3 Planning Criteria

In terms of the overall planning criteria, KWHI, like most Ontario utilities, has adopted a deterministic or redundancy standard for distribution system planning. The redundancy standard will trigger an investment when the capacity of an asset, such as a station transformer, is exceeded under normal or contingency operating standards depending on the type of asset. Redundancy, in terms of capacity, is built into the distribution system to deal with unique contingency situations. However, customers will experience an interruption, upon loss of a distribution system element, while backup capacity is engaged, or an asset is replaced. Outage time is also impacted by the level of distribution automation present in the system.

KWHI, like other distribution utilities strives to ensure its distribution system provides a reliable level of service to existing customers and connection capacity for forecasted demand growth and as such

must be able to handle customer supply needs during normal and certain contingency situations. Overloading of distribution equipment, as a result of inadequate investment, is avoided as much as possible.

Key Planning Criteria Overview

The planning criteria assume:

- that equipment maintenance, refurbishment and replacement programs are in place to ensure that the capacity and capability of the distribution system is maintained at reasonable level of risk of disruption due to lifecycle related equipment failure; and
- that incidences of extreme weather will continue to be manageable under existing standards of design and construction.

The following is a summary of KWHI's key criteria's and planning guidelines.

Table 4-19: KWHI's key criteria's and planning guidelines

Criteria	Planning Guideline
General	In planning the system, "good utility practice" shall be followed.
System Voltages	The primary supply voltage for the Kitchener service area shall be 13.8 kV supplied from KWHI owned transformer stations. In the Wilmot service area, the primary supply voltage will be 8.32 kV supplied from distribution stations or 27.6 kV supplied from KWHI owned transformer station.
Transformer Stations	Transformer stations (TS) shall be standard DESN configuration – Bermondsey/Jones layout connected to the 115 kV or 230 kV transmission grid. Maximum transformer size shall be 100 MVA. Transformer station feeders shall be 13.8 kV or 27.6 kV. TS planned loading shall be to the nameplate rating of one of the station transformers. Under normal situations, station transformers will be loaded up to 50% of their nameplate rating. A station transformer can be loaded up to 120% of nameplate for 2 hours a day for 60 days to allow for transmission/transformer contingency capability.
Distribution Stations	Distribution Stations (DS) will be 27.6 kV primary supply. The DS secondary supply voltage shall be 8.32kV. DS transformer size shall be 5MVA. Long term strategy is to convert 8.32kV plant to 27.6kV and eliminate the DS. DS Transformer planned loading shall be 100% of normal nameplate rating. DS Transformers maximum allowable loading, under normal conditions shall be their ONAN or ONAF ratings. The distribution system shall be constructed and configured to allow for DS transformers to be backed up by one or more neighbouring DS stations in the event of a station contingency situation. The typical number of feeders emanating from a DS shall be 3. Planned average loading of 200 amps per 8.32 kV feeder will be used.
Feeders	All 13.8 kV feeders shall be designed for full backup capability over peak loading conditions through the switching of load to an adjacent feeder or multiple adjacent feeders. To facilitate this restoration capability, normal feeder loading will be planned to a maximum of 50% of circuit rating under normal operation. Overhead circuit rating is primarily a thermal rating determination such that the conductor does not sustain significant loss of strength due to annealing over its useful life. Underground circuit

Criteria	Planning Guideline
	ratings are based on applicable cable ampacity ratings based on the type of cable and conditions of installation, to optimize cable loss of life over its lifecycle. Overhead 13.8 kV feeders shall be 556 kcmil Al. Planned loading shall be 400amps. Overhead 27.6 kV feeders shall be 556 kcmil Al. on poles with armless construction. Planned loading shall be 400 amps. Laterals shall be 3/0 Al. Underground 13.8 kV feeders in subdivisions shall be #1 TRXLPE CU cables Maximum cable loading shall be 200A. Underground 27.6 kV feeders in subdivisions shall be 1/0 TRXLPE CU cables Maximum cable loading shall be limited to the station recloser rating. Current unbalance is defined as the maximum phase current deviation from the average phase current, as a percentage of the average phase current. Feeders with a phase current deviation in excess of 20% from average will be considered for rebalancing. New single-phase load additions should be connected to the phase with the least connected KVA, if it is available, to maintain a balanced circuit. Under normal and contingency situations, circuit voltage drop shall be managed such that customer service voltages shall comply with the standards of the Canadian Standards Association, CSA Standard CAN3-C235 (latest edition). Losses on three phase feeders should be kept to a minimum using appropriately sized conductor, optimal feeder loading and load sharing, phase balancing, and in some cases, applications of shunt capacitors. Currently, the industry standard for a typical urban utility is in the range of 2.5 -3.5%.
Planning Horizon	The planning horizon shall be 5 years to align with the DSP requirements. Regional planning exercises may identify planning needs in excess of the DSP 5-year planning horizon.
Distribution Automation	Distribution automation through remote switching and automatic reclosing is to be provided, when cost justified, to ensure that load lost during single contingencies can be restored in a minimum amount of time. Distribution automation should also be considered during plant rebuild and new construction as an alternative to manual operated switches to aid in reliability improvement (response and restoration time).
Protection Philosophy	KWHI 13.8 kV and 27.6 kV is primarily an overhead distribution system. Feeder protection shall incorporate appropriate auto reclose settings to mitigate the impact of transient faults. In certain circumstances the auto reclose setting will be disabled where all faults on the circuit are expected to be permanent in nature, e.g. feeders with underground cable only. Trip saving protection will be enabled to allow fuses and reclosers to isolate faults where they provide the first line of protection.
Distribution Transformers	Distribution transformers with a normal residential load profile can be loaded up to 150% of nominal rating. For other loads, 130% of nominal rating.
Fleet and tools	Replacement of fleet vehicles and tools shall be scheduled and prioritized to ensure the reliable and timely execution of maintenance and capital expenditure programs.
IT Systems and Infrastructure	Procurement of new IT systems shall consider commercial off the shelf systems with a focus on configuration rather than customization. Cyber security shall be considered in procuring or deploying IT systems. Cloud computing shall be considered as a solution option for infrastructure, platform and software provided that availability, security, flexibility and costs are reasonable.

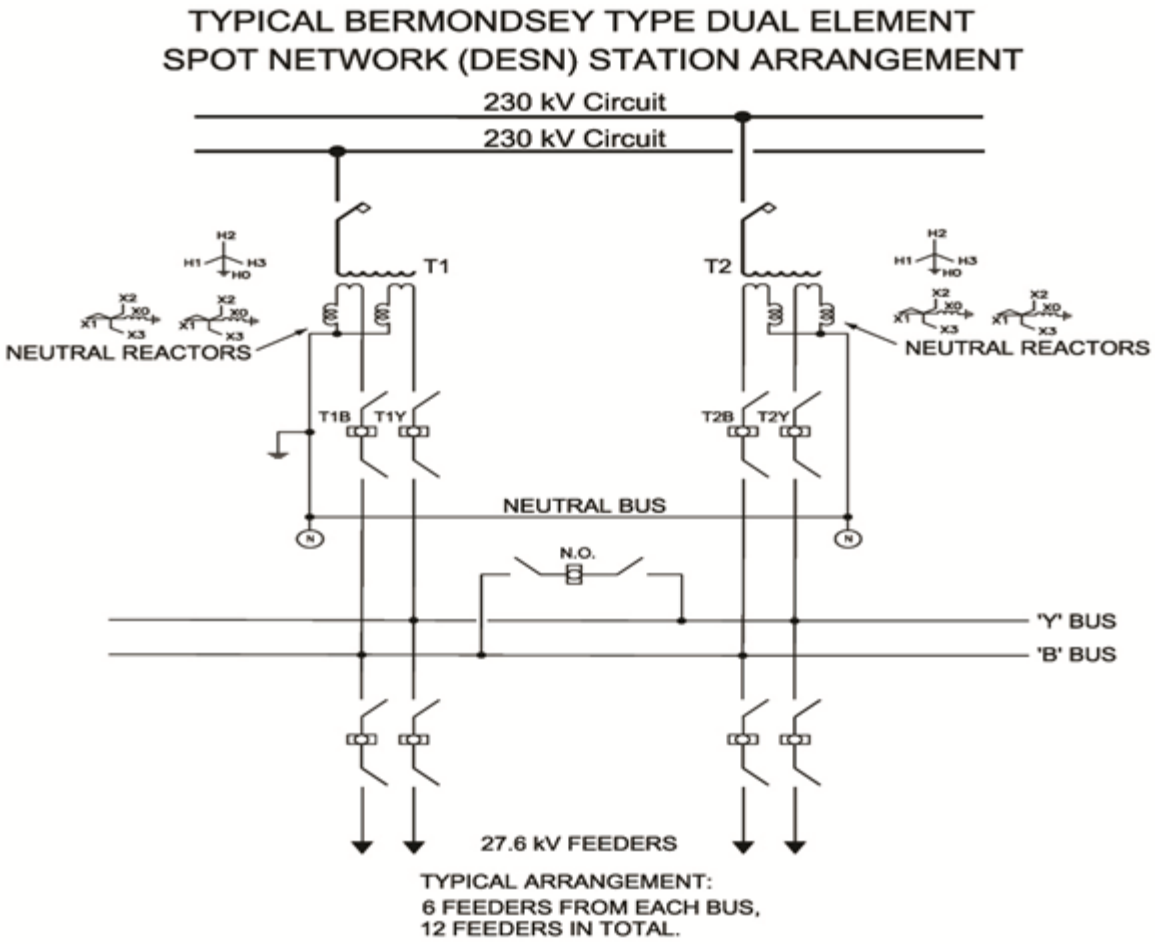
Criteria	Planning Guideline
Equipment Asset Management	Equipment shall be procured, installed, maintained and disposed of through KWHI's Asset Management process.
Undergrounding	Undergrounding of existing KWHI overhead assets shall be considered where there are external cost recovery mechanisms, outside the electricity rate setting process, or where municipal zoning does not allow for overhead distribution.

Transformer Stations Criteria

KWHI owns and operates eight transformer stations (TS) that are connected to the 115 kV or 230 kV transmission grid in a DESN arrangement. A DESN station is a particular configuration of a step-down transformer station having no high-side circuit breakers, serving local load, based on a two-transmission line supply and designed to avoid interruption of load in the event of loss of one transmission line or one transformer. Seven of the TS transform power down to a 13.8 kV distribution voltage. These stations service the City of Kitchener. Kitchener T9 TS transforms power down to 27.6 kV to service Wilmot Township DS.

Typical connection diagrams of a Bermondsey and a Jones type station, including the features of each connection type, are shown below:

Figure 4.15: Bermondsey type station layout



Each transformer station consists of a DESN pair of transformers (T1 & T2). Each transformer of a pair is connected to a separate high voltage (HV) supply circuit through a motor operated disconnect switch or a circuit switcher. The two transformers each have double secondary windings. One winding of each transformer supplies each of the two separate 13.8 kV buses. These windings are connected in parallel through circuit breakers to the two separate 13.8 kV feeder buses. A bus tiebreaker is operated normally open, since if closed, the maximum permissible short circuit rating of equipment outside the station would be exceeded during a fault.

Each transformer has a self-cooled/forced-cooled continuous rating of 100/167% at an ambient of 30º C and is equipped for under-load tap changing (ULTC). That is, it has internal automatic switching facilities that can operate while the transformer is loaded to change the HV/LV winding ratio to maintain the secondary voltage at desired levels.

Under normal operation with all facilities in service, the load supplied by a pair of circuits and transformers will normally be shared equally by each element. If a fault develops in one element, the faulted half of the DESN is switched out of service and the supply to the 13.8 kV bus is maintained through the unfaulted half of the station.

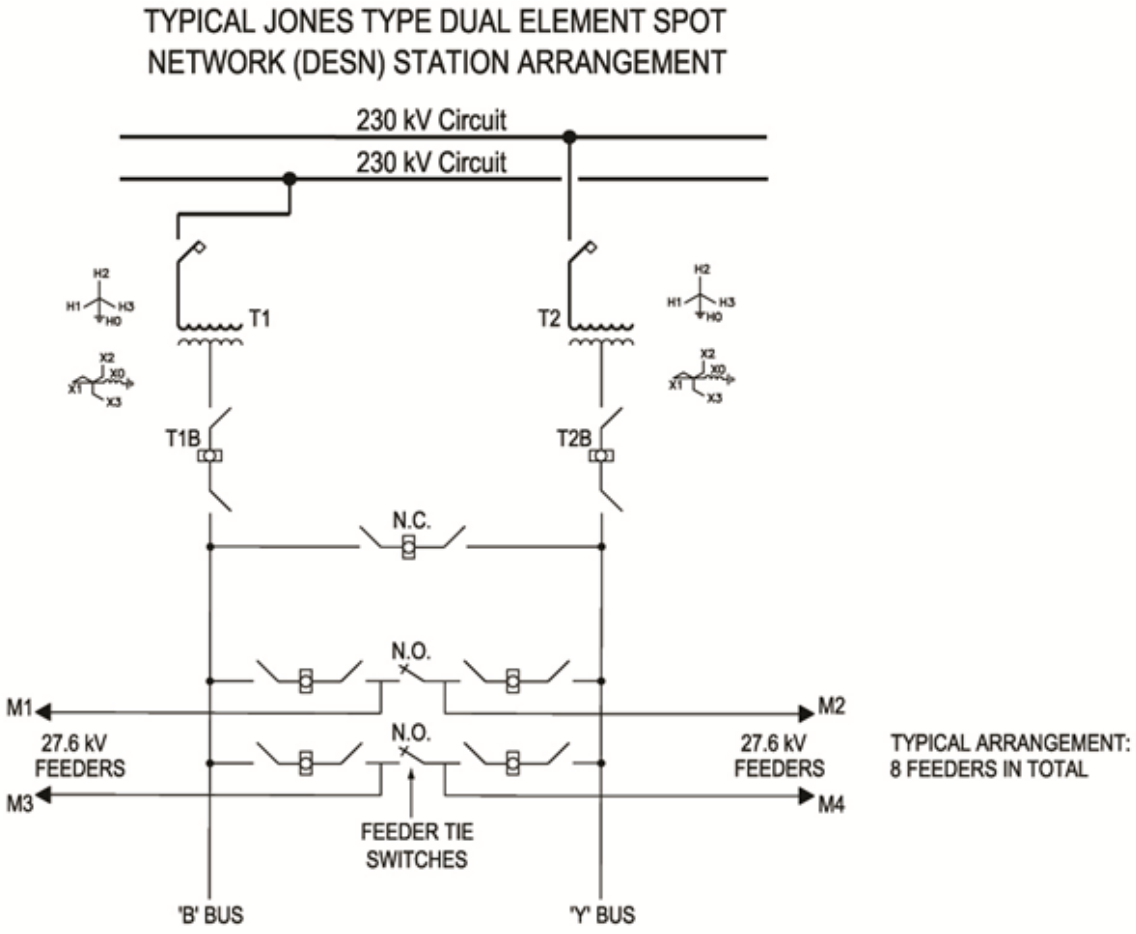
Kitchener 3TS, 4TS, 5TS and 6TS are Bermondsey Type stations, shown in Table 4-20 with additional details listed.

Table 4-20: Listing of Bermondsey type Stations

TS Name	Details	Transformer Sizes	Normal TS Capacity	Contingency TS Capacity
Kitchener No.3	Primary 115kV; Secondary 13.8kV	T1 60/100 MVA T2 60/100 MVA	100 MVA	120 MVA
Kitchener No.4	Primary 115kV; Secondary 13.8kV	T1 50/83 MVA T2 50/83 MVA	83 MVA	99.6 MVA
Kitchener No.5	Primary 115kV; Secondary 13.8kV	T1 50/83 MVA T2 50/83 MVA	83 MVA	88.5 MVA
Kitchener No.6	Primary 230kV; Secondary 27.6kV	T1 50/83 MVA T2 50/83 MVA	83 MVA	99.6 MVA

Note that Kitchener 5TS is limited to 88.5 MVA (106%) under contingency situations due to ampacity ratings of the 13.8 kV transformer-switchgear bus connection.

Figure 4.16: Jones type station layout



The HV connections to a Jones type station are similar to a Bermondsey type station. However, as shown in Figure 4.16, there are a couple of major differences between the two station arrangements with regards to the transformers and the 13.8 kV bus arrangement.

The two transformers (T1 & T2) each have a single secondary winding instead of two windings. The secondary winding of each transformer supplies one secondary bus through a normally closed bus tiebreaker, therefore the two transformers are in parallel.

Kitchener 1TS, 7TS, 8TS and 9TS are Jones type stations, shown in Table 4-21 with additional details listed. For planning purposes, Transformer Stations can be loaded up to 100% of nameplate of a single transformer. For contingency purposes, there is a 60-day overload capacity of approximately 120% for at least 2 hours a day. This will allow sufficient time for a worst-case transformer failure requiring the replacement of the transformer.

Table 4-21: Listing of Jones type stations

TS Name	Details	Transformer Sizes	Normal TS Capacity	Contingency TS Capacity
Kitchener No. 1	Primary 115kV; Secondary 13.8kV	T1 30/50 MVA T2 30/50 MVA	50 MVA	60 MVA
Kitchener No. 7	Primary 230kV; Secondary 13.8kV	T1 30/50 MVA T2 30/50 MVA	50 MVA	60 MVA
Kitchener No. 8	Primary 230kV; Secondary 13.8kV	T1 30/50 MVA T2 30/50 MVA	50 MVA	60 MVA
Kitchener No. 9	Primary 230kV; Secondary 27.6kV	T1 50/83 MVA T2 50/83 MVA	83 MVA	99.6 MVA

Distribution Stations Criteria

Distribution Stations (DS) are also critical components of the distribution system whose service disruption results in a large number of customers being out of supply. There are seven KWHI-owned DS operating at 27.6kV (primary supply) to 8.32kV (secondary output) servicing the Wilmot Township area. DS consist of a single power transformer, connected to an upstream sub-transmission feeder. The number of distribution feeders egressing from the station depends on the size of the transformer.

Table 4-22: Distribution Stations listing

DS Name	Details	Transformer Sizes	Normal DS Capacity
1DS	Primary 27.6kV; Secondary 8.32kV	5 MVA ONAN	5 MVA
2DS	Primary 27.6kV; Secondary 8.32kV	5 MVA ONAN	5 MVA
3DS	Primary 27.6kV; Secondary 8.32kV	5 MVA ONAN	5 MVA
5DS	Primary 27.6kV; Secondary 8.32kV	5 MVA ONAN	5 MVA
6DS	Primary 27.6kV; Secondary 8.32kV	5/6.66 MVA ONAN/ONAF	6.66 MVA
7DS	Primary 27.6kV; Secondary 8.32kV	5 MVA ONAN	5 MVA
8DS	Primary 27.6kV; Secondary 8.32kV	5/6.66 MVA ONAN/ONAF	6.66 MVA

DS are planned, configured and loaded to 100% normal rating. There are sufficient 8.32kV feeder interconnections that allow for an entire DS to be backed up from one or more adjacent DS. A DS transformer should not be loaded above its normal rating during non-contingency situations. Operating above normal rating will result in a shortening of the transformer service life. Under contingency situations load is to be transferred to other distribution stations, without exceeding the normal rating of the distribution station transformers or circuits receiving the load, as soon as possible.

27.6 kV, 13.8 kV & 8.32 kV Feeders Criteria

The 13.8kV distribution feeders from each transformer station in the Kitchener service area are in a grid configuration. Multiple feeders traverse the distribution area with multiple interconnections between the feeders at various points. 13.8kV feeders are critical components of the distribution system. Service disruption results in a large number of customers being out of supply. To this end 13.8kV feeders are planned, configured and loaded to provide some measure of reserve capacity for contingency situations. To facilitate this restoration capability, normal feeder loading is planned to be a maximum of 50% of circuit rating under normal operation. Under contingency situations, all interrupted load should be restored within a short time period. Sectionalizing devices are installed on circuits to isolate faulted conductors and to permit the circuits to be subdivided if required. Normally open ties are provided between adjacent circuits to permit transfer of load during contingencies.

For the Township of Wilmot, the distribution stations are supplied by 27.6 kV feeders from HONI owned stations. The 8.32 kV feeders egressing from distribution stations are also in a grid configuration which allows for full backup of each DS load to one or more adjacent DS.

Other distribution assets service a much smaller number of customers and may not have as high a disruptive impact when unavailable. To this end, planning criteria are established to provide planners with guides to the design and operation of the distribution system under normal and contingency situations.

Reliability Performance Criteria

The distribution system will achieve certain levels of reliability performance depending on the planning criteria in place and asset lifecycle support programs. For KWHI, the planning criteria should ensure that the following annual reliability service level objectives are achieved, presented in Table 4-23.

Table 4-23: Reliability performance objectives

Service function	Objective
System Outage Duration	SAIDI within range of past 5-year performance
System Outage Frequency	SAIFI within range of past 5-year performance
Other Index of Reliability (IOR)	IOR within range of past 5-year performance
Emergency response	60 minutes maximum/80% of the time - City 120 minutes maximum/80% of the time - Rural

The 2010 OEB-sponsored Pollara survey solicited the opinions of consumers from across the province regarding electricity outages and other reliability related issues. The survey indicated that most consumers are generally satisfied with the current levels of system reliability and do not favour increasing their rates to fund improvements in system reliability. KWHI believes that maintaining reliability performance within range of the past 5-year performance is appropriate and sustainable. In this sense KWHI is seeking to balance reliability performance with customer cost.

Distribution System Contingencies

Contingency plans are required to deal with any asset related event that affects the functionality of the distribution system. Contingency planning deals with potential high-impact/low-probability (HILP) events that can have major repercussions on the distribution system and KWHI customers. This will mostly apply to critical assets such as station transformers and 27.6 kV or 13.8 kV feeders. All other events, that are generally regular occurrences, low-impact/low-scope and have established processes to deal with them, are not detailed here. The HILP events considered here are shown in the Table 4-24.

Table 4-24: Contingency events and plans

Asset Class	Contingency Event	Contingency Plan
TS Power Transformers	Transformer failure requiring off-site servicing	1. Supply from alternate transformer (DESN) – 60-day LTR (120%) 2. Spare Transformer 3. Storage location for spare 4. Plans to move spare to affected TS
TS Circuit breaker or bus	Circuit breaker failure; bus fault	1. Supply from alternate bus (DESN) – 60-day LTR (120%) 2. Feeder emergency loading capability 3. Ties to alternate TS supplies 4. Spares – critical parts list 5. Contact plan for manufacturer repair support
DS Power Transformers	Transformer failure requiring off-site servicing	1. Supply from one or more adjacent DS 2. Repair transformer or purchase replacement
DS Circuit breaker or reclosers	Circuit breaker failure	1. Feeder supply from alternate DS 2. Spares – Critical parts list 3. Contact plan for manufacturer repair/replace support 4. Feeder emergency loading capability 5. Ties to alternate DS supplies
TS/DS Feeder cables	Failure of one or more underground cables	1. Spare cable reel 2. Ties to alternate TS/DS supplies
TS/DS SCADA	Failure of SCADA leading to loss of station control	1. Standby staff to man station 2. Contact plan for manufacturer repair support
Station Protective Devices	Device failure leading to full/partial loss of station	1. Spare – Critical Parts list 2. Ties to alternate TS/DS supplies
Poles/conductors	Loss of high number of pole structures through high impact event (severe weather, etc.)	1. Stock poles/conductors 2. Supplier stock 3. Neighbouring LDC stock

In all cases if available contingency measures prove insufficient, load shedding may be required to ensure equipment is not loaded beyond approved tolerances.

Distribution planning is part of the Asset Management process and is a year-round activity. Issues of growth and reliability are evaluated on an ongoing basis to determine optimal solutions that feed into the investment process. Computer modelling tools, such as CYME, are used in conjunction with GIS information to evaluate distribution system configuration performance with respect to the planning criteria. Solutions incorporate a balance of corporate and stakeholder interests.

4.2.1.4 Outlook and Objectives for Accommodating REG

It is KWHI's assessment that the distribution system has sufficient capacity to accommodate foreseeable renewable generation connections within the period covered by the DSP. KWHI's planning objective with respect to renewable generation is to continue to facilitate the connection of renewable generation in a timely manner consistent with the provisions of the Distribution System Code.

4.2.2 Processes, Tools, and Methods (5.4.1b)

Project Identification

The projects that KWHI selects for its capital budget are the ones that promote safety, efficiency, and reliability of its distribution system to allow KWHI to carry out its obligation to distribute electricity within its service area as defined by the Distribution System Code.

System Access projects such as development and municipal plant pole relocation projects are identified throughout the year by way of engagement with external proponents. These projects are mandatory in nature and are budgeted and scheduled to meet the timing needs of the external proponents.

System Renewal projects are identified through KWHI's Asset Management process. The project needs for a specific period are supported by a combination of asset inspection, individual asset performance, and asset condition assessments as summarized in the Asset Management Plan.

System Service projects are identified through KWHI's Asset Management process and operational needs to ensure that any forecasted load changes that constrain the ability of the system to provide consistent service delivery are dealt with in a timely manner.

General Plant projects are identified through KWHI's Asset Management process and internally by specific departments (engineering, finance, operations, administration, etc.). These projects tend to fall into two categories, routine investments such as vehicle replacement and special projects such as new CIS, GIS, OMS, etc. Special projects are supported through specific business cases for the specific need.

Project Selection and Prioritization

Mandatory projects are automatically selected and prioritized based on externally driven schedules and needs. System Access projects fall into this category and may involve multi-year investments to meet proponent needs. Road widening projects requiring pole line relocation are examples of this.

Remaining capital investments are selected and prioritized based on benefit and risk mitigation for each project with consideration to project cost and annual budget allocation. Most System Renewal, System Service and General Plant projects fall into this category and some projects may involve multi-year program investments to meet Asset Management Objective needs. All projects are assessed against the corporate values through Asset Managements Objectives and their respective weights shown in Figure 4.17 and Table 4-25. The current prioritization tool's primary goal is to provide a list of prioritized projects within a given budget that would return that greatest benefit to the utility based on the identified risks to be avoided or mitigated.

KWHI's project selection tool calculates the overall project score with respect to KWHI's Asset Management Objectives. Each objective is weighted appropriately in accordance to customer feedback and KWHI's leadership team. The calculated project score is an index to measure the value of each capital project to other capital project values. The highest valued project for each year is selected that fits the annual budgets. Projects that do not meet the budget are allocated for next year. The next project with the highest value that can fit the annual budget is selected. It is important to note that KWHI's selection tool considers project interdependencies as well. In most cases, the value of a multi-phase project is realized in the last phase. The selection tool identifies these project interdependencies and prioritizes the leading phases prior to the closing phase. The output of the tool presents a project list selected for the annual budget year. These projects are then prioritized based on KWHI's resource capability and external factors. The current process used is in the early stages of

project prioritization and will continue to evolve towards a refined Risk Model with dynamic prioritization indicators.

Figure 4.17: Objective weightings for prioritizing projects

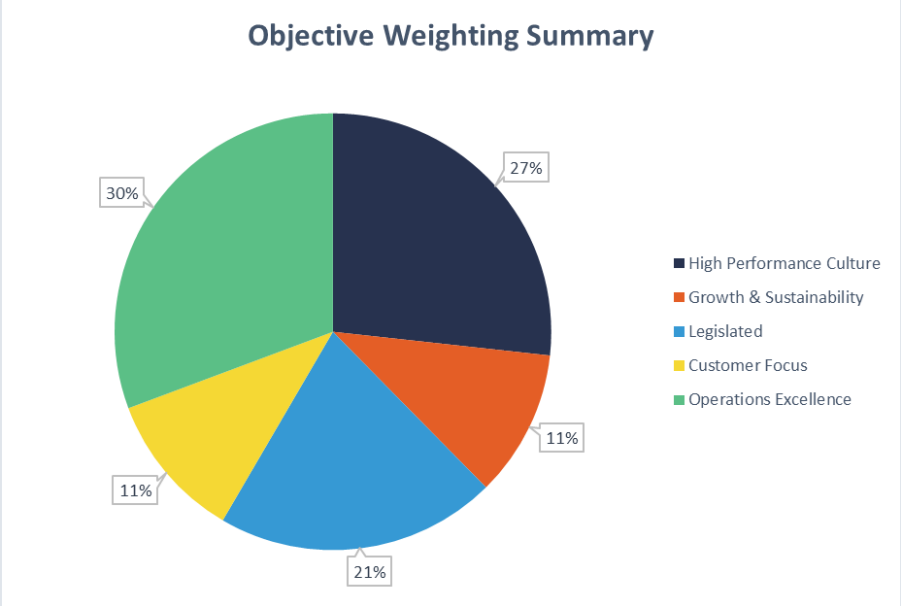


Table 4-25: Decision criteria descriptions

Corporate Values	Decision Criteria	Description
High Performance Culture	Public Safety	Public safety refers to the welfare and protection of the public. Primary goal is prevention and protection of the public from dangers affecting safety.
	Employee Safety	Under the OSH law, employers have a responsibility to provide a safe workplace to their employees.
Growth & Sustainability	System Expansion/Efficiency	System expansion is needed as the utility's customer base grows. This includes an increasing population within the utility's boundaries as well as the growth of urban and sub-urban areas. To accommodate the growth, projects are required to expand the system to reach the customers and producing a high efficiency of energy delivered. Additional project developments involve the future growth in identified areas in the near term.
Legislated	Cyber Security	Cybersecurity is the protection of internet-connected systems from cyberattacks. Security comprises cybersecurity and physical security – both are used by enterprises to protect against unauthorized access to data centers and other computerized systems.
	Relocations	If a proposed project cannot accommodate the existing utility infrastructure the utility is required to relocate their assets for future accommodations.
Customer Focus	Customer Preference	Customer preferences are expectations, likes, dislikes, motivations and inclinations. It compliments the customer needs of the utility. The customer preferences are identified through utility-customer engagements such as surveys. For increased acceptance of the project, the project is aligned to those identified customer preferences.

Operation Excellence	Reliability	The simplest definition for reliability is power that's there when its needed by the customer – limiting the number of outages experienced by the customer. Projects that maintain or upgrade the infrastructure can improve or maintain the reliability experienced by the customer. Additionally, it assists in meeting the reliability indices SAIFI and SAIDI which are generally used for performance measures. Lastly, reliability focuses on reducing the number of momentary losses experienced on the system which are impactful to customers who are sensitive to those losses.
	Asset Health Impacts	Maintaining the "health" of each asset class at the desired, acceptable and tolerable level for the utility. Asset health includes the end of life of an asset to ensure the asset's full life is used efficiently. Additionally, projects can influence the asset's life to minimize the overall capital cost in the short term in means of extending the asset's life.
	Substandard Conditions	If an existing design does not maintain standard clearances or contains conditions deemed to be out of practice, outdated and/or obsolete, the utility can act on upgrading the design to current accepted conditions.

Project Pace

Project pace for System Access projects is generally determined by external schedules and needs. System Service and General Plant projects tend to be lumpy in nature and most are paced to begin and complete within a specific budget year. System Renewal projects tend to be multi-year programs and are paced to balance the Asset Management objective needs of the specific program with regard to available resources and managing the program impacts on the customer's bill. In this sense program benefit and deferral risk are weighed against the ability of the customer to pay. KWHI's multi-year System Renewal programs have been prepared and paced based on the Asset Condition Assessment report prepared by METSCO. Project pacing for each project is further explained in the respective project descriptions.

4.2.3 REG Investment Prioritization (5.4.1c)

The prioritization process for REG expansions is the same as for distribution system expansion projects where the REG expansion is triggered and driven by customer requirements.

When KWHI is required to do an expansion or enhancement to the distribution system to connect an embedded generation facility, the provisions of the *OEB DSC Section 3.2* will apply. KWHI will perform an economic evaluation to determine the generator's share of the present value of the projected capital costs and ongoing maintenance costs of the expansion. KWHI assumes that future revenue and avoided costs will be zero.

4.2.4 Assessing Non-Distribution System Alternatives to Relieving System Capacity (5.4.1d)

KWHI's activities in this area are delivered through the KWHI 2015-2020 CDM programs in accordance with the CDM requirement included in KWHI's licence as issued by the OEB. KWHI's total 2015 – 2020 CDM target is 105.71 GWh as determined by the IESO.

KWHI's 2015-2020 CDM programs are consistent with OEB policy and the OEB's 2015 CDM Guidelines of putting conservation first into distribution planning. KWHI's CDM programs are designed to reduce electricity consumption and draw from the grid upstream of the customer. KWHI's CDM program consists of IESO funded programs and KWHI specific programs that are to be funded solely through distribution rates.

Proposed distribution rate funded programs may consist of:

1. CDM programs that target peak demand (kW) reductions to address a local constraint of KWHI's distribution system.
2. Demand response programs whose primary purpose is peak demand reduction to defer capital investment for specific KWHI distribution infrastructure.
3. Programs to improve the efficiency of the distribution system and reduce distribution losses. (i.e. re-conductor to larger size, voltage conversion, etc.).
4. Energy storage programs whose primary purpose is to defer specific capital spending for the KWHI distribution system.

KWHI is also participating in an IESO funded project to investigate the use of battery storage on transmission grid operations. A 2.0 MW battery storage system is being constructed by Hecate LLC on KWHI property. KWHI is facilitating the project through a land lease and connection point at No. 5 TS to the 115kV transmission network. The facility will absorb power during periods of excess energy supply and provide it back to the transmission grid when energy demand is high. KWHI will have monitoring capabilities installed at the energy storage site to collect operational data and study the behaviour and impact of the plant.

KWHI actively participates in the Regional Planning process to identify any system capacity or operational constraint relief that can be achieved through cooperative planning and program execution with regional distributors and transmitters. KWHI's detailed CDM programs actively encourage customers to conserve energy through a variety of means, providing an implicit area wide capacity and operational relief effort.

KWHI notes that non-distribution investments to relieve capacity or operational constraints need to be optimal solutions. The solution must be optimal with respect to the uncertainty of future system loading. The non-distribution system investments need to ensure that distribution system investments can be deferred by a specific time with certainty. Future uncertainties about local distribution capacity demand need to be factored into the value of the non-distribution system investment.

The impact of renewable generation and CDM programs is factored into the load forecast for determining capacity growth/decline impacts. The 2019 and 2020 forecasted CDM and renewable generation impacts are noted in Table 4-26. At the time of writing this DSP, years 2021 to 2023 have limited data available to validate a projection for those future years.

Table 4-26: Forecast CDM and REG contributions

Summary Of CDM/REG portfolio savings			
Year	**CDM (MW)**	**CDM (MWh)**	**REG (MW)**
2019	4.68	27,789	0.82
2020	2.47	16,619	0.82
2021	0	0	0.82
2022	0	0	0.82
2023	0	0	0.82
Plan Total	**7.15**	**44,408**	**4.10**

The amount of proposed renewable energy generation and CDM program impact, during the period of the DSP does not offer any significant capacity or operational constraint relief to KWHI's distribution system.

4.2.5 System Modernization (5.4.1e)

Grid modernisation includes technological improvements to aid in situational awareness (for customers and utility), responding to outages and cyber attacks, defending the grid, controlling the grid, and enabling integration of distributed energy resources. The following are strategies or initiatives KWHI used in taking advantage of opportunities that arise during system planning to implement cost-effective modernization.

- KWHI has considered options in planning the replacement of its legacy CIS to facilitate customer access to consumption data in an electronic format. One of the CIS requirements was for customers to have easy electronic access to consumption data. Phase 1 will implement the core CIS that has the structure and capability for ease of data access while phase 2 includes a proposal to implement a customer portal to facilitate the transactions in a seamless manner and provide customers with self serve options.
- Mechanisms to facilitate real-time data access and behind the meter services and applications have also been considered for the purpose of providing customers with the ability to make decisions about their electricity costs. These include:
    - CIS requirements for the application to have the capability of supporting the Green Button Data standard which will facilitate near real-time open data access for customers using third party applications.
    - During the planning stage to replace and renew end of life smart meters, KWHI will investigate the feasibility of installing smart meters equipped with low power, encrypted, wireless communication module that adheres to industry standards (such as Zigbee) to provide near real-time data access to consumers using in-home display devices.
- Included in KWHI's distribution planning process for system renewal projects are considerations for increasing feeder capacity, replacing transformer station switchgear with sufficient fault handling capability, adding remote switching devices for feeder segmentation, and implementing alternative means to monitor and control DERs. These initiatives will serve to facilitate greater penetration of DERs.
- KWHI has considered and in some cases implemented several technology-enabling opportunities increasing operational efficiencies, improving asset management or enhancing services to customers. These include; ongoing implementation of an automated crew call out application, automated field switching devices (reclosers), and communication network. Initiatives planned for implementation include; risk-based asset management system, Interactive Voice Response system, and customer self-service portal as part of CIS phase 2.

KWHI also plans to modernize its grid by replacing assets that no longer meet KWHI's design standards with assets that will contribute to operational efficiencies where applicable, such as automated switches. In addition, KWHI has plans to make investments within its IT software and hardware infrastructure. Investing in IT allows for KWHI to maintain its operation and adopting new services and technologies to continue providing excellent service to its customers. Section 3.5 explains KWHI's IT asset management strategy.

Additionally, through the feeder voltage conversion activities, KWHI will investigate options where it can modernize its system to provide additional visibility to its customers. Example, adding line sensors, automated switches, etc. However, system modernization will depend on multiple factors and limits and will be revaluated on a project by project basis.

4.2.6 Rate-Funded Activities to Defer Distribution Infrastructure (5.4.1f & 5.4.1.1)

Under the new Conservation First Framework for the 2015 to 2020 period, the provincial CDM focus has shifted to only energy savings and KWHI has an allocated savings target of 105.71 GWh. At the end of 2017, KWHI's progress has reached 83% compared to the savings target and are well on track on reaching the target by the year 2020. This is due to KWHI's continued efforts in engaging its customers in CDM programs.

Ontario runs two REG programs. FIT ("Feed-in Tariff") applicants are those customers setting up solar or other renewable generation equipment to generate more than 10 kW of electricity at a time. MicroFIT applicants are those customers applying to generate electricity at a level less than or equal to 10 kW of electricity at a time. Based on Kitchener-Wilmot Hydro's FIT/microFIT data and the future assumptions, it is estimated that the connection of Renewable Energy projects under FIT and microFIT programs will remain steady beyond 2018 and into the DSP forecast period.

As previously noted, KWHI is also participating in an IESO funded project to investigate the use of battery storage on transmission grid operations. A 2.0 MW battery storage system is being constructed by Hecate LLC on KWHI property. KWHI is facilitating the project through a land lease and connection point at No. 5 TS to the 115kV transmission network. The facility will absorb power during periods of excess energy supply and provide it back to the transmission grid when energy demand is high. KWHI will have monitoring capabilities installed at the energy storage site to collect operational data and study the behaviour and impact of the plant. KWHI will review the outcome of the current project and will be used for consideration of potential future applications.

Furthermore, KWHI is planning a voltage conversion in parts of its distribution system. These projects will support the reliability performance and operational efficiency as expected by customers as well as employees. In addition, the voltage conversions will further reduce KWHI's distribution losses mitigating the cost impact on its customers. KWHI is planning a few material investments that would include voltage conversion as part of the scope but not as the primary trigger driver.

Additionally, KWHI is sampling its meters to determine if they are operating and reading at acceptable levels. Should the meters be tested positive, KWHI can extend the seal life of its meters by eight years, further reducing the costs and allowing KWHI to invest in its assets. If the meter sample returns a negative test, a meter replacement program will have to be planned and initiated. KWHI recognizes this as a small risk and expects the sampling test to return as positive, hence there is no proposed material investment program in the DSP forecast period.

4.3 CAPITAL EXPENDITURE SUMMARY (5.4.2)

The Capital Expenditure Summary provides a ‘snapshot’ of KWHI’s capital expenditures over a 11-year period, which includes six historical years and five forecast years. The costs of individual projects or activities are allocated to one of four investment categories based on the primary (i.e. initial or ‘trigger’) driver of the investment.

Table 4-27: Historical capital expenditures and system O&M

Category	Historical (rounded values) [GROSS]															
	2014			2015			2016			2017			2018			2019
	Plan	Act.	Var.	Plan	Act.	Var.	Plan	Act.	Var.	Plan	Act.	Var.	Plan	Act.	Var.	Plan*
	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000
System Access	10296	11687	13.5	12255	15817	29.1	11468	16918	47.5	8866	11815	33.3	7465	8107	8.6	7,432
System Renewal	5970	4821	(19.2)	4791	3322	(30.7)	4805	4616	(3.9)	7539	5377	(28.7)	8159	7728	(5.3)	8,545
System Service	1520	1545	1.6	1620	839	(48.2)	3050	2420	(20.6)	2630	1458	(44.6)	2350	1476	(37.4)	2,100
General Plant	3150	2280	(27.6)	1920	1859	(3.2)	2229	2105	(5.6)	3760	2807	(25.3)	5465	3030	(44.6)	7,125
Gross Total	20936	20333	(2.9)	20586	21838	6.1	21551	26059	20.9	22796	21457	(5.9)	23438	20340	(13.2)	25201
System O&M	11280	10117	(10.3)	11280	9320	(17.4)	11280	9498	(15.8)	11280	10625	(5.8)	11280	11811	4.7	12576

** includes 0 months of actual expenditures*

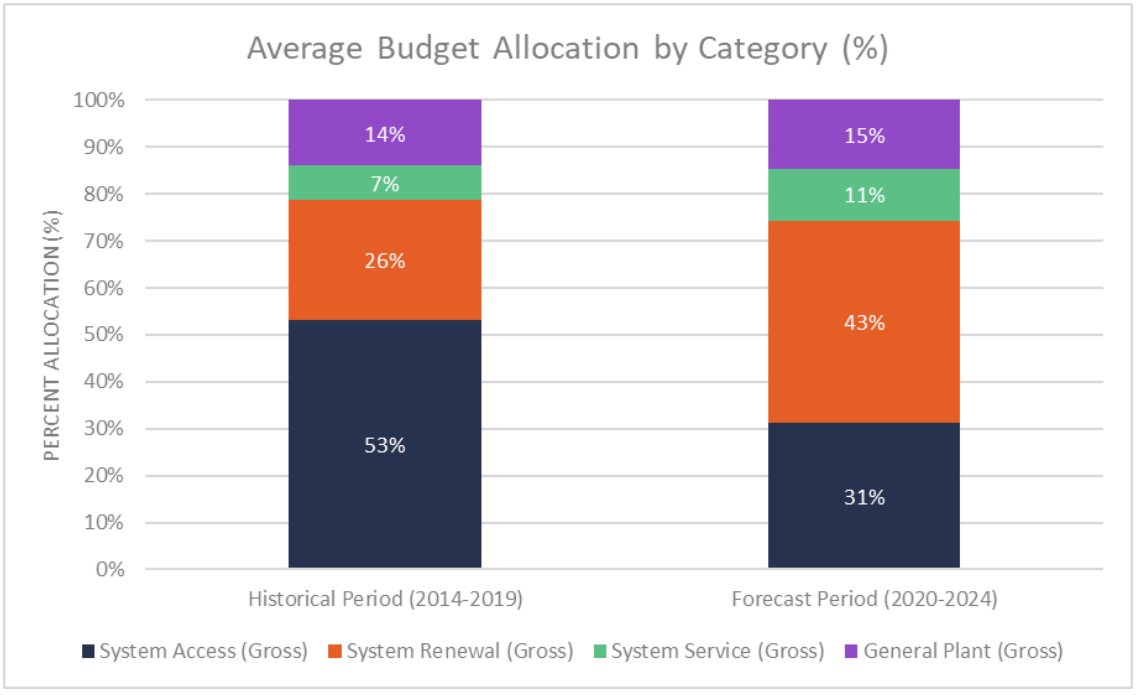
Note: Since this is KWHI's first DSP; the amount shown above for "Plan" by category are the annual budget amounts approve by KWHI Board of Directors. 2014 amount is Board approved.

Table 4-28: Forecast capital expenditures and system O&M

Category	Forecast (rounded values) [GROSS]				
	2020	2021	2022	2023	2024
	$ '000	$ '000	$ '000	$ '000	$ '000
System Access	7,664	7,767	7,817	7,717	7,767
System Renewal	9,415	10,350	10,650	11,400	11,500
System Service	3,200	3,200	2,800	2,300	2,300
General Plant	4,295	3,275	3,565	3,500	3,480
Gross Total	24,574	24,592	24,832	24,917	25,047
System O&M	13,162				

A comparison can be made of KWHI's annual budget allocation between the historical period and the forecast period within the DSP period seen in Figure 4.18. It is evident that KWHI has been largely investing in System Access projects and significantly deferring System Renewal projects. Over the forecast period, System Access spending experiences a decrease in spending and is estimated to be 31% of total spending, accounting for the city's growth of subdivisions. System Renewal spending experiences the largest increase and is estimated to be 43% of the total spending. The increase is a reflection of the deferral of System Renewal work in the historical period and is now required to be executed each year to address the aging infrastructure and maintain system reliability. System Service accounts for a slight increase to 11% of the total spending, as well General Plant experiences a slight increase to 15% of the total spending. Incremental investments within each of these categories are needed to further automate the system and upgrade KWHI's IT infrastructure for implementation of a new CIS, and smart grid functionalities. There are no expenditures for non-distribution activities in KWHI's proposed budget.

Figure 4.18: Average Budget Allocation by Category



4.3.1 Variances in Capital Expenditures

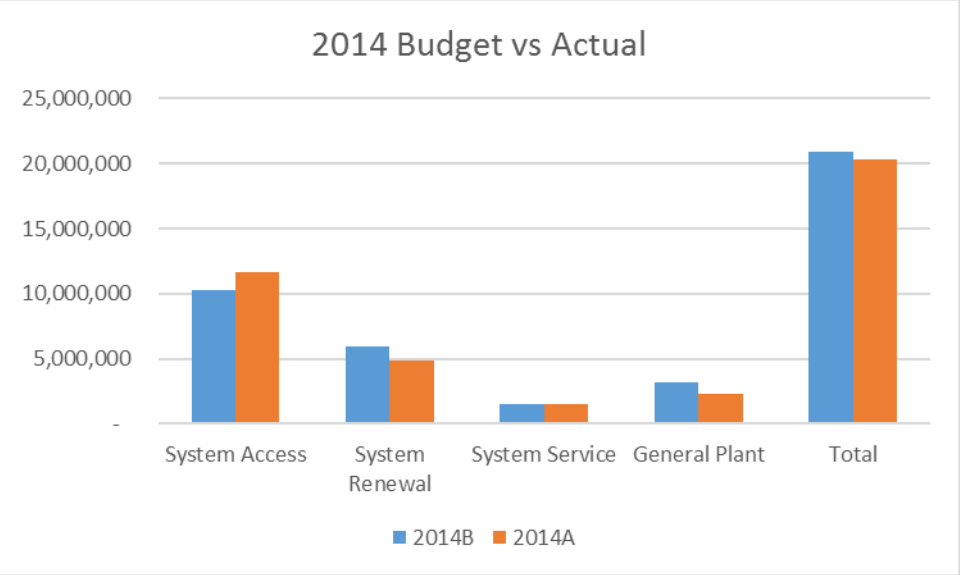
KWHI is filing its first DSP and therefore has no OEB-approved historical planned values. However, the historical planned values are based on KWHI's annual budget approved by KWHI's Board of Directors. The breakdown provided is based on a best estimate at slotting the 2014-2019 projects into the respective categories. Historical variance is looked at each year in reference to Table 4-27 and variance that exceeds +/-10% is explained below. KWHI attempts to maintain a low variance between its planned and actual budgets. In the historical years, majority of variances were attributed to allocating and shifting funds from other projects into the additional non-discretionary expenditures in System Access that were not identified in an earlier time period. KWHI notes that predicting projects that are required and captured under the System Access category is difficult, though it does attempt to be as accurate as possible with the supplied information it receives. Moving forward, KWHI continues to be engaged with third-party groups that drive the non-discretionary funding to appropriately plan and accommodate resources in order to reduce the variance found within the System Access category.

The following sections support the OEB Chapter 2 Appendix 2-AA that is filed as part of KWHI complete rate application.

2014 Variance Summary

In 2014, the total variance is -2.9%, which is well within a 10% variance. The figure below followed by category breakdown details the larger variances experienced between KWHI's budget and actual costs. O&M actuals were less than budgeted due to the required resources to address additional non-discretionary projects. However, KWHI continues to meet the requirements and standards set in the DSC.

Figure 4.19: 2014 Historical Variance by Category



2014 System Access [+13.5%]

- +$1.56M: Relocations due to LRT were the main driver for this variance. $3.5M was budgeted for this project in 2014 while the actual expenditure was $5.06M. This resulted from an increase in scope of work associated with LRT relocations.

- +$0.37M: Residential underground distribution had a positive variance resulting from an increase in the number of services installed (1,350) compared to the budgeted amount (900).
- -$0.23M: Large Commercial, Industrial & Apartment Service saw a decline in activities in 2014 compared to previous years. This is not considered a trend since timing of commercial activities don't necessarily coordinate in step with residential developments.

2014 System Renewal [-19.2%]

- -$0.99M: Several pole line system renewal projects were deferred to allow for increase activities associated with LRT relocations. Deferred projects include; Ardelt Place - Ardelt Dr. to Overland Dr., Krug St - Lancaster St. to Hwy 7, and single-phase pole line rebuilds.
- -$0.25M: Installation of underground conduits to replace direct buried cable in older subdivisions was deferred because of higher than normal quoted contract prices.

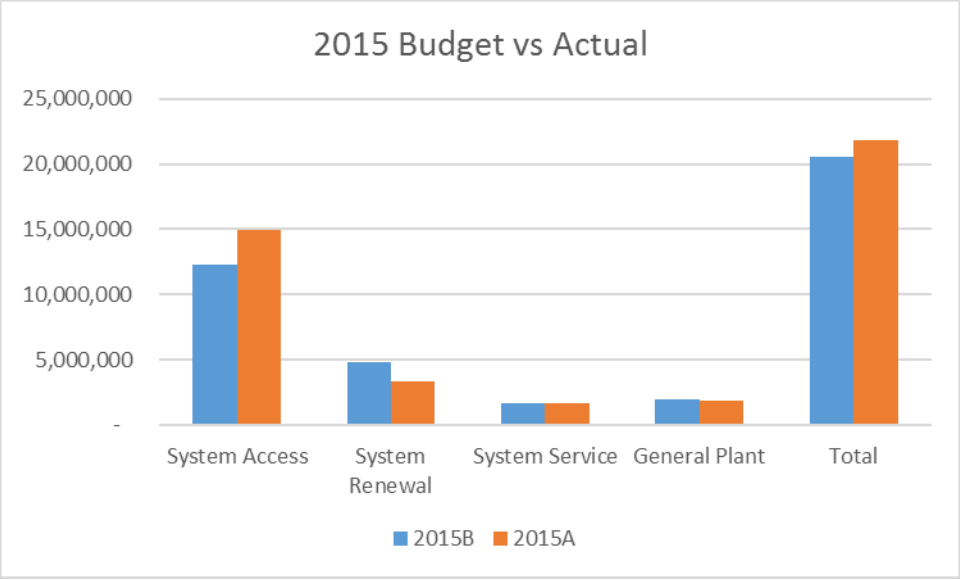
2014 General Plant [-27.6%]

- -$1.23M: 2014 budget for Land and Buildings was $1.35M which included the allocation of $1.0M to purchase land adjacent to the main office. This purchase did not occur.

2015 Variance Summary

In 2015, the total variance is 6.1%, which is well within a 10% variance. The figure below followed by category breakdown details the larger variances experienced between KWHI's budget and actual costs. O&M actuals were less than budgeted due to the required resources to address additional non-discretionary projects. However, KWHI continues to meet the requirements and standards set in the DSC.

Figure 4.20: 2015 Historical Variance by Category



2015 System Access [+29.1%]

- +$3.12M: Relocations due to LRT was the main driver for this variance. This resulted from an increase in scope of work associated with LRT relocations.

- +$0.15M: Residential underground distribution had a positive variance resulting from an increase in the number of services installed (1,320) compared to the budgeted amount (1,200).

- +$0.55M: Large Commercial, Industrial & Apartment Service had a positive variance compared to budget due to the increase in activities required to service LRT infrastructure being installed (traction power substations, track heaters, lighting, etc.).

2015 System Renewal [-30.7%]

- -$0.83M: Several pole line rebuild projects that were budgeted for in 2015 were deferred to accommodate LRT-related work. The projects include.
    - Cedar Street: Courtland Ave E to Charles St E – deferred
    - Krug Street: Lancaster St to Hwy 7 - deferred
    - Ardelt Place: Ardelt Dr. to Overland Dr. - deferred
    - Single Phase Pole Line Rebuilds – lower actual project cost
- -$0.40M: System renewal work budgeted for at the transformer station facilities was higher than actual. The following projects were not completed as planned:
    - No. 5TS P&C Cell Wiring and Commissioning
    - No. 5TS Bell Circuit Movement and New Isolation

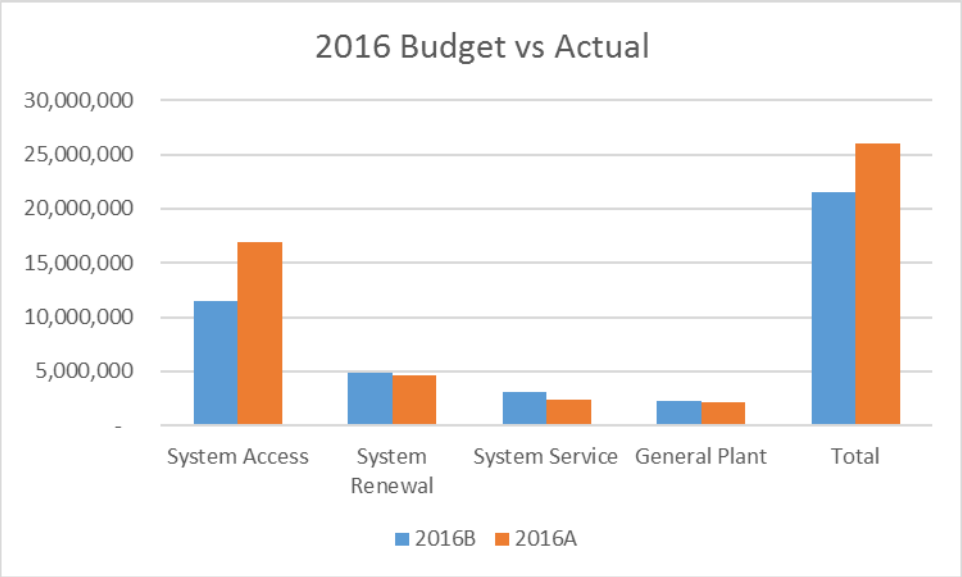
2015 System Service [-48.2%]

- -$0.84M: There was a one-time credit given back to KWHI by HONI for Detweiler TS bypass cost. When KWHI constructed its No. 9TS in Wilmot Township, a bypass cost was charged by HONI for stranded Detweiler TS assets. After reconciling the project, a refund was given back to KWHI. This resulted in an offset in the total expenditures for System Service since construction of the TS would have been categorised as a System Service investment.

2016 Variance Summary

In 2016, the total variance is 20.9%. The variance surpasses the 10% variance due to the impact of the LRT project changing in scope. The figure below followed by category breakdown details the larger variances experienced between KWHI's budget and actual costs. O&M actuals were less than budgeted due to the required resources to address additional non-discretionary projects. However, KWHI continues to meet the requirements and standards set in the DSC.

Figure 4.21: 2016 Historical Variance by Category



2016 System Access [+47.5%]

- +$4.58M: Relocations due to LRT was the main driver for this variance. This resulted from an increase in scope of work associated with LRT relocations.
- +$0.40M: Relocations due to roadworks were greater than anticipated.

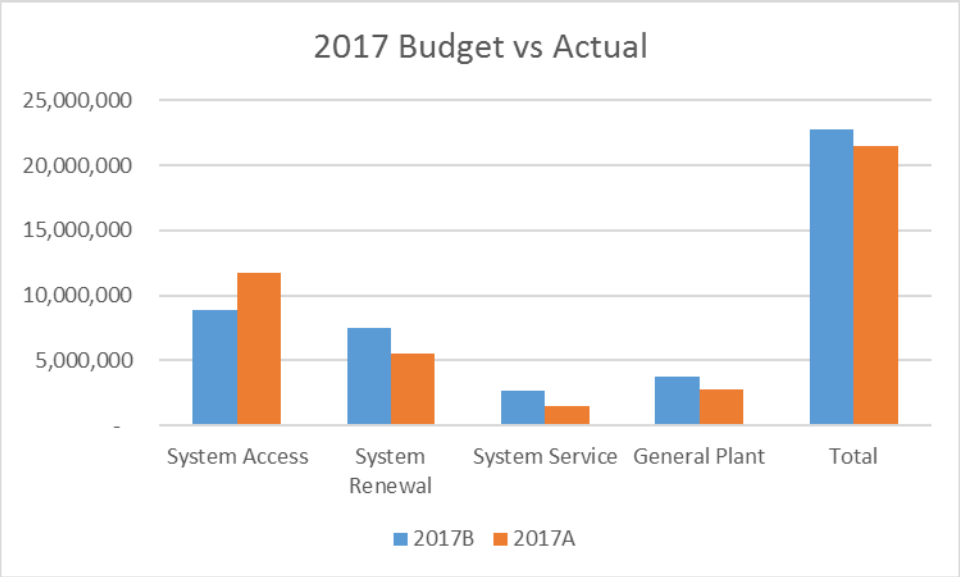
2016 System Service [-20.6%]

- -$0.24M: Portion of a Voltage Conversion projects that was budgeted for as System Service in 2016 was categorised as System Access during design and construction. The project in question is Notre Dame Drive, Berlett's Road to Moser Young that was rebuild as a shared pole line between KWHI and Waterloo North Hydro.
- -$0.14M: Kings St. E Phase 2: H/Way 8 Bridge to Sportworld Dr. – the expenditures associated with phase 2 of this project was less than anticipated. This project involves the construction of a new distribution feeder to supply load growth in the Sportsworld area of Kitchener.
- -$0.13M: Innovation and Reliability expenditures were less than anticipated.

2017 Variance Summary

In 2017, the total variance is -5.9%, which is well within a 10% variance. The figure below followed by category breakdown details the larger variances experienced between KWHI's budget and actual costs. O&M actuals were less than budgeted due to the required resources to address additional non-discretionary projects. However, KWHI continues to meet the requirements and standards set in the DSC.

Figure 4.22: 2017 Historical Variance by Category



2017 System Access [+31.8%]

- +$2.03M: Relocations due to LRT was the main driver for this variance. Initial budget was lower for this project in 2017 in anticipation of the project winding down while the actual expenditure was significantly higher. This resulted from an increase in scope of work associated with LRT relocations.
- +$0.29M: Relocations due to roadworks were greater than anticipated.
- -$0.64M: Residential underground distribution had a negative variance resulting from lower expenditures than anticipated.

2017 System Renewal [-26.8%]

- -$0.23M: System renewal work done on transformer station facilities was less than anticipated.
- -$0.65M: Several pole line rebuild projects that were budgeted for in 2017 were either deferred to accommodate LRT-related work or portion carry forward to 2018. There was also simultaneous increase in expenditures resulting from projects that were continuing from 2016. The projects include:
    - Bleams Rd: Otonabee Dr to Homer Watson Blvd - deferred
    - Schweitzer Rd: Bridge St to Sylvia St - deferred
    - Nafziger Rd Stage 1: Erbs Rd - Carmel Koch Rd
    - 5M23 rear of Craig and Hickson Dr.: Ottawa to Crosby Dr. – deferred
    - Highland Rd E: Patricia to Stirling – not completed – carry forward to 2018
    - Miscellaneous overhead distribution – expenditures increased
- -$0.86M: Replacement of primary cables and conduits due to age and condition did not occur as planned.

2017 System Service [-44.6%]

- -$0.41M: Actual expenditures for System Expansion to Supply New Developments that were attributed to System Service was less than budgeted. Some System Expansion expenditures were categorized as System Access at time of design.
- -$0.25M: Innovation and Reliability expenditures were less than anticipated. The installation of reclosers and capacitor banks were completed. However, underground network transformer remote monitoring and overhead to underground conversion at Trussler Road and Highway No. 8 were deferred.
- -$0.47M: Voltage Conversion that was scheduled for Huron Road, Pinehill and Strauss Court was not completed as planned. It should be noted that voltage conversion projects are budgeted as either System Renewal or System Service during the planning stage depending on the primary driver for the project.

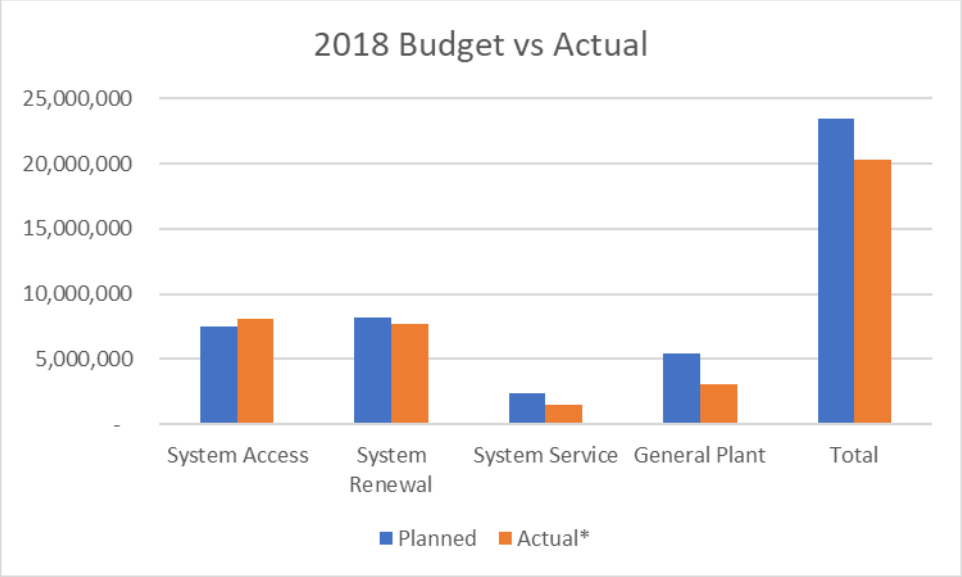
2017 General Plant [-25.4%]

- -$1.07M: The main driver for the variance in General Plant expenditures was deferral of the CIS replacement project. $1.60M was budgeted for in Information Technology with $1.3M allocated for CIS, however, actual expenditures in IT were only $0.6M.
- -$0.08M: Actual expenditures for vehicle was less than anticipated.

2018 Variance Summary

In 2018, the estimated total variance is -13.2%. The largest impacts were the deferral of a CIS replacement. The figure below followed by category breakdown details the larger variances experienced between KWHI's budget and actual costs. O&M actuals are estimated to be higher than budgeted. This is in response to address issues that were identified as critical and required intervention.

Figure 4.23: 2018 Historical Variance by Category (Est.)



2018 System Access [+11.6%]

- +$0.20M: Relocations due to roadworks were greater than anticipated. Phase 2 of underground relocation work at Highway 85 North for MTO was lower than initially budgeted.

- +$0.37M: Costs to supply underground services to Large Commercial, Industrial & Apartment Services were higher than budgeted for. Particularly the underground service to the redeveloped Pioneer Park Plaza at 123 Pioneer Park Drive in Kitchener.
- +$0.11M: Installation of New Revenue Meters was higher than anticipated. There were three large behind the meter generation projects (299 Trillium Drive, 2196 Gerber Road, and 1473 Gingerich Road) that were not included in the original budget but were connected in 2018.
- -$0.18M: Residential underground distribution had a negative variance resulting from lower expenditures than anticipated. 1200 services budgeted for, while actual was 1000.

2018 System Renewal [-8.1%]

- -$0.46M: System renewal work done on transformer station facilities was less than anticipated. The postponement of No. 3 Transformer Station T52 reactor replacement was the main driver for this variance. Reduction in expenditures associated with No. 5 Transformer Station protection and control work and deferral of RTU upgrade at No. 4 and No. 9 transformer stations also contributed to the variance.
- -$0.13M: Replacement of primary cables, conduits and civil structures due to age and condition did not occurred as planned. Part of this program includes replacement/major repairs of network transformer vaults. However, in 2018, two vaults were budgeted for roof replacement and only one was replaced.

2018 System Service [-37.2%]

- -$0.60M: Actual expenditures for System Expansion to Supply New Developments that were attributed to System Service was less than budgeted. The main reason was deferral of projects. The following projects were deferred.
    - New 7M4 feeder to provide load relief for 5TS – deferred to 2021 to coincide with anticipated road relocation works by the City of Kitchener.
    - Manitou Drive: Cayuga Drive to Doon Village Rd – deferred due to additional time that is required to acquire easement.
- -$0.40M: Innovation and Reliability expenditures were less than anticipated. The main reasons for this variance are; the number of automated switches (reclosers) that were installed were less than budgeted and the underground innovation program budgeted for did not go ahead due to re-allocation of resources.

2018 General Plant [-44.6%]

- -$2.39M: The main driver for the variance in General Plant expenditures was the continued deferral of the CIS replacement project. $3.55M was budgeted for in Information Technology with $2.6M allocated for CIS, however, actual expenditures in IT were only $1.17M. The deferral of the CIS project is a result of KWHI's continued effort to find the right solution at an affordable price.

4.4 JUSTIFYING CAPITAL EXPENDITURES (5.4.3)

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

4.4.1 Overall Plan (5.4.3.1)

4.4.1.1 Comparative Expenditures over the Historical Period by Category

The comparative expenditures by category over the historical period are shown in Table 4-29 and Table 4-30 below and in the following charts (Figure 4.24) as trend lines. At the time of preparing the DSP, 2019 data is based on planned (budgeted) expenditures. Additionally, KWHI system has the capacity available for new connections and does not anticipate any issues in the forecast period.

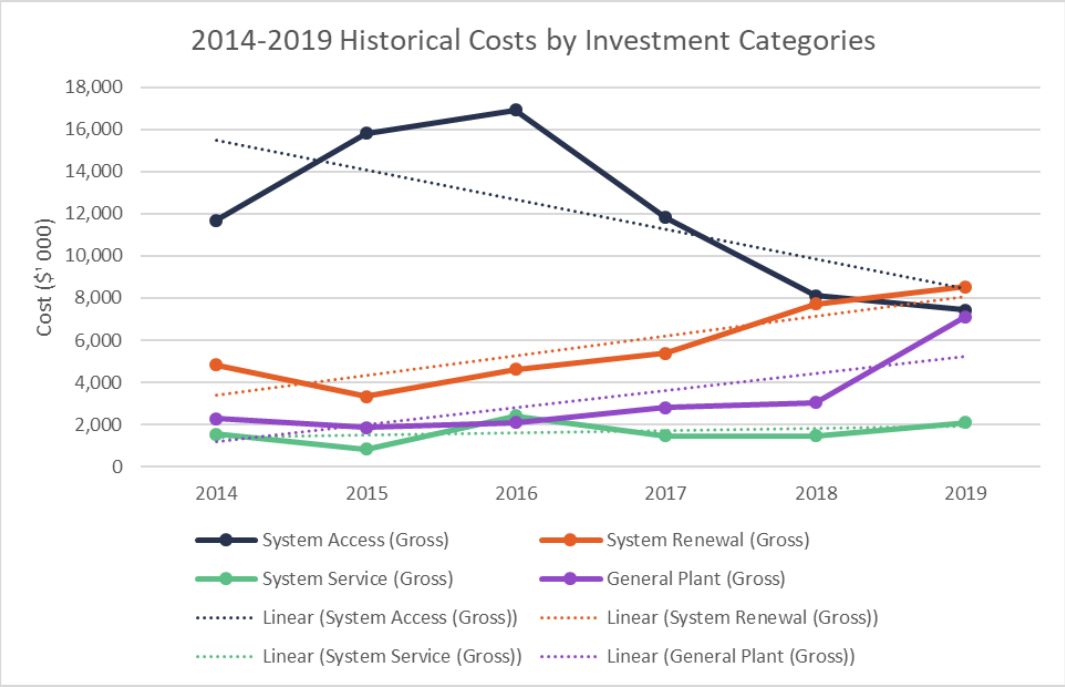
Table 4-29: Historical DSP Period Actual Expenditures by Category ($'000)

Category	2014	2015	2016	2017	2018	2019B
System Access	11,687	15,817	16,918	11,815	8,107	7,432
System Renewal	4,821	3,322	4,616	5,377	7,728	8,545
System Service	1,545	840	2,420	1,458	1,470	2,100
General Plant	2,280	1,859	2,105	2,807	3,030	7,125
Gross Total	**20,333**	**21,838**	**26,059**	**21,457**	**20,335**	**25,201**
System O&M	10,117	9,320	9,498	10,625	11,811	12,576

Table 4-30: Historical DSP Period Actual Expenditures Year over Year Percentage Variance

Category		2015 v 2014	2016 v 2015	2017 v 2016	2018 v 2017	2019B v 2018
System Access		35%	7%	-30%	-31%	-8%
System Renewal		-31%	39%	16%	44%	11%
System Service		-46%	188%	-40%	1%	43%
General Plant		-18%	13%	34%	8%	135%
Gross Total		7%	19%	-18%	-5%	24%

Figure 4.24: 2014 – 2019 Capital Expenditure Historical Graphs with Trends



The charts in Figure 4.24 shows the historical trending of capital expenditures by investment categories over the period 2014 to 2019. System Access shows a general declining trend as is expected due to the initial ramp up to fund LRT-related relocation projects and the subsequent completion of such project in 2017.

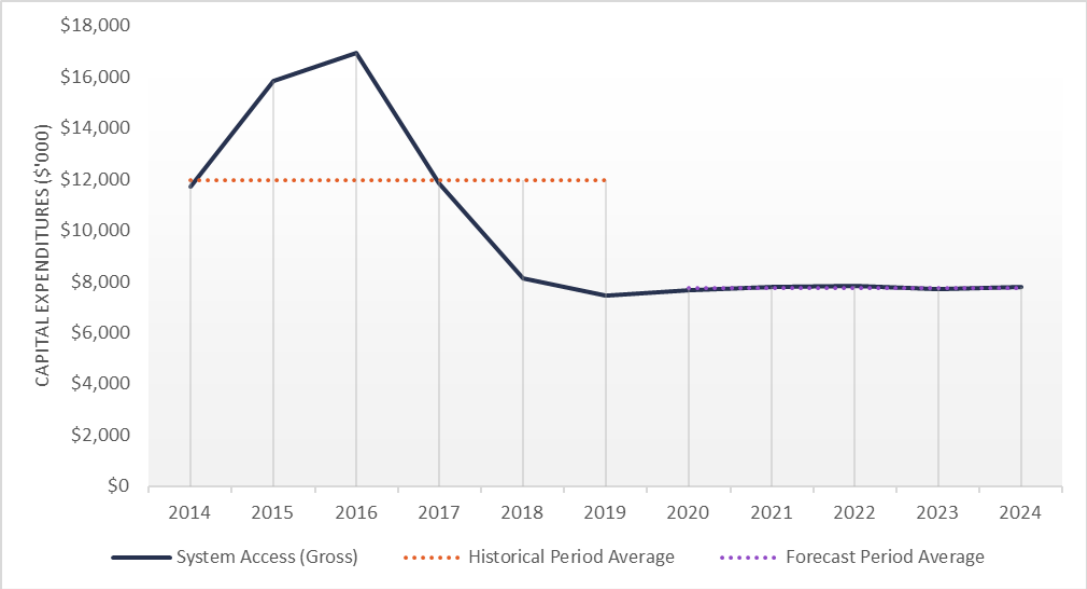
System Renewal shows an inverse trend to System Access. That is, capital expenditures due to System Renewal increase as System Access decrease to maintain a steady overall capital expenditures budget. System Service and General Plant capital expenditures also show slight increase over the historical period. A year over year variance explanation by category is provided.

System Access

The historical trend with System Access was highly variable year over year due to LRT activities. As seen in Figure 4.25, the annual forecast average is 33% less than the annual historical average over the total DSP period. This is equivalent to a 20% decrease in total gross spending in KWHI's annual budget as seen in Table 4-29. This allows for KWHI to allocate funds to other categories where historical expenditures have been lower than planned.

System Access activities moving forward will continue to focus on customer connections, plant relocation activities and mandated service obligations. Forecast expenditures are projected to be less variable between the years and lower in comparison to historical years due to less expected mandated projects. Historical expenditure analysis is provided below.

Figure 4.25: System Access Expenditures



There was a 35% increase in System Access expenditures from 2014 to 2015 actuals.

- The increase in expenditures in this category is predominantly due to increase of activities undertaken to enable LRT relocations. The LRT relocations expenditure in 2014 was $5,071,748 compared to $7,524,064 in 2015 – a $2,452,316 increase. LRT relocations are driven by the need for KWHI to relocate its overhead and underground distribution plant to suit Regional work associated with building the infrastructure for an LRT system. These expenditures are customer driven and mandatory.
- In 2012 through 2017, the LRT Phase 1 project work was a major undertaking (approximately $27M gross cost of utility relocation work) requiring considerable relocation of KWHI plant and allocation of associated resources. Cost savings in the form of capital contributions amounted to $16M. The allocation of financial and human resources to this endeavour resulted in reduced spending for remaining identified investments in the other capital investment categories. The values in Table 4-31 represents the total expenditure associated with the LRT relocation project and varies slightly from the actual amount allocated to System Access.

Table 4-31: LRT Expenditures Summary

Description	KWHI LRT Expenditures Summary (Actual) [$]						
	2012	2013	2014	2015	2016	2017	Total
Grand Total	54,362	2,622,782	5,071,748	7,524,064	8,641,021	2,958,154	26,872,131
Variance (Year-to-Year)		2,568,420	2,448,966	2,452,316	1,116,957	-5,682,867	

- Other drivers for the increase in System Access expenditures are:
  - Large Commercial & Industrial Services –In 2015, there were several large commercial projects compared to 2014 that required underground servicing.
  - Relocations Due to Road Works – Relocations due to road works are mandatory projects and timing is generally driven by the road authority. There was an increase in the number of overhead plant relocations required in 2015.

There was a 13% increase in System Access expenditures from 2015 to 2016 actuals.

- The increase in expenditures in this category is predominantly due to increase activities undertaken for LRT relocations. There was also a decrease in expenditures associated with supplying and servicing new subdivisions. While the number of units serviced did not change significantly, the types of units differs (that is, more multi-family units vs single family units). Additionally, there was an increase in metering expenditures.

There was a 7% increase in System Access expenditures from 2015 to 2016 actuals.

- The increase was driven by increased activities associated with relocations due to LRT, and servicing of commercial and industrial customers.

There was a 30% decrease in System Access expenditures from 2016 to 2017 actuals.

- The reduction in expenditures in this category was a result of significantly less LRT-related work that was undertaken in 2017.

There was a 31% decrease in System Access expenditures from 2017 to 2018 actuals.

- The reduction in expenditures in this category was a result of no LRT-related work being undertaken in 2018. Also, there was a 26% (-$620K) decline in capital expenditures associated with road relocation projects in 2018 compared to 2017.

There is an 8% proposed decrease in System Access expenditures from 2018 actuals to 2019 budget.

- The proposed reduction in expenditures in this category is attributed to a reduction in Revenue Meter and Generation Connection costs ($192K). Previous years had substantial costs associated with installing transfer trip and communication facilities to enable large behind the meter generation projects. Also, for budgeting purpose, miscellaneous overhead customer connections and miscellaneous transformers installed are allocated to System Renewal. However, when the actual expenditures occur, they are allocated to the investment category that triggers the investment. 2018 actual for these two programs was $301K with $0 allocated for 2019.

There is a 3% proposed increase in System Access expenditures from 2019 to 2020 budget.

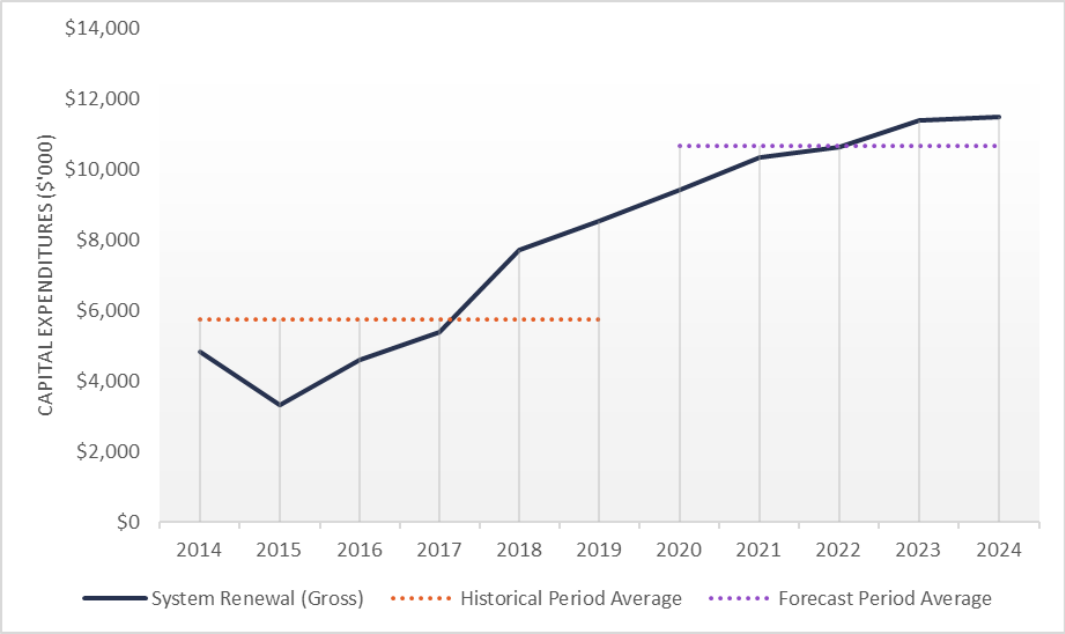
- This increase is not considered to be material. The increase is related to anticipated increase in expenditures for relocations due to roadway ($150K), and servicing costs for commercial, industrial and apartment buildings ($124K).

System Renewal

The historical trend with System Renewal was steadily increasing year over year to address the underlying goal of maintaining the distribution system healthy and reliable. As seen in Figure 4.26, the forecast average is 86% more than the historical average over the total DSP period. This is equivalent to a 18% increase in total gross spending in KWHI's annual budget as seen in Table 4-29.

Historically, System Renewal projects were mostly deferred to allocate the budget for System Access projects. The forecast expenditures are projected to be higher to accommodate for the historical deferrals KWHI implemented to accommodate for additional budget requirements within other system categories. System Renewal activities moving forward will continue to focus on renewal of assets at end of their service life. Historical expenditure analysis is provided below.

Figure 4.26: System Renewal Expenditures



There was a 31% decrease in System Renewal expenditures from 2014 to 2015 actuals.

- The large decline is directly attributed to the increase in LRT-related work. In order to undertake additional mandatory LRT-related work, KWHI reduced expenditures in other areas (such as pole line replacement due to age and condition) to pace the overall capital expenditure budget.

There was a 39% increase in System Renewal expenditures from 2015 to 2016 actuals.

- This increase was predominantly due to the increase in activities associated with the replacement of pole line assets due to age/condition and voltage conversion. In 2015, several pole lines rebuild projects were deferred to allow for the execution of time sensitive LRT relocation projects.

There was a 16% increase in System Renewal expenditures from 2016 to 2017 actuals.

- The main driver for this increase was increase activities in pole line replacement due to age and condition. During the period when LRT relocations expenditures were high, a decision was made to defer some system renewal projects to maintain the overall capital expenditures at a reasonable level. In 2017, LRT relocations were projected to wind down, hence, a gradual return to investment in system renewal was undertaken.

There was a 44% increase in System Renewal expenditures from 2017 to 2018 actuals.

- The main driver for this increase was increased activities in pole line replacement due to age and condition including voltage conversion related projects. In 2018, KWHI continued to ramp up its pole replacement program to accommodate pole replacements that were deferred in earlier years due to increased activities in LRT-related work and roadway relocations work. The level of activities undertaken in this program in 2018 is close to the optimal value of investments that KWHI believes is required to sustain pole line assets.

There is an 11% proposed increase in System Renewal expenditures from 2018 actuals to 2019 budget.

- The main drivers for this increase are; increase in transformer stations (TS) renewal investment ($923K) and increase in rebuilding network transformer vault roofs ($178K). There is a planned increase in TS renewal investment to replace the switchgear equipment at the No. 5TS with arc resistance equipment & remote racking capabilities so that the dangers of arc flash can be mitigated. Also, in 2019, KWHI will be rebuilding two below grade network transformer vault roofs compared to one that was rebuilt in 2018.

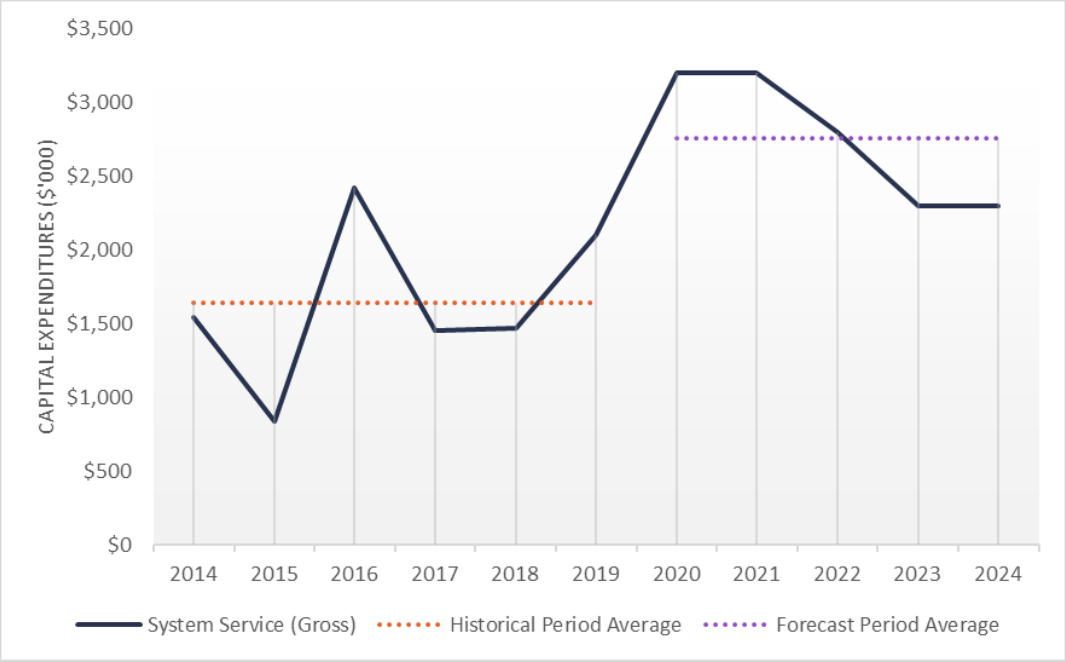
There is a 10% proposed increase in System Renewal expenditures from 2019 to 2020 budget.

- The increase is directly attributed to the proposed increase in; expenditures for replacement of pole line assets ($466K) to achieve the target of replacing 425-450 poles per year as identified in the ACA (Asset Condition Assessment) report, and transformer station renewal ($380K). In 2020, KWHI is proposing to continue with the replacement of the P&C and SCADA system at its No. 6 TS which includes replacement of all the end of life electro-mechanical relays with digital relays.

System Service

The historical trend with System Service was variable year over year. As seen in Figure 4.27, the forecast average is 48% more than the historical average over the total DSP period. This is equivalent to a 3% increase in total gross spending in KWHI's annual budget. Forecast expenditures are projected to be higher as a result of KWHI's focus on investing in Smart Grid technology and improving system performance. System Service activities moving forward will continue to focus on reliability, power quality and system efficiency initiatives. Historical expenditure analysis is provided below.

Figure 4.27: System Service Expenditures



There was a 46% decrease in System Service expenditures from 2014 to 2015 actuals.

- The decrease in expenditures can be attributed to a one-time credit of $835,324 given back to KWHI by HONI for Detweiler TS bypass cost. When KWHI constructed its No. 9TS in Wilmot Township, a bypass cost was charged by HONI for stranded Detweiler TS assets. After reconciling the project, a refund was given back to KWHI. This resulted in an offset in the total

expenditures for System Service since construction of the TS would have been categorised as a System Service investment.

There was a 188% increase in System Service expenditures from 2015 to 2016 actuals.

- Expenditures associated with System Expansion to Supply New Developments saw an increase from 2015 to 2016. This increase is a result of expansion work done to supply three of the seven traction power substations (TPSS) for LRT, distribution line upgrade along the LRT route and construction of a new distribution feeder to supply load growth in the Sportsworld area of Kitchener.
- There were increased expenditures associated with innovation and reliability activities in 2016. $110K vs $425K. Eight automated reclosers were installed in 2016 vs three in 2015.
- 2015 expenditures were also lower because of a one-time credit given back to KWHI by HONI for Detweiler TS bypass cost as explained earlier.

There was a 40% reduction in System Service expenditures from 2016 to 2017.

- The reduction can be attributed to the decrease in activities to supply new developments and LRT traction power substations relative to 2016.
- Prior to 2017, voltage conversion activities were deemed as System Service because their trigger was to increase reliability, power quality, and system flexibility. Beginning in 2017, these activities were classified as System Renewal since the main driver was condition of the distribution pole lines and the need to replace them. This resulted in a decrease of $484K in System Access costs when compared to 2016.

There was a 1% increase in System Service expenditures from 2017 to 2018 actuals.

- This change is not material.

There is a 43% proposed increase in System Service expenditures from 2018 actuals to 2019 budget.

- The proposed increase can be attributed to the increase in expenditures for the Innovation & Reliability ($423K) program in which two underground switchgear are targeted for upgrade with remote switching and monitoring capabilities to alleviate the issue with crews manually operating the switch in a below grade enclosure. The upgrade will also allow the control room to remotely operate the devices before dispatching a crew and be able to monitor the performance of the switchgear. Also, in 2018 only five of the seven line reclosers budgeted for implementation were installed. 2019 budget includes cost for seven reclosers.
- System expansion to supply new developments is proposed to have increase expenditures ($213K) due to the higher than normal number of new developments that are being built along the LRT route and in other areas of the city of Kitchener.

There is a 52% proposed increase in System Service expenditures from 2019 to 2020 budget.

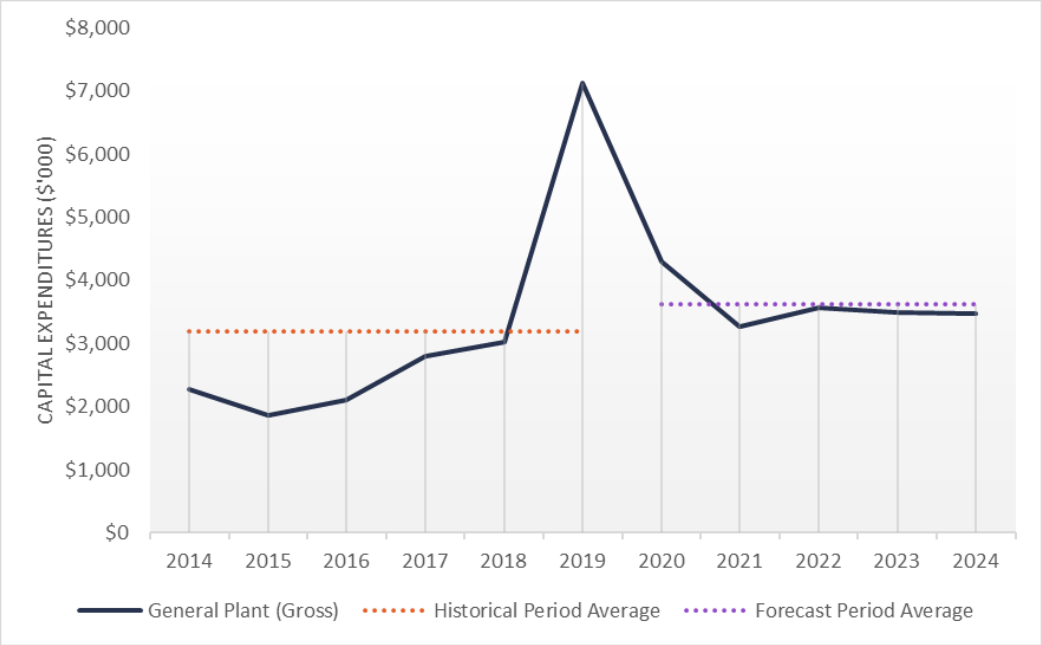
- The increase is directly attributed to the proposed construction of a new underground distribution feeder to supply load growth in downtown Kitchener. The project is a multi-year project with $1M budgeted for in 2020 and an overall estimate of $2.5M over three years (2020-2022).

General Plant

The historical trend with General was low and then had peaked to address the renewal of KWHI's fleet, IT and buildings. As seen in Figure 4.28, the forecast average is 1% more than the historical average over the total DSP period. This is equivalent to a 1% increase in total gross spending in

KWHI's annual budget. The forecast expenditures are projected to be in alignment with historical expenditures except for 2019, where KWHI is investing in major IT, building and fleet upgrades. Historical expenditure analysis is provided below.

Figure 4.28: General Plant Expenditures



There was a 18% decrease in General Plant expenditures from 2014 to 2015 actuals.

- The reduction in General Plant capital expenditures in 2015 is a result of reduced expenditures associated with KWHI's Service Centre renovation when compared to 2014. Vehicles also saw a reduction in capital expenditures. These reduction in General Plant expenditures were further offset by an increase in expenditures associated with Information Technology hardware and software.

There was a 13% increase in General Plant expenditures from 2015 to 2016 actuals.

- There are several activities that contribute to the total costs in this category. While the individual activities may vary year over year, the overall variance is within the materiality threshold. One item activity that had a significant variation was purchasing of vehicles. Purchasing of large vehicles may present a timing issue between when the vehicle purchase is made and when the vehicle is delivered, and final payments are made. Therefore, a year over year comparison isn't always the best method to compare expenditures associated with this activity.

There was a 33% increase in General Plant expenditures from 2016 to 2017 actuals.

- The main driver for this increase was building upgrade. In 2017, KWHI undertook a project to replace the external cladding and upgrade the insulation of the main office building located at 301 Victoria Street. This project became necessary because of the age and condition of the exterior cladding.

There was an 8% increase in General Plant expenditures from 2017 to 2018 actuals.

- The main driver for this increase in 2018 over 2017 is a combination of changes in land and building investments, and IT/OT investments. Investments in land and buildings decline from $1,141K to $750K while investments in IT/OT systems increased from $593K to $1,165K. The

net change between these two programs is $181K. In 2018, the main investments in land and buildings was the renovation of KWHI's control room and IT department and a temporary space in the basement to house both teams during the main space renovation. This project costs was significantly less than the previous year project which included replacement of the external cladding and upgrading of the building insulation at the main office. With regards to IT/OT investments, the main physical server infrastructure used in virtualisation was replaced with a hyper-converged infrastructure. This was a result of the server infrastructure being at end of life.

There is a 135% proposed increase in General Plant expenditures from 2018 actuals to 2019 budget.

- The proposed increase is directly attributed to the replacement of the legacy customer information system which will begin in 2019. The effect of this project on the IT expenditures in 2019 over 2018 is a $4M increase.

There is a 40% proposed decrease in General Plant expenditures from 2019 to 2020 budget .

- The proposed decrease (-$2.83M) is a result of the CIS replacement project wrapping up in 2020. The project will commence in 2019 with most of the expenditures allocated to that year due to the large upfront capital outlay required to pay for licenses and IT infrastructure.

Historical Impact of Investments on System O&M Costs

The relationship between capital expenditures and system O&M costs is dependent on the proportion of capital expenditure investments in new assets vs replacement assets, and KWHI's total expenditure (capital plus O&M) balance budget philosophy.

- New vs Replacement Asset Mix

  In general, investment in capital programs does not materially impact system O&M costs unless a significant amount of new assets are added to the system which will result in future O&M costs for ongoing upkeep. Investment in System Renewal programs tends to reduce/avoid near-term O&M costs associated with the asset while investment in System Service and System Access programs are typically associated with installation of new/upgraded assets which will increase future O&M costs required to maintain the assets. This relationship is not tracked by KWHI and therefore it is difficult to estimate the historical impact of capital expenditures on system O&M costs.

- Total Expenditure Balance Budget Philosophy

  KWHI has over the years tried to use a total spend approach so that its spending (and distribution rates) is reasonably level and predictable. In order to attain this, KWHI identifies where its spending is to be focused and then balances its annual spend, recognizing that it has resource constraints, both internal and external. During years where capital requirements are higher than normal, KWHI will shift resources, where feasible, to reduce its budgeted O&M so that its total level of spending remains about the same as the previous year. If maintenance requirements are significant in any given year, KWHI will shift its resources, again where feasible, to reduce its capital spend during the year, in order to maintain level spending. Reducing capital spending is more difficult than reducing spending on operating and maintenance costs, as much of capital spending is not discretionary. The historical (2014-2019) impact of capital expenditures on O&M costs as shown in Table 4-29 reflects the philosophy described above. 2014-2016 shows increasing capital expenditures mainly due to System Access costs associated with relocations due to LRT while the same time period

shows a decrease in system O&M costs. In 2017-2019, capital expenditures decreased while system O&M costs shows an increase.

4.4.1.2 Forecast Impact of System Investment on System O&M Costs

System investments in each of the system categories will result in:

- the addition of incremental plant (e.g. poles, cable, conduit, vaults, transformers, etc.);
- the relocation/replacement of existing plant (e.g. road authority related work);
- the replacement of end of life plant with new plant (e.g. cables, poles, transformers, etc.); and
- new/replacement system support expenditures (e.g. fleet, software, etc.)

In general, incremental plant additions will be integrated into the Asset Management system and will require incremental resources for ongoing O&M purposes. This is expected to put upward pressure on O&M costs.

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

Replacement of end of life assets will still require the allocation of resources for ongoing O&M purposes. Repair would be the most significant O&M activity impacted by new plant. Certain assets, such as poles, offer few opportunities for repair related activities and generally require replacement when deemed at end of normal life or critically damaged. Other assets such as direct buried cable offer opportunities for repair related activities (e.g. splices) up to a point where further repairs are not warranted due to end of life conditions. In a few areas cable faults will not be repaired due to cable end of life. When faulted, the faulted cable section will be replaced, normally a section between two distribution transformers. For planned cable replacement in a subdivision, new primary cable installed in duct replaces direct buried primary cable and is expected to provide higher reliability and life. This will shift response activity for a cable failure from repair (O&M) to replacement (Capital). If assets approaching end of life are replaced at a rate that maintains the existing system's condition, then the expectation would be little or no change to O&M costs under no growth scenarios but would still see upward O&M cost pressure on growth scenarios (more cumulative assets to maintain each year). Replacement rates that improve equipment class average condition could result in lowering certain maintenance activities costs (e.g. pole testing, reactive repairs, etc.). Overall this is expected to put downward pressure on O&M repair related costs.

System support expenditures (e.g. SCADA) are expected to provide a better overall understanding and capability assessment of KWHI's assets that will lead to more efficient and optimized design, utilization, maintenance and investment activities going forward. Improved asset information will allow existing resources to partially compensate for growth related increases in O&M activities. The increased level of investment and the desire to optimize the total lifecycle costs and benefits to customers requires additional staff and skillsets for system planning and analysis, which will add to O&M costs going forward. Fleet replacement expenditures will result in reduced O&M for new units, however, this will be offset by increasing O&M of remaining units as they get older.

Replacement of the legacy CIS with a commercial best in class application is one of the main capital investment expenditures that will be undertaken in the IT program during the forecast period. Additional O&M costs will be offset by re-allocating some existing IT staff to deal with initiatives that would have otherwise required additional staff/resource. There are also additional costs anticipated to implement the Cyber Security Framework that came into effect early 2018.

Overall the system investments are not expected to have a significant impact on total O&M costs in the forecast period. Table 4-32: presents the overview of O&M cost impacts on an asset level.

Table 4-32: System O&M Impacts

Item	Growth impact on O&M	Relocate impact on O&M	Replace impact on O&M	Support impact on O&M
Poles	Increase	Neutral	Neutral	Increase
Cables	Increase	N/A	Decrease (repairs only)	Neutral
Vaults, manholes and duct	Increase	N/A	Neutral	Neutral
UG Transformers	Increase	N/A	Neutral	Neutral
UG Switchgear	Increase	N/A	Neutral	Neutral
OH Transformers	Increase	Neutral	Neutral	Neutral
TS/DS Transformers	Increase	N/A	Decrease (repairs only)	Decrease
TS/DS Circuit breakers	Increase	N/A	Decrease (repairs only)	Decrease
Meters	Increase	N/A	Neutral	Increase
Fleet	Neutral	Neutral	Neutral	Neutral
Information Technology	Increase	N/A	N/A	Increase

4.4.1.3 Investment Drivers by Category

The below sections identify the investment

System Access

System Access investments include the following drivers:

- Customer Service Requests - Continued development of Kitchener as an Urban Growth Centre requiring new customer connections (site redevelopment; subdivisions). Forecasts assume increased investment needs due to urban intensification (Kitchener area)
- 3rd party infrastructure – Road widenings will require plant relocation.

In summary, due to the forecast employment and population growth in the City of Kitchener under the Places to Grow Act, System Access needs in the 2020 – 2024 period will continue to focus on new subdivision connections, connection upgrades due to suite redevelopment, and plant relocation due to urbanization and intensification of the road network. No change in drivers is expected over the forecast period.

System Renewal

System Renewal investments include the following drivers:

- Failure Risk - Multiyear planned asset replacement programs that address assets at end of life condition. Historical trend has seen lower investment amounts due to resource reallocation to mandatory System Access investments related to third party plant relocations.
- Functional Obsolescence – Voltage conversion in the Wilmott area began in 1995. Most of the voltage conversion will happen through the pole line rebuild process as existing plant reaches end of life.
- Failure - Emergency reactive replacement of distribution system assets (poles, transformers, switches, switchgear, cable, conductor, insulators, guys, anchors, etc.) due to unanticipated failure, storms, motor vehicle accidents, vandalism, etc.

In summary, system renewal spending will focus on planned proactive asset replacement programs as identified in the ACA. There will be increased expenditure in this area for the forecast period since several system renewal projects had to be deferred to reallocate resources during the years 2013-2017 to accommodate LRT relocations. No change in drivers is expected over the forecast period.

System Service

System Service investments include the following drivers:

- System Constraints – Line extensions and feeder interconnections to accommodate grid load growth. Downtown Kitchener is seeing an upsurge in mix use (combination of residential and commercial) developments resulting from three main factors; development charge exemption from Region of Waterloo, LRT infrastructure, and booming hi-tech industry. Current plans do not foresee the need to provide additional TS/DS capacity over the forecast period.
- System Operational Objectives – Investments to innovation, system reliability and efficiency (i.e. secondary network monitoring through fibre).

In summary, system service spending will continue to focus on maintaining operational performance and the efficient utilization of system plant. System service budget is higher in the forecast period in comparison to the historical spending due to the continuous deferral of added value projects for non-discretionary projects. KWHI is proposing to invest in innovative technology that would promote efficiency and improve system reliability in troublesome areas. No change in drivers is expected over the forecast period.

General Plant

General Plant investments include the following drivers:

- System Maintenance Support – Replacement of rolling stock and tools. Historical investments have resulted in specific rolling stock and tool replacement as required. Replacement of major fleet units tends to be a high lumpy cost in a specific investment year when compared to the replacement costs of small fleet units. Forecast investments include the replacement of major fleet units every 5 years.
- Business Operations Efficiency – CIS upgrade; ERP system (JD Edwards) upgrade. The existing CIS is a legacy in-house developed system with only one subject matter expert remaining in the organization who is cable of supporting the system. This presents a high risk to customer information, billing, reporting and recording should a software problem develop.

- Non-system Physical plant – Forecast investments focus on renovations and upgrades to KWHI's facility at 301 Victoria St. S. Chief among these investments is the replacement of the 30-year-old standby generator that is currently installed on the roof of the office building.

In summary, general plant spending will continue to focus on ensuring fleet asset performance meets KWHI operational and reliability needs, software platform upgrades and modernization, and facility works to sustain buildings and lands. Over the forecast period, on average, general plant expenditures will be higher due to the proposed CIS replacement project. The main driver for this project as identified above is business operations efficiency. No change in drivers is expected over the forecast period.

4.4.2 Material Investments (5.4.3.2)

The focus on this section is on projects/activities that meet the materiality threshold set out in Chapter 2 of the Filing Requirements. KWHI's revenue requirement is between $10M and $200M and therefore is using *0.5% × revenue requirement formula* to determine materiality threshold. The formula in Chapter 2 would result in a materiality threshold of approximately $200,000. KWHI will therefore be reporting on investments or variances above $200,000.

Material capital expenditures for the 2020 test year are summarized in the table below and are justified in the following section, Appendix A.

Table 4-33: Material Investments Allocated for 2020

Category	Category Total Expenditure $'000	Project Name/Description	2020 $'000	Priority Ranking
System Access	**3,463**	Underground Residential Distribution Servicing	1,464	3
		Relocations Due to Roadway Modification Projects	1,160	6
		Large Commercial and Industrial Services	242	7
		Meter Installation and Replacement	597	11
System Renewal	**9,074**	Spot Replacement of Deteriorated Poles	425	2
		Network Transformer Replacements	192	5
		No. 6 Transformer Station Rebuild P & C and SCADA Equipment and Wiring	879	8
		Stage 1-River Road East between Ottawa Street North and Halliwell Drive	201	10
		No. 4 Transformer Station Replacement of 115 kV Switch with Circuit Switcher	229	12
		Underground System Renewal	850	13
		6M11 Feeder-H1 ROW between rear of 83 Trailwood Cres to Royal Orchard Dr	353	14
		Notre Dame Drive: Wilby Road to Erb's Rd, Township of Wilmot	340	15
		Franklin Avenue South between Wilson Avenue and Connaught Street	177	17
		Mill Street: Ottawa Street South to Carwood Avenue	329	18

Category	Category Total Expenditure $'000	Project Name/Description	2020 $'000	Priority Ranking
		Bridge Street: Puddicombe Road to Pinehill Road, Township of Wilmot	289	19
		4M26 Feeder - Pole Line Rebuild-Stage 1-H1 ROW from Fischer-Hallman Road to Westmount	265	20
		Three Phase Transformer Vault Roof Replacements	240	21
		Victoria Street North between Weber Street West and Margaret Avenue	574	22
		No.5 TS Switchgear Arc Resistance	757	23
		Single Phase & Secondary Pole Line Rebuilds Due to Age and Condition	935	25
		Wilby Road: Nafziger Road and the Nith River, Township of Wilmot	289	27
		Overhead Transformer Purchases	500	28
		Transformer installations excluding URD	850	29
		Underground Voltage Conversion	400	30
System Service	**2,912**	System Expansion to Supply New Developments	1,700	4
		Mannheim Rd: Witmer Rd to Huron Rd Line Extension	403	9
		Strasburg Rd Stage 1: Templewood Dr to South of Rockcliffe Dr.	259	16
		Innovation and Reliability Improvement	550	24
General Plant	**3,375**	CIS Replacement	1,675	1
		Emergency Backup Generator Replacement	350	26
		Vehicle Replacement	1,000	31
		Pavement Replacement at Main Office – Phase 2	350	32
Total	**18,824**		**18,824**	

Appendix A:
2020 Test Year Material Investment Justifications

Category	Category Total Expenditure $'000	Project #	Project Name/Description	2020 Total $'000	Page #
System Access	**3,463**	SA 3-20-3	Relocations Due to Roadway Modification Projects	1,160	1
		SA 4-20-2	Underground Residential Distribution Servicing	1,464	7
		SA 4-20-3	Large Commercial and Industrial Services	242	16
		SA 7-20-1	Meter Installation and Replacement	597	23
System Renewal	**9,074**	SR 2-20-1	No. 4 Transformer Station Replacement of 115 kV Switch with Circuit Switcher	229	30
		SR 2-20-2	No.5 TS Switchgear Arc Resistance	757	38
		SR 2-20-3	No. 6 Transformer Station Rebuild P & C and SCADA Equipment and Wiring	879	45
		SR 3-20-1	Spot Replacement of Deteriorated Poles	425	52
		SR 3-20-4	Single Phase & Secondary Pole Line Rebuilds Due to Age and Condition	935	60
		SR 3-20-5a	Notre Dame Drive: Wilby Road to Erb's Rd, Township of Wilmot	340	68
		SR 3-20-5b	Bridge Street: Puddicombe Road to Pinehill Road, Township of Wilmot	289	76
		SR 3-20-5c	Wilby Road: Nafziger Road and the Nith River, Township of Wilmot	289	85
		SR 3-20-8	4M26 Feeder - Pole Line Rebuild-Stage 1-H1 ROW from Fischer-Hallman Road to Westmount	265	93
		SR 3-20-9	6M11 Feeder-H1 ROW between rear of 83 Trailwood Cres to Royal Orchard Dr	353	101
		SR 3-20-10	Victoria Street North between Weber Street West and Margaret Avenue	574	109
		SR 3-20-11	Mill Street: Ottawa Street South to Carwood Avenue	329	117
		SR 3-20-12	Franklin Avenue South between Wilson Avenue and Connaught Street	177	126
		SR 3-20-13	Stage 1-River Road East between Ottawa Street North and Halliwell Drive	201	134
		SR 4-20-7	Underground Voltage Conversion	400	143
		SR 4-20-8	Underground System Renewal	850	151
		SR 4-20-11	Three Phase Transformer Vault Roof Replacements	240	160
		SR 5-20-1	Transformer installations excluding URD	850	167
		SR 5-20-6	Network Transformer Replacements	192	173

Category	Category Total Expenditure $'000	Project #	Project Name/Description	2020 Total $'000	Page #
System Service	**2,912**	SS 3-20-2a	Strasburg Rd Stage 2: Rockcliffe Dr. to Robert Ferrie	259	179
		SS 3-20-2b	Mannheim Rd: Witmer Rd to Huron Rd Line Extension	403	185
		SS 3-20-7	Innovation and Reliability Improvement	550	192
		SS 4-20-5	System Expansion to Supply New Developments	1,700	200
General Plant	**3,375**	GP 1-20-1	Emergency Backup Generator Replacement	350	208
		GP 1-20-2	Pavement Replacement at Main Office – Phase 2	350	214
		GP 10-20-3	CIS Replacement	1,675	219
		GP 11-20-1	Vehicle Replacement	1,000	226
Total	**18,824**			**18,824**	

Capital Project Summary

Project Name: Relocations Due to Roadway Modifications

Budget Year: 2020 **Budget Item No.:** 3-20-3 and 4-20-6

OEB Investment Category: System Access

General Information on Project (5.4.3.2.A)

Project Summary	These projects consist of relocating existing overhead and underground plants to suit roadway modifications by the Region of Waterloo, the City of Kitchener, the Township of Wilmot or the Ministry of Transportation. Specific projects depend on the construction schedule of the road works. It is generally our intention to complete the relocation 1 year prior to the road works. Possible projects for 2020 are: (i) Fairway Rd S: Wilson Ave to Manitou Dr (ii) Bleams Rd: Fischer-Hallman Rd to Trussler Rd (iii) Fischer-Hallman Rd: creek to Plains Rd (iv) Westmount Rd W: Glasgow St to Highland Rd W (v) Mill St: Ottawa St S to Courtland Ave (vi) Ottawa St S: Fischer-Hallman Rd to Alpine Rd

	Description	**Estimated Cost**
Capital Investment (5.4.3.2.A.i)	**Labour:**	$680,300
	Materials:	$489,200
	Contract:	$275,000
	Engineering:	$195,500
Capital Contributions (5.4.3.2.A.ii)	**Total Estimated Cost:**	**$1,700,000**
	Recoverable:	$539,745
	KWHI Estimated Cost	**$1,160,255**

Customer Attachments / Load (kVA) (5.4.3.2.A.iii) **(if applicable)**	The size of load and number of customers affected varies by project. The budget categories will include several relocation projects; however, the exact number of projects is not known until closer to when the municipal budgets have been established and designs have been completed.
Project Dates (5.4.3.2.A. iv)	**Start Date:** **January 2, 2020** **In Service Date:** **December 31, 2020**

Estimated Expenditure Timing (5.4.3.2.A.iv)	**Q1**	**Q2**	**Q3**	**Q4**
	$425,000	$425,000	$425,000	$425,000

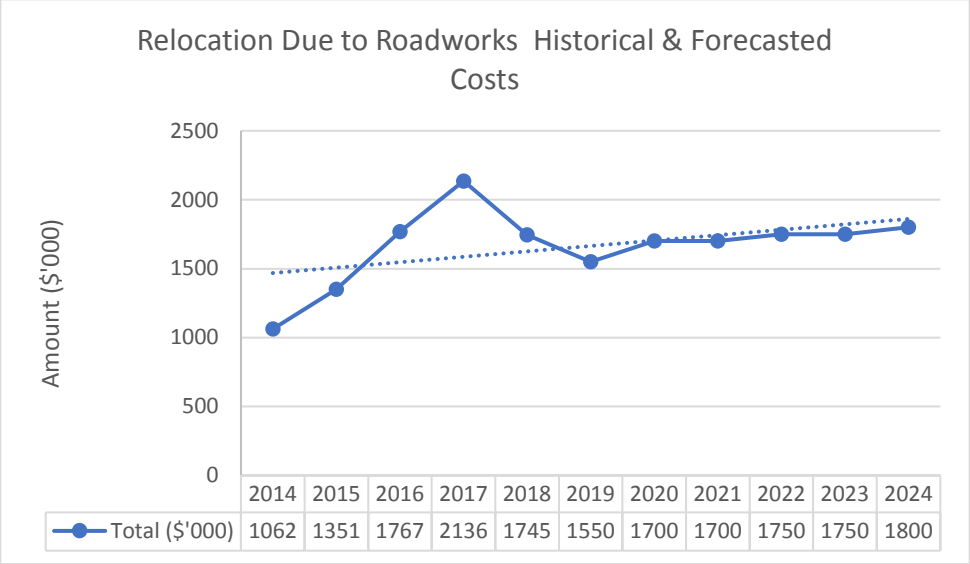
Project Name: Relocations Due to Roadway Modification Projects

Schedule Risk and Risk Mitigation (5.4.3.2.A.v)

The scheduled risks for executing this program is primarily the timing of the municipality's roadway schedule and KWHI has limited authority over the timing and scope of these projects. KWHI maintains a high level of frequent communication with all municipalities in order to ensure a timely and efficient exchange of information. It is generally our intention to complete the relocations prior to their work, typically 1 year prior. This enables enough time for the plant to be relocated, all third-party attachments to be transferred and the old plant to be removed. However, if the design of the pending roadwork is delayed for any reason, then a project may be delayed.

Comparative Information from Equivalent Projects (5.4.3.2.A.vi) **(where available)**

The amount budgeted for relocation projects is based on historical trends/averages and information provided by the road authority. Relocation costs will vary depending on the required plant in need of relocation on each project. Historical costs (2014-2018) and forecasted (2019-2024) costs for these projects are shown in the figure below.



Total Capital and OM&A Costs Associated with REG Investments (5.4.3.2.A.vii)

There is no REG investment associated with this program.

Leave to Construct Approval (5.4.3.2.A.viii) **(where applicable)**

N/A

Evaluation Criteria and Information (5.4.3.2.B)

Efficiency, Customer Value, Reliability (5.4.3.2.B.1)

Investment Driver (5.4.3.2.B.1.a)

The main driver for this investment is municipal and/or MTO road works which require the relocation of KWHI's assets. As relocation projects are initiated by municipalities or the MTO, KWHI undertakes such initiatives when requested.

Project Name: Relocations Due to Roadway Modification Projects

Secondary Driver (5.4.3.2.B.1.a) **(where applicable)**

The secondary driver for the relocation program is KWHI's mandated obligation to relocate assets as outlined in the *Public Service Works on Highways Act (PSWHA).* The PSWHA requires KWHI to work with road authorities requesting relocation of electric utility plants to permit the maintenance and improvement of public road infrastructure in a timely manner.

Good Utility Practice (5.4.3.2.B.1.b)

KWHI has an ongoing yearly process to relocate existing plants to suit roadway modification projects which will help improve reliability. Discussion for specific projects may start with the municipality or MTO up to 3-5 years ahead of the road construction.

Investment Priority (5.4.3.2.B.1.c)

The priority of this investment program is 1 (highest) as this is a mandated obligation to relocate assets on a roadway based on municipal/MTO request. Therefore, such a request cannot be deferred or neglected. Relocation projects will be planned in coordination with other KWHI's projects to ensure access to the appropriate resources and equipment. In addition, relocation projects will be coordinated with respective municipalities/MTO to ensure the projects are completed in a timely manner.

Analysis of Project and Project Alternatives – Effect of the investment on system operation efficiency and cost-effectiveness (5.4.3.2.B.1.d.i)

When KWHI is relocating assets as part of this program, the opportunity will be used to upgrade and/or modify as needed, the existing system to create flexibility in operations and accommodate for potential future needs of the system. This will assist in reducing the need for system renewal and/or system service work required in future years as well as contribute to long-term enhanced system operation efficiency and cost effectiveness. KWHI always works closely with the requesting municipality/MTO to see if minor changes in roadway design can reduce the relocation requirements and thereby lower costs for both parties since there is cost sharing for KWHI's relocation work. In addition, KWHI ensures that all relocation projects are completed in accordance with KWHI's standards which have been designed to minimize overall cost and expenses.

Analysis of Project & Alternatives – Net benefits accruing to customers (5.4.3.2.B.1.d.ii)

KWHI's customers benefit from new electrical assets which enhance the delivery of safe and reliable electricity.

Analysis of Project & Alternatives – Impact of the investment on reliability performance including frequency and duration of outages (5.4.3.2.B.1.d.iii)

The primary purpose of these budget items is not to improve reliability, however the installation of new electrical assets based on current design standards contributes to a reduced risk of failure.

Project Alternatives (Design, Scheduling, Funding/Ownership (5.4.3.2.B.1.d.iii)

Project Design Alternatives:

i. Relocate existing plant – like for like.
ii. Relocate existing plant with upgrades for future development.

Option (i) is normally selected since the municipality or MTO is typically responsible for 50% of the labour and labour savings device costs. However, if there is anticipated future upgrade required to the distribution plant, KWHI will use the opportunity to upgrade the plant and gain efficiency. The marginal cost for upgrade is borne by KWHI which is more economical in the long term than going back later to perform system upgrades.

Scheduling Alternatives:

Depending on the impact of the existing plant, relocations may be deferred until after the road work has been completed. This decision would be decided mutually with KWHI and the municipality, with coordination with third party tenants.

Ownership Alternatives:

KWHI maintains sole ownership of all power distribution assets that are relocated.

Safety (5.4.3.2.B.2)

Relocating of all plants are completed in accordance with KWHI's standards and Ontario Regulation 22/04 to ensure no undue safety hazards. Work is inspected by KWHI and signed off as safe prior to energization.

Cyber-Security and Privacy (5.4.3.2.B.3) **(where applicable)**

This project does not impact cyber security or privacy.

Co-ordination and Interoperability (5.4.3.2.B.4)

Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.3.2.B.4.a) **(where applicable)**

Relocation of all plants may be coordinated with the Region of Waterloo, the City of Kitchener, the Township of Wilmot, the Ministry of Transportation, Bell Canada, Rogers Cable TV, Telus, Zayo, Hydro One Networks, Grand River Conservation Authority (GRCA), Canadian National Railway (CNR), Canadian Pacific Railway (CPR), where applicable or any of their consultants. When needed, co-ordination with neighbouring LDCs such as Energy+ or Waterloo North Hydro may also be necessary.

Enabling of Future Technology and/or Future Operational Requirements (5.4.3.2.B.4.b)

The investment in relocation projects can potentially enable future technological functionality as some relocations are used as an opportunity to upgrade and/or modify the existing distribution system. As a result, KWHI can account for future operational requirements.

Environmental Benefits (5.4.3.2.B.2.B.5) **(where applicable)**

As part of a relocation, it may be necessary to replace older poles which are predominately treated with chemicals that do not meet with today's environmental standards. As a result, replacing pole lines with new poles would adhere to current environmental standards. It may also be necessary to relocate/remove existing underground asbestos ducts that do not meet today's standards, which would be replaced with new PVC ducts.

Conservation and Demand Management (5.4.3.2.B.2.B.6) **(where applicable)**

N/A

Category - Specific Requirements -System Access (5.4.3.2.SA - C)

Factors Affecting Timing/Priority (5.4.3.2 SA – C.i)

Relocation projects are initiated by the decisions of municipal governments and the MTO. As a result, KWHI has very limited control over the timing of relocation projects. KWHI maintains a high level of frequent communication with the Region of Waterloo, the City of Kitchener, the Township of Wilmot and the MTO in

order to ensure a timely and efficient exchange of information. This ensures that all relocation projects are accounted for and appropriately coordinated with other projects/programs.

The priority of relocation projects is High, as they are part of KWHI's mandated service obligations and therefore unable to be deferred without consequences. If KWHI did not proceed with relocation projects throughout its distribution service area, municipal/MTO road projects would be delayed and KWHI would be required to pay compensation to the municipality/MTO as per the *Public Service Works on Highways Act*. KWHI's project Prioritization Tool was used to prioritize all material projects for 2020 and this project was ranked as 6 out of 31.

Factors Related to Customer/Third-Party Preferences (5.4.3.2 SA – C.ii)

KWHI's immediate customer for relocation work is the municipality or MTO. They provide input into the proposed relocation design and ultimately must approve the plans as the roadway authority. KWHI's electricity customers also have an opportunity for input as project letters are provided to customers in the area in which the relocation work is being undertaken.

Factors Affecting the Final Cost (5.4.3.2 SA – C.iii)

Factors effecting the final cost of these projects can include scope or timing changes in the road work resulting in potential scope or timing changes in the relocation design. Once detailed roadway designs are completed, KWHI reviews them and may suggest changes which can reduce relocation costs.

Methods Utilized to Minimize Controllable Costs (5.4.3.2 SA – C.iv)

KWHI ensures that all relocation projects are completed in accordance with KWHI's standards which have been designed to minimize overall costs and impact on customers.

Other Planning Objectives (5.4.3.2 SA – C.v) **(where applicable)**

Where applicable, KWHI's planning objectives, as detailed in Section 5.4.1 of the DSP are considered on an individual project basis. Examples include safety and reliability.

Technically Feasible Project Design and/or Implementation Options Exist (5.4.3.2 SA – C.vi)

KWHI considers all feasible design and implementation option when specific details of each relocation project become available. Some of the options normally considered include; working with the road authority to adjust curb and sidewalk alignment to reduce impact on poles or underground plant, having the road authority contractor performs some of the relocation work if cost efficient, lowering poles vs replacement when grade change is being considered, etc.

Summary of Results Analysis – "Least Cost", "Cost Efficient" Options (5.4.3.2 SA – C.vii)

The options described above are not evaluated until the specific details of a project is known.

Results of a Final Economic Evaluation (5.4.3.2 SA – C.viii) **(where applicable)**

N/A

System Impact Costs & Cost Recovery Method (5.4.3.2 SA – C.ix) **(where applicable)**

N/A.

Project Name: Relocations Due to Roadway Modification Projects

Images

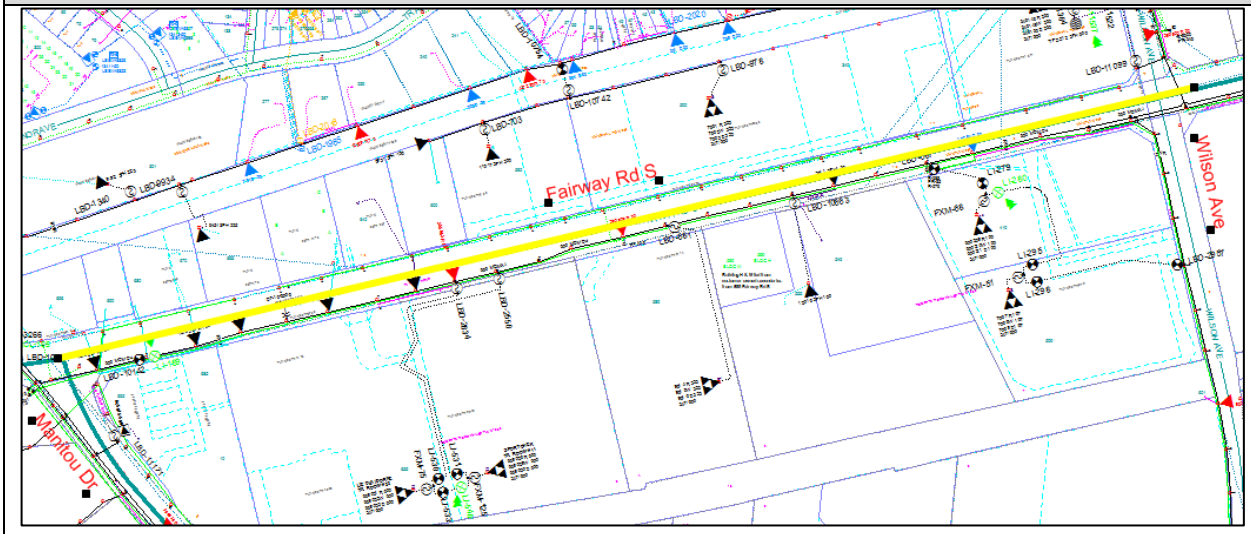


Figure 1: Fairway Rd S between Manitou Dr and Wilson Ave – existing poles are 45' CL.E concrete (vintage 2003) and 45' CL.3 wood (vintage 1961)

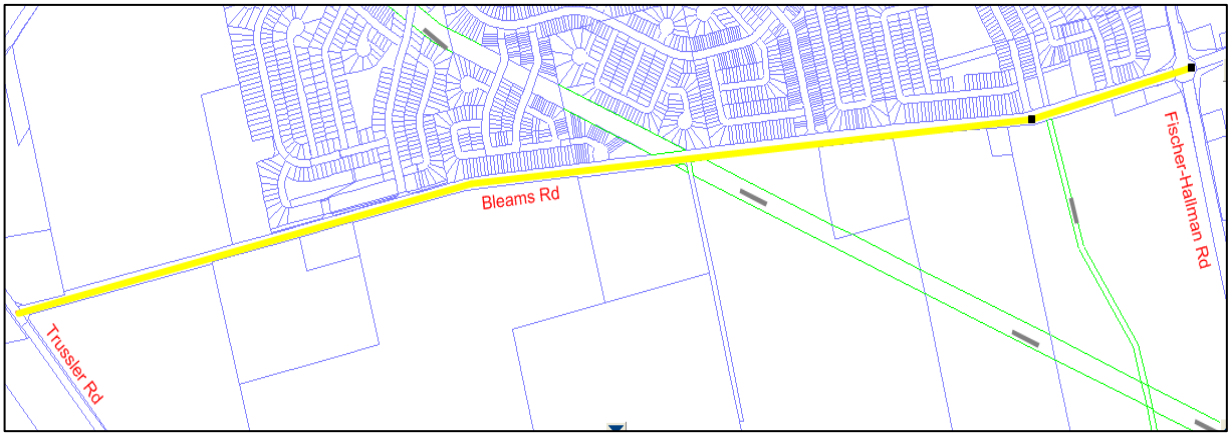


Figure 2: Bleams Rd between Trussler Rd and Fischer-Hallman Rd – existing poles are 50' & 55' CL.3 wood (vintage 2002)

Project Authorization

Prepared By: S. Ferneyhough

Date: January 9, 2019

Authorized By: G. Cameron

Date April 5, 2019

Completion Date: _____

Capital Project Summary

Project Name: Underground Residential Distribution Servicing

Budget Year: 2020 **Budget Item No.:** 4-20-2, 4-20-4, 5-20-2, 5-20-5

OEB Investment Category: **System Access**

General Information on Project (5.4.3.2.A)

Project Summary

Underground Residential Distribution (URD) consist of several individually budgeted project activities such as; Installation of Underground Residential Distribution, Installation of Residential Underground Services, and Purchase and Installation of URD transformers. These activities form a subset of System Expansion to Supply New Developments that are customer driven. Investments in URD is in response to requests from a developer to supply new infrastructure to serve residential subdivisions (single family, semi-detached and townhouse). KWHI is budgeting to supply and install 1,200 residential services for the 2020 Test Year. The forecasted number of units is based on historical trends and anticipated future single family and townhouse developments. Investments in this program is customer driven and is mandatory.

The scope of work for this program includes:

- Labour and materials required to install the underground distribution system consisting of conduits and cables.
- Labour and materials required to install distribution transformers (submersible and mini-pad) in the new residential subdivisions
- Labour and materials required to install vault collars for submersible transformers installed in previous years, work which must be deferred until final landscaping has been completed.
- Labour and materials required to connect the meter at each new home to the URD system that was installed when the subdivision was serviced.
- Purchasing of transformers for new URD developments and the replacement of existing URD transformers that have failed and are at end of life. For investment categorization purpose, this project is classified as System Access since approximately 70% of the cost is typically associated with transformers purchased for new developments. The transformers purchased in this category are single-phase submersible and pad-mounted transformers.

Capital Investment (5.4.3.2.A.i)

Description	Estimated Cost
Labour:	$822,300
Materials:	$1,918,100
Contract:	$607,400
Engineering:	$359,700

Project Name: Underground Residential Distribution Servicing

Capital Contributions (5.4.3.2.A.ii)	**Total Estimated Cost:** **$3,707,500** **Recoverable:** $2,244,00 **KWHI Estimated Cost** **$1,463,500** Note – the estimate above includes the cost of purchasing 50 submersible transformers to replace failed units in existing subdivisions.	
Customer Attachments / Load (kVA) (5.4.3.2.A.iii) **(if applicable)**	1,200 new customer lots (600 Single family, 600 Townhomes) are forecasted to be serviced in 2020. 4,750 kVA connected load (95 transformers @ 50 kVA each)	
Project Dates (5.4.3.2.A.iv)	**Start Date:** January 2, 2020 **In Service Date:** December 31, 2020	

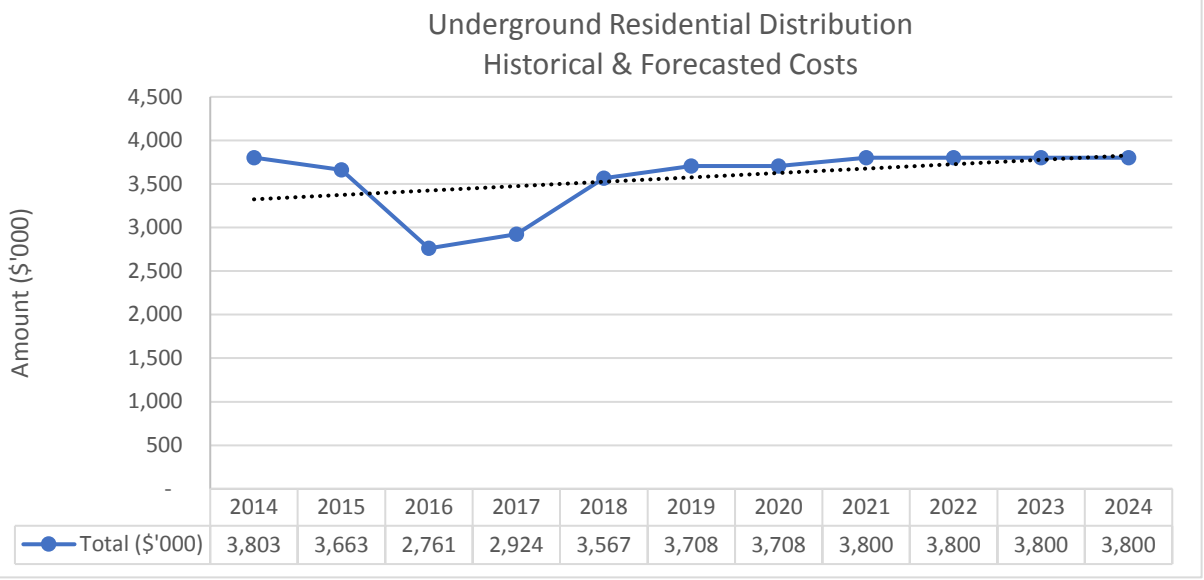
Estimated Expenditure Timing (5.4.3.2.A.iv)	**Q1**	**Q2**	**Q3**	**Q4**	
	$741,000	$741,000	$1,12,750	$1,12,750	

Schedule Risk and Risk Mitigation (5.4.3.2.A.v)

The schedule risks for executing this program is primarily the timing of developers' sites for servicing and the availability of KWHI's resource (in house and contractors) to service the development. The availability of developers' sites for servicing doesn't necessarily occur even throughout the year. To mitigate contractors' availability, KWHI awards annual contracts through a competitive bid process to one contractor who is available throughout the year to execute projects that are ready for construction. KWHI also has a crew dedicated for servicing subdivisions and utilises project management techniques to monitor and track activities and resources.

Comparative Information from Equivalent Projects (5.4.3.2.A.vi) **(where available)**

URD servicing is developer driven and expenditures vary with demand, economic activity and the type of residential services. That is, single family vs townhouses vs stacked townhomes require different quantity of materials and labour effort. The higher the density the lower the cost per service is. The figure below shows the variation in expenditures over the historical period of 2014 to 2018. 2018 is based on a forecast to year end using 6 months of actual data. The forecast for the DSP period (2020-2024) is $3.8M which correlates well with the trend line.



	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Total ($'000)	3,803	3,663	2,761	2,924	3,567	3,708	3,708	3,800	3,800	3,800	3,800

Total Capital and OM&A Costs Associated with REG Investments (5.4.3.2.A.vii)

There is no REG investment associated with this program.

Leave to Construct Approval (5.4.3.2.A.viii) **(where applicable)**

N/A

Evaluation Criteria and Information (5.4.3.2.B)

Efficiency, Customer Value, Reliability (5.4.3.2.B.1)

Investment Driver (5.4.3.2.B.1.a)

The main driver for this investment is customer service requests. As part of meeting customers' demand for housing, developers are required to make provision for electrical servicing to each unit. Developers in turn apply to KWHI to provide the electrical infrastructure including the service to the customers' meter base. At the time of taking ownership, the customer makes an application to KWHI to install the electric meter and energize the service.

Secondary Driver (5.4.3.2.B.1.a) **(where applicable)**

The secondary drivers for this investment are:

- KWHI's mandated service obligation to connect new customers within its distribution service area per the DSC and KWHI's Conditions of Service.
- Replacement of failed transformers in existing subdivisions. As mentioned earlier, approximately 30% of the transformers purchased under this program are used to replace failed units in existing subdivisions.

Good Utility Practice (5.4.3.2.B.1.b)

The URD system is designed and constructed to provide a resilient distribution system that addresses existing reliability concerns such as failure rate of submersible transformers and poor reliability experience with aluminum cable. Grid modernisation is also considered such as the need to upgrade

customers' service cables from 100A to 200A to facilitate customer load growth and electric vehicle (EV) charging. To address these concerns, KWHI use stainless equipment for below grade applications, above ground pad-mounted transformers where applicable, only copper cable and connectors in underground application, and 200A cable as the minimum size for all residential service to accommodate future EV charging.

Investment Priority (5.4.3.2.B.1.c)

The priority of this program is High since it is a mandatory program and is driven by KWHI's desire to provide customers with timely service connection and KWHI's regulatory obligation under the DSC to connect new customers within its service territory. KWHI's project Prioritization Tool was used to prioritize all material projects for 2020 and this project was ranked as 3 out of 31.

Analysis of Project and Project Alternatives – Effect of the investment on system operation efficiency and cost-effectiveness (5.4.3.2.B.1.d.i)

Cost effectiveness
Funding for this program is based on an economic evaluation model where the developer is credited for the net benefit accrued to the system and the shortfall is paid for as a contributed capital. Historically, between 60 and 65% of the total cost of this program is funded by the developer with the remainder recovered through rates that the connected customers will pay over a 25-year connection horizon.

The installation of underground cable vs overhead wires avoids future operating and maintenance costs associated with tree contacts, animal contacts, weather-related events (ice storm, wind storm, etc.) and issues associated with clearance to buildings and signs.

Analysis of Project & Alternatives – Net benefits accruing to customers (5.4.3.2.B.1.d.ii)

New customers benefit from having a distribution system that is modern, reliable, efficient and built to current standards. Existing customers benefit from having a larger pool of customers sharing the distribution system and thereby reducing distribution rate impacts.

Analysis of Project & Alternatives – Impact of the investment on reliability performance including frequency and duration of outages (5.4.3.2.B.1.d.iii)

Reliability is expected to be the same or better for the new customers since the probability of equipment failure is less due to new equipment being installed and installation being below grade and not impacted by weather-related events (except for submersible transformers that may be impacted by flooding).

Project Alternatives (Design, Scheduling, Funding/Ownership (5.4.3.2.B.1.d.iii)

Project Design Alternatives:

KWHI is responsible for all system design and ultimate ownership of the distribution plant. The options for design alternatives are limited to underground supply based on City of Kitchener and Township of Wilmot both require underground utility servicing for all new residential subdivisions.

Developers are given the option of scheduling, funding and constructing the underground distribution system to KWHI's standard based on the Alternative Bid process. If this option is selected, the developer is required to transfer ownership of the plant to KWHI at the end of construction and energization of the plant.

Scheduling Alternatives:

See above.

Ownership Alternatives:

See above.

Safety (5.4.3.2.B.2)

All new services are installed underground in accordance with KWHI's standards, Canadian Standards Association (CSA) underground standards, and meets the safety requirements of Ontario Regulation 22/04.

The installation of underground cable reduces the likelihood of energized wires coming in contact with buildings and other objects. It also reduces the likelihood of supporting pole structures falling and causing personal injury and property damage. However, the underground electrical plant does increase the likelihood of someone digging without a proper locate and contacting energized equipment. To mitigate this risk, KWHI has a robust underground locating team that responds to over 23,000 locate requests each year and identify the locations of KWHI's electrical underground plants.

Cyber-Security and Privacy (5.4.3.2.B.3) **(where applicable)**

This program does not have a direct impact on cyber security or privacy. However, during the setup of new customer accounts, KWHI handles customers' personal information in accordance with established privacy policies and guidelines.

Co-ordination and Interoperability (5.4.3.2.B.4)

Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.3.2.B.4.a) **(where applicable)**

Co-ordination of residential subdivisions servicing is a well-established practice at KWHI. Co-ordination starts at the City and Township level where KWHI gathers information on the long-term planning outlook and zoning of the area to be serviced. KWHI then creates a high-level design concept that guides the electrical servicing of the subdivisions that will be constructed. KWHI also provides feedback to the City of Kitchener on their pre-submission and site plan approval process to identify any unusual request for future developments in an area.

KWHI manages the overall co-ordination process for joint use trenching with other 3rd party communication companies such as Bell Canada and Rogers Communications. Construction of the underground plant is co-ordinated between KWHI's site inspector, Kitchener Utilities (gas supplier in Kitchener), Union Gas (gas supplier in Wilmot township), Bell Canada, Rogers Communications, other 3rd parties, and the developer's site supervisor to ensure that the plant is constructed as designed and conflicts are resolved in a timely manner. KWHI also participates in the City of Kitchener monthly Utilities Coordination Committee meeting.

The final step in the co-ordination process is with Electrical Safety Authority (ESA). ESA inspect all new residential services and provides KWHI with a Connection Authorisation prior to energization of each service.

Enabling of Future Technology and/or Future Operational Requirements (5.4.3.2.B.4.b)

New residential subdivisions are designed with capacity and capability to permit behind the meter customer generation and electric vehicle charging. Each service to a new residential building is sized for 200A to facilitate customer load growth.

Environmental Benefits (5.4.3.2.B.2.B.5) **(where applicable)**

New residential subdivisions are serviced using high efficiency transformer with lower losses. They are also fitted with internal current limiting fuse to prevent rupturing of the transformer tank in the event of a failure. This alleviates the spilling of mineral oil from failed transformers.

Conservation and Demand Management (5.4.3.2.B.2.B.6) **(where applicable)**

There is no direct CDM impact associated with underground subdivision servicing.

Category - Specific Requirements -System Access (5.4.3.2.SA - C)

Factors Affecting Timing/Priority (5.4.3.2 SA – C.i)

The following factors may impact the timing and/or priority of underground residential subdivisions.

- Availability of main distribution – the availability of existing main distribution system within proximity of the proposed development will have the biggest impact on timing. That is, if new 3-phase distribution facilities have to be constructed to provide access for servicing the proposed developments, the lead time can be more than 1 year. KWHI mitigates this factor by coordinating its long-term distribution plans with the City of Kitchener and Township of Wilmot to understand the areas slated for development and make the necessary plans to have infrastructure available.
- Developers schedule – KWHI does not start design for URD projects until a deposit is paid by the developer. Similarly, construction cannot be started until an Offer to Connect is signed. These activities are dependent on developers' timing and if this does not occur evenly throughout the budget year, it can impact the pacing of the investment.
- Availability of labour resources – KWHI uses a combination of internal resources and contractors to construct the electrical plant for underground residential subdivisions. Depending on the number of projects proposed each year, the available resource may not be sufficient to meet the developers' demands.
- Coordination with 3rd Parties – KWHI coordinate subdivision design and construction with gas, water and communication companies. The availability of design information from these 3rd party agencies can impact the timing of URD projects. KWHI is also required to get municipal consent (approvals for construction) from the relevant municipalities with jurisdiction where the subdivision is being constructed. Construction cannot proceed without these approvals. KWHI's long-term working relationship with these 3rd parties helps to mitigate the potential of design and construction delays.
- Number of significant unplanned events – System Access projects normally has the highest priority since they are part of KWHI's mandatory obligations. However, there is limited resources available to construct subdivisions and other capital projects while also responding to major unplanned events such as wind storms, ice storms, flooding, etc. Therefore, if there are higher than usual major events that occurred in a budget year there is the potential for delays in constructing capital-related projects.

Factors Related to Customer/Third-Party Preferences (5.4.3.2 SA – C.ii)

The electrical plant for residential subdivisions is constructed in direct response to customer needs via developer request for servicing of new homes. KWHI is also part of the City of Kitchener Subdivision Servicing Agreement and both entities have standardised their requirements (e.g. location and offset of underground plant) for servicing subdivisions.

Factors Affecting the Final Cost (5.4.3.2 SA – C.iii)

The final cost of residential subdivision servicing is dependent on the scope of work, types of services (e.g. single-family vs townhouse) and access to existing distribution facilities. Typical cost per service ranges from $2,500 to $4,500 per service.

Methods Utilized to Minimize Controllable Costs (5.4.3.2 SA – C.iv)

Controllable costs are minimized through use of standardize materials, standardize design, and a competitive bid process used to select a contractor for constructing parts of the residential subdivisions.

Project Name: Underground Residential Distribution Servicing

Other Planning Objectives (5.4.3.2 SA – C.v) (where applicable)

When designing the electrical distribution system for residential subdivisions, KWHI takes into consideration other relevant planning objectives such as future load growth (e.g. servicing for future stages) and future electricity use (e.g. electric vehicle charging).

Technically feasible project design and/or implementation options exist (5.4.3.2 SA – C.vi)

The options for servicing residential subdivisions are limited since underground service is mandated by the City of Kitchener and Township of Wilmot.

KWHI currently service all single family residential subdivisions using submersible (below grade) type transformers. The failure rate of these transformers is higher (2 to 4 times) than that of pad-mounted transformers. While using pad-mounted transformers for servicing these subdivisions is technically feasible, KWHI has faced several setbacks primarily from developers who prefer the more aesthetically pleasing appearance of submersible transformer installations. KWHI is currently working with the City of Kitchener to implement a solution that will satisfy the need of the developers and the desire of KWHI to install a higher reliability system.

Summary of results analysis – "Least Cost", "Cost efficient" options (5.4.3.2 SA – C.vii)

Utilising pad-mounted transformers to service subdivisions will have a lower total ownership cost than the current method of using submersible transformers. There is also savings associated with replacement labour cost since it takes approximately 6 hours to replace a submersible transformer vs approximately 4 hours for a pad-mounted transformer. Analysis done shows that there is potential savings of approximately $4K per transformer installation. However, as mentioned above developers are reluctant to support a shift from submersible to pad-mounted transformers.

Results of a final Economic Evaluation (5.4.3.2 SA – C.viii**) (where applicable)**

KWHI conducts economic evaluations of underground residential subdivisions in accordance with Section 3.2 of the Distribution System Code and Section 2.1.2 of KWHI's Conditions of Service. The results of these evaluations vary. However, a typical residential subdivision usually has 65% of the total project costs designated as contributed capital and the remaining 35% as expansion deposit that the developer is eligible to recover within the connection horizon (5-years of the subdivision being energized).

System impact costs & cost recovery method (5.4.3.2 SA – C.ix) **(where applicable)**

There is no additional system impact (e.g. REG investment) associated with residential subdivision servicing.

Images



Figure 1: Submersible Transformer Installed in Subdivision



Figure 2: Servicing of New Subdivision with Submersible Transformers

Project Name: Underground Residential Distribution Servicing

Project Authorization	
Prepared By: S. Wang	Authorized By: G. Cameron
Date: March 18, 2018	Date April 5, 2019
	Completion Date: _____

Capital Project Summary

Project Name: Large Commercial and Industrial Services

Budget Year: 2020 **Budget Item No.:** 4-20-3, 5-20-4

OEB Investment Category: System Access

General Information on Project (5.4.3.2.A)

Project Summary

Large Commercial & Industrial Services consist of two individually budgeted project activities. These activities are; Installation of underground 3-phase primary services, and Purchase and Installation of 3-phase transformers to supply the underground services. These activities form a subset of System Expansion to Supply New Developments that are customer driven. Investments in Large Commercial & Industrial Services are in response to requests from developers to supply new infrastructure to serve commercial & industrial sites. KWHI is budgeting to supply and install 13 large commercial and industrial services for the 2020 Test Year. The forecasted number of services is based on historical trends and anticipated future developments. Investments in this program are customer driven and mandatory.

The scope of work for this program includes:

- Labour and materials required to connect the meter at each new service.
- Labour and materials required to install the underground distribution system consisting of conduits and cables.
- Labour and materials required to install the 3-phase switches and 3-phase distribution transformers (room type or pad-mounted)
- Purchasing of switches and transformers for new or upgrade large Commercial & Industrial Services. The transformers purchased in this category are three-phase room type and pad-mounted transformers.

	Description	Estimated Cost
Capital Investment (5.4.3.2.A.i)	**Labour:**	$362,000
	Materials:	$742,900
	Contract:	
	Engineering:	$104,100
Capital Contributions (5.4.3.2.A.ii)	**Total Estimated Cost:**	**$1,209,000**
	Recoverable:	$724,000
	KWHI Estimated Cost	**$485,000**

Project Name: Large Commercial & Industrial Services

Customer Attachments / Load (kVA) (5.4.3.2.A.iii) **(if applicable)**	13 large commercial & industrial services (8 radial-feed and 5 loop-feed, mainly for Kitchener downtown area) are forecasted to be serviced in 2020. 9,750 kVA connected load (Average size 750 kVA each)				
Project Dates (5.4.3.2.A.iv)	**Start Date:** January 2, 2020 **In Service Date:** December 31, 2020				
Estimated Expenditure Timing (5.4.3.2.A.iv)	**Q1**	**Q2**	**Q3**	**Q4**	
	$150,000	$375,000	$384,000	$300,000	

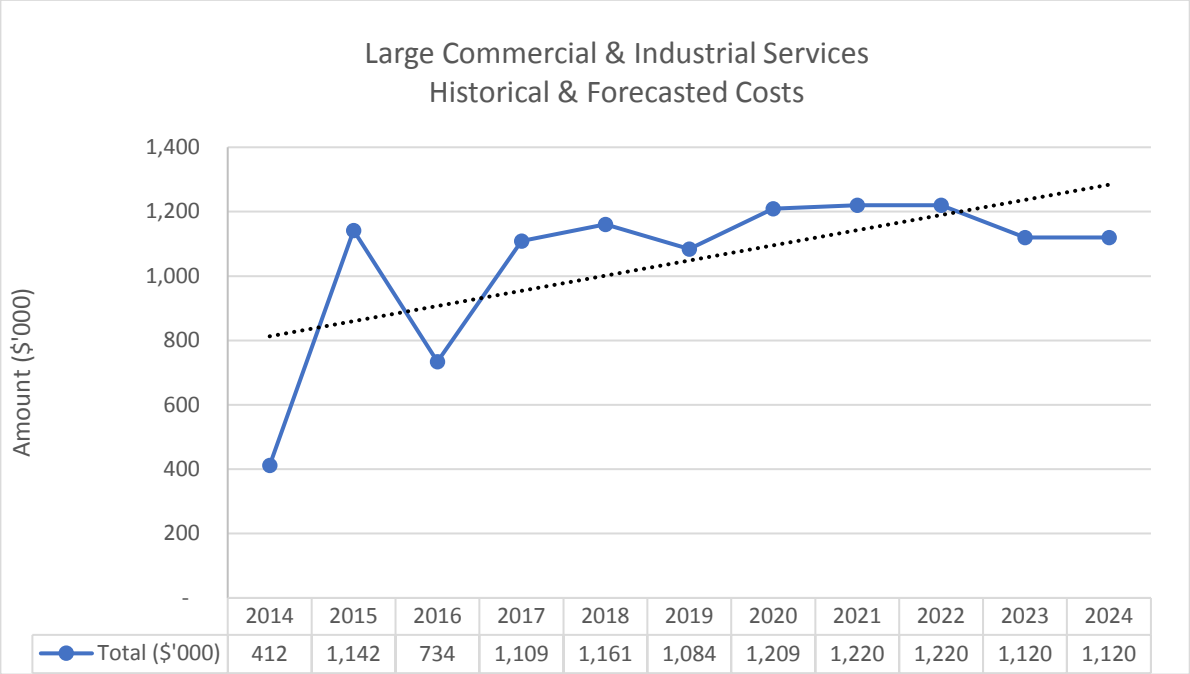
Schedule Risk and Risk Mitigation (5.4.3.2.A.v)

The schedule risks for executing this program is primarily the timing of developers' sites for servicing and the availability of KWHI's resources (typically in house) to service the development. The availability of developers' sites for servicing doesn't necessarily occur evenly throughout the year. To mitigate schedule risk, KWHI works closely with the developers, the suppliers and other 3rd parties such as the region, city to ensure timely service connection.

Lead time for major materials such as transformers and switchgear can impact the schedule as well. To mitigate this risk, KWHI orders equipment with enough lead time (16-20 weeks) to ensure that equipment is available in inventory prior to being needed for installation.

Comparative Information from Equivalent Projects (5.4.3.2.A.vi) **(where available)**

Large commercial & industrial services are developer driven and expenditures vary with demand, location and the type of services. That is, different sites require different quantity of materials and labour effort. The figure below shows the variation in actual expenditures over the historical period of 2014 to 2018. The forecast for the DSP period (2020-2024) is $1.12M to $1.2M.



Total Capital and OM&A Costs Associated with REG Investments (5.4.3.2.A.vii)

There is no REG investment associated with this program.

Leave to Construct Approval (5.4.3.2.A.viii) **(where applicable)**

N/A

Evaluation Criteria and Information (5.4.3.2.B)

Efficiency, Customer Value, Reliability (5.4.3.2.B.1)

Investment Driver (5.4.3.2.B.1.a)

The main driver for this investment is customer service requests. When a new or upgraded commercial or industrial development is undertaken, developers apply to KWHI to provide the electrical infrastructure required to supply the development. KWHI in turn provides the developer with an Offer to Connect which initiates the investment.

Secondary Driver (5.4.3.2.B.1.a) **(where applicable)**

The secondary driver for this investment is KWHI's mandated service obligation to connect new customers or service upgrades within its distribution service area per the DSC and KWHI's Conditions of Service.

Good Utility Practice (5.4.3.2.B.1.b)

Investment Priority (5.4.3.2.B.1.c)

The priority of this program is High since it is a mandatory program and is driven by KWHI's desire to provide customers with timely service connection and regulatory requirement under the DSC. KWHI's project Prioritization Tool was used to prioritize all material projects for 2020 and this project was ranked as 7 out of 31.

Analysis of Project and Project Alternatives – Effect of the investment on system operation efficiency and cost-effectiveness (5.4.3.2.B.1.d.i)

Cost effectiveness
Funding for this program is based on the actual connection cost where the developer pays 100% of the service costs. Historically, around 85% of the total cost of this program is considered as service cost which is funded by the developer, with the remainder (typically the material cost of the 3-phase transformers) recovered through rates.

Analysis of Project & Alternatives – Net benefits accruing to customers (5.4.3.2.B.1.d.ii)

New customers benefit from having a distribution service that is modern, reliable, efficient and built to current standards. Existing customers benefit from having a larger pool of customers sharing the distribution system and thereby reducing distribution rate impacts.

Project Name: Large Commercial & Industrial Services

Analysis of Project & Alternatives – Impact of the investment on reliability performance including frequency and duration of outages (5.4.3.2.B.1.d.iii)

Reliability is expected to be the same or better for the new customers since the probability of equipment failure is less due to new equipment being installed and installation being below grade and not impacted by weather-related events.

Project Alternatives (Design, Scheduling, Funding/Ownership (5.4.3.2.B.1.d.iii)

Project Design Alternatives:

KWHI is responsible for the system design and connection. For large commercial service, each developer has their own specific requirements, like the service size, transformer type (room vs pad-mounted), transformer ownership (KWHI-owned vs customer-owned). Developers are involved in the KWHI design process from the beginning of the project. They are given the options based on KWHI's standards and Conditions of Service. KWHI and the developers work together until the service plan is determined. KWHI will design and schedule the work to meet the site service plan. There is typically no design/scheduling/ownership alternatives once the service plan is finalized.

Scheduling Alternatives:

These projects are customer driven and do not have alternative scheduling options withy the exception of minor variation in timing of connecting the service.

Ownership Alternatives:

Customers have the option of owning the load transformer.

Safety (5.4.3.2.B.2)

All new large commercial & industrial services are installed underground in accordance with KWHI's standards, Canadian Standards Association (CSA) underground standards, and meet the safety requirements of Ontario Regulation 22/04.

The installation of underground cable reduces the likelihood of energized wires coming in contact with buildings and other objects and supporting pole structures falling and causing personal injury and property damage. However, the underground electrical plant does increase the likelihood of someone digging without a proper locate and contacting energized equipment. To mitigate this risk, KWHI has a robust underground locating team that responds to over 23,000 locate requests each year and identify the location of KWHI's electrical underground plants.

Cyber-Security and Privacy (5.4.3.2.B.3) **(where applicable)**

This program does not have a direct impact on cyber security or privacy. However, during the setup of new customer accounts, KWHI handles customers' personal information in accordance with established privacy policies and guidelines.

Co-ordination and Interoperability (5.4.3.2.B.4)

Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.3.2.B.4.a) **(where applicable)**

Co-ordination of large commercial & industrial services is a well-established practice at KWHI. Co-ordination starts at the City and Township level where KWHI gathers information on the site plan pre-approval process. KWHI then discusses with the developers and creates a high-level design concept that guides the electrical servicing of the site that will be constructed. KWHI provides feedback to the City of Kitchener on their pre-submission process to identify any unusual requests ahead of time.

KWHI manages the overall co-ordination process for joint use trenching with other 3rd party communication companies such as Bell Canada and Rogers. Construction of the underground plant is co-ordinated between KWHI's site inspector, Kitchener Utilities (gas supplier in Kitchener), Union Gas (gas supplier in Wilmot township), Bell Canada, Rogers Communications, other 3rd parties, and the developer's site supervisor to ensure that the plant is constructed as designed and conflicts are resolved in a timely manner. KWHI also participates in the City of Kitchener monthly Utilities Coordination Committee meeting.

The final step in the co-ordination process is with the Electrical Safety Authority (ESA). ESA inspects all new large commercial & industrial services and provides KWHI with a Connection Authorisation prior to energization of each service.

Enabling of Future Technology and/or Future Operational Requirements (5.4.3.2.B.4.b)

There is no direct impact associated with large commercial & industrial servicing.

Environmental Benefits (5.4.3.2.B.2.B.5) **(where applicable)**

N/A

Conservation and Demand Management (5.4.3.2.B.2.B.6) **(where applicable)**

There is no direct CDM impact associated with large commercial & industrial servicing.

Category - Specific Requirements -System Access (5.4.3.2.SA - C)

Factors Affecting Timing/Priority (5.4.3.2 SA – C.i)

The following factors may impact the timing and/or priority of large commercial & industrial services

- Availability of main distribution – the availability of existing main distribution system within proximity of the proposed development will have the biggest impact on timing. That is, if new 3-phase distribution facilities have to be constructed to provide access for servicing the proposed developments, the lead time can be more than 1 year. KWHI mitigates this factor by coordinating its long-term distribution plans with the City of Kitchener and Township of Wilmot to understand the areas slated for development and make the necessary plans to have infrastructure available.
- Developers' schedule – KWHI does not start design for large commercial & industrial projects until a deposit is paid by the developer. Similarly, construction cannot be started until an Offer to Connect is signed. These activities are dependent on developers' timing and if they do not occur evenly throughout the budget year this can impact pacing of the investment.
- Availability of labour resources – KWHI uses a combination of internal resources and contractors to construct the electrical plant for large commercial & industrial services.
- Coordination with 3rd Parties – KWHI coordinates the design and construction with gas, water and communication companies, especially for the work planned on public right of way. The availability of design information from these 3rd party agencies can impact the timing of URD projects. Construction cannot proceed without the coordination. KWHI's long-term working relationship with these 3rd parties help to alleviate the potential of design and construction delays.
- Number of significant unplanned events – System Access projects normally have the highest priority since they are part of KWHI's mandatory obligations. However, there are limited resources available to connect the large commercial & industrial services and other related capital projects while also responding to major unplanned events such as wind storms, ice

storms, flooding, etc. Therefore, if there are higher than usual major events that occur in a budget year there is the potential for delays in constructing capital-related projects.

Factors Related to Customer/Third-Party Preferences (5.4.3.2 SA – C.ii)

The electrical plant for large commercial & industrial services is constructed in direct response to customer needs via developer request for new services or service upgrades. KWHI is responsible for the system design and connection. For large commercial & industrial service, each developer has their own specific requirements, like the service size, transformer type (room vs pad-mounted), transformer ownership (KWHI-owned vs customer-owned). Developers are involved in the KWHI design process from the beginning of the project. They are given the options based on KWHI's standards and Conditions of Service. KWHI and the developers work together to ensure the best interest of the customer.

Factors Affecting the Final Cost (5.4.3.2 SA – C.iii)

The final cost of large commercial & industrial servicing is dependent on the scope of work, types of services (e.g. loop feed vs radial feed) and access to existing distribution facilities. Typical cost per project (including transformer cost) varies significantly, from $25,000 to $500,000.

Methods Utilized to Minimize Controllable Costs (5.4.3.2 SA – C.iv)

Controllable costs are minimized through the use of standard materials and standardized designs.

Other Planning Objectives (5.4.3.2 SA – C.v) **(where applicable)**

When designing the electrical distribution system for large commercial & industrial services, KWHI takes into consideration other relevant planning objectives such as future load growth (e.g. servicing for future stages), and future electricity use (e.g. electric vehicle charging) in the nearby area.

Technically feasible project design and/or implementation options exist (5.4.3.2 SA – C.vii)

The options for servicing large commercial & industrial services are limited due to the size of the services, and the location of the project.

In Kitchener downtown area, KWHI services the large commercial & industrial sites by primary loop feed, i.e. 13.8 kV feed in and out, to supply load customers more than 500 kW. To service these sites, KWHI requires 13.8 kV switchgear (KWHI-owned) and transformer (either customer-owned or KWH-owned) on each site. In other areas, KWHI services the large commercial & industrial sites by radial feed, i.e. single 13.8 kV primary feed from adjacent overhead pole line to a KWHI-owned or customer-owned transformer.

Typically it is more expensive to supply from primary loop feed than radial feed.

Summary of results analysis – "Least Cost", "Cost efficient" options (5.4.3.2 SA – C.vii)

Developers are involved in the KWHI design process from the beginning of the project. They are given the options based on KWHI's standards and Conditions of Service. KWHI and the developers work together to ensure the best interest of the customer.

Results of a final Economic Evaluation (5.4.3.2 SA – C.viii) **(where applicable)**

The connection cost of the large commercial & industrial services is 100% chargeable to the developer. KWHI only conducts economic evaluations of large commercial & industrial in accordance with Section 3.2 of the Distribution System Code if distribution system expansion work is required. The results of these evaluation vary.

Project Name: Large Commercial & Industrial Services

System impact costs & cost recovery method (5.4.3.2 SA – C.ix) **(where applicable)**

There is no additional system impact (e.g. REG investment) associated with large commercial & industrial servicing.

Images



Figure 1: Pad-mounted Transformer and Underground Switchgear for a Commercial Plaza

Project Authorization

Prepared By:	S. Wang	Authorized By:	G. Cameron
Date:	March 18, 2018	Date	April 5, 2019
		Completion Date:	_____

Capital Project Summary

Project Name: Meter Installation and Replacement

Budget Year: 2020 **Budget Item No.:** 7-20-1

OEB Investment Category: System Access

General Information on Project (5.4.3.2.A)

Project Summary

This program includes expenditures related to the supply and installation of revenue meters that are installed at each customer service point for retail settlement and billing purposes for each customer connected to KWHI's distribution system. The budget for revenue meters includes installation of single-phase residential meters (both load and generation customers), polyphase meters for small commercial customers (General Service less than 50 KW), Meters Inside the Settlement Timeframe ("MIST") meters for General Service customers with a monthly demand greater than 50 kW, and primary metering equipment (instrument transformers and potential transformers). Revenue meters have four primary drivers; new meters for new customers, replacement of failed units, reliability (elimination of meter types that have history of poor reliability) and standardization (elimination of meter types for which we have only a few in services e.g. 600V Delta).

KWHI is forecasting approximately 1,400 revenue meters for installation in each of the forecast years. The number of revenue meters forecasted for installation in each year is based on historical trends and the expected customer growth.
These investments are required by the Distribution System Code, customer driven and mandatory.

Capital Investment (5.4.3.2.A.i)

Description	Estimated Cost
Labour:	$66,100
Materials:	$530,900
Contract:	$
Engineering:	$

Capital Contributions (5.4.3.2.A.ii)

Total Estimated Cost:	**$597,000**
Recoverable:	$
KWHI Estimated Cost	**$597,000**

Customer Attachments / Load (kVA) (5.4.3.2.A.iii) **(if applicable)**

1,400 customers. Approximately 5,000 kVA based on average peak demand of 3.5 kVA per customer (taking into consideration all customer types).

Project Name: Meter Installation and Replacement

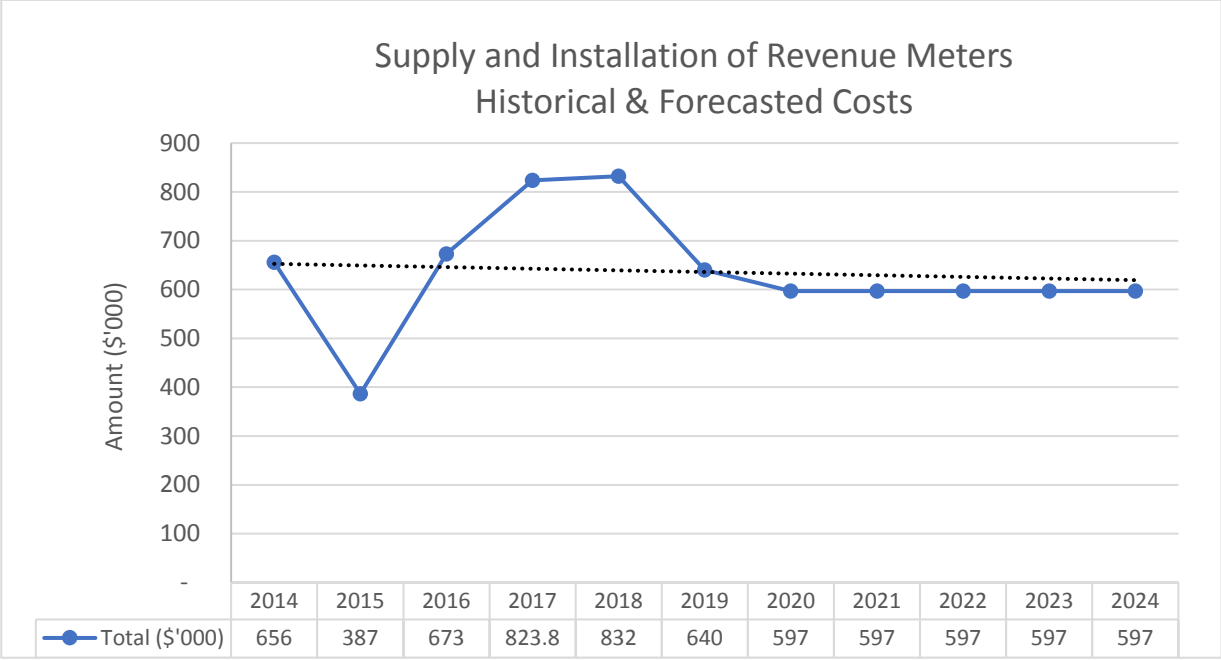
Project Dates (5.4.3.2.A.iv)	**Start Date:** January 2020 **In Service Date:** December 2020				
Estimated Expenditure Timing (5.4.3.2.A.iv)	**Q1**	**Q2**	**Q3**	**Q4**	
	$120,000	$120,000	$176,000	$176,000	

Schedule Risk and Risk Mitigation (5.4.3.2.A.v)

Delivery of meters from the vendor is the largest schedule risk that this program faces. If meters are not received in a timely manner, there will be a delay in installation which leads to a delay in energizing new or upgraded services. To mitigate this risk, KWHI order meters with enough lead time to ensure that meters are available in inventory prior to being needed for installation or replacement.

Comparative Information from Equivalent Projects (5.4.3.2.A.vi) **(where available)**

KWHI uses a sampling of previous year expenditures for metering projects/activities. Furthermore, the comparator expenditure is based on the amount required for providing complete meter supply and installation services, this includes the cost of the meter, equipment and labour. The quantity of meters supplied and installed is developer driven and expenditures vary with demand, economic activity and the type of development (individual metering vs bulk metering). Individual metering requires a larger quantity of meters since it is a one-to-one relationship between number of service points and number of meters supplied and installed. Bulk metering on the other hand requires a single meter to supply multiple customers. There are also occasionally large metering costs associated with some generation projects that require monitoring and/or transfer trip capabilities. The figure below shows the variation in expenditures over the historical period of 2014 to 2018. 2019 is based on a budgeted amount for the Bridge Year. The forecast for the DSP period (2020-2024) is $597K per year which correlates well with the trend line.



Total Capital and OM&A Costs Associated with REG Investments (5.4.3.2.A.vii)

N/A

Leave to Construct Approval (5.4.3.2.A.viii) **(where applicable)**

N/A

Evaluation Criteria and Information (5.4.3.2.B)

Efficiency, Customer Value, Reliability (5.4.3.2.B.1)

Investment Driver (5.4.3.2.B.1.a)

The primary driver for this program is KWHI's mandated requirement to provide metering equipment for new customers, replacement of failed units, and elimination of meter types that have history of poor reliability while ensuring compliance with Measurement Canada and other applicable regulatory requirements.

Secondary Driver (5.4.3.2.B.1.a) **(where applicable)**

The secondary driver includes mandated technology upgrades and enabling of distributed energy resource (DER) programs implemented by KWHI's customers.

Good Utility Practice (5.4.3.2.B.1.b)

Smart meters will be installed which is a mandated directive. These devices help to advance KWHI's grid modernisation efforts by providing timely access to energy use and outage information. They also allow KWHI to monitor the distribution system performance by providing access to voltage information.

Investment Priority (5.4.3.2.B.1.c)

The priority of this program is High since it is a mandatory program and is driven by KWHI's desire to provide customers with timely service connection and KWHI's regulatory obligation under the DSC to connect new customers within its service territory. KWHI's project Prioritization Tool was used to prioritize all material projects for 2020 and this project was ranked as 11 out of 31.

Analysis of Project and Project Alternatives – Effect of the investment on system operation efficiency and cost-effectiveness (5.4.3.2.B.1.d.i)

The benefit of installing meters that can be read remotely is that it reduces the requirement to go to the customers premises in order to attain energy information. These devices also help to advance KWHI's grid modernisation efforts by providing timely access to energy use, voltage profile and outage information. The information from smart meters are fed into KWHI's outage management system (OMS) and used to identify the location and extent of power outages.

Analysis of Project & Alternatives – Net benefits accruing to customers (5.4.3.2.B.1.d.ii)

The net benefit that customers will experience from the installation of mew meters is their ability to manage their energy usage and be billed hourly rates. Customers are also provided with real-time outage information that is supplied by smart meters into KWHI's OMS.

Analysis of Project & Alternatives – Impact of the investment on reliability performance including frequency and duration of outages (5.4.3.2.B.1.d.iii)

The installation of new meters will reduce the likelihood of meter failure due to age or condition. Furthermore, by managing electricity meters, KWHI can attain vital information pertaining to the consumption of electricity throughout the service area. KWHI is then able to use information collected from

the meters to monitor power quality and analyze trends to reduce service interruptions caused by system overload.

The installation of smart meters with Last Gasp Functionality enables Control Room Operators to identify the location of outages and quickly direct field crews to the appropriate location. This reduces the duration of outages (SAIDI).

Project Alternatives (Design, Scheduling, Funding/Ownership) (5.4.3.2.B.1.d.iii)

Project Design Alternatives:

None. All customer connections are required to be metered to determine consumption.

Scheduling Alternatives:

This is a mandatory activity and meters are supplied and installed accordingly with each customer service connection.

Ownership Alternatives:
Developers of multi-residential developments can choose to have a bulk meter from KWHI with individual suite meters provided by another entity or by KWHI.

Safety (5.4.3.2.B.2)

Meter installations are completed in accordance with KWHI's standards and Ontario Regulation 22/04 to ensure there are no undue safety hazards. Work is inspected by KWHI and signed off as safe prior to energization.

Cyber-Security and Privacy (5.4.3.2.B.3) **(where applicable)**

Metering information is delivered through a secure network.

Co-ordination and Interoperability (5.4.3.2.B.4)

Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.3.2.B.4.a) **(where applicable)**

This investment incorporates standards from groups such as the Canadian Standards Association (CSA) and the Institute of Electrical and Electronics Engineers (IEEE). This investment applies the requirements of the Ontario Regulation 22/04 as overseen by the Electrical Safety Authority (ESA), who provide clearance prior to final energization.

Enabling of Future Technology and/or Future Operational Requirements (5.4.3.2.B.4.b)

This investment enables future technological functionality as the meters can be read remotely and operate through the usage of a wireless network, thereby presenting opportunities for future functionality.

Environmental Benefits (5.4.3.2.B.2.B.5) **(where applicable)**

N/A

Conservation and Demand Management (5.4.3.2.B.2.B.6) **(where applicable)**

Data from smart meters plays an integral role in helping customers to participate in CDM programs that are delivered by the IESO and KWHI.

Project Name: Meter Installation and Replacement

Category - Specific Requirements -System Access (5.4.3.2.SA - C)

Factors Affecting Timing/Priority (5.4.3.2 SA – C.i)

The main element impacting the timing and priority of this program is customer availability and requests. In some cases, KWHI requires customers to be present during the installation of a meter. If customers are not available at certain times or days, it will affect the timing of this project. In addition, the occurrence of meter failures will impact program timing and priority since a failed or broken meter will need to be replaced in a timely manner as it directly affects attaining accurate and reliable energy usage information from customers.

Factors Related to Customer/Third-Party Preferences (5.4.3.2 SA – C.ii)

The supply and installation of meters for all customer classes is in direct response to customer needs expressed via developers for subdivisions, contractors/consultants for commercial developments, and individual customer requests for servicing.

Factors Affecting the Final Cost (5.4.3.2 SA – C.iii)

Through purchasing meters from a vendor via a competitive bid process, KWHI can attain savings due to economy of scale.

Methods Utilized to Minimize Controllable Costs (5.4.3.2 SA – C.iv)

Controllable costs are minimized through the use of standardized equipment, standardized designs, and bulk purchasing when possible. The approved products for different types and class of meters are Sensus (used for residential and GS< 50kW services), Elster (used for GS< 50kW services) and ITRON (used for GS> 50kW services). Since the products are not fully interchangeable, KWHI relies on feedback from other utilities on unit cost and plans purchasing of meters to occur in large quantities so as to secure volume discounts.

Other Planning Objectives (5.4.3.2 SA – C.v) **(where applicable)**

Where applicable, KWHI's planning objectives, as detailed in Section 5.4.2 of the distribution System Plan are considered on an individual project basis. Examples include safety and reliability.

Technically feasible project design and/or implementation options exist (5.4.3.2 SA – C.vi)

KWHI considers several elements pertaining to planning for this program which includes working with developers to understand their timelines and coordinating with the Operations department during the time of subdivision energization. During the design stage for multi-residential developments, options for bulk metering, individual smart meter, or suite metering is considered and explored with the developer.

Summary of results analysis – "Least Cost", "Cost efficient" options (5.4.3.2 SA – C.vii)

The supply and installation of metering equipment is a well understood and standardise process that normally does not provide many options for further cost optimisation. The options described above for multi-residential developments are not explored until the project is in the design stage, at which point a least cost- or cost-efficient option is selected based on the developer's preference.

Results of a final Economic Evaluation (5.4.3.2 SA – C.viii) **(where applicable)**

Where applicable (when a capital contribution is required), economic evaluations for meter installation are included with underground residential distribution projects. These are done in accordance with Section 3.2 of the Distribution System Code and Section 2.1.2 of KWHI's Conditions of Service.

System impact costs & cost recovery method (5.4.3.2 SA – C.ix) **(where applicable)**

There is no additional system impact (e.g. REG investment) associated with residential meter supply and installation. Meters are installed for all new REG connections costs are fully recovered.

Images



Project Name: Meter Installation and Replacement

Project Authorization	
Prepared By: S. Ferneyhough	Authorized By: W. Meston
Date: January 22, 2019	Date April 2, 2019
	Completion Date: _____

Capital Project Summary

Project Name: No. 4 Transformer Station Replacement of 115 kV Switch with Circuit Switcher

Budget Year: 2020 **Budget Item No.:** 2-20-1

OEB Investment Category: System Renewal

General Information on Project (5.4.3.2.A)

Project Summary	Replacement of one 115 kV switch at No.4 Transformer Station with a circuit switcher, includes the replacement of a 48-year-old switch and a 30-year-old circuit switcher interrupter along with their concrete foundations and control wiring. Protection and Control and SCADA required by the new circuit switcher will be checked and commissioned. Installation of the new circuit switcher for the second 115 kV circuit at No.4 Transformer Station is planned for 2021.	
Capital Investment (5.4.3.2.A.i)	**Description**	**Estimated Cost**
	Labour:	$53,000
	Materials:	$150,000
	Contract:	$0
	Engineering:	$26,400
Capital Contributions (5.4.3.2.A.ii)	**Total Estimated Cost:**	**$229,400**
	Recoverable:	$0
	KWHI Estimated Cost	**$229,400**
Customer Attachments / Load (kVA) (5.4.3.2.A.iii) **(where applicable)**	18,168 Customers / 56,900 kW at 2018 peak	
Project Dates (5.4.3.2.A.iv)	**Start Date:** August, 2020 **In Service Date:** December, 2020	

Estimated Expenditure Timing (5.4.3.2.A.iv)	**Q1**	**Q2**	**Q3**	**Q4**
	$0	$0	$169,500	$59,900

Schedule Risk and Risk Mitigation (5.4.3.2.A.v)

The highest schedule risk to this project would come from an unscheduled catastrophic failure of critical equipment at another transformer station that would require immediate repair by the staff otherwise assigned to this job. This risk is mitigated by continuous online monitoring, weekly inspections and yearly maintenance of all station equipment to identify equipment at risk of failing and taking actions to prevent its failure.

Comparative Information from Equivalent Projects (5.4.3.2.A.vi) **(where available)**

The replacement of two 115 kV switches with circuit switchers at No.3 T.S. in 1997 cost $317,000 or $158,500 per circuit switcher. The replacement of two 115 kV switches and termination structures with circuit switchers and a new termination structure at No.5 T.S. in 1998 cost $489,500 or $244,750 per circuit. (This project at No.4 T.S. does not include the replacement of the existing termination structure.)

Total Capital and OM&A Costs Associated with REG Investments (5.4.3.2.A.vii)

There is no REG investment associated with this project.

Leave to Construct Approval (5.4.3.2.A.viii)

Not Applicable

Evaluation Criteria and Information (5.4.4.2.B)

Efficiency, Customer Value, Reliability (5.4.3.2.B.1)

Investment Driver (5.4.3.2.B.1.a)

The main driver of this investment is the increased safety to workers that will result from replacing the existing 115 kV switches that are mounted on cap and pin insulators. Old cap and pin insulators have a history of breaking and an E&USA Hazard Alert from 02/2001 has directed that structures equipped with this style of insulator will be considered a special hazard and that Air Break Switches with this type of insulator are not to be operated. (This E&USA Hazard Alert is found in Appendix A.) Replacing the switch with cap and pin insulators with a new circuit switcher will eliminate this hazard. Also, the new circuit switcher will have a 3-phase grounding switch to ground the HV winding of the power transformer using an operating handle accessible from the ground. This grounding switch on the new circuit switcher will eliminate the need for workers to work at heights on top of the transformer to manually apply transformer grounds.

Secondary Driver (5.4.3.2.B.1.a) **(where applicable)**

A secondary driver of this investment is the improved reliability that will result from replacing old, obsolete equipment, for which there are no spare parts, with new equipment with standard components. Repairs on the existing old 115 kV switches require weeks due to the fact that spare parts are not available. During those weeks of time that the switch is open and out of service, the customers fed by this transformer station face a lack of redundancy, with one of the two redundant transformers de-energized by the open 115 kV switch.

Good Utility Practice (5.4.3.2.B.1.b)

In planning and designing the replacement for the circuit switcher, considerations are given to existing reliability concerns and grid modernisation. The new circuit switcher will be equipped with epoxy style station post insulators and modern protection and control equipment to enable remote monitoring and

control of the device from KWHI's SCADA system. The combination of the existing air break switch and circuit switcher into one device is a more reliable and cost-effective options that KWHI and other utilities have been implementing.

Investment Priority (5.4.3.2.B.1.c)

KWHI identifies its oldest equipment for the most in-depth evaluation of whether its condition has deteriorated to the point that it requires replacement. At the No.4 T.S., the 115 kV switches are 48 years old and are built with obsolete, hard to obtain hardware. In 2015, the failure of a trunnion on one of the switches resulted in that switch and the transformer it isolated being out of service for 8 weeks. To prevent a similar outage caused by the failure of an old, obsolete component in the existing switches, they should be replaced with new circuit switchers which have standard, readily available components. KWHI's project Prioritization Tool was used to prioritize all material projects for 2020 and this project was ranked as Medium, 12 out of 31.

Analysis of Project and Project Alternatives – Effect of the investment on system operation efficiency and cost-effectiveness (5.4.3.2.B.1.d.i)

By replacing two old devices, an air break switch and a circuit switcher interrupter, with a single, new circuit switcher, our maintenance costs will be reduced.

Analysis of Project & Alternatives – Net benefits accruing to customers (5.4.3.2.B.1.d.ii)

The net benefits that accrue to customers is the reduction in ongoing maintenance costs and reduced probability of outages occurring due to equipment failure.

Analysis of Project & Alternatives – Impact of the investment on reliability performance including frequency and duration of outages (5.4.3.2.B.1.d.iii)

Timely replacement of the end of life devices will reduce the likelihood of an unplanned equipment failure which could result in an outage impacting the entire transformer station that serves approximately 18,168 customers. If the transformer station is in a N-1 contingency during the failure, the outage could last an average of 4-hours before all the load could be transferred to alternative feeders.

Project Alternatives (Design, Scheduling, Funding/Ownership (5.4.3.2.B.1.d.iii)

Project Design Alternatives:

The following alternatives were considered for the interruption and isolation of the 115 kV supply to the two transformers at No.4 T.S.:

1. Continue to Maintain Existing Switch and Circuit Switcher Interrupter. Leaving the existing air break switches in service will not eliminate the hazard that their cap and pin insulators present to our workers and is therefore unacceptable.

2. Replace Old Air Break Switch and Maintain Old Circuit Switcher Interrupter. Replacing the old air break switch with a new switch with station post insulators will eliminate the hazard presented by existing cap and pin insulators. In 2018, one of the 6 insulating support columns on the two circuit switcher interrupters had to be replaced. Maintaining the existing circuit switcher interrupters will require a minimum of $50,000 to replace the remaining 5 insulating support columns within 10 years. Furthermore, the existing 30-year-old circuit switcher interrupters would be due for replacement 10 years after the switch replacement. In the long run, replacing these two high voltage devices with functionally identical devices is a more expensive option and leaves us with a non-standard method of high voltage interruption with no gang-operated transformer grounding switch.

3. Replace Old Air Break Switch and Circuit Switcher Interrupter with New Circuit Switcher. By replacing the air break switch and the circuit switcher interrupter with a single circuit switcher

with its own integral air break switch, the equipment doing the high voltage interruption and isolation at No.4 T.S. will be identical to the standard equipment in use at all of our other transformer stations. Replacing the existing 30-year-old circuit switcher interrupter with a new circuit switcher will eliminate the imminent need to replace 5 of the remaining insulating support columns at a cost of $50,000.

Scheduling Alternatives:

None

Ownership Alternatives:

None

Safety (5.4.3.2.B.2)

By installing new circuit switchers with 3-phase gang-operated transformer grounding switches, the hazard from the existing cap and pin insulators will be eliminated and the need to work on top of the transformers to ground the transformers' high voltage windings will be eliminated by using a ground accessible handle on the 3-phase ground switch on the new circuit switcher.

Cyber-Security and Privacy (5.4.3.2.B.3) **(where applicable)**

Not Applicable

Co-ordination and Interoperability (5.4.3.2.B.4)

Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.3.2.B.4.a) **(where applicable)**

Not Applicable

Enabling of Future Technology and/or Future Operational Requirements (5.4.3.2.B.4.b)

Not Applicable

Environmental Benefits (5.4.3.2.B.2.B.5) **(where applicable)**

Not Applicable

Conservation and Demand Management (5.4.3.2.B.2.B.6) **(where applicable)**

Not Applicable

System Renewal Specific Requirements (5.4.3.2.C.b)

Asset Performance Target and Asset Lifecycle Optimization (5.4.3.2.C.b.i.a)

At KWHI, the expected lifetime of a Station Disconnect Switch is 40 years. The air break disconnect switches and circuit switcher interrupters at No.4 T.S. are 48 and 30 years old respectively. The air break switch has remained in service beyond its expected lifetime and it is obsolete so that replacement parts are no longer readily available. To keep the existing circuit switcher interrupters in service for the next 10 years, a minimum of $50,000 will be required to replace their remaining insulating support columns. The existing combination of an air break switch and circuit switcher interrupter is the only non-

standard high voltage isolation system in service at our 8 transformer stations. By replacing them with a single circuit switcher, all stations will have identical system for high voltage interruption and isolation. Also, their replacement with circuit switchers with gang operated transformer grounding switches will eliminate the need to climb on top of the transformer to ground a transformer's high voltage windings.

Asset Condition Relative to Typical Life Cycle (5.4.3.2.C.b.i.b)

Even though the 48-year-old air break disconnect switches have exceeded their expected lifetime of 40 years, they remain in good condition due to ongoing repairs and yearly maintenance. However, 6 of K-W Hydro's other old air break disconnect switches were found to be functionally obsolete due to insufficient interrupting capability and, before they reached their expected lifetime, were replaced by circuit switchers to ensure high voltage interruption. Therefore, we do not have good comparators for high voltage switch assets reaching their expected lifetime.

Number of Customers Impacted (5.4.3.2.C.b.i.c)

The installation of new circuit switchers will enhance the redundancy of No.4 T.S. and all of the **18,168 customers** fed by it.

Quantitative Customer Impact and Risk (5.4.3.2.C.b.i.d)

Due to the redundant design at KWHI's transformer stations, a failure of a circuit switcher under normal condition should not result in an outage. However, if the station was operating under contingency mode, a failure could result in the interruption of power to all 18,168 customers that are supplied by the station. This is equivalent to SAIFI of 0.2. Duration will vary and is dependent on the availability of other feeders to carry the interrupted load.

Qualitative Customer Impact and Risk (5.4.3.2.C.b.i.e)

Failure of this equipment as described above could lead to significant customer dissatisfaction depending on the length of the outage.

Value of Customer Impact (5.4.3.2.C.b.i.f)

The value of customer impact is high. A failure of a circuit switcher can impact an entire transformer station with up to 18,168 residential and commercial customers being affected.

Other Factors Affecting Project Timing (5.4.3.2.C.b.ii)

This project is the second highest ranked transformer station renewal project in 2020 and as such is expected to be executed unless there is a delay in equipment or if a mandatory System Access project utilized significantly more resources than budgeted.

Impact on System O&M Costs (5.4.3.2.C.b.iii)

Buying new circuit switchers will eliminate the expected $50,000 of maintenance costs that would be spent to replace the remaining 5 insulating support columns on the circuit switcher interrupters.

Reliability and Safety Factors (5.4.3.2.C.b.iv)

Replacing the existing air break disconnect switches will eliminate the hazard presented by their cap and pin insulators. Installing a new circuit switcher with a gang-operated transformer grounding switch will eliminate the falling hazard arising from working at heights in order to manually apply grounding cables on the top of the transformer.

Analysis of Project Benefits, Costs, Alternatives and Timing (5.4.3.2.C.b.v)

The benefits to be derived from this investment include; avoiding loss and damages due to a large-scale outage, elimination of a safety hazard, and maintaining high reliability standards for our customers. The

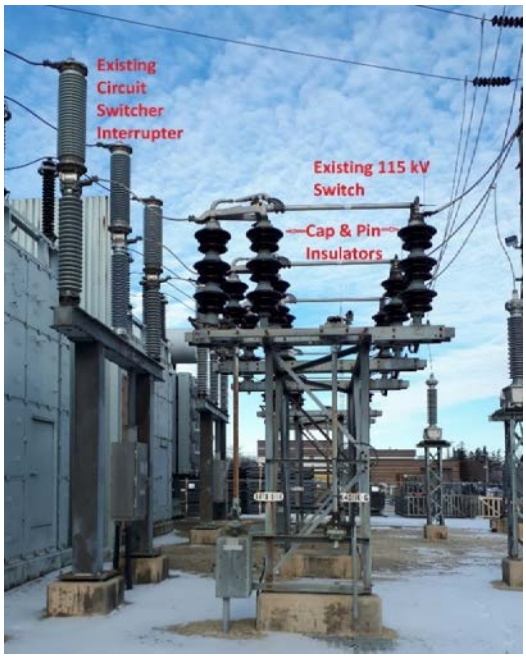
costs to implement this project can be deferred to a later date with the risk of an equipment failure but cannot be avoided. KWHI own and maintains eight transformer stations. In order to pace investments in renewal of these transformer stations, asset replacement is prioritized and budgeted so as to prevent lumpy spending.

Like-for-Like Renewal Analysis (5.4.3.2.C.b.vi)

Due to the fact that the 48-year-old 115 kV air break switches are obsolete equipment, like for like replacement is not possible.

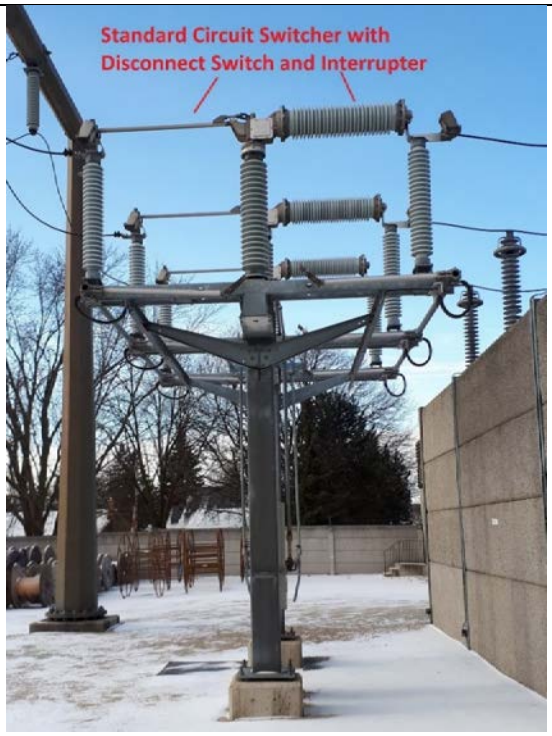
Images

Existing No.4 Transformer Station 115 kV Switch with Circuit Switcher Interrupter



Standard Circuit Switcher Complete with 115 kV Switch and Interrupter in Use at All 115 kV Transformer Stations Except for No.4 Transformer Station

Project Name: No. 4 Transformer Station Replacement of 115 kV Switch with Circuit Switcher



Appendix

E&USA HAZARD ALERT

02/2001

CAP-AND-PIN INSULATORS

The accompanying photograph depicts a style of insulator identified as being prone to sudden mechanical failure.

A recent failure resulted in the supporting steel structure becoming energized and a worker receiving third degree burns to the fingers of both hands.



These insulators are to be considered prone to sudden mechanical failure and may fall or allow the conductor and/or equipment they are supporting to move or otherwise fail.

The utility involved in the occurrence also issued the following directive:

"Effective immediately, poles and structures equipped with this style of insulator will be considered a special hazard.

These structures will not be climbed or worked on from below.

Air Break Switches with this style of insulator are not to be operated.

If this equipment is encountered in the course of work, request alternate work instructions from your supervisor."

Project Authorization

Prepared By: Robert Costen

Date: December, 2018

Authorized By: G. Cameron

Date: April 5, 2019

Completion Date: _____

Capital Project Summary

Project Name: No.5 Transformer Station Switchgear Arc Resistance and Remote Racking Upgrade Including 3 New Vacuum Breakers

Budget Year: 2020 **Budget Item No.:** 2-20-2

OEB Investment Category: System Renewal

General Information on Project (5.4.3.2.A)

Project Summary	No. 5 TS switchgear modification to include front, side and rear door replacement to an arc resistant standard, replacement of 3 SF6 breakers with vacuum breakers and installation of remote racking for all breakers. This is phase 2 of a multi-year project. A total of 24 breakers will be retrofitted over a two-year period (2019 – 2020). Twelve (12) breakers are proposed for retrofitting in 2020.		
Capital Investment (5.4.3.2.A.i)	**Description**	**Estimated Cost**	
	Labour:	$49,800	
	Materials:	$1,100	
	Contract:	$619,200	
	Engineering:	$87,100	
Capital Contributions (5.4.3.2.A.ii)	**Total Estimated Cost:**	**$757,200**	
	Recoverable:	$0	
	KWHI Estimated Cost	**$757,200**	
Customer Attachments / Load (kVA) (5.4.3.2.A.iii) **(where applicable)**	22,390 Customers / 81,100 kW at 2016 peak		
Project Dates (5.4.3.2.A.iv)	**Start Date:** January, 2020 **In Service Date:** March, 2020		

Estimated Expenditure Timing (5.4.3.2.A.iv)	**Q1**	**Q2**	**Q3**	**Q4**
	$757,200	$0	$0	$0

Schedule Risk and Risk Mitigation (5.4.3.2.A.v)

The highest schedule risk to this project would come from an unscheduled catastrophic failure of critical equipment at another transformer station that would require immediate repair by the staff otherwise assigned to this job. This risk is mitigated by continuous on line monitoring, weekly inspections and yearly maintenance of all station equipment to identify equipment at risk of failing and taking action to prevent its failure.

Comparative Information from Equivalent Projects (5.4.3.2.A.vi) **(where available)**

In 2013, two lineups of switchgear with the same number of cells at our No.4 T.S. received an equivalent upgrade that included the replacement of doors on the front, back and sides of the switchgear to upgrade it to an arc resistant standard and the addition of remote racking mechanisms on all breakers. This No.4 T.S. project did not include the replacement of any existing breakers with new vacuum breakers. The total cost for that previous project was $1,248,152.

Total Capital and OM&A Costs Associated with REG Investments (5.4.3.2.A.vii)

Not Applicable

Leave to Construct Approval (5.4.3.2.A.viii) **(where applicable)**

Not Applicable

Evaluation Criteria and Information (5.4.4.2.B)

Efficiency, Customer Value, Reliability (5.4.3.2.B.1)

Investment Driver (5.4.3.2.B.1.a)

The main driver of this investment is the increased safety to workers brought about by removing the arc flash hazard from the 13.8 kV switchgear in the switchgear room. The upgrade of the switchgear to make it arc resistant on the front, rear and sides will remove the arc flash hazards to workers in the switchgear room provided that all cell doors are closed. By installing remote breaker racking mechanisms, workers will not be exposed to arc flash hazards while performing breaker racking in and out operations.

Secondary Driver (5.4.3.2.B.1.a) **(where applicable)**

A secondary driver of this investment is the increased reliability resulting from the replacement of 3 SF6 breakers with vacuum breakers. Of the 35 SF6 breakers of the same design that KWHI originally had in service, 20 (or 57%) have been removed from service before they reached their expected lifetime of 30 years and that number includes 4 catastrophic failures. KWHI has 60 vacuum replacement breakers of the design that we would use for replacements here and none of them have been removed from service. By replacing the 3 SF6 feeder breakers with vacuum breakers, the reliability of the distribution feeder protection will be increased.

Good Utility Practice (5.4.3.2.B.1.b)
Performing work/operations on energized equipment such as racking in of circuit breakers posed an arc-flash hazard to workers. As such, new switchgear equipment is designed and manufactured with arc resistant capabilities and existing equipment are modified, where feasible, to eliminate/reduce the safety hazard.

Project Name: No.5 Transformer Station Switchgear Arc Resistance and Remote Racking Upgrade Including 3 New Vacuum Breakers

Investment Priority (5.4.3.2.B.1.c)

KWHI identifies its oldest equipment for the most in-depth evaluation of whether its condition has deteriorated to the point that it requires replacement. At the No.5 T.S., the metal clad enclosure on the 13.8 kV switchgear, at 40 years old has the oldest doors and rear panels of all our transformer stations' switchgear. Not only are the doors old but the front doors still have decommissioned protection and control relays filling holes in the doors. To remove the old relays, new doors are required. When the doors are replaced, new doors must be arc resistant to match the standard that KWHI has required for new switchgear over the last 25 years. KWHI's project Prioritization Tool was used to prioritize all material projects for 2020 and this project was ranked as Medium, 23 out of 31.

Analysis of Project and Project Alternatives – Effect of the investment on system operation efficiency and cost-effectiveness (5.4.3.2.B.1.d.i)

The investment does not directly impact operation efficiency but will have a positive impact on safety.

Retrofitting the switchgear is more cost effective than replacing it. The cost to supply and install one line-up of 14 cells of 15 kV switchgear, including 12 new breakers, is $1,400,000 compared to the proposed cost of $757,200 to retrofit the switchgear.

Analysis of Project & Alternatives – Net benefits accruing to customers (5.4.3.2.B.1.d.ii)

The biggest component and benefit of this job is related to worker safety. The replacement of the SF6 breakers will remove the risk of a premature failure similar to past activities that have occurred with this vintage of equipment. The net benefits to customer include the avoidance of a long duration unplanned outage that may result from pre-mature equipment failure.

Analysis of Project & Alternatives – Impact of the investment on reliability performance including frequency and duration of outages (5.4.3.2.B.1.d.iii)

The retrofitted arc-resistant switchgear does not have any direct impact on system reliability. However, the replacement of SF6 breakers with vacuum breakers will reduce the likelihood of a feeder outage due to an equipment failure. A typical feeder from No. 5TS has 2,500 customers and a feeder outage due to a breaker failure will last an average of two hours until the necessary load can be transferred.

Project Alternatives (Design, Scheduling, Funding/Ownership (5.4.3.2.B.1.d.iii)

Project Design Alternatives:

The following alternatives were considered for the enclosure of the 13.8 kV switchgear:

1. Leave Existing Old Switchgear Doors in Service: Leaving the existing old switchgear doors with the decommissioned relays on them does not bring the switchgear enclosure to the current standard of being arc resistant. Without this arc resistance installed, workers in the switchgear room are exposed to arc flash hazards in the event of a switchgear or breaker failure inside the switchgear.

2. Replacing Front and Rear Doors with Arc Resistant Doors: Replacing the front and rear doors with arc resistant doors will reduce the arc flash hazard for workers who are inside the switchgear room but not working on the switchgear. Workers racking breakers in and out of switchgear cells will not be protected by the switchgear enclosure from arc flash hazards.

3. Replacing Front and Rear Doors with Arc Resistant Doors and Installing Remote Racking Devices on Breakers: By adding the remote racking devices on the breakers, workers will be protected from arc flash hazards while racking breakers in and out of switchgear cells in addition to the protection provided in Alternative 2 above. This alternative is the preferred alternative because it provides the safest protection from the arc flash hazards in the switchgear.

Scheduling Alternatives:

None

Ownership Alternatives:

Not Applicable

Safety (5.4.3.2.B.2)

By installing arc resistant doors and panels on the front, rear and sides of the switchgear and by installing remote racking devices on the breakers, workers will be protected from the arc flash hazard available in the 13.8 kV equipment while they are outside the switchgear walls and while they are racking breakers in and out.

Cyber-Security and Privacy (5.4.3.2.B.3) **(where applicable)**

Not Applicable

Co-ordination and Interoperability (5.4.3.2.B.4)

Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.3.2.B.4.a) **(where applicable)**

Not Applicable

Enabling of Future Technology and/or Future Operational Requirements (5.4.3.2.B.4.b)

The breakers will be retrofitted with remote racking capabilities which will enable workers to be physically separated from the breakers when they are racking breakers in and out. This will enhance the safety of the employees and provide functionalities that are part of future operational requirements for high voltage switchgear.

Environmental Benefits (5.4.3.2.B.2.B.5) **(where applicable)**

Not Applicable

Conservation and Demand Management (5.4.3.2.B.2.B.6) **(where applicable)**

Not Applicable

System Renewal Specific Requirements (5.4.3.2.C.b)

Asset Performance Target and Asset Lifecycle Optimization (5.4.3.2.C.b.i.a)

At KWHI, the expected lifetime of switchgear and the building that houses it is 50 years. By adding arc resistance protection on the front, rear and sides of the switchgear cells and installing remote racking devices on the breakers, we can bring the switchgear arc resistance up to a current standard without replacing it with new arc resistant switchgear. This modification will extend the life of the switchgear beyond its expected 50 year life and avoid the higher cost of replacing the switchgear with new arc resistant switchgear and modifying the switchgear building to accommodate the new switchgear.

Project Name: No.5 Transformer Station Switchgear Arc Resistance and Remote Racking Upgrade Including 3 New Vacuum Breakers

Asset Condition Relative to Typical Life Cycle (5.4.3.2.C.b.i.b)

The three SF6 breakers will be 31 years old and beyond their expected life cycle. One of the SF6 breakers that was originally installed at No.5 T.S. had to be removed from service and 57% of this model of breaker have been removed from our transformer stations before their 30 year expected lifetime. Therefore, to prevent unplanned failures of SF6 breakers, it is necessary to replace the 3 remaining breakers.

Number of Customers Impacted (5.4.3.2.C.b.i.c)

This switchgear upgrade will affect all of the more than 22,000 customers fed from No.5 T.S.

Quantitative Customer Impact and Risk (5.4.3.2.C.b.i.d)

The retrofitted arc-resistant switchgear does not have any direct impact on system reliability. However, the replacement of SF6 breakers with vacuum breakers will reduce the likelihood of a feeder outage due to an equipment failure. A typical feeder from No. 5TS has 2,500 customers and a feeder outage due to a breaker failure will last an average of two hours until the necessary load can be transferred. This is equivalent to SAIFI of 0.026 and SAIDI of 0.05 hrs.

Qualitative Customer Impact and Risk (5.4.3.2.C.b.i.e)

Failure of a SF6 breaker or a switchgear during operation could lead to significant customer dissatisfaction depending on the length of the outage.

Value of Customer Impact (5.4.3.2.C.b.i.f)

The value of customer impact is medium. A failure of a SF6 circuit breaker can impact an entire feeder with up to 2,500 residential and commercial customers being affected.

Other Factors Affecting Project Timing (5.4.3.2.C.b.ii)

This project is the lowest ranked transformer station renewal material project in 2020 and as such could face deferral if other high priority station activities or System Access projects utilize more resources than budgeted for.

Impact on System O&M Costs (5.4.3.2.C.b.iii)

Metal clad switchgear requires low O&M costs and upgrading the switchgear has little impact on the O&M costs.

Reliability and Safety Factors (5.4.3.2.C.b.iv)

Installation of arc resistance protection on the front, rear and sides of the switchgear and use of remote racking mechanisms for all the breakers will reduce the arc flash hazard while performing most tasks in the switchgear room and therefore enhance its safety.

Analysis of Project Benefits, Costs, Alternatives, and Timing (5.4.3.2.C.b.v)

Due to the fact that the primary driver for this switchgear and breaker upgrade is the enhanced safety brought about by removing the arc flash hazards during most work in the switchgear room, this project has a high priority among transformer station upgrades now that the relays on the cell doors have been replaced with new relays in another room in October 2018.

Project Name: No.5 Transformer Station Switchgear Arc Resistance and Remote Racking Upgrade Including 3 New Vacuum Breakers

Like-for-Like Renewal Analysis (5.4.3.2.C.b.vi)

The existing three SF6 breakers in feeder positions 5M21, 5M22 and 5M23 are not interchangeable with the other feeder breakers in this T.S. By replacing them with vacuum breakers, the breakers from those positions will be available for replacing breakers in any other feeder position in a like-for-like replacement.

Images



Existing No. 5 Transformer Station Non-Arc Resistant Switchgear

Project Name: No.5 Transformer Station Switchgear Arc Resistance and Remote Racking Upgrade Including 3 New Vacuum Breakers



Switchgear at No.4 Transformer Station which has received an upgrade to install arc resistance and remote racking of breakers.

Project Authorization

Prepared By: Robert Costen

Date: December, 2018

Authorized By: G. Cameron

Date: April 5, 2019

Completion Date: _____

Capital Project Summary

Project Name: No. 6 Transformer Station Rebuild P & C and SCADA Equipment and Wiring

Budget Year: 2020 **Budget Item No.:** 2-20-3 & 2-20-4

OEB Investment Category: System Renewal

General Information on Project (5.4.3.2.A)

Project Summary	Replacement of all P&C relays and SCADA equipment including required protection panel wiring. The 2020 work is a continuation of work started in 2019. Work will include wiring in new relays and SCADA equipment, wire checking and final commissioning of SCADA and protection schemes.	
Capital Investment (5.4.3.2.A.i)	**Description**	**Estimated Cost**
	Labour:	$442,600
	Materials:	$315,300
	Contract:	$20,000
	Engineering:	$101,200
Capital Contributions (5.4.3.2.A.ii)	**Total Estimated Cost:**	**$879,100**
	Recoverable:	$0
	KWHI Estimated Cost	**$879,100**
Customer Attachments / Load (kVA) (5.4.3.2.A.iii) **(where applicable)**	30,500 Customers / 80 MW during 2016 peak	
Project Dates (5.4.3.2.A.iv)	**Start Date:** September 2019 **In Service Date:** October, 2020	

Estimated Expenditure Timing (5.4.3.2.A.iv)	**Q1**	**Q2**	**Q3**	**Q4**
	$518,400	$162,200	$150,900	$47,600

Schedule Risk and Risk Mitigation (5.4.3.2.A.v)

The highest schedule risk to this project would come from an unscheduled catastrophic failure of critical equipment at another transformer station that would require immediate repair by the staff otherwise assigned to this job. This risk is mitigated by continuous on-line monitoring, weekly inspections and

yearly maintenance of all station equipment to identify equipment at risk of failing and taking actions to prevent its failure.

Comparative Information from Equivalent Projects (5.4.3.2.A.vi) **(where available)**

Not Available. KWHI is currently undertaking a similar project on a smaller scale at our No. 3TS. This project is expected to be completed by Q3 2019 at which time a project cost will be available.

Total Capital and OM&A Costs Associated with REG Investments (5.4.3.2.A.vii)

There is no REG investment associated with this project.

Leave to Construct Approval (5.4.3.2.A.viii) **(where applicable)**

Not Applicable

Evaluation Criteria and Information (5.4.4.2.B)

Efficiency, Customer Value, Reliability (5.4.3.2.B.1)

Investment Driver (5.4.3.2.B.1.a)

The main driver of this investment is the improved reliability that will result from the installation of new digital relays. An automatic reclose scheme will be included with the new digital feeder protection so that momentary distribution feeder outages can be reduced from 60 seconds to 2 seconds. Furthermore, the increased risk of relay failure from the use of existing old relays near their end of life increases the probability of backup protection operating and resulting in a larger number of customers being out of power when a fault is isolated. Therefore, the replacement of old relays assessed to be in very poor condition will enhance reliability by reducing the probability of a relay failure resulting in backup protective relays operating in lieu of the failed relay and dropping more customers.

Secondary Driver (5.4.3.2.B.1.a) **(where applicable)**

A secondary driver of this investment is the improved efficiency that will occur during the future replacement of failed relays. 97% of the protective relays at this station are obsolete and, after a failure, the necessary redesign, purchase, rewiring and verification using new relays takes 2-4 months. After the installation of new relays, an equivalent relay replacement using modern spare relays will only take 2 days.

Good Utility Practice (5.4.3.2.B.1.b)

The age, condition and risk of failure are taken into consideration when planning the replacement of the relays. Half the relays at No.6 TS are at end of life per the 2018 ACA. Grid modernisation is also considered in selecting the replacement relays. The relays will be equipped with modern microprocessors and will have advanced diagnostic capabilities to allow for tele-protection capabilities, and easier fault finding and troubleshooting.

Investment Priority (5.4.3.2.B.1.c)

KWHI identifies its oldest equipment for the most in-depth evaluation of whether its condition has deteriorated to the point that it requires replacement. For Kitchener-Wilmot Hydro's Distribution System Plan, Metsco prepared an Asset Condition Assessment Report 2018 in which they identified that, in the stations, there were 86 protection relays in Very Poor condition which are recommended for immediate action. There are plans to replace all of these relays identified as being in Very Poor condition and this protection and control rebuild at No.6 T.S. will replace 42 of them. In the case of the No.6 T.S.

Protection & Control, not only will it be the oldest P&C equipment in service in 2020, with relays failing and spare parts unavailable, but its feeder relays do not have an automatic reclose scheme that will be included with the new relays. KWHI's project Prioritization Tool was used to prioritize all material projects for 2020 and this project was ranked as High, 8 out of 31.

Analysis of Project and Project Alternatives – Effect of the investment on system operation efficiency and cost-effectiveness (5.4.3.2.B.1.d.i)

When the 30-year-old relays are replaced with modern digital relays with sufficient new spare relays, after the upgrade is complete, the time to replace failed relays will be reduced from at least 2 months to 2 days.

Analysis of Project & Alternatives – Net benefits accruing to customers (5.4.3.2.B.1.d.ii)

Existing old feeder protection relays without an automatic reclose ability force the control room operators to manually reclose the feeder breaker after a feeder trip. The replacement of these old distribution feeder relays with new digital relays that will employ automatic reclosing will reduce the duration of momentary feeder outages from the manually operated reclose time of 60 seconds to the automatic reclose time of 2 seconds. This reduction in the length of momentary feeder outage times will benefit all of the more than 30,000 customers connected to the feeders at No.6 T.S.

Analysis of Project & Alternatives – Impact of the investment on reliability performance including frequency and duration of outages (5.4.3.2.B.1.d.iii)

In addition to reducing the duration of momentary outages from 60 to 2 seconds on feeders supplying over 30,000 customers, the new digital feeder relays will permit the addition of under frequency load shedding to meet future system UFLS requirements.

Project Alternatives (Design, Scheduling, Funding/Ownership (5.4.3.2.B.1.d.iii)

Project Design Alternatives:

The following alternatives were considered for replacing what will be the oldest relays on our system in 2020:

1. Use Existing Protective Relays: If we make no changes and use existing obsolete protective relays, we will not have spare relays to replace the relays as they fail. Individual replacements would require more money and time to install as replacement with new digital relays would have to be custom designed and wired. Replacing individual relays as they fail is a much less efficient method of relay replacement and would affect customers for longer periods of time. For example, one feeder relay failure requires that feeder to be taken out of service for 2-4 months while a new relay is purchased and the protection is rewired and verified. If we change all the relays in one job, we can change 4 feeder relays and 2 bus protection relays during the same outage time of 2 months.

2. Install New Digital Protective Relays in Existing Protection Panels: Installing new digital protective relays in the existing protection panels is the preferred option in that the work to replace all the relays at one time would be cheaper and faster than spot replacement as existing relays fail. Also, in the future, it would enable the inexpensive and quick like-for-like replacements of failed relays with modern spare relays.

Scheduling Alternatives:

None

Ownership Alternatives:

Not Applicable

Safety (5.4.3.2.B.2)

Upgrading all of the old relays with new relays that include continuous monitoring for the failure of each relay will enable our staff to remove the equipment protected by the failed relay from service sooner and therefore reduce the possibility of a failure of a protection scheme resulting in more widespread damage.

Cyber-Security and Privacy (5.4.3.2.B.3) **(where applicable)**

The digital relays and SCADA RTU will be secured in accordance with KWHI's cyber security practices.

Co-ordination and Interoperability (5.4.3.2.B.4)

Replacement of the protective relays at the transformer station will by coordinated with Hydro One Networks and the IESO.

Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.3.2.B.4.a) **(where applicable)**

Not Applicable

Enabling of Future Technology and/or Future Operational Requirements (5.4.3.2.B.4.b)

Connection of Distributed Generation large enough to require a transfer trip scheme is not possible with existing feeder protection relays. The new digital feeder relays being installed enable connection of large Distributed Generation. Also, under frequency detection on new digital feeder relays enables future changes in KWHI's under frequency load shedding plans.

Environmental Benefits (5.4.3.2.B.2.B.5) **(where applicable)**

Not Applicable

Conservation and Demand Management (5.4.3.2.B.2.B.6) **(where applicable)**

Not Applicable

System Renewal Specific Requirements (5.4.3.2.C.b)

Asset Performance Target and Asset Lifecycle Optimization (5.4.3.2.C.b.i.a)

At KWHI, the expected lifetime for solid state and electro-mechanical relays is 25 years and for SCADA equipment is 15 years. The solid state and electro-mechanical relays in use at No.6 T.S., which will be 30 years old in 2020, have remained in service well beyond their expected lifetime and are obsolete so that replacement parts are unavailable. Existing feeder relays are unable to meet current protection and communication standards which include feeder automatic reclosing, under frequency load shedding and transfer tripping of distribution generation. Most of the No.6 T.S. SCADA equipment will be 30 years old in 2020 and has remained in service well beyond its expected lifetime.

Asset Condition Relative to Typical Life Cycle (5.4.3.2.C.b.i.b)

Our existing Feeder and Bus Overcurrent protections use a model of relay that is obsolete and on which we have experienced about 50% failure rate over 30 years. After the most recent unplanned failure of one of these feeder protection relays, a spare relay was no longer available and its feeder breaker was out of service for a 4 month period in order to redesign, purchase, install and verify a replacement relay system. During that period, the feeder load was transferred to another feeder so that one breaker carried the customers of two feeders.

Project Name: No. 6 Transformer Station Rebuild P & C and SCADA Equipment and Wiring

Number of Customers Impacted (5.4.3.2.C.b.i.c)

30,516

Quantitative Customer Impact and Risk (5.4.3.2.C.b.i.d)

With the introduction of automatic reclosing to the feeder protections, the duration of momentary feeder outages for the 30,000 customers fed by No.6 T.S. will be reduced from 60 seconds to 2 seconds.

Qualitative Customer Impact and Risk (5.4.3.2.C.b.i.e)

Continuous on line monitoring available from new digital transformer, line, and bus relays will immediately sense the failure of a relay so that it can be replaced before it fails to operate for a fault and results in backup protection dumping more customers in order to isolate the fault. With new digital feeder relays set up for transfer tripping of large distribution generation, customers planning to install large distribution generation will not have to wait for a lengthy retrofit on the feeder protection to enable the connection of the generator with a transfer trip scheme between it and the feeder protection. The use of analog quantities from new digital protective relays will eliminate the need for most analog signal transducers in the new SCADA equipment and therefore make the replacement SCADA equipment cheaper.

Value of Customer Impact (5.4.3.2.C.b.i.f)

The value of customer impact is high. A failure of a relay can impact an entire feeder or station buss with up to 10,000 residential and commercial customers affected for the entire outage duration.

Other Factors Affecting Project Timing (5.4.3.2.C.b.ii)

This project is the highest ranked transformer station renewal project in 2020 and as such is expected to be executed unless there is a delay in equipment or a mandatory System Access project utilized significantly more resources than budgeted.

Impact on System O&M Costs (5.4.3.2.C.b.iii)

Spot replacement of failed obsolete relays now requires the redesign and rewiring of the failed protection at a cost of $40,000-$60,000 per relay failure. Use of new digital relays with modern spare relays in stock will permit fast replacement in the event of a relay failure at a smaller cost of $12,500 per relay failure.

Reliability and Safety Factors (5.4.3.2.C.b.iv)

Implementation of new feeder protection relays with automatic reclosing will reduce the length of momentary feeder outages from 60 seconds to 2 seconds.

Analysis of Project Benefits, Costs, Alternatives and Timing (5.4.3.2.C.b.v)

Of all the relays in service at KWHI's transformer stations in 2020, the 30-year-old relays proposed for replacement at No.6 T.S. will have the most years past their expected lifetime and therefore should be the first of our obsolete relays to be replaced.

Like-for-Like Renewal Analysis (5.4.3.2.C.b.vi)

Due to the fact that existing relays are obsolete and spare parts are unavailable, in the event of a relay failure, like-for-like renewal is no longer possible. Complete replacement of all relays with new relays, as proposed in this project, will permit fast and inexpensive like-for-like replacement in the future.

Images



Example of Obsolete Electronic Relays and Analog Meters to be Replaced with a Digital Feeder Relay with Auto-Reclose

Project Name: No. 6 Transformer Station Rebuild P & C and SCADA Equipment and Wiring

Project Authorization

Prepared By:	Robert Costen	Authorized By:	G. Cameron
Date:	December, 2018	Date:	April 2, 2019
		Completion Date:	_____

Capital Project Summary

Program Name: Spot Replacement of Deteriorated Poles

Budget Year: 2020 **Budget Item No.:** 3-20-1

OEB Investment Category: System Renewal

General Information on Project (5.4.4.2.A)

Program Summary	This project consists of replacing approximately 50 existing deteriorated wood poles in very poor condition at various locations and transferring existing primary, secondary and service conductors. The locations are prioritized based on condition of the assets from the 2018 ACA results and paced to maintain steady expenditures year over year.
Capital Investment (5.4.3.2.A.i)	**Description** — **Estimated Cost** **Labour:** $200,000 **Materials:** $180,000 **Contract:** $0 **Engineering:** $45,000 **Total Estimated Cost** **$425,000**
Capital Contributions (5.4.3.2.A.ii)	**Recoverable:** $0 **KWHI Estimated Cost** **$425,000**
Customer Attachments / Load (kVA) (5.4.3.2.A.iii) **(where applicable)**	Customer attachments varies depending on pole type to be replaced (single phase, three phase, or secondary) and location of pole.
Project Dates (5.4.3.2.A.iv)	**Start Date:** January 2020 **In Service Date:** December 2020

Estimated Expenditure Timing (5.4.3.2.A.iv)	**Q1**	**Q2**	**Q3**	**Q4**
	$25,000	$187,500	$187,500	$25,000

Schedule Risk and Risk Mitigation (5.4.3.2.A.v)

Schedule risks for this project include resource availability to replace smaller quantities of poles per location, having design information from joint use tenants, and getting timely municipal consent. To mitigate these risks, third-party contractors will be used to compliment KWHI's internal labour and the project will be designed at least 3 months in advance of the scheduled construction date. Also, KWHI works closely with other 3rd parties such as the communication companies, City of Kitchener and the Township of Wilmot to get their requirements and approvals in advance of the project start date to reduce the potential for last minute design and construction changes. The majority of the poles will be replaced as like for like thereby reducing the need for municipal consents.

Comparative Information from Equivalent Projects (5.4.3.2.A.vi) **(where available)**

Typically, on average, one deteriorated wood pole with single phase primary, secondary conductors with several overhead services can be replaced like for like for approximately $8500.

Total Capital and OM&A Costs Associated with REG Investments (5.4.3.2.A.vii)

There is no REG investment associated with this program.

Leave to Construct Approval (5.4.3.2.A.viii) **(where applicable)**

N/A

Evaluation Criteria and Information (5.4.4.2.B)

Efficiency, Customer Value, Reliability (5.4.3.2.B.1)

Investment Driver (5.4.3.2.B.1.a)

Condition/Age/Failure Risk - the main driver for this project is the condition coupled with age of the poles and the risk of failure. The poles range in age from 40 to 60+ years old and have health indices of Very Poor based on the 2018 ACA report.

Secondary Driver (5.4.3.2.B.1.a) **(where applicable)**

Reliability – deteriorated poles deemed to be in poor shape are at risk for failure. A planned process for replacement minimizes the risk of overhead line failure and unplanned outages.

Good Utility Practice (5.4.3.2.B.1.b)

KWHI has an ongoing yearly planned process to replace deteriorated poles which will help improve reliability.

Investment Priority (5.4.3.2.B.1.c)

The priority of this project relative to others is High. System Access (SA) projects have higher priority that System Renewal (SR) projects unless the condition of the assets associated with the SR project is in a very poor condition, which is the case for this project. One of our asset management strategies is to replace assets before they reach a stage of critical condition. KWHI's project Prioritization Tool was used to prioritize all material projects for 2020 and this project was ranked as 2 out of 31.

Analysis of Project and Project Alternatives – Effect of the investment on system operation efficiency and cost-effectiveness (5.4.3.2.B.1.d.i)

Project Name: Spot Replacement of Deteriorated Poles

By planning the replacement of poles rather than forced replacement at the time of a failure, the cost per pole can be managed utilising regular work hours and/or competitive bids and therefore not subject to overtime premiums.

Analysis of Project & Alternatives – Net benefits accruing to customers (5.4.3.2.B.1.d.ii)

By replacing the deteriorated poles, customers will experience an improvement in reliability (number of sustained outages). The risk associated with pole failure and possible downed power lines will also reduce with the installation of new poles and associated hardware with higher structural strength.

Through a recently conducted customer engagement process, KWHI's customers overwhelmingly said that they support the proposed approach or an accelerated approach to replace poles. See excerpt below.

Customer Engagement Activity	% who support proposed approach to pole replacement or accelerated approach
Low-volume online workbook	**84%**
Residential telephone survey	**81%**
Small business telephone survey	**75%**

Analysis of Project & Alternatives – Impact of the investment on reliability performance including frequency and duration of outages (5.4.3.2.B.1.d.iii)

By replacing deteriorated poles, customers will experience an improvement in reliability (number of sustained outages). The risk associated with pole failure and possible downed power lines will also reduce with the installation of new poles and associated hardware with higher structural strength.

Project Alternatives (Design, Scheduling, Funding/Ownership (5.4.3.2.B.1.d.iii)

Project Design Alternatives:

- Replace poles once they have failed – this is not advisable. The cost for replacement would be much higher if completed on an emergency basis then on a planned basis. This would lead to longer outages and increase in customer dissatisfaction.

- Replace poles as part of a pole line rebuild – this is done when possible. However, the number of poles that need attention, exceeds the budget amount for this type of work. Also, there may be locations where not all
  the poles in a line are deemed in poor condition. The risk to leave a pole in poor condition and wait until all or most need replacing is not acceptable.

Scheduling Alternatives:

If an unplanned job arises that has significantly higher priority than this job, a decision can be made to defer this project to a later date. However, not replacing an end of life asset is not an option due to public safety impacts, system reliability and possible increasing in OM&A costs.

Ownership Alternatives:

None. This project consists solely of KWHI's assets and is constructed on the public right-of-way.

Safety (5.4.3.2.B.2)

Replacement of deteriorated poles that are at the end of their useful life and in poor condition will reduce the likelihood of unexpected pole failures and possible downed wires. Having downed primary wires on the ground creates a safety hazard for the public and workers.

Cyber-Security and Privacy (5.4.3.2.B.3) **(where applicable)**

This project does not impact cyber security or privacy.

Co-ordination and Interoperability (5.4.3.2.B.4)

Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.3.2.B.4.a) **(where applicable)**

The replacement of these poles will be co-ordinated with the City of Kitchener and Township of Wilmot for their planned road work and joint use telecommunication companies for their attachment information.

Enabling of Future Technology and/or Future Operational Requirements (5.4.3.2.B.4.b)

This investment does not directly enable future technological functionality or operational requirements.

Environmental Benefits (5.4.3.2.B.2.B.5) **(where applicable)**

KWHI will be removing old poles which were predominately treated with chemicals that do not meet today's environmental standards. As a result, the new poles would adhere to current environmental standards.

Conservation and Demand Management (5.4.3.2.B.2.B.6) **(where applicable)**

N/A

System Renewal Specific Requirements (5.4.3.2.C.b)

Asset Performance Target and Asset Lifecycle Optimization (5.4.3.2.C.b.i.a)

The project supports the following asset performance and lifecycle optimization:

- Safety – by proactively replacing an end of life pole, safety issues associated with pole failures or down live wires are avoided.
- Operation Effectiveness – reliability indices (SAIDI and SAIFI) will be improved by not running a pole to failure.
- Customer Focus – replacing poles that are at end of life and in poor condition will reduce the likelihood of a long duration unplanned outage due to equipment failure.

Asset Condition Relative to Typical Life Cycle (5.4.3.2.C.b.i.b)

Through a useful life of assets study conducted by Kinetics for KWHI coupled with local experience, KWHI has identified the typical useful life (TUL) of wood poles and associated hardware as 40 years. The poles identified for replacement ranges in age from 40 to 60+ years old. The poles that will be replaced have exceeded the TUL for wood poles and therefore have performed well.

Project Name: Spot Replacement of Deteriorated Poles

Number of Customers Impacted (5.4.3.2.C.b.i.c)

The exact number of customers impacted is unknown until a detailed design is completed.

Quantitative Customer Impact and Risk (5.4.3.2.C.b.i.d)

Usually 1-6 customers may be directly impacted by a pole failure, however the failure could lead to higher customer impact if a feeder breaker opens.

Qualitative Customer Impact and Risk (5.4.3.2.C.b.i.e)

If these deteriorated poles are not replaced, the risk of unplanned outages and outage duration may increase resulting in lower customer satisfaction. One of the drivers for the project is reliability improvement.

Value of Customer Impact (5.4.3.2.C.b.i.f)

The value of customer impact is medium. A failure in any of these deteriorated poles would impact residential customers for the entire outage duration. However, the initial customer impact could be higher if the feeder breaker opened for a pole/line failure.

Other Factors Affecting Project Timing (5.4.3.2.C.b.ii)

If an unplanned job arises that has significantly higher priority than this job, a decision can be made to defer this project to a later date. However, not replacing end of life assets is not a good option due to public safety impacts, system reliability and possible increasing in OM&A costs.

Impact on System O&M Costs (5.4.3.2.C.b.iii)

- KWHI's current strategy for non-destructive pole testing is to test poles that are 40 years and older. By replacing poles in this program there will be no need to test them within the near future.
- Replacement of poles with new hardware and higher design standards will also reduce the cost of future repairs that may arise from potential pole failures.
- If the project is not implemented, there is a strong likelihood that forced outages will continue to occur, resulting in possible overtime response.

Reliability and Safety Factors (5.4.3.2.C.b.iv)

By proactively replacing deteriorated poles which have reached their EOL asset value, reliability and safety issues associated with poles failing are avoided.

Analysis of Project Benefits, Costs, Alternatives, and Timing (5.4.3.2.C.b.v)

This project to replace deteriorated poles is a constant in KWHI's yearly Capital Budget. It is recognized that waiting for EOL poles to fail and then replace them is not our preferred option. This work takes significate engineering, coordination and scheduling. The cost implication of completing this work on an emergency basis is high. The decrease in customer satisfaction due to unplanned outages is high. In order to pace investments, sustain our reliability and eliminate the risk of safety hazards, it is imperative that this project is ongoing.

Like-for-Like Renewal Analysis (5.4.3.2.C.b.vi)

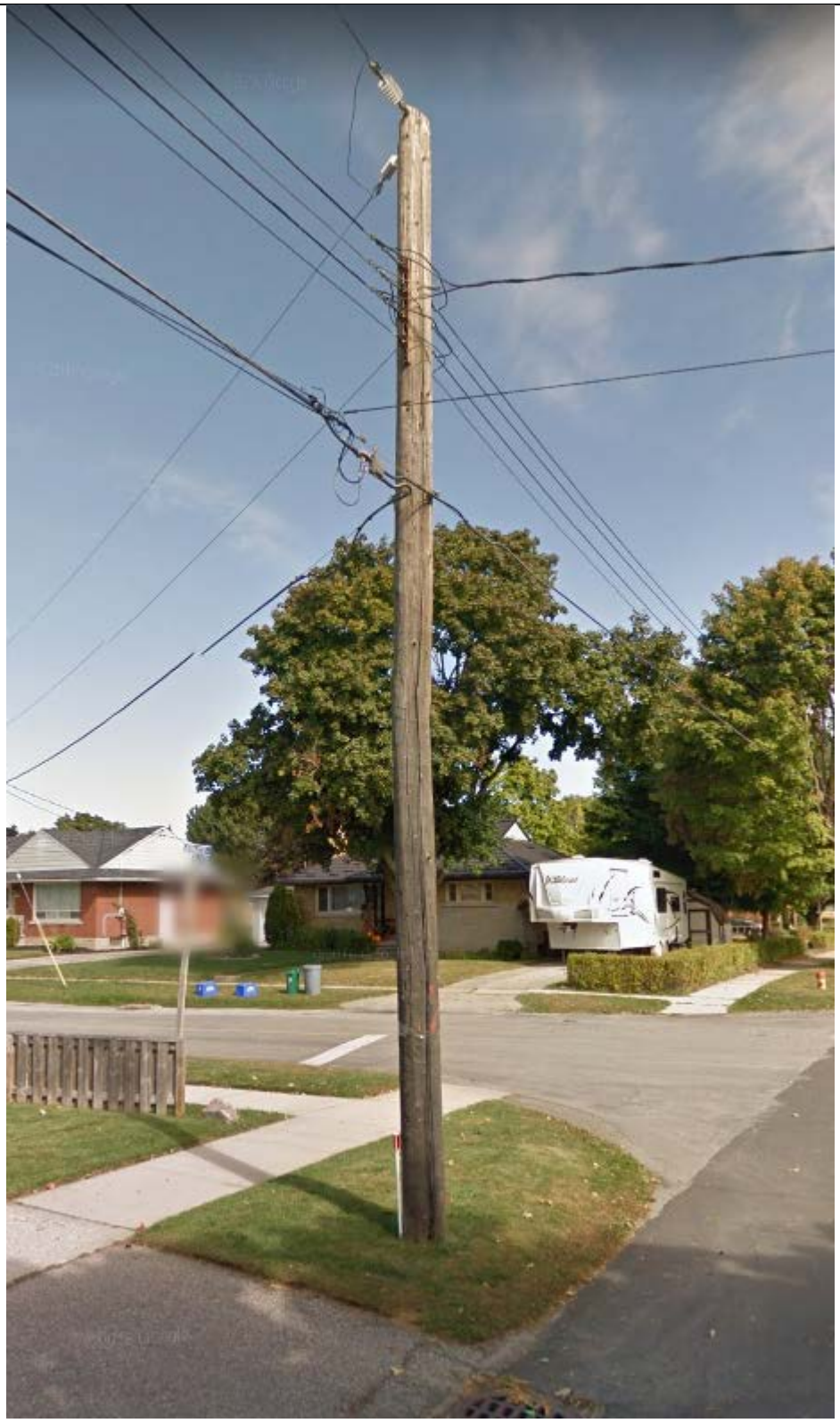
This program is considered a like-for-like replacement. Although these new poles will be built to today's standards including improved pole sizes and hardware, they will remain as distribution poles serving the same functions they perform today.

Project Name: Spot Replacement of Deteriorated Poles

Images



Sample of deteriorated pole – 59 Trafalgar Ave, Kitchener
Existing 35’ CL.4 wood pole, 1958 vintage (61 years old)



Sample of deteriorated pole at 70 Heather Ave, Kitchener
Existing 35’ CL.4 wood, 1953 vintage (66 years old)

Project Name: Spot Replacement of Deteriorated Poles

Project Authorization	
Prepared By: Sandy Ferneyhough	Authorized By: G. Cameron
Date: January 18, 2019	Date: April 5, 2019
	Completion Date: _____

Capital Project Summary

Project Name: Single Phase & Secondary Pole Line Rebuilds Due to Age and Condition

Budget Year: 2020 **Budget Item No.:** 3-20-4

OEB Investment Category: System Renewal

General Information on Project (5.4.4.2.A)

Project Summary	This program consists of rebuilding multiple existing 1-ph circuit pole lines which include the replacement of pole line assets with single phase primary and/or or low voltage secondary-only attachments that are at end of life. The program is prioritized based on condition of the assets from the 2018 ACA results and paced to maintain steady expenditures year over year. In 2020, approximately 110 wood poles are targeted for replacement. The existing spans of primary conductor will be replaced with 1-#2 ACSR, approximately 3.5km in circuit length. The existing secondary buss will also be replaced with 2-4/0 Al, 1-2/0 ACSR & 1-#2 Al quadruplex secondary conductor. Existing secondary services will be replaced or transferred to all new poles. The list of projects budgeted for 2020 include: • Adelaide St: Lawrence Ave to Belmont Ave - replace 8 poles • Wilson Ave: Traynor Ave to Franklin Blvd – replace 17 poles • Clive Rd: Brentwood Ave to Montgomery Rd – replace 10 poles • Boehmer St: Union St to Fairfield Ave – replace 13 poles • Rear of 341-405 Union Blvd: Aberdeen Rd to Westmount Rd W – replace 7 poles • Erb's Rd: Nafziger Rd to Wilmot-Easthope Rd - replace 35 poles • North St, New Dundee – replace 8 poles • Brunswick St: Blucher St to Hartwood Ave – replace 15 poles
Capital Investment (5.4.3.2.A.i)	**Description** — **Estimated Cost** **Labour:** $565,700 **Materials:** $261,700 **Contract:** $0 **Engineering:** $107,600
Capital Contributions (5.4.3.2.A.ii)	**Total Estimated Cost** **$935,000** **Recoverable:** $0 **KWHI Estimated Cost** **$935,000**
Customer Attachments / Load (kVA) (5.4.3.2.A.iii) **(where applicable)**	Approx. 440 customers /1,100 kVA transformation (assume 2.5 kVA per customer)

Project Name: Single Phase & Secondary Pole Line Rebuilds Due to Age and Condition

Project Dates (5.4.3.2.A.iv)	**Start Date:** January 1, 2020 **In Service Date:** December 31, 2020				
Estimated Expenditure Timing (5.4.3.2.A.iv)	**Q1**	**Q2**	**Q3**	**Q4**	
	$233,500	$234,000	$234,000	$233,500	

Schedule Risk and Risk Mitigation (5.4.3.2.A.v)

The project will be designed at least 3 months in advance of the scheduled construction date. KWHI works closely with other 3rd parties such as the City of Kitchener and the Township of Wilmot to get their requirements for system access projects at least 1 year in advance. This reduces the potential for last minute design and construction changes.

Comparative Information from Equivalent Projects (5.4.3.2.A.vi) **(where available)**

In 2018, a similar program was constructed in the City of Kitchener that involved the rebuilding of deteriorated pole lines. For example, the existing pole line on Wood Street was rebuilt with 11 new wood poles and stringing in 8 spans of new 1-#2 ACSR primary conductor and 10 Spans of new 2-4/0 Al, 1-2/0 ACSR & 1-#2 Al quadruplex secondary conductor. The project cost was $101,011 (approx. $9183 per pole). Another example would be the rebuilding of Gildner Street including 15 new wood poles, 9 spans of new 1-#2 ACSR primary conductor and 14 spans of new 2-4/0 Al, 1-2/0 ACSR & 1-#2 Al quadruplex secondary. The project cost was $111,993 (approx. $7,466 per pole).

Total Capital and OM&A Costs Associated with REG Investments (5.4.3.2.A.vii)

There is no REG investment associated with this program.

Leave to Construct Approval (5.4.3.2.A.viii) **(where applicable)**

N/A

Evaluation Criteria and Information (5.4.4.2.B)

Efficiency, Customer Value, Reliability (5.4.3.2.B.1)

Investment Driver (5.4.3.2.B.1.a)

Condition/Age/Failure Risk - the main driver for this project is the condition coupled with age of the poles and the risk of failure. The poles range in age from 44 to 60+ years old and have health indices of Very Poor to Good based on the 2018 ACA report. Majority of these pole lines have old 1-#2 ACSR or 1-#4 cu (40 + years old) primary conductor that has become brittle and is prone to breaking due to metal fatigue. The table below shows the distribution of pole age and condition, with over 70% of poles being older than 50-years and in Poor or Very Poor condition.

	AGE					
	0-10	**11-20**	**21-30**	**31-40**	**41-50**	**>50**
CONDITION	**Quantity**					
Very Good	3	1	-	-	-	-
Good	-	9	20	-	5	-
Fair	-	-	-	-	-	6
Poor	-	-	-	1	-	82
Very Poor	-	-	-	-	7	10

Project Name: Single Phase & Secondary Pole Line Rebuilds Due to Age and Condition

Secondary Driver (5.4.3.2.B.1.a) **(where applicable)**

Reliability – deteriorated poles deemed to be in poor shape are at risk for failure. A planned process for replacement minimizes the risk of overhead line failure and unplanned outages.

Good Utility Practice (5.4.3.2.B.1.b)

KWHI has an ongoing yearly planned process to replace deteriorated pole lines which will help improve the reliability.

Investment Priority (5.4.3.2.B.1.c)

The priority of this project relative to others is Medium. System Access (SA) projects have higher priority than System Renewal (SR) projects unless the condition of the assets associated with the SR project are in a very poor condition. One of our asset management strategies is to replace assets before they reach a stage of critical condition. KWHI's project Prioritization Tool was used to prioritize all material projects for 2020 and this project was ranked as 25 out of 31.

Analysis of Project and Project Alternatives – Effect of the investment on system operation efficiency and cost-effectiveness (5.4.3.2.B.1.d.i)

By planning the replacement of poles rather than forced replacement at the time of a failure, the cost per pole can be managed utilising regular work hours and/or competitive bids and therefore not subject to overtime premiums. Proactive replacement also means that additional objectives can be achieved such as coordination with 3rd parties (e.g. City of Kitchener and Township of Wilmot) for future road alignment change and system expansion (conductor upgrading for load transfers).

Analysis of Project & Alternatives – Net benefits accruing to customers (5.4.3.2.B.1.d.ii)

By rebuilding the pole lines and reconductoring, customers will experience an improvement in reliability (number of sustained outages). The risk associated with downed power lines will also reduce with the installation of poles, wires and associated hardware with higher structural strength.

Through a recently conducted customer engagement process, KWHI's customers overwhelmingly said that they support the proposed approach or an accelerated approach to replace poles. See excerpt below.

Customer Engagement Activity	% who support proposed approach to pole replacement or accelerated approach
Low-volume online workbook	**84%**
Residential telephone survey	**81%**
Small business telephone survey	**75%**

Analysis of Project & Alternatives – Impact of the investment on reliability performance including frequency and duration of outages (5.4.3.2.B.1.d.iii)

By rebuilding these pole lines and reconductoring, customers will experience an improvement in reliability (number of sustained outages). The risk associated with downed power lines will also reduce with the installation of poles, wires and associated hardware with higher structural strength.

Project Alternatives (Design, Scheduling, Funding/Ownership) (5.4.3.2.B.1.d.iii)

Project Design Alternatives:

i. Replace poles and hardware only and transfer existing conductor - the existing wire size is 1-#2 ACSR and/or 1-#4 cu and is the same age as the poles. It will be more difficult in the future to replace the wire without changing the poles. It is more cost effective to replace the wire at the same time as replacing the poles.
ii. Replace poles, wires and associated hardware – this is the preferred option which will maximize benefits to the customer and enhance safety.

Scheduling Alternatives:

If an unplanned job arises that has significantly higher priority than this job, a decision can be made to defer this project to a later date. However, not replacing end of life assets is not an option due to public safety impacts, system reliability and possible increasing OM&A costs.

Ownership Alternatives:

None. This project consists solely of KWHI's assets and is constructed on the public right-of-way.

Safety (5.4.3.2.B.2)

Replacement of these poles that are at the end of their useful life and in poor/fair condition will reduce the likelihood of unexpected pole failures. The program will also replace old conductors (40 year+) with smaller cross-sectional area which tend to break due to metal fatigue. Metal fatigue is the application and release of small stresses which weakens the metal resulting in an accumulation of small cracks. These small cracks grow slowly and eventually the metal becomes permanently deformed or breaks. Having "downed" primary wires on the ground creates a safety hazard for the public and workers.

Cyber-Security and Privacy (5.4.3.2.B.3) **(where applicable)**

This project does not impact cyber security or privacy.

Co-ordination and Interoperability (5.4.3.2.B.4)

Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.3.2.B.4.a) **(where applicable)**

The rebuilding of these pole lines will be co-ordinated with the City of Kitchener and Township of Wilmot for their planned road work.

Enabling of Future Technology and/or Future Operational Requirements (5.4.3.2.B.4.b)

This investment does not directly enable future technological functionality or operational requirements.

Environmental Benefits (5.4.3.2.B.2.B.5) **(where applicable)**

KWHI will be removing old poles which were predominately treated with chemicals that do not meet today's environmental standards. As a result, the new poles would adhere to current environmental standards.

Conservation and Demand Management (5.4.3.2.B.2.B.6) **(where applicable)**

N/A

Project Name: Single Phase & Secondary Pole Line Rebuilds Due to Age and Condition

System Renewal Specific Requirements (5.4.3.2.C.b)

Asset Performance Target and Asset Lifecycle Optimization (5.4.3.2.C.b.i.a)

The project supports the following asset performance and lifecycle optimization:

- Safety – by proactively replacing an end of life pole line, safety issues associated with pole failures or live wire down is avoided.
- Operation Effectiveness – reliability indices (SAIDI and SAIFI) will be improved by not running a pole line to failure.
- Customer Focus – replacing poles and wires that are at end of life and in poor condition will reduce the likelihood of a long duration unplanned outage due to equipment failure.

Asset Condition Relative to Typical Life Cycle (5.4.3.2.C.b.i.b)

Through a useful life of assets study conducted by Kinetics for KWHI coupled with local experience, KWHI has identified the typical useful life (TUL) of wood poles and associated hardware as 40 years. The poles identified for replacement ranges in age from 44 (1975) to 60+ (1959) years old. Most the poles that will be replaced have exceeded the TUL for wood poles and therefore have performed well.

Number of Customers Impacted (5.4.3.2.C.b.i.c)

The exact number of customers impacted in unknown**.**

Quantitative Customer Impact and Risk (5.4.3.2.C.b.i.d)

Usually 1-6 customers may be directly impacted by a pole failure, however the failure could lead to a higher customer impact if a feeder breaker opens. This project includes the replacement of up to 110 poles.

Qualitative Customer Impact and Risk (5.4.3.2.C.b.i.e)

If these pole lines are not rebuilt, the number of outages and outage duration may increase resulting in lower customer satisfaction. One of the drivers for the project is reliability improvement.

Value of Customer Impact (5.4.3.2.C.b.i.f)

The value of customer impact is medium. A failure in any of these line segments would impact residential customers for the entire outage duration. However, the initial customer impact could be higher if the feeder breaker opened for a pole/line failure.

Other Factors Affecting Project Timing (5.4.3.2.C.b.ii)

If an unplanned job arises that has significantly higher priority than this job, a decision can be made to defer some of this project to a later date. However, not replacing end of life assets is not a good option due to public safety impacts, system reliability and possible increasing OM&A costs.

Impact on System O&M Costs (5.4.3.2.C.b.iii)

- KWHI's current strategy for non-destructive pole testing is to test poles that are 40 years and older. By replacing poles in this program there will be no need to test them within the near future.
- Replacement of pole lines with new materials and higher design standards will also reduce the cost of future repairs that may arise from potential pole failures.
- If the project is not implemented, there is a strong likelihood that forced outages will continue to occur, resulting in possible overtime response.

Project Name: Single Phase & Secondary Pole Line Rebuilds Due to Age and Condition

Reliability and Safety Factors (5.4.3.2.C.b.iv)

By proactively replacing deteriorated pole lines which have reached their EOL asset value, reliability and safety issues associated with pole line failures are avoided.

Analysis of Project Benefits, Costs, Alternatives, and Timing (5.4.3.2.C.b.v)

The project to replace deteriorated single-phase pole lines is a constant in KWHI's yearly Capital Budget. It is recognized that waiting for EOL poles and conductors to fail and then replacing them is not our preferred option. This work takes significate engineering, coordination and scheduling. The cost implication of completing this work on an emergency basis is high. The decrease in customer satisfaction due to unplanned outages is high. In order to sustain our reliability and eliminate the risk of safety hazards, it is imperative that this project is ongoing.

Like-for-Like Renewal Analysis (5.4.3.2.C.b.vi)

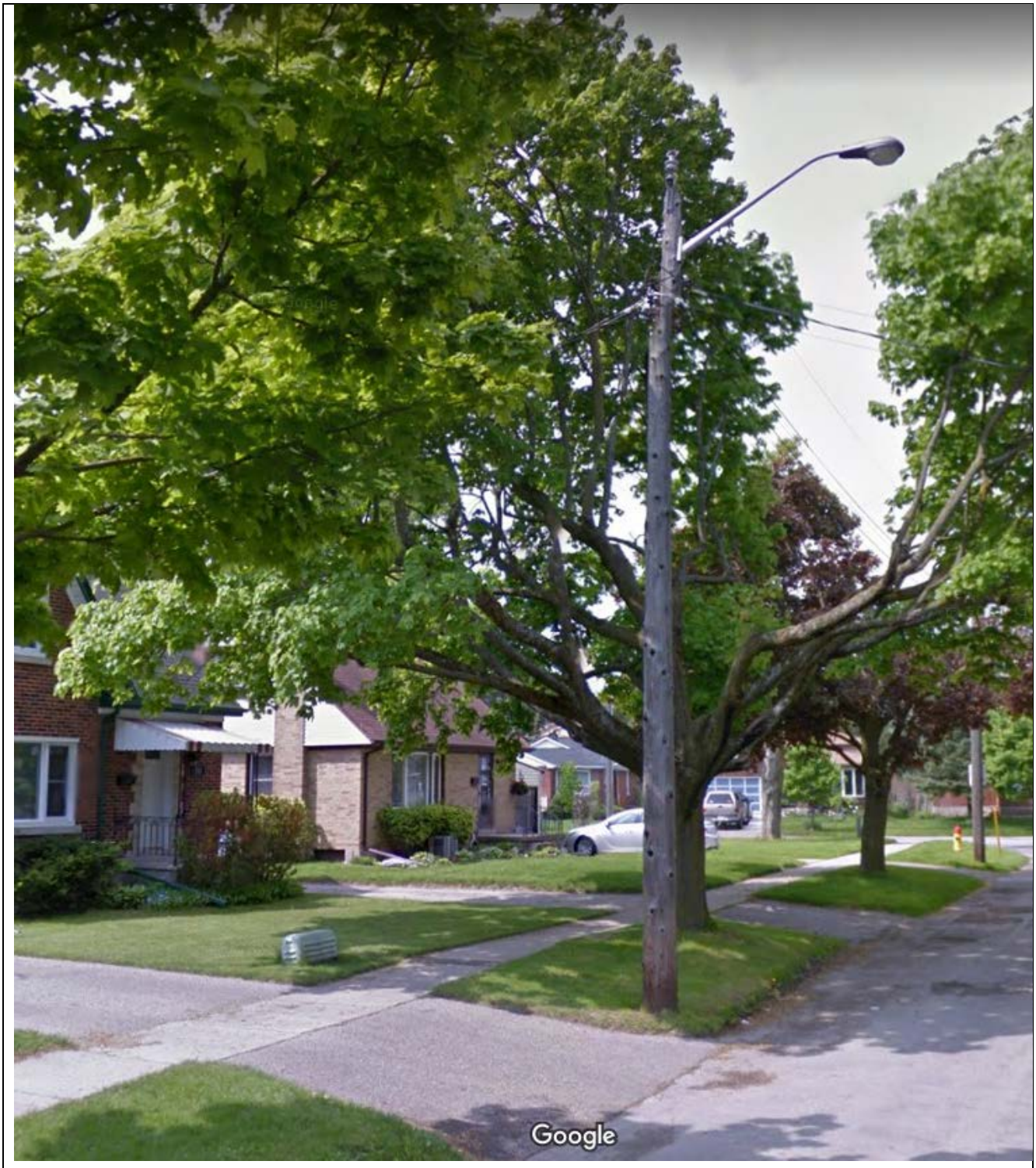
Yes, this program is considered a like-for-like replacement. Although these new distribution lines will be built to today's standards including improved pole sizes, hardware and equipment for proposed poles, they will remain single-phase pole lines feeding residential customers.

Images



Sample of scope of pole line rebuild – Adelaide St between Lawrence Ave and Belmont Ave

Project Name: Single Phase & Secondary Pole Line Rebuilds Due to Age and Condition



View of existing pole on Adelaide St – 1950 Vintage

Project Name: Single Phase & Secondary Pole Line Rebuilds Due to Age and Condition



View of existing pole on Wilson Ave – 1954 Vintage

Project Authorization

Prepared By: Sandy Ferneyhough

Date: December 18, 2018

Authorized By: G. Cameron

Date: April 5, 2019

Completion Date: _____

Capital Project Summary

Project Name: Notre Dame Drive: Wilby Road to Erbs Road, Township of Wilmot

Budget Year: 2020 **Budget Item No.:** 3-20-5 (part of)

OEB Investment Category: System Renewal

General Information on Project (5.4.4.2.A)

Project Summary	This is Stage 2 of a multi-stage project. The project consists of rebuilding an existing double circuit 3-ph pole line as a single circuit 3-ph pole line with 40 wood poles. The 37 spans of primary conductor will be replaced with 556 MCM ASC or approximately 1.7km in circuit length. Distribution class surge arrestors will be installed along the line at 500m intervals to improve lightning performance of the circuit. The existing lower 8.3 kV circuit will be removed and the loads converted to the new upper circuit at 27.6 kV. This line serves as a distribution feed to three 1-ph poles lines on side streets.
Capital Investment (5.4.3.2.A.i)	**Description** — **Estimated Cost** **Labour:** $205,000 **Materials:** $82,700 **Contract:** $13,500 **Engineering:** $39,100
Capital Contributions (5.4.3.2.A.ii)	**Total Estimated Cost** **$340,300** **Recoverable:** $0 **KWHI Estimated Cost** **$340,300**
Customer Attachments / Load (kVA) (5.4.3.2.A.iii) **(where applicable)**	31 customers /510 kVA transformation
Project Dates (5.4.3.2.A.iv)	**Start Date:** April 2020 **In Service Date:** June 2020

Estimated Expenditure Timing (5.4.3.2.A.iv)	**Q1**	**Q2**	**Q3**	**Q4**
	$0	**$**340,300	$0	$0

Project Name: Notre Dame Drive: Wilby Road to Erbs Road, Township of Wilmot

Schedule Risk and Risk Mitigation (5.4.3.2.A.v)

The project will be designed at least 3 months in advance of the scheduled construction date. KWHI will work closely with other 3rd parties such as the Region of Waterloo and Township of Wilmot to get their requirements for system access projects at least 1 year in advance to reduce the potential for last minute design and construction changes.

Comparative Information from Equivalent Projects (5.4.3.2.A.vi)

In 2018, a similar project was constructed in the Township of Wilmot (Nafziger Rd: Gerber Rd to Berletts Rd) that involved the rebuilding of a pole line with 57 new wood poles and stringing in 72 spans of new 3-556 ASC primary conductor. The project cost was $526,000 (approx. $9228 per pole).

Total Capital and OM&A Costs Associated with REG Investments (5.4.3.2.A.vii)

This project is not driven by REG investment. However, completion of this project will increase the load carrying capability of the feeder which will permit new REG to be connected.

Leave to Construct Approval (5.4.3.2.A.viii) **(where applicable)**

N/A

Evaluation Criteria and Information (5.4.4.2.B)

Efficiency, Customer Value, Reliability (5.4.3.2.B.1)

Investment Driver (5.4.3.2.B.1.a)

Condition/Age - the main driver for this project is the condition coupled with age of the poles. The poles range in age from 5 to 50 years old and has health indices of Poor to Good based on the 2018 ACA report. This section of pole line is connected to several other KWHI feeders (9M3 ,9M4, 9M9) and has been frequently used for load transfer during planned or unplanned outages. The old 336 MCM Al and 3/0 copper (40 + years old) conductor can only transfer maximum current of 500 amp. By rebuilding the pole line and reconductoring to 556 MCM Al, it will facilitate more load transfer capability (600A) of KWHI's distribution system.

	Age					
	0-10	**11-20**	**21-30**	**31-40**	**41-50**	**>50**
Condition	**Quantity**					
Very Good	1	-	-	-	-	-
Good	-	4	1	-	1	-
Fair	-	-	-	-	3	3
Poor	-	-	-	2	18	-
Very Poor	-	-	-	-	1	-

Secondary Driver (5.4.3.2.B.1.a) **(where applicable)**

Reliability and voltage conversion – the feeder that is being renewed has experienced several forced outages due to lightning, defective wood cross-arms and high wind gusts associated with easterly winds. Within the last 5 years, there has also been an incident where the 27.6 kV primary wires broke and came to the ground to contact the underbuilt 8.3 kV distribution lines as a result of an ice storm. KWHI has also started its voltage conversion program in the Township of Wilmot following the construction of its 28 kV No.9

Transformer Station and the area served by No. 3 DS will be converted within the next 5-years. This pole line is within this service area and will need to be rebuilt and insulated to 28 kV standards.

Good Utility Practice (5.4.3.2.B.1.b)

The source of information used to justify this investment are inspection/testing data, results from the Asset Conditions Survey conducted in 2018 and past failures of similar condition/type/age of overhead lines.

Investment Priority (5.4.3.2.B.1.c)

The priority of this project relative to others is Medium. System Access (SA) projects have higher priority than System Renewal (SR) projects unless the condition of the assets associated with the SR project is in a very poor condition. One of our asset management strategy is to replace assets before they reach a stage of critical condition. KWHI's project Prioritization Tool was used to prioritize all material projects for 2020 and this project was ranked as 15 out of 31.

Analysis of Project and Project Alternatives – Effect of the investment on system operation efficiency and cost-effectiveness (5.4.3.2.B.1.d.i)

By planning the replacement of poles rather than forced replacement at the time of a failure, the cost per pole can be managed utilizing regular work hours and/or competitive bids and therefore not subject to overtime premiums. Proactive replacement also means that additional objectives can be achieved such as coordination with 3rd parties (e.g. Region of Waterloo) for future road alignment change, system expansion and conductor upgrading for load transfers.

The rebuilding of this pole line is also required for voltage conversion from 4.8/8.32 kV to 16/27.6 kV which will reduce line losses, improve voltage profile, reduce ground currents and stray voltages, and allows for higher load transfer capability.

Analysis of Project & Alternatives – Net benefits accruing to customers (5.4.3.2.B.1.d.ii)

By rebuilding the pole line and reconductoring, customers will experience an improvement in reliability (number of sustained outages). The risk associated with downed power lines will also be reduced with the installation of poles, wires and associated hardware with higher structural strength.

Analysis of Project & Alternatives – Impact of the investment on reliability performance including frequency and duration of outages (5.4.3.2.B.1.d.iii)

By rebuilding the pole line and reconductoring, customers will experience an improvement in reliability (reduction in number of sustained outages). The risk associated with downed power lines will also be reduced with the installation of poles, wires and associated hardware with higher structural strength.

This section of pole line is connected to several other KWHI feeders (9M3, 9M4, 9M9). By rebuilding the pole line and reconductoring, it will facilitate more load transfer capability of KWHI's distribution system.

Project Alternatives (Design, Scheduling, Funding/Ownership (5.4.3.2.B.1.d.iii)

Project Design Alternatives:

i. Replace poles and hardware only and transfer existing conductor - the existing wire size is 336MCM Al. which does not have the electrical characteristics to allow 600 amps current according to KWHI maximum feeder load transfer requirements. 336 MCM AL conductor is non-standard with no replacement in KWHI's inventory.
ii. Replace poles, wires and associated hardware – this is the preferred option which will maximise benefits to the customer and enhance safety.

Project Name: Notre Dame Drive: Wilby Road to Erbs Road, Township of Wilmot

Scheduling Alternatives:

If an unplanned job arises that has significantly higher priority than this job, a decision can be made to defer this project to a later date. However, not replacing end of life assets is not an option due to public safety impacts, system reliability and possible increase in OM&A costs.

Ownership Alternatives:

None. This project consists solely of KWHI's assets and is constructed on the public right-of-way.

Safety (5.4.3.2.B.2)

Replacement of these poles that are at the end of their useful life and in poor/fair condition will reduce the likelihood of unexpected pole failures. The project will also replace non-standard and old conductors (50 year+) with smaller cross-sectional area which tend to break due to metal fatigue. Metal fatigue is the application and release of small stresses which weakens the metal resulting in an accumulation of small cracks. These small cracks grow slowly and eventually the metal becomes permanently deformed or breaks. Having "downed" primary wires on the ground creates a safety hazard for the public and workers.

Cyber-Security and Privacy (5.4.3.2.B.3) **(where applicable)**

This project does not impact cyber security or privacy.

Co-ordination and Interoperability (5.4.3.2.B.4)

Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.3.2.B.4.a) **(where applicable)**

The rebuilding of this pole line will be co-ordinated with the Township of Wilmot, Region of Waterloo, Bell Canada and Rogers Cable TV.

Enabling of Future Technology and/or Future Operational Requirements (5.4.3.2.B.4.b)

The pole line rebuild will facilitate more load transfer capability of KWHI's distribution system, permit higher DER penetration, reduce system losses, and improve voltage profile.

Environmental Benefits (5.4.3.2.B.2.B.5) **(where applicable)**

As part of the rebuild, KWHI will remove older poles which were predominantly treated with chemicals that do not meet today's environmental standards. As a result, rebuilding this pole line would be replacing older poles with poles that adhere to current environmental standards.

Conservation and Demand Management (5.4.3.2.B.2.B.6) **(where applicable)**

N/A

System Renewal Specific Requirements (5.4.3.2.C.b)

Asset Performance Target and Asset Lifecycle Optimization (5.4.3.2.C.b.i.a)

The project supports the following asset performance and lifecycle optimization:

- Safety – by proactively replacing the end of life pole line, safety issues associated with pole failures or live downed wires are avoided.
- Operation Effectiveness – reliability indices (SAIDI and SAIFI) will be improved by not running the pole line to failure.
- Customer Focus – replacing poles and wires that are at end of life and in poor condition will reduce the likelihood of a long duration unplanned outage due to equipment failure.

Asset Condition Relative to Typical Life Cycle (5.4.3.2.C.b.i.b)

Through a useful life of assets study conducted by Kinetics for KWHI coupled with local experience, KWHI has identified the typical useful life (TUL) of wood poles and associated hardware as 40 years. The poles identified for replacement ranges in age from 6 (2012) to 50 (1969) years old. Most of the poles (37) that will be replaced have exceeded the TUL for wood poles and therefore have performed well. Some poles (3) have not achieved a service life of 40 years old yet but will be replaced to facilitate a more efficient rebuild process for the entire line segment and consistency in structural integrity.

Number of Customers Impacted (5.4.3.2.C.b.i.c)

Although there are only 31 customers on this section, failure of assets associated with this line segment may cause outage which will impact the entire 9M7 feeder serving approximately 93 customers as well as the entire 8DS2 feeder servicing 181 customers.

Quantitative Customer Impact and Risk (5.4.3.2.C.b.i.d)

At least 31 customers are likely to be impacted by failure of assets associated with this line section. However, the initial customer impact could be higher (274) if the feeder breaker opened for a pole/line failure.

Qualitative Customer Impact and Risk (5.4.3.2.C.b.i.e)

If the pole line isn't rebuilt, the number of outages and outage duration may increase resulting in lower customer satisfaction. One of the drivers for the project is reliability improvement.

Value of Customer Impact (5.4.3.2.C.b.i.f)

The value of customer impact is low. A failure in this line segment would impact approximately 31 residential customers for the entire outage duration. However, the initial customer impact could be higher (274) if the feeder breaker opened for a pole/line failure.

Other Factors Affecting Project Timing (5.4.3.2.C.b.ii)

- Voltage Conversion – Stage 1 of the project is scheduled for 2019 and will see a section of the under-build 8.3 kV to be converted to 27.6 kV, which will leave Stage 2 without a viable backup in the case of an outage.
- Weather – because of the location of the pole line to be rebuilt (long, straight and rural road without curb) it is preferable to construct the pole line outside of Winter.

Impact on System O&M Costs (5.4.3.2.C.b.iii)

Project Name: Notre Dame Drive: Wilby Road to Erbs Road, Township of Wilmot

- KWHI's current strategy for non-destructive pole testing is to test poles that are 40 years and older. By replacing poles within this line segment there will be no need to test them within the near future.
- Replacement of the pole line with new materials and higher design standard will also reduce the cost of future repairs that may have arise from potential pole failures.
- If the project is not implemented, there is a strong likelihood that forced outages will continue to occur, resulting in possible overtime costs associated with responding to an outage outside working hours.

Reliability and Safety Factors (5.4.3.2.C.b.iv)

As discussed earlier.

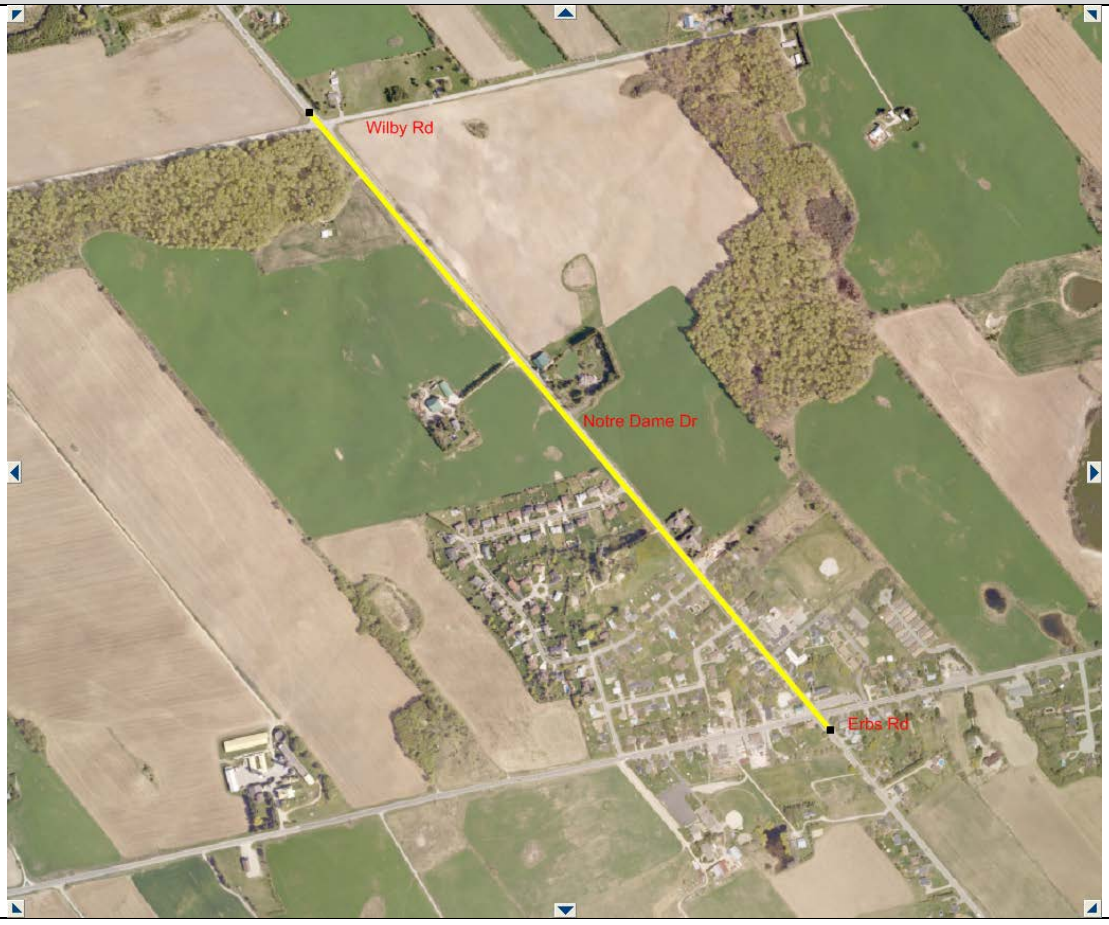
Analysis of Project Benefits, Costs, Alternatives, and Timing (5.4.3.2.C.b.v)

The rebuild of the pole line will avoid and/or reduce power outages. However, quantifying the financial benefit to customers impacted by this project is difficult. Maintaining the status quo ("Do Nothing") approach will result in possible future outages which will lead to customer dissatisfaction and unplanned work.

Like-for-Like Renewal Analysis (5.4.3.2.C.b.vi)

No, this project is not a like-for-like replacement. This new distribution line will be built to today's standards including improved pole sizes, hardware, equipment and reduced spacing for proposed poles. Through voltage conversion, this distribution line will be reduced from 2 primary 3-ph circuits to 1 primary 3-ph circuit.

Images



Project Name: Notre Dame Drive: Wilby Road to Erbs Road, Township of Wilmot

Scope of the pole line project – 1.7 km on Notre Dame Dr between Wilby Rd and Erbs Rd, Township of Wilmot



View of existing pole - 1969 Vintage



View of Existing Pole – 1970 vintage

Project Name: Notre Dame Drive: Wilby Road to Erbs Road, Township of Wilmot

Project Authorization	
Prepared By: Sandy Ferneyhough	Authorized By: G. Cameron
Date: December 18, 2018	Date: April 5, 2019
	Completion Date: _____

Capital Project Summary

Project Name: Bridge Street: Puddicombe Road to Pinehill Road, Township of Wilmot

Budget Year: 2020 **Budget Item No.:** 3-20-5 (part of)

OEB Investment Category: System Renewal

General Information on Project (5.4.4.2.A)

Project Summary	The project consists of rebuilding an existing 1-ph pole line circuit with 45 wood poles. The 45 spans of primary conductor will be replaced with 1-3/0 ACSR or approximately 2.5 km in circuit length. The existing neutral will also be replaced with 1-3/0 ACSR. Distribution class surge arrestors will be installed along the line at 500 m intervals to improve lightning performance of the circuit.
Capital Investment (5.4.3.2.A.i)	**Description** — **Estimated Cost** **Labour:** $184300 **Materials:** $58,300 **Contract:** $12,900 **Engineering:** $33,200
Capital Contributions (5.4.3.2.A.ii)	**Total Estimated Cost** **$288,700** **Recoverable:** $0 **KWHI Estimated Cost** **$288,700**
Customer Attachments / Load (kVA) (5.4.3.2.A.iii) **(where applicable)**	5 customers /122.5 kVA transformation
Project Dates (5.4.3.2.A.iv)	**Start Date:** **October 2020** **In Service Date: December 2020**

Estimated Expenditure Timing (5.4.3.2.A.iv)	**Q1**	**Q2**	**Q3**	**Q4**
	$0	$0	$0	**$**288,700

Schedule Risk and Risk Mitigation (5.4.3.2.A.v)

The project will be designed at least 3 months in advance of the scheduled construction date. KWHI will work closely with other 3rd parties such as the Township of Wilmot to get their requirements for system access projects at least 1 year in advance to reduce the potential for last minute design and construction changes.

Comparative Information from Equivalent Projects (5.4.3.2.A.vi) **(where available)**

In 2018, a similar project was constructed in the Township of Wilmot. Oxford-Waterloo Rd between Puddicombe Rd and Tye Rd involved the rebuilding of a pole line with 42 new wood poles and stringing in 42 spans of new 1-3/0 ACSR primary and 1-3/0 ACSR neutral conductors. The project cost was $304,700 (approx. $7,254 per pole).

Total Capital and OM&A Costs Associated with REG Investments (5.4.3.2.A.vii)

There is no REG investment associated with this project.

Leave to Construct Approval (5.4.3.2.A.viii) **(where applicable)**

N/A

Evaluation Criteria and Information (5.4.4.2.B)

Efficiency, Customer Value, Reliability (5.4.3.2.B.1)

Investment Driver (5.4.3.2.B.1.a)

Condition/Age - the main driver for this project is the condition coupled with age of the poles. The poles range in age from 44 to 70 years old and has health indices of Very Poor to Good based on the 2018 ACA report.

	Age					
	0-10	**11-20**	**21-30**	**31-40**	**41-50**	**>50**
Condition	**Quantity**					
Very Good	-	-	-	-	-	-
Good	-	1	-	-	23	-
Fair	-	-	-	-	-	6
Poor	-	-	-	-	1	-
Very Poor	-	-	-	-	-	4

Secondary Driver (5.4.3.2.B.1.a) **(where applicable)**

Reliability and voltage conversion – the feeder that is being renewed has experienced several forced outages due to lightning, defective porcelain insulators and broken wires. KWHI has also started its voltage conversion program in the Township of Wilmot following the construction of its 28 kV No.9 Transformer Station and the area served by No. 3 DS will be converted within the next 5-years. This pole line is within this service area and will need to be rebuild and insulated to 28 kV standards.

Good Utility Practice (5.4.3.2.B.1.b)

Project Name: Bridge Street: Puddicombe Road to Pinehill Road, Township of Wilmot

The source of information used to justify this investment are inspection/testing data, results from the Asset Condition Assessment survey conducted in 2018 and past failures of similar condition/type/age of overhead lines.

Investment Priority (5.4.3.2.B.1.c)

The priority of this project relative to others is Medium. System Access (SA) projects have higher priority than System Renewal (SR) projects unless the condition of the assets associated with the SR project is in a very poor condition. One of our asset management strategies is to replace assets before they reach a stage of critical condition. KWHI's project Prioritization Tool was used to prioritize all material projects for 2020 and this project was ranked as 19 out of 31.

Analysis of Project and Project Alternatives – Effect of the investment on system operation efficiency and cost-effectiveness (5.4.3.2.B.1.d.i)

By planning the replacement of poles rather than forced replacement at the time of a failure, the cost per pole can be managed utilizing regular work hours and/or competitive bids and therefore not subject to overtime premiums. Proactive replacement also means that additional objectives can be achieved such as coordination with 3rd parties (e.g. Township of Wilmot) for future road alignment changes, system expansion and conductor upgrading for load transfers.

The rebuilding of this pole line is also required for voltage conversion from 4.8/8.32 kV to 16/27.6 kV which will reduce line losses, improve voltage profile, reduce ground currents and stray voltages, and allows for higher load transfer capability.

Analysis of Project & Alternatives – Net benefits accruing to customers (5.4.3.2.B.1.d.ii)

By rebuilding the pole line and reconductoring, customers will experience an improvement in reliability (number of sustained outages). The risk associated with downed power lines will also be reduced with the installation of new poles, wires and associated hardware with higher structural strength.

Analysis of Project & Alternatives – Impact of the investment on reliability performance including frequency and duration of outages (5.4.3.2.B.1.d.iii)

By rebuilding the pole line and reconductoring, customers will experience an improvement in reliability (number of sustained outages). The risk associated with downed power lines will also be reduced with the installation of new poles, wires and associated hardware with higher structural strength.

Project Alternatives (Design, Scheduling, Funding/Ownership (5.4.3.2.B.1.d.iii)

Project Design Alternatives:

i. Replace poles and hardware only and transfer existing conductor - the existing wire size is 1-#2 ACSR and 1-#4 cu which does not have the mechanical characteristics to allow line crews to safely work on these line segments. Moreover, the copper wire accessories are not readily available and more expensive and have longer lead time to purchase than corresponding aluminum conductors.
ii. Replace poles, wires and associated hardware – this is the preferred option which will maximise benefits to the customer and enhance safety.

Scheduling Alternatives:

If an unplanned job arises that has significantly higher priority than this job, a decision can be made to defer this project to a later date. However, not replacing end of life assets is not an option due to public safety impacts, system reliability and possible increase in OM&A costs.

Ownership Alternatives:

None. This project consists solely of KWHI's assets and is constructed on the public right-of-way.

Safety (5.4.3.2.B.2)

Replacement of these poles that are at the end of their useful life and in poor/fair condition will reduce the likelihood of unexpected pole failures. The project will also replace old conductors (50 year+) with smaller cross-sectional area which tend to break due to metal fatigue. Metal fatigue is the application and release of small stresses which weakens the metal resulting in an accumulation of small cracks. These small cracks grow slowly and eventually the metal becomes permanently deformed or breaks. Having "downed" primary wires on the ground creates a safety hazard for the public and workers.

Cyber-Security and Privacy (5.4.3.2.B.3) **(where applicable)**

This project does not impact cyber security or privacy.

Co-ordination and Interoperability (5.4.3.2.B.4)

Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.3.2.B.4.a) **(where applicable)**

The rebuilding of this pole line will be co-ordinated with the Township of Wilmot for their planned road work.

Enabling of Future Technology and/or Future Operational Requirements (5.4.3.2.B.4.b)

The pole line rebuild will facilitate future voltage conversion of the distribution feeder which will permit higher DER penetration, reduce system losses, and improve voltage profile.

Environmental Benefits (5.4.3.2.B.2.B.5) **(where applicable)**

As part of the rebuild, KWHI will remove older poles which were predominantly treated with chemicals that do not meet today's environmental standards. As a result, rebuilding this pole line would be replacing older poles with poles that adhere to current environmental standards.

Conservation and Demand Management (5.4.3.2.B.2.B.6) **(where applicable)**

N/A

Project Name: Bridge Street: Puddicombe Road to Pinehill Road, Township of Wilmot

System Renewal Specific Requirements (5.4.3.2.C.b)

Asset Performance Target and Asset Lifecycle Optimization (5.4.3.2.C.b.i.a)

The project supports the following asset performance and lifecycle optimization:

- Safety – by proactively replacing the end of life pole line, safety issues associated with pole failures or live downed wires is avoided.
- Operation Effectiveness – reliability indices (SAIDI and SAIFI) will be improved by not running the pole line to failure.
- Customer Focus – replacing poles and wires that are at end of life and in poor condition will reduce the likelihood of a long duration unplanned outage due to equipment failure.

Asset Condition Relative to Typical Life Cycle (5.4.3.2.C.b.i.b)

Through a useful life of assets study conducted by Kinetics for KWHI coupled with local experience, KWHI has identified the typical useful life (TUL) of wood poles and associated hardware as 40 years. The poles identified for replacement ranges in age from 44 (1975) to 70 (1949) years old. All the poles (34) that will be replaced have exceeded the TUL for wood poles and therefore have performed well.

Number of Customers Impacted (5.4.3.2.C.b.i.c)

There are 5 customers on this section that would be impacted from a power outage.

Quantitative Customer Impact and Risk (5.4.3.2.C.b.i.d)

There are 5 customers are likely to be impacted by failure of assets associate with this line section.

Qualitative Customer Impact and Risk (5.4.3.2.C.b.i.e)

If the pole line isn't rebuilt, the number of outages and outage duration may increase resulting in lower customer satisfaction. One of the drivers for the project is reliability improvement.

Value of Customer Impact (5.4.3.2.C.b.i.f)

The value of customer impact is low. A failure in this line segment would impact approximately 5 residential customers for the entire outage duration.

Other Factors Affecting Project Timing (5.4.3.2.C.b.ii)

Weather – because of the location of the pole line to be rebuilt (long, straight and rural road) it is preferable to construct the pole line outside of winter.

Impact on System O&M Costs (5.4.3.2.C.b.iii)

- KWHI's current strategy for non-destructive pole testing is to test poles that are 40 years and older. By replacing poles within this line segment there will be no need to test them within the near future.
- Replacement of the pole line with new materials and higher design standards will also reduce the cost of future repairs that may arise from potential pole failures.
- If the project is not implemented, there is a strong likelihood that forced outages will continue to occur, resulting in possible overtime response.

Project Name: Bridge Street: Puddicombe Road to Pinehill Road, Township of Wilmot

Reliability and Safety Factors (5.4.3.2.C.b.iv)

By proactively replacing this deteriorated pole line which has reached it's EOL asset value, reliability and safety issues associated with pole lines failing are avoided.

Analysis of Project Benefits, Costs, Alternatives, and Timing (5.4.3.2.C.b.v)

The rebuild of the pole line will avoid and/or reduce power outages. However, quantifying the financial benefit to customers impacted by this project is difficult. Maintaining the status quo ("Do Nothing") approach will result in possible future outages which will lead to customer dissatisfaction and unplanned work.

Like-for-Like Renewal Analysis (5.4.3.2.C.b.vi)

Yes, this project is considered a like-for-like replacement. Although this new distribution line will be built to today's standards including improved pole sizes, hardware, equipment and reduced spacing for proposed poles, it will remain a single-phase pole line feeding rural residential customers.

Images



Scope of the pole line project – 2.5 km on Bridge St between Puddicombe Rd and Pinehill Rd, Township of Wilmot



View of existing pole - 1959 Vintage



View of Existing Pole – 1973 vintage

Project Name: Bridge Street: Puddicombe Road to Pinehill Road, Township of Wilmot

Project Authorization	
Prepared By: Sandy Ferneyhough	Authorized By: G. Cameron
Date: December 18, 2018	Date: April 5, 2019
	Completion Date: _____

Capital Project Summary

Project Name: Wilby Road between Nafziger Road and the Nith River, Township of Wilmot

Budget Year: 2020 **Budget Item No.:** 3-20-5 (part of)

OEB Investment Category: System Renewal

General Information on Project (5.4.4.2.A)

Project Summary	The project consists of rebuilding an existing circuit 1-ph pole line with 27 wood poles. The 27 spans of primary conductor will be replaced with 1-3/0 ACSR or approximately 1.5 km in circuit length. The existing neutral will also be replaced with 1-3/0 ACSR. Distribution class surge arrestors will be installed along the line at 500 m intervals to improve lightning performance of the circuit. The project will replace an end of life pole line and associated hardware and will facilitate voltage conversion from 4.8/8.32 kV to 16.0/27.6 kV.
Capital Investment (5.4.3.2.A.i)	**Description** — **Estimated Cost** **Labour:** $122,100 **Materials:** $37,700 **Contract:** $10,800 **Engineering:** $22,200
Capital Contributions (5.4.3.2.A.ii)	**Total Estimated Cost** **$192,800** **Recoverable:** $0 **KWHI Estimated Cost** **$192,800**
Customer Attachments / Load (kVA) (5.4.3.2.A.iii) **(where applicable)**	5 customers /125 kVA transformation
Project Dates (5.4.3.2.A.iv)	**Start Date:** **July 2020** **In Service Date: September 2020**

Estimated Expenditure Timing (5.4.3.2.A.iv)	**Q1**	**Q2**	**Q3**	**Q4**
	$0	$0	$192,800	$0

Project Name: Wilby Road between Nafziger Road and the Nith River, Township of Wilmot

Schedule Risk and Risk Mitigation (5.4.3.2.A.v)

The project will be designed at least 3 months in advance of the scheduled construction date. KWHI will work closely with other 3rd parties such as the Township of Wilmot to get their requirements for system access projects at least 1 year in advance to reduce the potential for last minute design and construction changes.

Comparative Information from Equivalent Projects (5.4.3.2.A.vi) **(where available)**

In 2018, a similar project was constructed in the Township of Wilmot on Oxford-Waterloo Rd between Puddicombe Rd and Tye Rd that involved the rebuilding of a pole line with 42 new wood poles and stringing in 42 spans of new 1-3/0 ACSR primary and neutral conductor. The project cost was $304,700 (approx. $7,254 per pole).

Total Capital and OM&A Costs Associated with REG Investments (5.4.3.2.A.vii)

There is no REG investment associated with this project.

Leave to Construct Approval (5.4.3.2.A.viii) **(where applicable)**

N/A

Evaluation Criteria and Information (5.4.4.2.B)

Efficiency, Customer Value, Reliability (5.4.3.2.B.1)

Investment Driver (5.4.3.2.B.1.a)

Condition/Age - the main driver for this project is the condition coupled with age of the poles. The poles range in age from 39 to 70 years old and have health indices of poor to fair based on the 2018 ACA report.

	Age					
	0-10	**11-20**	**21-30**	**31-40**	**41-50**	**>50**
Condition	**Quantity**					
Very Good	-	-	-	-	-	-
Good	-	-	-	-	-	-
Fair	-	-	-	-	-	19
Poor	-	-	-	2	1	-
Very Poor	-	-	-	-	-	1

Secondary Driver (5.4.3.2.B.1.a) **(where applicable)**

Reliability and Voltage Conversion – the feeder is being renewed to provide increased reliability for our customers. A planned process minimizes the risk of overhead line failure. It also assists in significantly reducing the likelihood of future unplanned customer outages. KWHI has also started its voltage conversion program in the Township of Wilmot following the construction of it's 28 kV No.9 Transformer Station. This pole line is part of the No. 5DS and No. 8DS service areas which have already started to be converted to 16/27.6 kV.

Good Utility Practice (5.4.3.2.B.1.b)

The source of information used to justify this investment are inspection/testing data, results from the Asset Conditions Survey conducted in 2018 and past failures of similar condition/type/age of overhead lines.

Project Name: Wilby Road between Nafziger Road and the Nith River, Township of Wilmot

Investment Priority (5.4.3.2.B.1.c)

The priority of this project relative to others is Low. System Access (SA) projects have higher priority that System Renewal (SR) projects unless the condition of the assets associated with the SR project is in a very poor condition. One of our asset management strategies is to replace assets before they reach a stage of critical condition. KWHI's project Prioritization Tool was used to prioritize all material projects for 2020 and this project was ranked as 27 out of 31.

Analysis of Project and Project Alternatives – Effect of the investment on system operation efficiency and cost-effectiveness (5.4.3.2.B.1.d.i)

By planning the replacement of poles rather than forced replacement at the time of a failure, the cost per pole can be managed utilising regular work hours and/or competitive bids and therefore not subject to overtime premiums. Proactive replacement also means that additional objectives can be achieved such as coordination with 3rd parties (e.g. Township of Wilmot) for future road alignment changes.

The rebuilding of this pole line is also required for voltage conversion from 4.8/8.32 kV to 16/27.6 kV which will reduce line losses, improve voltage profile, reduce ground currents and stray voltages, and allows for higher load transfer capability.

Analysis of Project & Alternatives – Net benefits accruing to customers (5.4.3.2.B.1.d.ii)

By rebuilding the pole line and reconductoring, customers will experience an improvement in reliability (number of sustained outages). The risk associated with downed power lines will also reduce with the installation of poles, wires and associated hardware with higher structural strength.

Analysis of Project & Alternatives – Impact of the investment on reliability performance including frequency and duration of outages (5.4.3.2.B.1.d.iii)

By rebuilding the pole line and reconductoring, customers will experience an improvement in reliability (number of sustained outages). The risk associated with downed power lines will also reduce with the installation of poles, wires and associated hardware with higher structural strength.

Project Alternatives (Design, Scheduling, Funding/Ownership (5.4.3.2.B.1.d.iii)

Project Design Alternatives:

Replace the poles and conductor once they have failed – this is not advisable. The cost for replacement would be much higher if completed on an emergency basis than on a planned basis. This would lead to longer outages and increase in customer dissatisfaction.

Scheduling Alternatives:

If an unplanned job arises that has significantly higher priority than this job, a decision can be made to defer this project to a later date. However, not replacing end of life assets is not an option due to public safety impacts, system reliability and possible increase in OM&A costs.

Ownership Alternatives:

None. This project consists solely of KWHI's assets and is constructed on the public right-of-way.

Project Name: Wilby Road between Nafziger Road and the Nith River, Township of Wilmot

Safety (5.4.3.2.B.2)

Replacement of these poles that are at the end of their useful life and in poor/fair condition will reduce the likelihood of unexpected pole failures. The project will also replace old conductors (50 year+) with smaller cross-sectional area which tend to break due to metal fatigue. Metal fatigue is the application and release of small stresses which weakens the metal resulting in an accumulation of small cracks. These small cracks grow slowly and eventually the metal becomes permanently deformed or breaks. Having "downed" primary wires on the ground creates a safety hazard for the public and workers.
Rebuilding of this pole line is completed in accordance with KWHI's standards and Ontario Regulation 22/04 to ensure no undue safety hazards. Work is inspected by KWHI and signed off as safe prior to energization.

Cyber-Security and Privacy (5.4.3.2.B.3) **(where applicable)**

This project does not impact cyber security or privacy.

Co-ordination and Interoperability (5.4.3.2.B.4)

Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.3.2.B.4.a) **(where applicable)**

The rebuilding of this pole line will be co-ordinated with the Township of Wilmot for their planned road work.

Enabling of Future Technology and/or Future Operational Requirements (5.4.3.2.B.4.b)

N/A

Environmental Benefits (5.4.3.2.B.2.B.5) **(where applicable)**

As part of the rebuild, KWHI will remove older poles which were predominantly treated with chemicals that do not meet today's environmental standards. As a result, rebuilding this pole line would be replacing older poles with poles that adhere to current environmental standards.

Conservation and Demand Management (5.4.3.2.B.2.B.6) **(where applicable)**

N/A

System Renewal Specific Requirements (5.4.3.2.C.b)

Asset Performance Target and Asset Lifecycle Optimization (5.4.3.2.C.b.i.a)

The project supports the following asset performance and lifecycle optimization:

- Safety – by proactively replacing the end of life pole line, safety issues associated with pole failures or live downed wire is avoided.
- Operation Effectiveness – reliability indices (SAIDI and SAIFI) will be improved by not running the pole line to failure.
- Customer Focus – replacing poles and wires that are at end of life and in poor condition will reduce the likelihood of a long duration unplanned outage due to equipment failure.

Asset Condition Relative to Typical Life Cycle (5.4.3.2.C.b.i.b)

Through a useful life of assets study conducted by Kinetics for KWHI coupled with local experience, KWHI has identified the typical useful life (TUL) of wood poles and associated hardware as 40 years. The poles identified for replacement ranges in age from 39 (1980) to 70 (1949) years old. Almost all the poles (22) that will be replaced have exceeded the TUL for wood poles and therefore have performed well.

Number of Customers Impacted (5.4.3.2.C.b.i.c)

There are 5 customers which are likely to be impacted by failure of assets associate with this line section.

Quantitative Customer Impact and Risk (5.4.3.2.C.b.i.d)

There are 5 customers which are likely to be impacted by failure of assets associate with this line section.

Qualitative Customer Impact and Risk (5.4.3.2.C.b.i.e)

If the pole line isn't rebuilt, the number of outages and outage duration may increase resulting in lower customer satisfaction. One of the drivers for the project is reliability improvement.

Value of Customer Impact (5.4.3.2.C.b.i.f)

The value of customer impact is low. A failure in this line segment would impact approximately 5 customers for the entire outage duration.

Other Factors Affecting Project Timing (5.4.3.2.C.b.ii)

Weather – because of the location of the pole line to be rebuilt (long, straight and rural road) it is preferable to construct the pole line outside of winter.

Impact on System O&M Costs (5.4.3.2.C.b.iii)

- KWHI's current strategy for non-destructive pole testing is to test poles that are 40 years and older. By replacing poles within this line segment there will be no need to test them within the near future.
- Replacement of the pole line with new materials and higher design standards will also reduce the cost of future repairs that may arise from potential pole failures.
- If the project is not implemented, there is a strong likelihood that forced outages will continue to occur, resulting in possible overtime response.

Reliability and Safety Factors (5.4.3.2.C.b.iv)

As discussed earlier.

Project Name: Wilby Road between Nafziger Road and the Nith River, Township of Wilmot

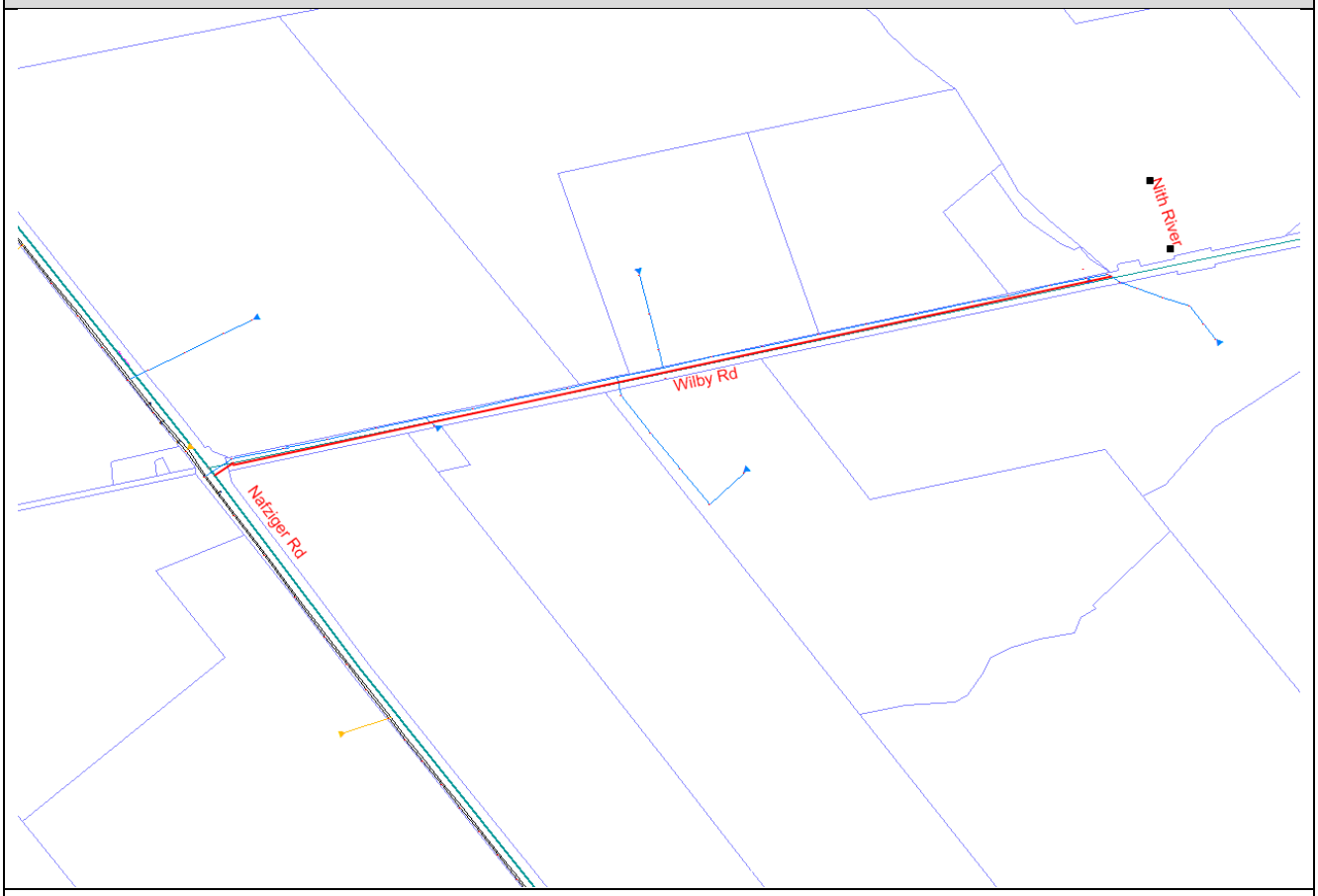
Analysis of Project Benefits, Costs, Alternatives, and Timing (5.4.3.2.C.b.v)

The rebuild of the pole line will avoid and/or reduce power outages. However, quantifying the financial benefit to customers impacted by this project is difficult. Maintaining the status quo ("Do Nothing") approach will result in possible future outages which will lead to customer dissatisfaction and unplanned work.

Like-for-Like Renewal Analysis (5.4.3.2.C.b.vi)

Yes, this project is considered a like-for-like replacement. Although this distribution line will be built to today's standards including improved pole sizes, hardware, equipment and reduced spacing for proposed poles, it will remain a single-phase pole line feeding rural residential customers.

Images



Scope of the pole line project – 1.5 km on Wilby Road between Nafziger Rd and the Nith River, Township of Wilmot

Project Name: Wilby Road between Nafziger Road and the Nith River, Township of Wilmot



View of existing pole - 1949 Vintage

Project Name: Wilby Road between Nafziger Road and the Nith River, Township of Wilmot



View of Existing Pole – 1949 vintage

Project Authorization

Prepared By:	Sandy Ferneyhough	Authorized By:	G. Cameron
Date:	December 18, 2018	Date:	April 5, 2019
		Completion Date:	_____

CAPITAL PROJECT SUMMARY

Project Name: 4M26 Feeder - Pole Line Rebuild-Stage 1-H1 ROW from Fischer-Hallman Road to Westmount Road West

Budget Year: 2020 **Budget Item No**.: 3-20-8

OEB Investment Category: System Renewal

General Information on Project (5.4.4.2.A)

Project Summary

This is Stage 1 of a multi-stage project. This project consists of rebuilding an existing single circuit 3-ph pole line with 22 wood poles. The 23 spans of existing 556 MCM Al primary conductor and existing 1-3/0 ACSR neutral conductor will be transferred to the new poles. The existing load interrupter switch will be replaced with an Automated Recloser. This is approximately 0.9 km in circuit length. The pole line is at end of life and was flagged for replacement in the recently completed ACA.

Capital Investment (5.4.3.2.A.i)

Description	Estimated Cost
Labour:	$158,300
Materials:	$75,000
Contract:	$9,400
Engineering:	$21,800

Capital Contributions (5.4.3.2.A.ii)

Total Estimated Cost	**$264,500**
Recoverable:	$0
KWHI Estimated Cost	**$264,500**

Customer Attachments / Load (kVA) (5.4.3.2.A.iii) **(where applicable)**

1 customer /150 kVA transformation directly connected to the line section to be rebuilt. However, this line segment is the start of a distribution feeder from No. 4TS with over 1,800 customers connected to it.

Project Dates (5.4.3.2.A.iv)

Start Date: April 2020

In Service Date: June 2020

Estimated Expenditure Timing (5.4.3.2.A.iv)

Q1	Q2	Q3	Q4
$0	$264,500	$0	$0

Project Name: 4M26 Feeder - Pole Line Rebuild-Stage 1-H1 ROW from Fischer-Hallman Road to Westmount Road West

Schedule Risk and Risk Mitigation (5.4.3.2.A.v)

The project will be designed at least 3 months in advance of the scheduled construction date. KWHI works closely with other 3rd parties such as the Region of Waterloo to get their requirements for system access projects at least 1 year in advance to reduce the potential for last minute design and construction changes.

Comparative Information from Equivalent Projects (5.4.3.2.A.vi) **(where available)**

In 2016, a similar project was constructed in the City of Kitchener on Cedar Street between Courtland Avenue and Charles Street East. There were 16 poles replaced and existing 3-556 MCM Al and secondary conductor transferred to the new poles. The cost per pole was $15,442. This proposed project has a lower cost per pole due to the ability to completely isolate the pole line being rebuilt and construct the line in a de-energized manner. There is also significantly less services to be transferred.

Total Capital and OM&A Costs Associated with REG Investments (5.4.3.2.A.vii)

There is no REG investment associated with this program.

Leave to Construct Approval (5.4.3.2.A.viii) **(where applicable)**

N/A

Evaluation Criteria and Information (5.4.4.2.B)

Efficiency, Customer Value, Reliability (5.4.3.2.B.1)

Investment Driver (5.4.3.2.B.1.a)

Condition/Age/Failure Risk - the main driver for this project is the condition coupled with age of the poles and the risk of failure. The poles range in age from 16 to 44 years old and has health indices of poor to fair based on the 2018 ACA report. This section of pole line is connected to several other KWHI feeders (1M3, 6M21, 6M25)) from different transformer stations and has been frequently used for load transfer during planned or unplanned outages.

	Age					
	0-10	11-20	21-30	31-40	41-50	>50
Condition	Quantity					
Very Good	-	-	-	-	-	-
Good	-	1	2	-	-	-
Fair	-	-	1	1	2	-
Poor	-	-	-	9	-	-
Very Poor	-	-	-	-	8	-

Secondary Driver (5.4.3.2.B.1.a) **(where applicable)**

Reliability – the feeder is being renewed to provide increased reliability for our customers. A planned process minimizes the risk of overhead line failure. It also assists in significantly reducing the likelihood of future unplanned customer outages.

Project Name: 4M26 Feeder - Pole Line Rebuild-Stage 1-H1 ROW from Fischer-Hallman Road to Westmount Road West

Good Utility Practice (5.4.3.2.B.1.b)

The source of information used to justify this investment are inspection/testing data, results from the Asset Condition Assessment conducted in 2018 and past failures of similar condition/type/age of overhead lines.

Investment Priority (5.4.3.2.B.1.c)

The priority of this project relative to others is Medium. System Access (SA) projects have higher priority than System Renewal (SR) projects unless the condition of the assets associated with the SR project are in a very poor condition. One of our asset management strategies is to replace assets before they reach a stage of critical condition. KWHI's project Prioritization Tool was used to prioritize all material projects for 2020 and this project was ranked as 20 out of 31.

Analysis of Project and Project Alternatives – Effect of the investment on system operation efficiency and cost-effectiveness (5.4.3.2.B.1.d.i)

By planning the replacement of poles rather than forced replacement at the time of a failure, the cost per pole can be managed utilising regular work hours and/or competitive bids and therefore not subject to overtime premiums. Proactive replacement also means that additional objectives can be achieved such as coordination with 3rd parties (e.g. Region of Waterloo) for future road alignment changes, system expansion and conductor upgrading for load transfers.

Analysis of Project & Alternatives – Net benefits accruing to customers (5.4.3.2.B.1.d.ii)

By rebuilding the pole line, customers will experience an improvement in reliability (number of sustained outages). The risk associated with downed power lines will also reduce with the installation of poles, wires and associated hardware with higher structural strength.

Analysis of Project & Alternatives – Impact of the investment on reliability performance including frequency and duration of outages (5.4.3.2.B.1.d.iii)

By rebuilding the pole line, customers will experience an improvement in reliability (number of sustained outages). The risk associated with downed power lines will also reduce with the installation of poles, wires and associated hardware with higher structural strength.

This section of pole line is connected to several other KWHI feeders (1M3, 6M21, 6M25) from different transformer stations and has been frequently used for load transfer during planned or unplanned outages. By rebuilding the pole line and reconductoring, it will facilitate more load transfer capability of KWHI's distribution system.

Project Alternatives (Design, Scheduling, Funding/Ownership (5.4.3.2.B.1.d.iii)

Project Design Alternatives:

i. Replace poles, wires and associated hardware – By replacing the wires as well as the poles and hardware, this will maximise benefits to the customer and enhance safety however it will be replacing a conductor which has not reached it's EOL and thus increasing costs.
ii. Replace poles once they have failed – this is not advisable. The cost for replacement would be much higher if completed on an emergency basis than on a planned basis. This would lead to longer outages and increase in customer dissatisfaction.

Scheduling Alternatives:

If an unplanned job arises that has significantly higher priority than this job, a decision can be made to defer this project to a later date. However, not replacing end of life assets is not an option due to public safety impacts, system reliability and possible increase in OM&A costs.

Project Name: 4M26 Feeder - Pole Line Rebuild-Stage 1-H1 ROW from Fischer-Hallman Road to Westmount Road West

Ownership Alternatives:

None. This project consists solely of KWHI's assets and is constructed on the Hydro One Networks right-of-way.

Safety (5.4.3.2.B.2)

Replacement of these poles that are at the end of their useful life and in poor/fair condition will reduce the likelihood of unexpected pole failures which could cause a safety hazard for the public and workers.

Cyber-Security and Privacy (5.4.3.2.B.3) **(where applicable)**

This project does not impact cyber security or privacy.

Co-ordination and Interoperability (5.4.3.2.B.4)

Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.3.2.B.4.a) **(where applicable)**

The rebuilding of this pole line will be co-ordinated with Region of Waterloo and Hydro One Networks Inc. for their planned road work.

Enabling of Future Technology and/or Future Operational Requirements (5.4.3.2.B.4.b)

The existing manual load interrupter switch will be replaced with an automated recloser that will be integrated into KWHI's SCADA system allowing remote operation and faster outage response times. The recloser will also be capable of automatically isolating all faults that are downstream of its installed location.

Environmental Benefits (5.4.3.2.B.2.B.5) **(where applicable)**

As part of the rebuild, KWHI will remove older poles which were predominantly treated with chemicals that do not meet today's environmental standards. As a result, rebuilding this pole line would be replacing older poles with poles that adhere to current environmental standards.

Conservation and Demand Management (5.4.3.2.B.2.B.6) **(where applicable)**

N/A

Project Name: 4M26 Feeder - Pole Line Rebuild-Stage 1-H1 ROW from Fischer-Hallman Road to Westmount Road West

System Renewal Specific Requirements (5.4.3.2.C.b)

Asset Performance Target and Asset Lifecycle Optimization (5.4.3.2.C.b.i.a)

The project supports the following asset performance and lifecycle optimization:

- Safety – by proactively replacing the end of life pole line, safety issues associated with pole failures or live downed wire is avoided.
- Operational Effectiveness – reliability indices (SAIDI and SAIFI) will be improved by not running the pole line to failure.
- Customer Focus – replacing poles and wires that are at end of life and in poor condition will reduce the likelihood of a long duration unplanned outage due to equipment failure.

Asset Condition Relative to Typical Life Cycle (5.4.3.2.C.b.i.b)

Through a useful life of assets study conducted by Kinetics for KWHI coupled with local experience, KWHI has identified the typical useful life (TUL) of wood poles and associated hardware as 40 years. The poles identified for replacement range in age from 16 (2003) to 44 (1975) years old. Most of the poles (19) that will be replaced have exceeded the TUL for wood poles and therefore have performed well. Some poles (3) have not achieved a service life of 40 years yet but will be replaced to facilitate a more efficient rebuild process for the entire line segment and consistency in structural integrity.

Number of Customers Impacted (5.4.3.2.C.b.i.c)

Although there is only 1 customer on this section, failure of assets associated with this line segment may cause outage which will impact the entire 4M26 feeder serving approximately 1873 residential and general class customers (industrial and institutional).

Quantitative Customer Impact and Risk (5.4.3.2.C.b.i.d)

At least 1 customer is likely to be impacted by failure of assets associate with this line section. However, the initial customer impact could be higher (1,873) if the feeder breaker opened for a pole/line failure.

Qualitative Customer Impact and Risk (5.4.3.2.C.b.i.e)

If the pole line isn't rebuilt, the number of outages and outage duration may increase resulting in lower customer satisfaction. One of the drivers for the project is reliability improvement.

Value of Customer Impact (5.4.3.2.C.b.i.f)

The value of customer impact is low. A failure in this line segment would impact 1 customer for the entire outage duration. However, the initial customer impact could be higher (1,873) if the feeder breaker opened for a pole/line failure.

Other Factors Affecting Project Timing (5.4.3.2.C.b.ii)

Weather – because of the location of the pole line to be rebuilt (H1 ROW), it is preferable to construct the pole line outside of spring to avoid wet conditions. This will help minimize restorations due to truck access to the site.

Impact on System O&M Costs (5.4.3.2.C.b.iii)

- KWHI's current strategy for non-destructive pole testing is to test poles that are 40 years and older. By replacing poles within this line segment there will be no need to test them within the near future.

Project Name: 4M26 Feeder - Pole Line Rebuild-Stage 1-H1 ROW from Fischer-Hallman Road to Westmount Road West

- Replacement of the pole line with new materials and higher design standards will also reduce the cost of future repairs that may arise from potential pole failures.
- If the project is not implemented, there is a strong likelihood that forced outages will continue to occur, resulting in possible overtime cost associated with responding to an outage outside working hours.

Reliability and Safety Factors (5.4.3.2.C.b.iv)

As discussed earlier.

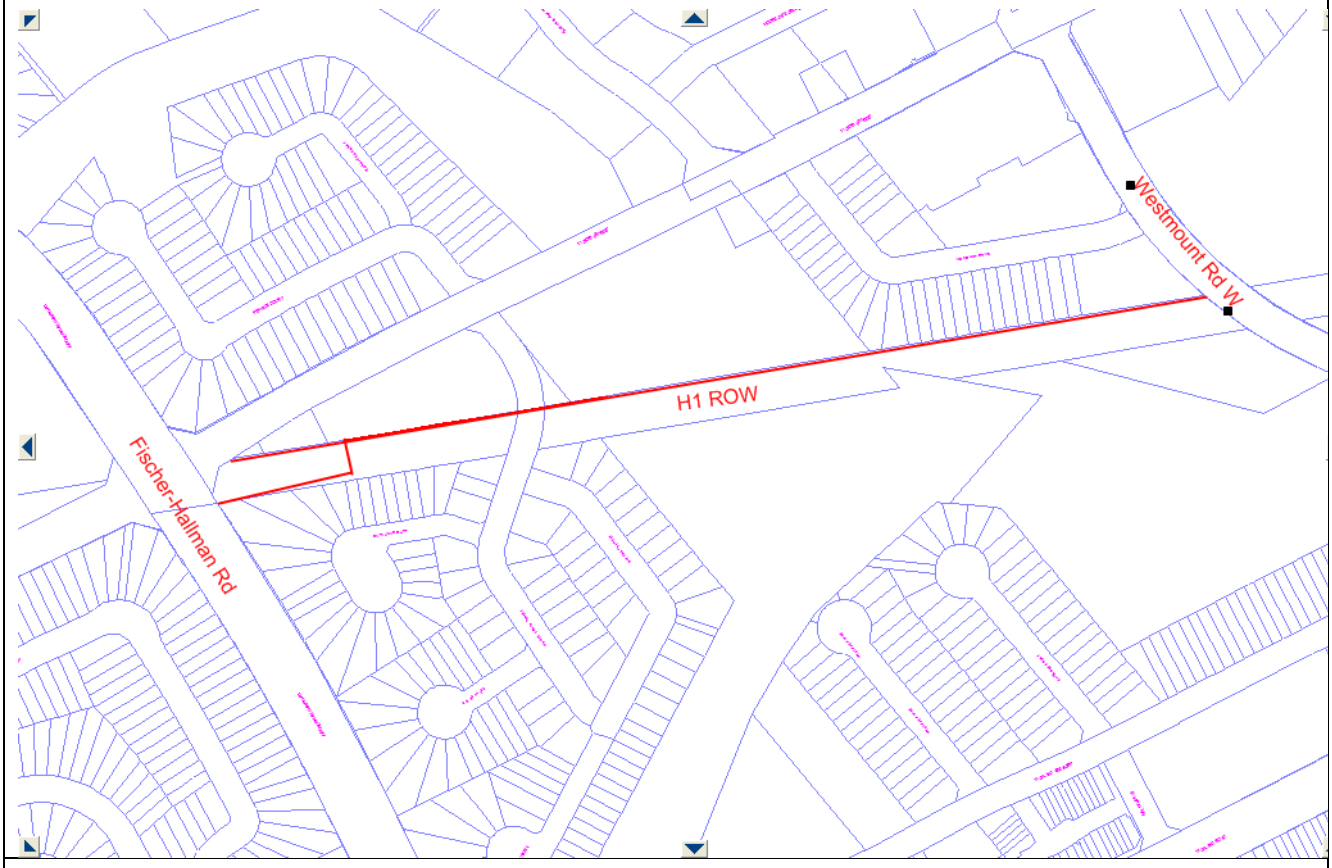
Analysis of Project Benefits, Costs, Alternatives, and Timing (5.4.3.2.C.b.v)

The rebuild of the pole line will avoid and/or reduce power outages. However, quantifying the financial benefit to customers impacted by this project is difficult. Maintaining the status quo ("Do Nothing") approach will result in possible future outages which will lead to customer dissatisfaction and unplanned work.

Like-for-Like Renewal Analysis (5.4.3.2.C.b.vi)

Yes, this project is considered a like-for-like replacement. This existing 3-ph distribution line will be built to today's standards including improved poles sizes, hardware and equipment. The existing load interrupter switch will be upgraded to an automated recloser.

Images



Scope of the pole line project – 0.9 km on H1 ROW between Fischer-Hallman Rd and Westmount Rd W

Project Name: 4M26 Feeder - Pole Line Rebuild-Stage 1-H1 ROW from Fischer-Hallman Road to Westmount Road West



View of existing pole - 1989 Vintage

Project Name: 4M26 Feeder - Pole Line Rebuild-Stage 1-H1 ROW from Fischer-Hallman Road to Westmount Road West



View of Existing Pole – 1977 vintage

Project Authorization

Prepared By:	Sandy Ferneyhough	Authorized By:	G. Cameron
Date:	December 18, 2018	Date:	April 5, 2019
		Completion Date:	_____

CAPITAL PROJECT SUMMARY

Project Name: 6M11 Feeder – H1 ROW between rear of 83 Trailwood Crescent to Royal Orchard Drive

Budget Year: 2020 **Budget Item No.:** 3-20-9

OEB Investment Category: System Renewal

General Information on Project (5.4.4.2.A)

Project Summary	The project consists of rebuilding an existing single circuit 3-ph pole line with 36 wood poles. The existing 37 spans of 3-556 MCM Al primary conductor and 1-3/0 ACSR neutral conductor will be transferred to the new poles, existing LI-594 to be replaced with an Automated Recloser. The pole line is at end of life and was flagged for replacement in the recently completed ACA.
Capital Investment (5.4.3.2.A.i)	**Description** — **Estimated Cost** **Labour:** $202,500 **Materials:** $107,300 **Contract:** $11,300 **Engineering:** $32,000
Capital Contributions (5.4.3.2.A.ii)	**Total Estimated Cost** **$353,100** **Recoverable:** $0 **KWHI Estimated Cost** **$353,100**
Customer Attachments / Load (kVA) (5.4.3.2.A.iii) **(where applicable)**	3 customers /750 kVA transformation
Project Dates (5.4.3.2.A.iv)	**Start Date: July 2020** **In Service Date: September 2020**

Estimated Expenditure Timing (5.4.3.2.A.iv)	**Q1**	**Q2**	**Q3**	**Q4**
	$0	$0	$353,100	$0

Schedule Risk and Risk Mitigation (5.4.3.2.A.v)

The project will be designed at least 3 months in advance of the scheduled construction date. KWHI will work closely with other 3rd parties such as the Region of Waterloo and the City of Kitchener to get their requirements for system access projects at least 1 year in advance to reduce the potential for last minute design and construction changes.

Comparative Information from Equivalent Projects (5.4.3.2.A.vi) **(where available)**
In 2016, a similar project was constructed in the City of Kitchener on Cedar Street between Courtland Avenue and Charles Street East. There were 16 poles replaced and existing 3-556 MCM Al and secondary conductor transferred to the new poles. The cost per pole was $15,442. This proposed project has a lower cost per pole due to the ability to completely isolate the pole line being rebuilt and construct the line in a de-energized manner. There are also significantly less services to be transferred.

Total Capital and OM&A Costs Associated with REG Investments (5.4.3.2.A.vii)

There is no REG investment associated with this program.

Leave to Construct Approval (5.4.3.2.A.viii) **(where applicable)**

N/A

Evaluation Criteria and Information (5.4.4.2.B)

Efficiency, Customer Value, Reliability (5.4.3.2.B.1)

Investment Driver (5.4.3.2.B.1.a)

Condition/Age/Failure Risk - the main driver for this project is the condition coupled with age of the poles and the risk of failure. The poles are 44 years old (1975) and have health indices of Poor to Good based on the 2018 ACA report. This section of pole line is connected to several other KWHI feeders (6M231, 6M25) and has been frequently used for load transfer during planned or unplanned outages.

	Age					
	0-10	**11-20**	**21-30**	**31-40**	**41-50**	**>50**
Condition	**Quantity**					
Very Good	1	-	-	-	-	-
Good	-	2	1	-	-	-
Fair	-	-	-	-	7	-
Poor	-	-	-	-	14	-
Very Poor	-	-	-	-	11	-

Secondary Driver (5.4.3.2.B.1.a) **(where applicable)**

Reliability – the feeder is being renewed to provide increased reliability for our customers. A planned process minimizes the risk of overhead line failure. It also assists in significantly reducing the likelihood of future unplanned customer outages.

Good Utility Practice (5.4.3.2.B.1.b)

The sources of information used to justify this investment are inspection/testing data, results from the Asset Condition Assessment conducted in 2018 and past failures of similar condition/type/age of overhead lines.

Project Name: 6M11 Feeder – H1 ROW between rear of 83 Trailwood Crescent to Royal Orchard Drive

Investment Priority (5.4.3.2.B.1.c)

The priority of this project relative to others is Medium. System Access (SA) projects have higher priority that System Renewal (SR) projects unless the condition of the assets associated with the SR project are in very poor condition. One of our asset management strategies is to replace assets before they reach a stage of critical condition. KWHI's project Prioritization Tool was used to prioritize all material projects for 2020 and this project was ranked as 14 out of 31.

Analysis of Project and Project Alternatives – Effect of the investment on system operation efficiency and cost-effectiveness (5.4.3.2.B.1.d.i)

By planning the replacement of poles rather than forced replacement at the time of a failure, the cost per pole can be managed utilising regular work hours and/or competitive bids and therefore not subject to overtime premiums.

Analysis of Project & Alternatives – Net benefits accruing to customers (5.4.3.2.B.1.d.ii)

By rebuilding the pole line, customers will experience an improvement in reliability (number of sustained outages). The risk associated with unplanned outages will also be reduced with the installation of new poles and associated hardware with higher structural strength.

Analysis of Project & Alternatives – Impact of the investment on reliability performance including frequency and duration of outages (5.4.3.2.B.1.d.iii)

By rebuilding the pole line, customers will experience an improvement in reliability (number of sustained outages). The risk associated unplanned outages will also be reduced with the installation of new poles and associated hardware with higher structural strength.

Project Alternatives (Design, Scheduling, Funding/Ownership (5.4.3.2.B.1.d.iii)

Project Design Alternatives:

- Replace poles, wires and associated hardware – by replacing the wires as well as the poles and hardware, this will maximise benefits to the customer and enhance safety however it will be replacing a conductor which has not reached it's EOL and thus increasing costs.
- Replace the poles once they have failed – this is not advisable. The cost for replacement would be much higher if completed on an emergency basis than on a planned basis. This would lead to longer outages and increase in customer dissatisfaction.

Scheduling Alternatives:

If an unplanned job arises that has significantly higher priority than this job, a decision can be made to defer this project to a later date. However, not replacing end of life assets is not an option due to public safety impacts, system reliability and possible increasing in OM&A costs.

Ownership Alternatives:

This project consists solely of KWHI's assets and is constructed on an easement on the Hydro One Networks right of way.

Safety (5.4.3.2.B.2)

Replacement of these poles that are at the end of their useful life and in poor/fair condition will reduce the likelihood of unexpected pole failures and possible downed wires. Having downed wires on the ground creates a safety hazard for the public and workers.

Cyber-Security and Privacy (5.4.3.2.B.3) **(where applicable)**

This project does not impact cyber security or privacy.

Co-ordination and Interoperability (5.4.3.2.B.4)

Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.3.2.B.4.a) **(where applicable)**

The rebuilding of this pole line will be co-ordinated with the Region of Waterloo and Hydro One Networks for their planned road work.

Enabling of Future Technology and/or Future Operational Requirements (5.4.3.2.B.4.b)

The existing manual load interrupter switch will be replaced with an automated recloser that will be integrated into KWHI's SCADA system allowing remote operation and faster outage response times. The recloser will also be capable of automatically isolating all faults that are downstream of its installed location.

Environmental Benefits (5.4.3.2.B.2.B.5) **(where applicable)**

KWHI will be removing old poles which were predominantly treated with chemicals that do not meet today's environmental standards. As a result, the new poles would adhere to current environmental standards.

Conservation and Demand Management (5.4.3.2.B.2.B.6) **(where applicable)**

N/A

System Renewal Specific Requirements (5.4.3.2.C.b)

Asset Performance Target and Asset Lifecycle Optimization (5.4.3.2.C.b.i.a)

The project supports the following asset performance and lifecycle optimization:

- Safety – by proactively replacing the end of life pole line, safety issues associated with pole failures or live downed wire is avoided.
- Operational Effectiveness – reliability indices (SAIDI and SAIFI) will be improved by not running the pole line to failure.
- Customer Focus – replacing poles that are at end of life and in poor condition will reduce the likelihood of a long duration unplanned outage due to equipment failure.

Asset Condition Relative to Typical Life Cycle (5.4.3.2.C.b.i.b)

Through a useful life of assets study conducted by Kinetics for KWHI coupled with local experience, KWHI has identified the typical useful life (TUL) of wood poles and associated hardware as 40 years. The poles identified for replacement are 44 (1975) years old. All the poles (36) that will be replaced have exceeded the TUL for wood poles and therefore have performed well.

Number of Customers Impacted (5.4.3.2.C.b.i.c)

Although there are only 3 customers on this section, failure of assets associated with this line segment may cause outage which will impact the entire 6M11 feeder serving approximately 741 residential and general class customers (industrial and institutional).

Quantitative Customer Impact and Risk (5.4.3.2.C.b.i.d)

At least 3 customers are likely to be impacted by failure of assets associate with this line section. However, the initial customer impact could be higher (741) if the feeder breaker opened for a pole/line failure.

Qualitative Customer Impact and Risk (5.4.3.2.C.b.i.e)

If the pole line isn't rebuilt, the number of outages and outage duration may increase resulting in lower customer satisfaction. One of the drivers for the project is reliability improvement.

Value of Customer Impact (5.4.3.2.C.b.i.f)

The value of customer impact is low. A failure in this line segment would impact approximately 3 customers for the entire outage duration. However, the initial customer impact could be higher (741) if the feeder breaker opened for a pole/line failure.

Other Factors Affecting Project Timing (5.4.3.2.C.b.ii)

Weather – because of the location of the pole line to be rebuilt (Hydro One ROW) it is preferable to construct the pole line outside of spring to avoid wet conditions. This will help minimize restorations due to truck access to the site.

Impact on System O&M Costs (5.4.3.2.C.b.iii)

- KWHI's current strategy for non-destructive pole testing is to test poles that are 40 years and older. By replacing poles within this line segment there will be no need to test them within the near future.
- Replacement of the pole line with new materials and higher design standard will also reduce the cost of future repairs that may have arisen from potential pole failures.
- If the project is not implemented, there is a strong likelihood that forced outages will continue to occur, resulting in possible overtime cost associated with responding to an outage outside working hours.

Project Name: 6M11 Feeder – H1 ROW between rear of 83 Trailwood Crescent to Royal Orchard Drive

Reliability and Safety Factors (5.4.3.2.C.b.iv)

By proactively replacing deteriorated poles with have reached their EOL asset value, reliability and safety issues associated with poles failing are avoided.

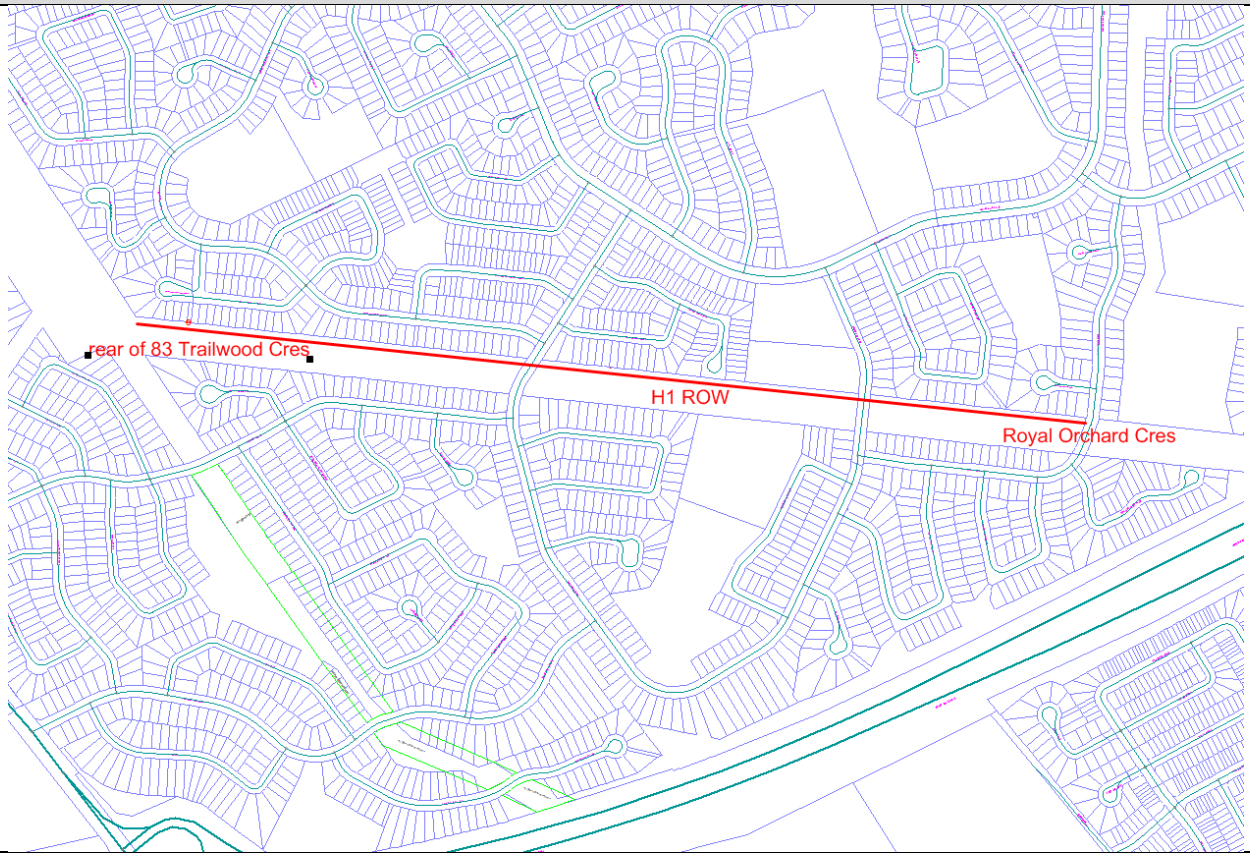
Analysis of Project Benefits, Costs, Alternatives, and Timing (5.4.3.2.C.b.v)

The rebuild of the pole line will avoid and/or reduce power outages. However, quantifying the financial benefit to customers impacted by this project is difficult. Maintaining the status quo ("Do Nothing") approach will result in possible future outages which will lead to customer dissatisfaction and unplanned work.

Like-for-Like Renewal Analysis (5.4.3.2.C.b.vi)

Yes, this project is considered a like-for-like replacement. However, this existing single 3-ph distribution line will be built to today's standards including improved pole sizes, hardware and equipment. The existing load interrupter switch will be upgraded to an automated recloser.

Images



Scope of the pole line project – 1.6km H1 ROW from rear of 83 Trailwood Cres to Royal Orchard Dr



View of existing pole - 1975 Vintage

Project Name: 6M11 Feeder – H1 ROW between rear of 83 Trailwood Crescent to Royal Orchard Drive



View of Existing Pole – 1975 vintage

Project Authorization

Prepared By: Sandy Ferneyhough

Date: December 19, 2018

Authorized By: G. Cameron

Date: April 5, 2019

Completion Date: _____

CAPITAL PROJECT SUMMARY

Project Name: Victoria Street North between Weber Street West and Margaret Avenue

Budget Year: 2020 **Budget Item No.:** 3-20-10

OEB Investment Category: System Renewal

General Information on Project (5.4.4.2.A)

Project Summary	The project consists of rebuilding an existing single circuit 3-ph pole line and replacing it with a double circuit 3-ph pole line with 20 wood poles. The existing 500 MCM Copper 3-phase primary conductor will be replaced in the lower circuit position with 556 MCM ASC for approximately 550 m in circuit length. A new 3-556 MCM ASC upper circuit will also be installed for future expansion. Framing for both primary circuits will be road side vertical construction to allow for more clearance from existing buildings along the route. The existing 8 spans of 4 open wire secondary buss will be replaced with 2-4/0 Al, 1-2/0 ACSR & 1-#2 Al quadruplex secondary conductor and 11 spans of existing quadruplex will be transferred. A new automated recloser will be installed in the lower circuit. All existing overhead services will be transferred to new poles. The line section to be replaced contains a concentration of poles that were rated Poor to Fair in the Asset Condition Assessment (ACA) conducted in 2018. This rebuild is on a high traffic street, with a combination of residential and commercial customers as well as multiple radial 3-ph taps. This project will be considered for completion by an outside Contractor via a competitive bid process in an attempt to reduce the costs.
Capital Investment (5.4.3.2.A.i)	**Description** / **Estimated Cost** **Labour:** $0 **Materials:** $112,400 **Contract:** $401,000 **Engineering:** $60,800
Capital Contributions (5.4.3.2.A.ii)	**Total Estimated Cost** **$574,200** **Recoverable:** $0 **KWHI Estimated Cost** **$574,200**
Customer Attachments / Load (kVA) (5.4.3.2.A.iii) **(where applicable)**	41 customers /295 kVA transformation
Project Dates (5.4.3.2.A.iv)	**Start Date:** **April 2020** **In Service Date: June 2020**

Project Name: Victoria Street North between Weber Street West and Margaret Avenue

Estimated Expenditure Timing (5.4.3.2.A.iv)	Q1	Q2	Q3	Q4	
	$0	$574,200	$0	$0	

Schedule Risk and Risk Mitigation (5.4.3.2.A.v)

- The Region of Waterloo has some planned road work in this area in 2021. A possible schedule change may expedite or delay the proposed pole line project.
- Availability of resources to design and construct the pole line considering other higher priority jobs that were not known in advance. To mitigate this risk, the project will be designed at least 3 months in advance of the scheduled construction date. KWHI has access to external contractors who are often used to supplement the internal resources. Also, KWHI works closely with other 3rd parties such as the Region and City to get their requirements for system access projects at least 1 year in advance to reduce the potential for last minute design and construction.

Comparative Information from Equivalent Projects (5.4.3.2.A.vi) **(where available)**

In 2017, KWHI rebuilt an existing pole line on Ottawa Street North between Franklin Ave and River Rd E. replacing 25 single 3-ph circuit with 25 double 3-ph circuit poles, transferring the existing 3-556 MCM ASC primary circuit, stringing new 3-556 MCM ASC primary and new secondary conductors. The total cost was $331,325 ($13,253 /pole). Some noticeable differences however are that there were no automated reclosers installed and the existing 3-ph circuit was transferred and not replaced. This job was completed by a Contractor via a competitive bid process.

Total Capital and OM&A Costs Associated with REG Investments (5.4.3.2.A.vii)

This project is not driven by REG investment. However, completion of this project will increase the load carrying capability of the feeder which will permit new REG to be connected.

Leave to Construct Approval (5.4.3.2.A.viii) **(where applicable)**

N/A

Evaluation Criteria and Information (5.4.4.2.B)

Efficiency, Customer Value, Reliability (5.4.3.2.B.1)

Investment Driver (5.4.3.2.B.1.a)

Condition/Age/Failure Risk - the main driver for this project is the condition coupled with age of the poles and the risk of failure. The poles range in age from (6 to 62 years old) and have health indices of Poor to Very Good based on the pole inspection results and ACA conducted in 2018. This section of pole line is connected to several other KWHI feeders (1M1, 1M8, 4M12, 4M27, 5M11, 5M14, 5M27) from different transformer stations and has been frequently used for load transfer during planned or unplanned outages. The old 4/0 copper (50 years +) conductor can only carry 500amp current. By rebuilding the pole line and reconductoring to 556 MCM ASC, it will facilitate more load transfer capability (600A) of KWHI's distribution system.

	Age					
	0-10	11-20	21-30	31-40	41-50	>50
Condition	Quantity					
Very Good	3	-	-	-	-	-
Good	1	3	1	-	-	-
Fair	-	-	3	-	6	2
Poor	-	-	-	-	-	7
Very Poor	-	-	-	-	-	-

Project Name: Victoria Street North between Weber Street West and Margaret Avenue

Secondary Driver (5.4.3.2.B.1.a) **(where applicable)**

System Expansion – the secondary driver for this project is system expansion to supply load growth. An additional supply feeder is being planned from Kitchener No. 4TS to interconnect with feeder 5M11 from Kitchener No. 5TS and help with off-loading the No.5 Transformer Station. This section of pole line will serve as part of the proposed route and will include provision for a second circuit.

Good Utility Practice (5.4.3.2.B.1.b)

The sources of information used to justify this investment are inspection/testing data, results from the Asset Condition Assessment conducted in 2018 and past failures of similar condition/type/age of overhead lines. KWHI has an ongoing process to replace deteriorated plants.

Investment Priority (5.4.3.2.B.1.c)

The priority of this project relative to others is Medium. System Access (SA) projects have higher priority than System Renewal (SR) projects unless the condition of the assets associated with the SR project are in very poor condition. One of our asset management strategies is to replace assets before they reach a stage of critical condition. KWHI's project Prioritization Tool was used to prioritize all material projects for 2020 and this project was ranked as 22 out of 31.

Analysis of Project and Project Alternatives – Effect of the investment on system operation efficiency and cost-effectiveness (5.4.3.2.B.1.d.i)

By planning the replacement of poles rather than forced replacement at the time of a failure, the cost per pole can be managed utilising regular work hours and/or competitive bids and is therefore not subject to overtime premiums. Proactive replacement also means that additional objectives can be achieved such as coordination with 3rd parties (e.g. Region of Waterloo) for future road alignment change and system expansion (conductor upgrading for load transfers).

Analysis of Project & Alternatives – Net benefits accruing to customers (5.4.3.2.B.1.d.ii)

By rebuilding the pole line and reconductoring, customers will experience an improvement in reliability (number of sustained outages). The risk associated with downed power lines will also be reduced with the installation of poles, wires and associated hardware with higher structural strength.

Analysis of Project & Alternatives – Impact of the investment on reliability performance including frequency and duration of outages (5.4.3.2.B.1.d.iii)

By rebuilding the pole line and reconductoring, customers will experience an improvement in reliability (number of sustained outages). The risk associated with downed power lines will also be reduced with the installation of poles, wires and associated hardware with higher structural strength.

This section of pole line is connected to several other KWHI feeders (1M1, 1M8, 4M12, 4M27, 5M11, 5M14, 5M27) from different transformer stations and has been frequently used for load transfers during planned or unplanned outages. By rebuilding the pole line and reconductoring, it will facilitate more load transfer capability of KWHI's distribution system.

Project Alternatives (Design, Scheduling, Funding/Ownership (5.4.3.2.B.1.d.iii)

Project Design Alternatives:

i. Replace poles and hardware only and transfer existing conductor - the existing wire size is 500 MCM copper and the copper wire accessories are not readily available, are more expensive, and have longer lead time to purchase than corresponding aluminum conductor.

ii. Replace poles, wires and associated hardware, single circuit only – this is not the preferred option. If system planning indicates a future need, it is more cost effective to add the new circuit at the same time as the rebuild.
iii. Rebuild pole line on the opposite side of the road – This is not a viable option due to the limited boulevard and close proximity to buildings.

Scheduling Alternatives:

If an unplanned job arises that has significantly higher priority than this job, a decision can be made to defer this project to a later date. However, not replacing end of life asset is not an option due to public safety impacts, system reliability and possible increasing in OM&A costs.

Ownership Alternatives:

None. This project consists solely of KWHI's assets and is constructed on the public right-of-way

Safety (5.4.3.2.B.2)

Replacement of these poles that are at the end of their useful life and in poor/fair condition will reduce the likelihood of unexpected pole failures and downed wires. Having downed wires on the ground creates a safety hazard for the public and workers.

Cyber-Security and Privacy (5.4.3.2.B.3) **(where applicable)**

This project does not impact cyber security or privacy

Co-ordination and Interoperability (5.4.3.2.B.4)

Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.3.2.B.4.a) **(where applicable)**

The rebuilding of this pole line will be co-ordinated with the Region of Waterloo, City of Kitchener, Bell Canada and Rogers Cable TV.

Enabling of Future Technology and/or Future Operational Requirements (5.4.3.2.B.4.b)

The pole line rebuild will facilitate more load transfer capability of KWHI's distribution system.

Environmental Benefits (5.4.3.2.B.2.B.5) **(where applicable)**

As part of the rebuild, KWHI will remove older poles which were predominantly treated with chemicals that do not meet today's environmental standards. As a result, rebuilding this pole line would be replacing older poles with poles that adhere to current environmental standards.

Conservation and Demand Management (5.4.3.2.B.2.B.6) **(where applicable)**

N/A

Project Name: Victoria Street North between Weber Street West and Margaret Avenue

System Renewal Specific Requirements (5.4.3.2.C.b)

Asset Performance Target and Asset Lifecycle Optimization (5.4.3.2.C.b.i.a)

The project supports the following asset performance and lifecycle optimization:

- Safety – by proactively replacing the end of life pole line, safety issues associated with pole failures or live wire down is avoided.
- Operation Effectiveness – reliability indices (SAIDI and SAIFI) will be improved by not running the pole line to failure.
- Customer Focus – replacing poles and wires that are at end of life and in poor condition will reduce the likelihood of a long duration unplanned outage due to equipment failure.

Asset Condition Relative to Typical Life Cycle (5.4.3.2.C.b.i.b)

Through a useful life of assets study conducted by Kinetrics for KWHI coupled with local experience, KWHI has identified the typical useful life (TUL) of wood poles and associated hardware as 40 years. The poles identified for replacement ranges in age from 62 (1957) to 6 (2013) years old. Most of the poles (14) that will be replaced have exceeded the TUL for wood poles and therefore have performed well. Some poles (6) have not achieved a service life of 40 years old yet but will be replaced to facilitate a more efficient rebuild process for the entire line segment and consistency in structural integrity.

Number of Customers Impacted (5.4.3.2.C.b.i.c)

Although there are only 41 customers on this section, failure of assets associated with this line segment may cause outage which will impact the entire 4M15 feeder serving approximately 199 residential and general class customers (industrial and institutional).

Quantitative Customer Impact and Risk (5.4.3.2.C.b.i.d)

At least 41 customers are likely to be impacted by failure of assets associated with this line section. However, the initial customer impact could be higher (199) if the feeder breaker opened for a pole/line failure.

Qualitative Customer Impact and Risk (5.4.3.2.C.b.i.e)

If the pole line isn't rebuilt, the number of outages and outage duration may increase resulting in lower customer satisfaction. One of the drivers for the project is reliability improvement.

Value of Customer Impact (5.4.3.2.C.b.i.f)

The value of customer impact is low. A failure in this line segment would impact approximately 41 commercial and residential customers for the entire outage duration. However, the initial customer impact could be higher (199) if the feeder breaker opened for a pole/line failure.

Other Factors Affecting Project Timing (5.4.3.2.C.b.ii)

The Region of Waterloo or City of Kitchener road work schedule may affect the timing of this project.

Impact on System O&M Costs (5.4.3.2.C.b.iii)

KWHI's current strategy for non-destructive pole testing is to test poles that are 40 years and older. By replacing poles within this line segment there will be no need to test them in the near future. Replacement of the pole line with new materials and higher design standard will also reduce the cost of future repairs that may have arisen from potential pole failures.

Project Name: Victoria Street North between Weber Street West and Margaret Avenue

Reliability and Safety Factors (5.4.3.2.C.b.iv)

By proactively replacing deteriorated poles which have reached their EOL asset value, reliability and safety issues associated with poles failing are avoided.

Analysis of Project Benefits, Costs, Alternatives, and Timing (5.4.3.2.C.b.v)

The rebuild of the pole line will avoid and/or reduce power outages. However, quantifying the financial benefit to customers impacted by this project is difficult. Maintaining the status quo ("Do Nothing") approach will result in possible future outages which will lead to customer dissatisfaction and unplanned work.

Like-for-Like Renewal Analysis (5.4.3.2.C.b.vi)

No, the project is not considered a like-for like replacement. Although the same number of poles are being replaced, the replacement of the existing copper conductor with aluminium conductor, upgrading the poles, hardware and equipment as well as adding an additional 3-ph circuit will substantially increase the abilities of this pole line.

Images



Scope of the pole line project – Victoria Street North from past Weber Street West to past Margaret Avenue – Approx.550m

Project Name: Victoria Street North between Weber Street West and Margaret Avenue



View of existing pole - 1964 Vintage (ACA Health Index: Fair)

Project Name: Victoria Street North between Weber Street West and Margaret Avenue



View of Existing Pole – 1964 vintage (ACA Health Index: Fair)

Project Authorization

Prepared By: Sandy Ferneyhough

Date: December 18, 2018

Authorized By: G. Cameron

Date: April 5, 2019

Completion Date: _____

Capital Project Summary

Project Name: Mill Street: Ottawa Street South to Carwood Avenue

Budget Year: 2020 **Budget Item No.:** 3-20-11

OEB Investment Category: System Renewal

General Information on Project (5.4.4.2.A)

Project Summary	The project consists of reconductoring and rebuilding a single circuit 3-ph pole line with 25 wood poles. The existing 4/0 Copper 3-ph primary conductor will be replaced with 556 MCM ASC for approximately 450 m in circuit length. The existing 4-open wire secondary buss will also be replaced with 2-4/0 Al, 1-2/0 ACSR & 1-#2 Al quadruplex secondary conductor. The line section to be replaced contains a concentration of poles that were rated Poor and Fair in the Asset Condition Assessment (ACA) conducted in 2018.
Capital Investment (5.4.3.2.A.i)	**Description** / **Estimated Cost** **Labour:** $180,900 **Materials:** $110,600 **Contract:** 0 **Engineering:** $37,900
Capital Contributions (5.4.3.2.A.ii)	**Total Estimated Cost** **$329,400** **Recoverable:** $0 **KWHI Estimated Cost** **$329,400**
Customer Attachments / Load (kVA) (5.4.3.2.A.iii) **(where applicable)**	70 customers /2100 kVA transformation
Project Dates (5.4.3.2.A.iv)	**Start Date:** January 2020 **In Service Date:** March 2020

Estimated Expenditure Timing (5.4.3.2.A.iv)	**Q1**	**Q2**	**Q3**	**Q4**
	$329,400	$0	$0	$0

Project Name: Mill Street: Ottawa Street South to Carwood Avenue

Schedule Risk and Risk Mitigation (5.4.3.2.A.v)

- City of Kitchener has some planned road work in this area. The possible schedule change may expedite or delay the proposed pole line project.
- Availability of resources to design and construct the pole line considering other higher priority jobs that were not known in advance. To mitigate this risk, the project will be designed at least 3 months in advance of the scheduled construction date. KWHI has access to external contractors who are often used to supplement the internal resource. Also, KWHI works closely with other 3rd parties such as the City of Kitchener to get their requirements for system access projects at least 1 year in advance to reduce the potential for last minute design and construction.

Comparative Information from Equivalent Projects (5.4.3.2.A.vi) **(where available)**

In 2017, a similar project was constructed in the City of Kitchener (Belmont Ave between Highland Rd and Victoria St S) that involved the rebuilding of a pole line by KWHI crews with 26 wood poles and stringing in 16 spans of new 3-556 MCM ASC conductor and 10 spans of new 1-#2 ACSR primary. The project cost was $288,820 (approx. $11,600 per pole). However, there are some differences to be noted, namely; stringing new 1-#2 ACSR conductor is significantly cheaper than removing existing copper conductor and stringing new 3-556 MCM ASC conductor.

Total Capital and OM&A Costs Associated with REG Investments (5.4.3.2.A.vii)

This project is not driven by REG investment. However, completion of this project will increase the load carrying capability of the feeder which will permit new REG to be connected.

Leave to Construct Approval (5.4.3.2.A.viii) **(where applicable)**

N/A

Evaluation Criteria and Information (5.4.4.2.B)

Efficiency, Customer Value, Reliability (5.4.3.2.B.1)

Investment Driver (5.4.3.2.B.1.a)

Condition/Age/Failure Risk - the main driver for this project is the condition coupled with age of the poles and the risk of failure. The poles range in age from (40-60 years old) and have health indices of Poor to Fair based on the 2018 ACA report. This section of pole line is connected to several other KWHI feeders (1M9, 6M17 & 5M13) from different transformer stations and has been frequently used for load transfer during planned or unplanned outages. The old 4/0 copper (50 years +) conductor can only carry 500A current. By rebuilding the pole line and reconductoring to 556 MCM Al., it will facilitate more load transfer capability (600A) of KWHI's distribution system.

	AGE					
	0-10	**11-20**	**21-30**	**31-40**	**41-50**	**>50**
CONDITION	**Quantity**					
Very Good	2	-	-	-	-	-
Good	-	2	2	-	-	-
Fair	-	-	-	-	4	-
Poor	-	-	-	8	2	11
Very Poor	-	-	-	-	1	1

Project Name: Mill Street: Ottawa Street South to Carwood Avenue

Secondary Driver (5.4.3.2.B.1.a) **(where applicable)**

Relocation Due to City's Roadworks – The City of Kitchener plans to work on this section in 2020 to widen the pavement and add curbs and sidewalks for Mill St between Ottawa Street South and Courtland Ave, which may require poles to be relocated.

Good Utility Practice (5.4.3.2.B.1.b)

The sources of information used to justify this investment are inspection/testing data, results from the Asset Condition Assessment conducted in 2018 and past failures of similar condition/type/age of overhead lines. KWHI has an ongoing planned process to replace deteriorated poles which will help improve reliability.

Investment Priority (5.4.3.2.B.1.c)

The priority of this project relative to others is Medium. System Access (SA) projects have higher priority that System Renewal (SR) projects unless the condition of the assets associated with the SR project are in a very poor condition. One of our asset management strategies is to replace assets before they reach a stage of critical condition. KWHI's project Prioritization Tool was used to prioritize all material projects for 2020 and this project was ranked as 18 out of 31.

Analysis of Project and Project Alternatives – Effect of the investment on system operation efficiency and cost-effectiveness (5.4.3.2.B.1.d.i)

By planning the replacement of poles rather than forced replacement at the time of a failure, the cost per pole can be managed utilising regular work hours and/or competitive bids and therefore is not subject to overtime premiums. Proactive replacement also means that additional objectives can be achieved such as coordination with 3rd parties (e.g. City of Kitchener) for future road alignment change and system expansion (conductor upgrading for load transfers).

Analysis of Project & Alternatives – Net benefits accruing to customers (5.4.3.2.B.1.d.ii)

By rebuilding the pole line and reconductoring, customers will experience an improvement in reliability (reduction in number of sustained outages). The risks associated with downed power lines will also be reduced with the installation of poles, wires and associated hardware with higher structural strength.

Analysis of Project & Alternatives – Impact of the investment on reliability performance including frequency and duration of outages (5.4.3.2.B.1.d.iii)

By rebuilding the pole line and reconductoring, customers will experience an improvement in reliability (number of sustained outages). The risks associated with downed power lines will also be reduced with the installation of poles, wires and associated hardware with higher structural strength.

This section of pole line is connected to several other KWHI feeders (1M9, 6M17 and 5M13) from different transformer stations and has been frequently used for load transfer during planned or unplanned outages. By rebuilding the pole line and reconductoring, it will facilitate more load transfer capability of KWHI's distribution system.

Project Alternatives (Design, Scheduling, Funding/Ownership (5.4.3.2.B.1.diii)

Project Design Alternatives:

- Replace poles and hardware only and transfer existing conductor - the existing wire size is #4/0 Copper which does not have the electrical characteristics to allow 600A current according to KWHI maximum feeder load transfer requirements. Moreover, the copper wire accessories are not readily available, more expensive, and have longer lead time to purchase than corresponding aluminum conductor.

- Replace poles and wire once they have failed -this is not advisable. The cost for replacement would be much higher if completed on an emergency basis than on a planned basis. This would lead to longer outages and increase in customer dissatisfaction.

Scheduling Alternatives:

If an unplanned job arises that has significantly higher priority than this job, a decision can be made to defer this project to a later date. However, not replacing end of life assets is not an option due to public safety impacts, system reliability and possible increasing in OM&A costs.

Ownership Alternatives:

None. This project consists solely of KWHI's assets and is constructed on the public right-of-way.

Safety (5.4.3.2.B.2)

Rebuilding of this pole line is completed in accordance with KWHI's standards and Ontario Regulation 22/04 to ensure no undue safety hazards. Work is inspected by KWHI and signed off as safe prior to energization. Replacement of deteriorated poles and wires that are at the end of their useful life and in poor condition will reduce the likelihood of unexpected pole failures and possible downed wires. Having downed wires on the ground creates a safety hazard for the public and workers.

Cyber-Security and Privacy (5.4.3.2.B.3) **(where applicable)**

This project does not impact cyber security or privacy.

Co-ordination and Interoperability (5.4.3.2.B.4)

Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.3.2.B.4.a) **(where applicable)**

The rebuilding of this pole line will be co-ordinated with Bell Canada, Rogers Cable TV and the City of Kitchener.

Enabling of Future Technology and/or Future Operational Requirements (5.4.3.2.B.4.b)

The pole line rebuild will facilitate more load transfer capability of Kitchener-Wilmot Hydro distribution system.

Environmental Benefits (5.4.3.2.B.2.B.5) **(where applicable)**

As part of the rebuild, KWHI will remove older poles which were predominantly treated with chemicals that do not meet today's environmental standards. As a result, rebuilding this pole line would be replacing older poles with poles that adhere to current environmental standards.

Conservation and Demand Management (5.4.3.2.B.2.B.6) **(where applicable)**

N/A

Project Name: Mill Street: Ottawa Street South to Carwood Avenue

System Renewal Specific Requirements (5.4.3.2.C.b)

Asset Performance Target and Asset Lifecycle Optimization (5.4.3.2.C.b.i.a)

The project supports the following asset performance and lifecycle optimization:

- Safety – by proactively replacing the end of life pole line, safety issues associated with pole failures or live wire down is avoided.
- Operational Effectiveness – reliability indices (SAIDI and SAIFI) will be improved by not running the pole line to failure.
- Customer Focus – replacing poles and wires that are at end of life and in poor condition will reduce the likelihood of a long duration unplanned outage due to equipment failure.

Asset Condition Relative to Typical Life Cycle (5.4.3.2.C.b.i.b)

Through a useful life of assets study conducted by Kinetrics for KWHI coupled with local experience, KWHI has identified the typical useful life (TUL) of wood poles and associated hardware as 40 years. The poles identified for replacement ranges in age from 35 (1984) to 67 (1951) years old. Most of the poles (27) that will be replaced have exceeded the TUL for wood poles and therefore have performed well. Some poles (8) have not achieved a service life of 40 years old yet but will be replaced to facilitate a more efficient rebuild process for the entire line segment and consistency in structural integrity.

Number of Customers Impacted (5.4.3.2.C.b.i.c)

Although there are only 70 customers on this section, failure of assets associated with this line segment may cause outage which will impact the entire 3M21 feeder serving approximately 1,750 residential and general class customers (industrial and institutional).

Quantitative Customer Impact and Risk (5.4.3.2.C.b.i.d)

At least 70 customers are likely to be impacted by failure of assets associate with this line section. However, the initial customer impact could be higher (1,750) if the feeder breaker opened for a pole/line failure.

Qualitative Customer Impact and Risk (5.4.3.2.C.b.i.e)

If the pole line isn't rebuilt, the number of outages and outage duration may increase resulting in lower customer satisfaction. One of the drivers for the project is reliability improvement.

Value of Customer Impact (5.4.3.2.C.b.i.f)

The value of customer impact is low. A failure in this line segment would impact approximately 70 residential customers for the entire outage duration. However, the initial customer impact could be higher (1,750) if the feeder breaker opened for a pole/line failure.

Other Factors Affecting Project Timing (5.4.3.2.C.b.ii)

The City of Kitchener road work schedule may affect the timing of this project.

Impact on System O&M Costs (5.4.3.2.C.b.iii)

KWHI's current strategy for non-destructive pole testing is to test poles that are 40 years and older. By replacing poles within this line segment there will be no need to test them in the near future. Replacement of the pole line with new materials and higher design standards will also reduce the cost of future repairs that may have arisen from potential pole failures.

Project Name: Mill Street: Ottawa Street South to Carwood Avenue

Reliability and Safety Factors (5.4.3.2.C.b.iv)

By proactively replacing deteriorated poles and conductors which have reached their EOL asset value, reliability and safety issues associated with poles failing are avoided.

Analysis of Project Benefits, Costs, Alternatives, and Timing (5.4.3.2.C.b.v)

This project has been deferred more than once in order to accommodate other projects that had higher priority. Executing this project in 2020 is required based on results from the recently conducted ACA survey that ranked most of the poles to be in poor condition. There is also planned City of Kitchener road works along sections of the line to be rebuilt. This will maximize the benefit associated with rebuilding the pole line since coordination with the City will be achieved.

The rebuild of the pole line will avoid and/or reduce power outages. However, quantifying the financial benefit to customers impacted by this project is difficult. Maintaining the status quo ("Do Nothing") approach will result in possible future outages which will lead to customer dissatisfaction and unplanned work.

Like-for-Like Renewal Analysis (5.4.3.2.C.b.vi)

Yes, the project is like-for like replacement and has not been configured at extra cost to address other KWHI planning objectives. The replacement of the existing copper conductor with aluminium conductor is in line with KWHI current standards. The spacing of the existing poles meets the current KWHI standard and therefore will be maintained. This single 3-ph circuit will remain a single 3-ph circuit.

Images



Scope of the pole line project- Mill St between Ottawa St s and Carwood Ave

Project Name: Mill Street: Ottawa Street South to Carwood Avenue



View of existing pole - 1951 Vintage (ACA Health Index: Poor)

Project Name: Mill Street: Ottawa Street South to Carwood Avenue



Deteriorated pole on Mill Street

Project Name: Mill Street: Ottawa Street South to Carwood Avenue

Project Authorization	
Prepared By: Sandy Ferneyhough	Authorized By: G. Cameron
Date: March 19, 2019	Date: April 5, 2019
	Completion Date: _____

Capital Project Summary

Project Name: Franklin Ave South between Wilson Avenue and Connaught Street

Budget Year: 2020 **Budget Item No.:** 3-20-12

OEB Investment Category: System Renewal

General Information on Project (5.4.4.2.A)

Project Summary	The project consists of reconductoring and rebuilding a single circuit 3-ph pole line with 13 wood poles. The existing 4/0 Copper 3-ph primary conductor will be replaced with 556 MCM ASC for approximately 400 m in circuit length. The existing 4-open wire secondary buss will be replaced with 2-4/0 Al, 1-2/0 ACSR & 1-#2 Al quadruplex secondary conductor. The line section to be replaced contains a concentration of poles that were rated Poor and Good in the Asset Condition Assessment (ACA) conducted in 2018.

Capital Investment (5.4.3.2.A.i)

Description	**Estimated Cost**
Labour:	$123,000
Materials:	$26,400
Contract:	$7,500
Engineering:	$20,400

Capital Contributions (5.4.3.2.A.ii)

Total Estimated Cost	**$177,300**
Recoverable:	$0
KWHI Estimated Cost	**$177,300**

Customer Attachments / Load (kVA) (5.4.3.2.A.iii) **(where applicable)**

34 customers /150 kVA transformation

Project Dates (5.4.3.2.A.iv)

Start Date: October 2020

In Service Date: December 2020

Estimated Expenditure Timing (5.4.3.2.A.iv)

Q1	Q2	Q3	Q4
$0	$0	$0	$177,300

Project Name: Franklin Ave South between Wilson Avenue and Connaught Street

Schedule Risk and Risk Mitigation (5.4.3.2.A.v)

- City of Kitchener has some planned road work in this area. The possible schedule change may expedite or delay the proposed pole line project.
- Availability of resources to design and construct the pole line considering other higher priority jobs that were not known in advance. To mitigate this risk, the project will be designed at least 3 months in advance of the scheduled construction date. KWHI has access to external contractors who are often used to supplement internal resources. Also, KWHI works closely with other 3rd parties such as the City of Kitchener to get their requirements for system access projects at least 1 year in advance to reduce the potential for last minute design and construction.

Comparative Information from Equivalent Projects (5.4.3.2.A.vi) **(where available)**

In 2017, a similar project was constructed in the City of Kitchener (Belmont Ave between Highland Rd and Victoria St S) that involved the rebuilding of a pole line by KWHI crews with 26 wood poles and stringing in 16 spans of new 3-556 MCM ASC conductor and 10 spans of new 1-#2 ACSR primary. The project cost was $288,820 (approx. $11,600 per pole). However, there are some differences to be noted, namely; stringing new 1-#2 ACSR conductor is significantly cheaper than removing existing copper conductor and stringing new 3-556 MCM ASC conductor.

Total Capital and OM&A Costs Associated with REG Investments (5.4.3.2.A.vii)

This project is not driven by REG investment. However, completion of this project will increase the load carrying capability of the feeder which will permit new REG to be connected.

Leave to Construct Approval (5.4.3.2.A.viii) **(where applicable)**

N/A

Evaluation Criteria and Information (5.4.4.2.B)

Efficiency, Customer Value, Reliability (5.4.3.2.B.1)

Investment Driver (5.4.3.2.B.1.a)

Condition/Age/Failure Risk - the main driver for this project is the condition coupled with age of the poles and the risk of failure. The poles range in age from (7-67 years old) and have health indices of Poor to Good based on the 2018 ACA report. This section of pole line is connected to several other KWHI feeders (3M20, 5M26 & 7M10) from different transformer stations and has been frequently used for load transfer during planned or unplanned outages. The old 4/0 copper (50 years +) conductor can only carry 500 A current. By rebuilding the pole line and reconductoring to 556 MCM Al., it will facilitate more load transfer capability (600 A) of KWHI's distribution system.

	Age					
	0-10	**11-20**	**21-30**	**31-40**	**41-50**	**>50**
Condition	**Quantity**					
Very Good	3					
Good			2			
Fair						
Poor						8
Very Poor						

Project Name: Franklin Ave South between Wilson Avenue and Connaught Street

Secondary Driver (5.4.3.2.B.1.a) **(where applicable)**

Reliability – the feeder is being renewed to provide increased reliability for our customers. A planned process minimizes the risk of overhead line failure. It also assists in significantly reducing the likelihood of future unplanned customer outages.

Good Utility Practice (5.4.3.2.B.1.b)

The sources of information used to justify this investment are inspection/testing data, results from the Asset Condition Assessment conducted in 2018 and past failures of similar condition/type/age of overhead lines. KWHI has an ongoing planned process to replace deteriorated poles which will help improve reliability.

Investment Priority (5.4.3.2.B.1.c)

The priority of this project relative to others is Medium. System Access (SA) projects have higher priority that System Renewal (SR) projects unless the condition of the assets associated with the SR project are in very poor condition. One of our asset management strategies is to replace assets before they reach a stage of critical condition. KWHI's project Prioritization Tool was used to prioritize all material projects for 2020 and this project was ranked as 17 out of 31.

Analysis of Project and Project Alternatives – Effect of the investment on system operation efficiency and cost-effectiveness (5.4.3.2.B.1.d.i)

By planning the replacement of poles rather than forced replacement at the time of a failure, the cost per pole can be managed utilising regular work hours and/or competitive bids and therefore not subject to overtime premiums. Proactive replacement also means that additional objectives can be achieved such as coordination with 3rd parties (e.g. City of Kitchener) for future road alignment changes and system expansion (conductor upgrading for load transfers).

Analysis of Project & Alternatives – Net benefits accruing to customers (5.4.3.2.B.1.d.ii)

By rebuilding the pole line and reconductoring, customers will experience an improvement in reliability (reduction in number of sustained outages). The risk associated with downed power lines will also be reduced with the installation of poles, wires and associated hardware with higher structural strength.

Analysis of Project & Alternatives – Impact of the investment on reliability performance including frequency and duration of outages (5.4.3.2.B.1.d.iii)

By rebuilding the pole line and reconductoring, customers will experience an improvement in reliability (number of sustained outages). The risk associated with downed power lines will also be reduced with the installation of poles, wires and associated hardware with higher structural strength.

This section of pole line is connected to several other KWHI feeders (3M20, 5M26, 7M10) from different transformer stations and has been frequently used for load transfers during planned or unplanned outages. By rebuilding the pole line and reconductoring, it will facilitate more load transfer capability of KWHI's distribution system.

Project Alternatives (Design, Scheduling, Funding/Ownership (5.4.3.2.B.1.d.iii)

Project Design Alternatives:

- Replace poles and hardware only and transfer existing conductor - the existing wire size is #4/0 Copper which does not have the electrical characteristics to allow 600 A current according to KWHI maximum feeder load transfer requirements. Moreover, the copper wire accessories are not readily available, are more expensive, and have longer lead time to purchase than corresponding aluminum conductor.

- Replace poles and wire once they have failed -this is not advisable. The cost for replacement would be much higher if completed on an emergency basis than on a planned basis. This would lead to longer outages and increase in customer dissatisfaction.

Scheduling Alternatives:

If an unplanned job arises that has significantly higher priority than this job, a decision can be made to defer this project to a later date. However, not replacing end of life assets is not an option due to public safety impacts, system reliability and possible increasing OM&A costs.

Ownership Alternatives:

None. This project consists solely of KWHI's assets and is constructed on the public right-of-way.

Safety (5.4.3.2.B.2)

Rebuilding of this pole line is completed in accordance with KWHI's standards and Ontario Regulation 22/04 to ensure no undue safety hazards. Work is inspected by KWHI and signed off as safe prior to energization. Replacement of deteriorated poles and wires that are at the end of their useful life and in poor condition will reduce the likelihood of unexpected pole failures and possible downed wires. Having downed wires on the ground creates a safety hazard for the public and workers.

Cyber-Security and Privacy (5.4.3.2.B.3) **(where applicable)**

This project does not impact cyber security or privacy.

Co-ordination and Interoperability (5.4.3.2.B.4)

Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.3.2.B.4.a) **(where applicable)**

The rebuilding of this pole line will be co-ordinated with Bell Canada, Rogers Cable TV and the City of Kitchener.

Enabling of Future Technology and/or Future Operational Requirements (5.4.3.2.B.4.b)

The pole line rebuild will facilitate more load transfer capability of KWHI's distribution system.

Environmental Benefits (5.4.3.2.B.2.B.5) **(where applicable)**

As part of the rebuild, KWHI will remove older poles which were predominantly treated with chemicals that do not meet today's environmental standards. As a result, rebuilding this pole line would be replacing older poles with poles that adhere to current environmental standards.

Conservation and Demand Management (5.4.3.2.B.2.B.6) **(where applicable)**

N/A

Project Name: Franklin Ave South between Wilson Avenue and Connaught Street

System Renewal Specific Requirements (5.4.3.2.C.b)

Asset Performance Target and Asset Lifecycle Optimization (5.4.3.2.C.b.i.a)

The project supports the following asset performance and lifecycle optimization:

- Safety – by proactively replacing the end of life pole line, safety issues associated with pole failures or live wire down are avoided.
- Operational Effectiveness – reliability indices (SAIDI and SAIFI) will be improved by not running the pole line to failure.
- Customer Focus – replacing poles and wires that are at end of life and in poor condition will reduce the likelihood of a long duration unplanned outage due to equipment failure.

Asset Condition Relative to Typical Life Cycle (5.4.3.2.C.b.i.b)

Through a useful life of assets study conducted by Kinetrics for KWHI coupled with local experience, KWHI has identified the typical useful life (TUL) of wood poles and associated hardware as 40 years. The poles identified for replacement ranges in age from 7 (2012) to 67 (1952) years old. Most of the poles (8) that will be replaced have exceeded the TUL for wood poles and therefore have performed well. Some poles (5) have not achieved a service life of 40 years old yet but will be replaced to facilitate a more efficient rebuild process for the entire line segment and consistency in structural integrity.

Number of Customers Impacted (5.4.3.2.C.b.i.c)

Although there are only 34 customers on this section, failure of assets associated with this line segment may cause outage which will impact the entire 7M5 feeder serving approximately 313 residential and general class customers (industrial and institutional).

Quantitative Customer Impact and Risk (5.4.3.2.C.b.i.d)

At least 34 customers are likely to be impacted by failure of assets associate with this line section. However, the initial customer impact could be higher (313) if the feeder breaker opened for a pole/line failure.

Qualitative Customer Impact and Risk (5.4.3.2.C.b.i.e)

If the pole line isn't rebuilt, the number of outages and outage duration may increase resulting in lower customer satisfaction. One of the drivers for the project is reliability improvement.

Value of Customer Impact (5.4.3.2.C.b.i.f)

The value of customer impact is low. A failure in this line segment would impact approximately 34 residential customers for the entire outage duration. However, the initial customer impact could be higher (313) if the feeder breaker opened for a pole/line failure.

Other Factors Affecting Project Timing (5.4.3.2.C.b.ii)

The City of Kitchener road work schedule may affect the timing of this project.

Impact on System O&M Costs (5.4.3.2.C.b.iii)

KWHI's current strategy for non-destructive pole testing is to test poles that are 40 years and older. By replacing poles within this line segment there will be no need to test them in the near future. Replacement of the pole line with new materials and higher design standard will also reduce the cost of future repairs that may have arisen from potential pole failures.

Project Name: Franklin Ave South between Wilson Avenue and Connaught Street

Reliability and Safety Factors (5.4.3.2.C.b.iv)

By proactively replacing deteriorated poles and conductors which have reached their EOL asset value, reliability and safety issues associated with poles failing are avoided.

Analysis of Project Benefits, Costs, Alternatives, and Timing (5.4.3.2.C.b.v)

This project has been deferred more than once in order to accommodate other projects that had higher priority. Executing this project in 2020 is required based on results from the recently conducted ACA survey that ranked most of the poles to be in poor condition.

The rebuild of the pole line will avoid and/or reduce power outages. However, quantifying the financial benefit to customers impacted by this project is difficult. Maintaining the status quo ("Do Nothing") approach will result in possible future outages which will lead to customer dissatisfaction and unplanned work.

Like-for-Like Renewal Analysis (5.4.3.2.C.b.vi)

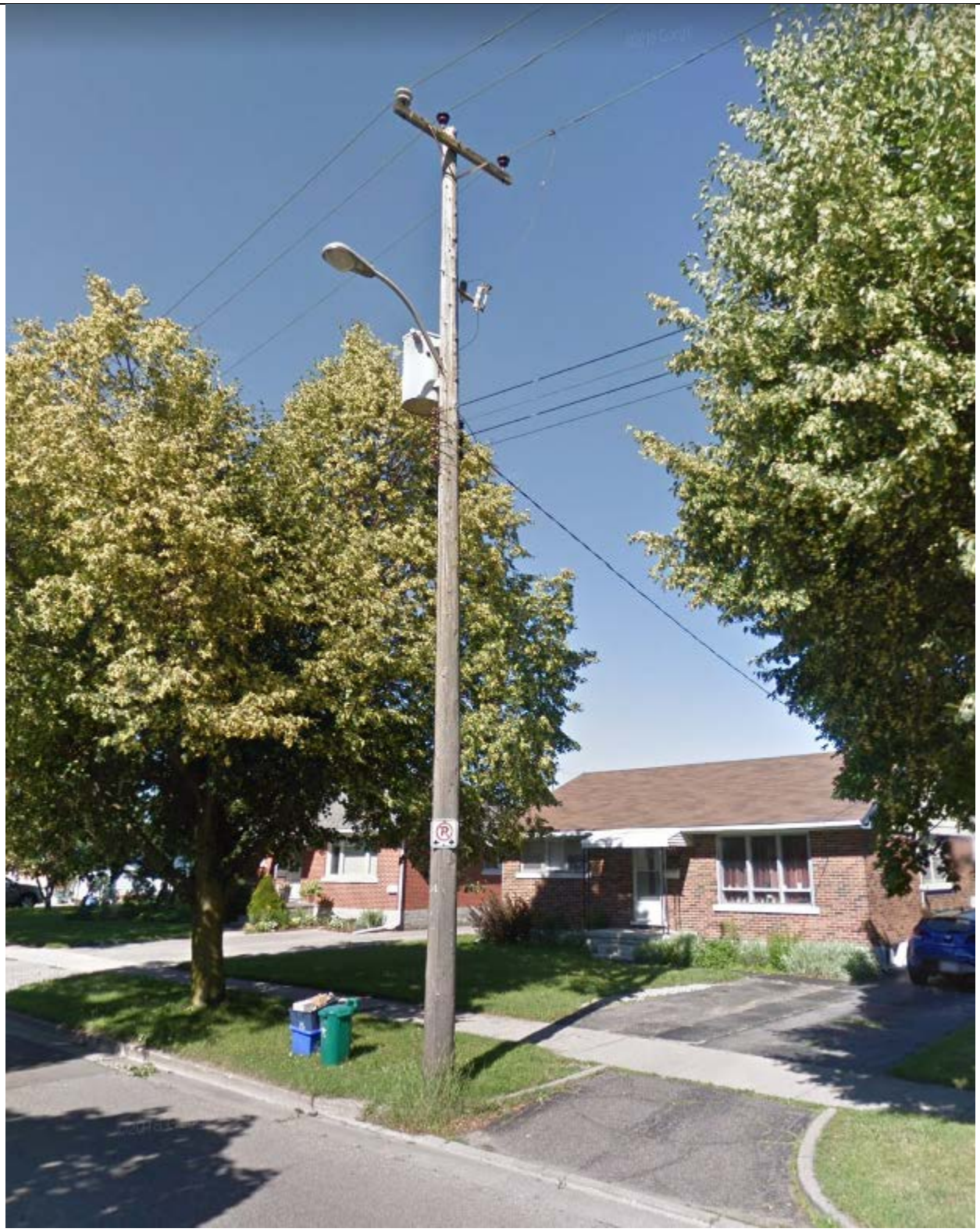
Yes, the project is like-for like replacement. The replacement of the existing copper conductor with aluminium conductor is in line with KWHI current standard. The spacing of the existing poles meets the current KWHI standard and therefore will be maintained. This single 3-ph circuit will remain a single 3-ph circuit.

Images



Scope of the pole line project- Franklin Ave S between Wilson Ave and Connaught St.

Project Name: Franklin Ave South between Wilson Avenue and Connaught Street



View of existing pole - 1952 Vintage (ACA Health Index: Poor)

Project Name: Franklin Ave South between Wilson Avenue and Connaught Street



View of Existing Pole – 1975 vintage (ACA Health Index: Fair)

Project Authorization

Prepared By: Sandy Ferneyhough

Date: December 19, 2018

Authorized By: G. Cameron

Date: April 5, 2019

Completion Date: _____

Capital Project Summary

Project Name: Stage 1- River Road East between Ottawa Street North and Halliwell Drive

Budget Year: 2020 **Budget Item No.:** 3-20-13

OEB Investment Category: System Renewal

General Information on Project (5.4.4.2.A)

Project Summary

This is Stage 1 of the project. The project consists of upgrading an existing pole line from a single circuit 3-ph pole line to a double circuit 3-ph pole line to provide a bypass for a pole line that is at end of life and installed in a rear yard location which is difficult to access. This includes replacing 8 existing 45' poles to 50' poles, re-framing the existing 3-556 MCM Al. upper circuit primary to cross-arm construction on 15 existing poles, installing 23 spans of new 3-556 MCM Al primary c/w cross-arm construction in the lower circuit position, transferring existing quadruplex secondary buss to new poles and removing redundant plant. Stage 2 of this project planned for 2021 will consist of removing a deteriorated distribution feeder from a hard to access, heavily treed, and sometimes swampy location. This feeder has experienced multiple unplanned outages especially during inclement weather.

Capital Investment (5.4.3.2.A.i)

Description	Estimated Cost
Labour:	$134,400
Materials:	$39,400
Contract:	$4,000
Engineering:	$23,100

Capital Contributions (5.4.3.2.A.ii)

Total Estimated Cost	**$200,900**
Recoverable:	$0
KWHI Estimated Cost	**$200,900**

Customer Attachments / Load (kVA) (5.4.3.2.A.iii) **(where applicable)**

60 customers /400 kVA transformation

Project Dates (5.4.3.2.A.iv)

Start Date: **August 2020**

In Service Date: November 2020

Estimated Expenditure Timing (5.4.3.2.A.iv)

Q1	Q2	Q3	Q4
$0	$0	$100,900	$100,000

Schedule Risk and Risk Mitigation (5.4.3.2.A.v)

- Region of Waterloo or City of Kitchener may have some planned road work in this area. The possible schedule change may expedite or delay the proposed pole line project.
- Availability of resources to design and construct the pole line considering other higher priority jobs that were not known in advance. To mitigate this risk, the project will be designed at least 3 months in advance of the scheduled construction date. KWHI has access to external contractors who are often used to supplement the internal resources. Also, KWHI works closely with other 3rd parties such as the Region and City to get their requirements for system access projects at least 1 year in advance to reduce the potential for last minute design and construction.

Comparative Information from Equivalent Projects (5.4.3.2.A.vi) **(where available)**

KWHI has not undertaken any similar project in recent years that involved the addition of a second circuit to an existing pole line and replacing some of the poles.

Total Capital and OM&A Costs Associated with REG Investments (5.4.3.2.A.vii)

This project is not driven by REG investment. However, completion of this project will increase the load carrying capability of the feeder which will permit new REG to be connected.

Leave to Construct Approval (5.4.3.2.A.viii) **(where applicable)**

N/A

Evaluation Criteria and Information (5.4.4.2.B)

Efficiency, Customer Value, Reliability (5.4.3.2.B.1)

Investment Driver (5.4.3.2.B.1.a)

Condition/Age/Failure Risk - the main driver for this project is the condition coupled with age of the poles in Stage 2 of this project and the risk of failure. The deteriorated poles range in age from (40 to 60 years old) and have health indices of Poor to Fair based on the pole inspection results from an ACA Survey conducted in 2018. The existing 3-ph feeder that is being replaced is located on heavily treed trail lands owned by the City of Kitchener, which not only acts as a circuit tie for the distribution feeder 5M23 but feeds residential properties from the rear. For Stage 2 of this project, this feeder tie is being moved out of the heavily treed area and onto the Region of Waterloo right of way. This section of pole line is connected to several other KWHI feeders (5M11, 5M17, 5M21, 5M22, 5M23, 5M25) and has been frequently used for load transfers during planned or unplanned outages.

Secondary Driver (5.4.3.2.B.1.a) **(where applicable)**

Reliability – The 5M23 feeder that is being relocated as part of Stage 2 of this project has experienced several outages due to lightning, defective equipment and tree branches falling onto the conductors due to high winds and adverse weather conditions. By moving the distribution feeder out of the heavily treed, sometimes swampy area, this will increase the reliability to our customers and reduce unplanned power outages.

Project Name: Stage 1- River Road East between Ottawa Street North and Halliwell Drive

Good Utility Practice (5.4.3.2.B.1.b)

The sources of the information used to justify this investment are inspection/testing data, results from the Asset Conditions Survey conducted in 2018 and past failures of similar condition/type/age of overhead lines.

Investment Priority (5.4.3.2.B.1.c)

The priority of this project relative to others is High. System Access (SA) projects have higher priority than System Renewal (SR) projects unless the condition of the assets associated with the SR project are in very poor condition. One of our asset management strategies is to replace assets before they reach a stage of critical condition. KWHI's project Prioritization Tool was used to prioritize all material projects for 2020 and this project was ranked as 10 out of 31.

Analysis of Project and Project Alternatives – Effect of the investment on system operation efficiency and cost-effectiveness (5.4.3.2.B.1.d.i)

By planning the relocation of the distribution feeder and replacement of deteriorated poles rather than forced replacement at the time of a failure, the cost per pole can be managed utilizing regular work hours and/or competitive bids and therefore not subject to overtime premiums. Proactive replacement also means that additional objectives can be achieved such as coordination with 3rd parties (e.g. Region of Waterloo) for future road alignment changes and system expansion (conductor upgrading for load transfers).

By relocating the pole line to the public right of way, there will be increased ease of access, reduction in frequency of tree trimming, and reduction in outages associated with tree contacts.

Analysis of Project & Alternatives – Net benefits accruing to customers (5.4.3.2.B.1.d.ii)

By relocating the distribution feeder, customers will experience an improvement in reliability (reduction in number of sustained outages and duration of outages). The risk associated with downed power lines will also be reduced with the installation of poles, wires and associated hardware with higher structural strength. Also, the proximity to large mature trees will be eliminated, resulting in a less likelihood that trees will cause a power outage on this section of pole line.

Analysis of Project & Alternatives – Impact of the investment on reliability performance including frequency and duration of outages (5.4.3.2.B.1.d.iii)

By relocating the distribution feeder, customers will experience an improvement in reliability (number of sustained outages). The risks associated with downed power lines will also be reduced with the installation of poles, wires and associated hardware with higher structural strength.

This section of pole line is connected to several other KWHI feeders (5M11, 5M17, 5M17, 5M21, 5M23, 5M25) and has been frequently used for load transfers during planned or unplanned outages. By rebuilding the pole line and reconductoring, it will facilitate more load transfer capability of KWHI's distribution system.

Project Alternatives (Design, Scheduling, Funding/Ownership (5.4.3.2.B.1.d.iii)

Project Design Alternatives:

i. Replace poles and hardware in the same location (City heavily treed trail lands) and transfer existing conductor – this is not a preferred option. The location of the existing poles makes them difficult to maintain due to the thick forest with no road access. The existing wire size is 500 Copper and accessories are not readily available, are more expensive, and have longer lead time to purchase than corresponding aluminum conductors.
ii. Replace poles, wires and associated hardware in the same location (City heavily treed trail lands) – this is not the preferred option. The location of the existing poles makes them difficult to maintain due to the thick forest with no road access.

Project Name: Stage 1- River Road East between Ottawa Street North and Halliwell Drive

Scheduling Alternatives:

If an unplanned job arises that has significantly higher priority than this job, a decision can be made to defer this project to a later date. However, not replacing end of life assets is not an option due to public safety impacts, system reliability and possible increase in OM&A costs.

Ownership Alternatives:

None. Stage 1 of this project consists solely of KWHI's assets and is constructed on the public right-of-way

Safety (5.4.3.2.B.2)

Replacement of these poles that are at the end of their useful life and in poor/fair condition will reduce the likelihood of unexpected pole failures. Rebuilding of this pole line is completed in accordance with KWHI's standards and Ontario Regulation 22/04 to ensure no undue safety hazards. Work is inspected by KWHI and signed off as safe prior to energization

Cyber-Security and Privacy (5.4.3.2.B.3) **(where applicable)**

This project does not impact cyber security or privacy.

Co-ordination and Interoperability (5.4.3.2.B.4)

This project incorporates KWHI's standards which in turn incorporates standards from groups such as the Canadian Standards Association (CSA) and the Institute of Electrical and Electronics Engineers (IEEE). This project applies the requirements of the Ontario Regulation 22/04 as overseen by the Electrical Safety Authority (ESA).

Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.3.2.B.4.a) **(where applicable)**

The rebuilding of this pole line will be co-ordinated with Region of Waterloo, Bell Canada and Rogers Cable TV for their planned road work.

Enabling of Future Technology and/or Future Operational Requirements (5.4.3.2.B.4.b)

This investment does not directly enable future technological functionality. However, it will enable operational requirements to be satisfied such as ease of access to maintain and repair the pole line when needed.

Environmental Benefits (5.4.3.2.B.2.B.5) **(where applicable)**

As part of the rebuild, KWHI will remove older poles which were predominantly treated with chemicals that do not meet today's environmental standards. As a result, rebuilding this pole line would be replacing older poles with poles that adhere to current environmental standards.

Conservation and Demand Management (5.4.3.2.B.2.B.6) **(where applicable)**

N/A

System Renewal Specific Requirements (5.4.3.2.C.b)

Asset Performance Target and Asset Lifecycle Optimization (5.4.3.2.C.b.i.a)

The project supports the following asset performance and lifecycle optimization:

- Safety – by proactively replacing the end of life pole line, safety issues associated with pole failures or live wire down is avoided.
- Operational Effectiveness – reliability indices (SAIDI and SAIFI) will be improved by not running the pole line to failure.
- Customer Focus – replacing poles and wires that are at end of life and in poor condition will reduce the likelihood of a long duration unplanned outage due to equipment failure.

Asset Condition Relative to Typical Life Cycle (5.4.3.2.C.b.i.b)

Through a useful life of assets study conducted by Kinetrics for KWHI coupled with local experience, KWHI has identified the typical useful life (TUL) of wood poles and associated hardware as 40 years. The poles identified for replacement in Stage 1 of the Project are 42 years old and have exceeded the TUL for wood poles. The poles identified for replacement in Stage 2 of the Project ranges in age from 2 (2017) to 68 (1951) years old. Most of the poles (19) that will be replaced have exceeded the TUL for wood poles and therefore have performed well. Some poles (3) have not achieved a service life of 40 years old yet but will be replaced to facilitate a more efficient rebuild process for the entire line segment and consistency in structural integrity.

Number of Customers Impacted (5.4.3.2.C.b.i.c)

Although there are only 60 customers on Stage 2 of this project, failure of assets associated with this line segment may cause outage which will impact the entire 5M23 feeder serving approximately 971 residential and general class customers (industrial and institutional).

Quantitative Customer Impact and Risk (5.4.3.2.C.b.i.d)

At least 60 customers are likely to be impacted by failure of assets associated with this line section. However, the initial customer impact could be higher (971) if the feeder breaker opened for a pole/line failure.

Qualitative Customer Impact and Risk (5.4.3.2.C.b.i.e)

If the pole line isn't rebuilt, the number of outages and outage duration may increase resulting in lower customer satisfaction. One of the drivers for the project is reliability improvement.

Value of Customer Impact (5.4.3.2.C.b.i.f)

The value of customer impact is low. A failure in this line segment would impact approximately 60 residential customers for the entire outage duration. However, the initial customer impact could be higher (971) if the feeder breaker opened for a pole/line failure.

Other Factors Affecting Project Timing (5.4.3.2.C.b.ii)

Region of Waterloo road work schedule.

Impact on System O&M Costs (5.4.3.2.C.b.iii)

KWHI's current strategy for non-destructive pole testing is to test poles that are 40 years and older. By replacing poles within this line segment there will be no need to test them in the near future. Replacement of

the pole line with new materials and higher design standards will also reduce the cost of future repairs that may have arisen from potential pole failures.

Reliability and Safety Factors (5.4.3.2.C.b.iv)

By proactively replacing deteriorated poles and wires which have reached their EOL asset value, reliability and safety issues associated with poles failing are avoided.

Analysis of Project Benefits, Costs, Alternatives, and Timing (5.4.3.2.C.b.v)

This project has been deferred more than once in order to accommodate other projects that had higher priority. Executing this project in 2020 is required based on results from the recently conducted ACA survey that ranked the poles in Stage 2 as being in poor condition.

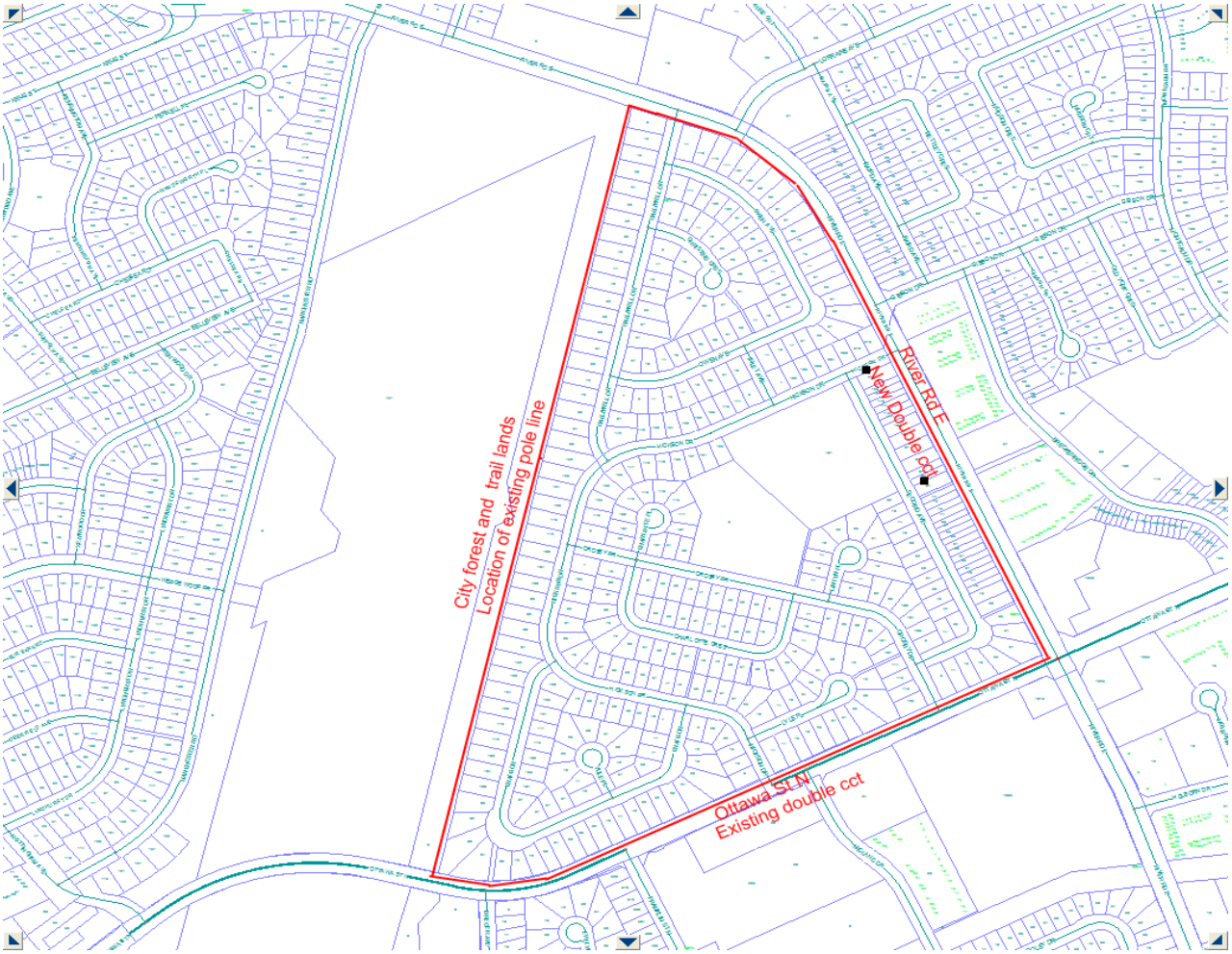
The rebuild of the pole line will avoid and/or reduce power outages. However, quantifying the financial benefit to customers impacted by this project is difficult. Maintaining the status quo ("Do Nothing") approach will result in possible future outages which will lead to customer dissatisfaction and unplanned work.

Like-for-Like Renewal Analysis (5.4.3.2.C.b.vi)

Yes, the project is considered a like-for like replacement. The location of the new distribution feeder will have the same capabilities and capacities in the new location on River Rd E as it does in the old location on City lands.

Project Name: Stage 1- River Road East between Ottawa Street North and Halliwell Drive

Images



Scope of the pole line project – Stage 1 – River Rd E between Ottawa St N and Halliwell Dr

Project Name: Stage 1- River Road East between Ottawa Street North and Halliwell Drive



View of existing pole - 1976 Vintage (ACA Health Index: Good)

Project Name: Stage 1- River Road East between Ottawa Street North and Halliwell Drive



View of Existing Pole – 1996 vintage (ACA Health Index: Good)

Project Authorization

Prepared By: Sandy Ferneyhough

Date: December 18, 2018

Authorized By: G. Cameron

Date: April 5, 2019

Completion Date: _____

Capital Project Summary

Project Name: Underground Voltage Conversion

Budget Year: 2020 **Budget Item No.:** 4-20-7 and 5-20-7

OEB Investment Category: System Renewal

General Information on Project (5.4.3.2.A)

Project Summary

This program consists of renewing and upgrading the necessary underground infrastructure (cable, conduits, and accessories) that is required for voltage conversion from 4.8/8.32 kV to 16/27.6 kV. It also includes the replacement of any customer-owned service cables, underground or overhead transformers if required to facilitate a voltage conversion project in 2020.

On December 31, 2018, there were 68.2 km of single phase URD primary cable installed in the 8.3 kV distribution system. All of it must be converted to 27.6 kV operation when the upstream pole lines are converted. All URD primary cable installed in the 8.3 kV distribution system since 1995 (approximately 43.2 km) is insulated for 27.6 kV operation. This cable can be converted relatively inexpensively by replacing the switches, lightning arresters, transformers and elbow connectors. The remainder of the cable (approximately 25 km) must be replaced. Fortunately, this is also the oldest cable and would eventually have to be replaced due to age/condition.

The following locations are targeted for underground voltage conversion in 2020:

- Casselholme Crescent and Kenneth Fried Place, New Dundee – this project includes the installation of approximately 500 m of 1/c-1/0 cu-28 kV primary cable in new 63mm HDPE pipe, 2-16 kV submersible transformers utilizing the existing concrete vaults, 3-16 kV padmount transformers utilizing the existing concrete foundations, all required switches, direct buried pull boxes for splicing, connections and hardware. This will also include the removal of all redundant plant including 5-4.8 kV transformers. The existing 4.8 kV direct buried primary cable will be abandoned.
- Poth Drive, New Dundee Avenue, New Dundee - this project includes the installation of approximately 1000 m of 1/c-1/0 cu-28 kV primary cable in new 63mm HDPE pipe, 6-16 kV submersible transformers utilizing the existing concrete vaults, all required switches, direct buried pull boxes for splicing, connections and hardware. This also to include the removal of all redundant plant including 6-4.8 kV submersible transformers. The existing 4.8 kV direct buried primary cable will be abandoned.

Project Name: Underground Voltage Conversion

Capital Investment (5.4.3.2.A.i)	**Description**	**Estimated Cost**				
	Labour:	$221,200				
	Materials:	$132,700				
	Contract:	$0				
	Engineering:	$46,100				
Capital Contributions (5.4.3.2.A.ii)	**Total Estimated Cost:**	**$400,000**				
	Recoverable:	$0				
	KWHI Estimated Cost	**$400,000**				
Customer Attachments / Load (kVA) (5.4.3.2.A.iii) **(where applicable)**	81 customers / 700 kVA					
Project Dates (5.4.3.2.A.iv)	**Start Date: July 2020** **In Service Date: September 2020**					
Estimated Expenditure Timing (5.4.3.2.A.iv)	**Q1**	**Q2**	**Q3**	**Q4**		
	$0	$0	$400,000	$0		

Schedule Risk and Risk Mitigation (5.4.3.2.A.v)

- The project will be designed at least 3 months in advance of the scheduled construction. KWHI will work closely with other 3rd parties such as the Township of Wilmot to get their requirements for system access projects at least 1 year in advance to reduce the potential for last minute design and construction changes.
- In order to complete the voltage conversion in New Dundee, the pole line on Queen St also needs to be rebuilt and ready for voltage conversion. That project is scheduled for 2019 construction, however if it is delayed, it might also delay this underground work.

Comparative Information from Equivalent Projects (5.4.3.2.A.vi) **(where available)**

In 2016, a similar project was completed on Strauss Court in Wilmot Township including installation of 150m of new 1/c- 1/0 cu cable in HDPE duct, replacing the transformer utilizing the existing submersible vault and converting to 16 kV distribution. The total cost was $231.81 per meter.

Total Capital and OM&A Costs Associated with REG Investments (5.4.3.2.A.vii)

There is no REG investment associated with this program.

Leave to Construct Approval (5.4.3.2.A.viii) **(where applicable)**

N/A

Project Name: Underground Voltage Conversion

Evaluation Criteria and Information (5.4.4.2.B)

Efficiency, Customer Value, Reliability (5.4.3.2.B.1)

Investment Driver (5.4.3.2.B.1.a)

Functional Obsolescence – voltage conversion is the main investment driver for this program which includes converting underground plant to 16/27.6 kV distribution and replacing obsolete equipment. The 8.3 kV distribution system is being replaced over time with a more robust and efficient 27.6 kV distribution system. This process has already begun with the construction and commissioning of Kitchener No. 9 TS in 2010.

Secondary Driver (5.4.3.2.B.1.a) **(where applicable)**

Reliability and Condition/Age - the secondary driver is to replace plant that has reached it's end of life asset value. The existing direct buried primary cable on Casselholme Crescent is 1979 vintage (40 years old) and has reached it's EOL value. The existing direct buried cable on Poth Dr and New Dundee Ave is 1989 vintage (30 years old). Without conduit it does not allow for quick and easy replacement when the cable faults.

Good Utility Practice (5.4.3.2.B.1.b)

The sources of information used to justify this investment are results from the Asset Condition Assessment conducted in 2018 and the need to convert a system with obsolete voltage and equipment to current standards.

Investment Priority (5.4.3.2.B.1.c)

The priority of this program compared to others is Low. System Access (SA) projects have higher priority than System Renewal (SR) projects unless the condition of the assets associated with the SR project are in very poor condition. One of our asset management strategies is to replace assets before they reach critical condition. KWHI's project prioritization Tool was used to prioritize all materials projects for 2020 and this project was ranked 29 out of 31.

Analysis of Project and Project Alternatives – Effect of the investment on system operation efficiency and cost-effectiveness (5.4.3.2.B.1.d.i)

By planning the conduit installation and/or cable replacement, competitive bids can be received, and emergency replacement minimized or eliminated which will increase system operation efficiency and cost-effectiveness.

Analysis of Project & Alternatives – Net benefits accruing to customers (5.4.3.2.B.1.d.ii)

KWHI realizes that failures will begin to happen more frequently once cable has reached its EOL value in this project area, resulting in unplanned customer outages. By having the conduit in place prior to the cable faulting or reaching it's EOL, work can be planned, and outages minimized and coordinated with the customers.

Analysis of Project & Alternatives – Impact of the investment on reliability performance including frequency and duration of outages (5.4.3.2.B.1.d.iii)

KWHI realizes that failures will begin to happen more frequently once cable has reached its EOL value in this project area, resulting in unplanned customer outages. By having the conduit in place prior to the cable faulting or reaching it's EOL, work can be planned, and outages minimized and coordinated with the customers.

Project Name: Underground Voltage Conversion

Project Alternatives (Design, Scheduling, Funding/Ownership (5.4.3.2.B.1.d.iii)

Project Design Alternatives:

Install a step-down transformer on distribution pole line – while this option would allow us to maintain the 4.8 kV transformers and primary cables, it is only a short-term measure which will eventually require replacement of the assets since they are at end of life. KWHI has started its voltage conversion program in the Township of Wilmot following construction of its 28 kV No.9 Transformer Station and in order to maintain system flexibility and reliability, all 8.3 kV distribution systems will require conversion at some point in time. This is not a preferred option.

Scheduling Alternatives:

If an unplanned job arises that has significantly higher priority than this job, a decision can be made to defer this project to a later date. However, not installing the conduit or replacing EOL cable could lead to poor system reliability and possible increasing OM&A costs.

Ownership Alternatives:

This program consists solely of KWHI's assets and is constructed on the public right of way.

Safety (5.4.3.2.B.2)

This program will be completed in accordance with KWHI's standards and Ontario Regulation 22/04 to ensure no undue safety hazards. Work completed by a Contractor is inspected by KWHI.

Cyber-Security and Privacy (5.4.3.2.B.3) **(where applicable)**

This program does not impact cyber security or privacy.

Co-ordination and Interoperability (5.4.3.2.B.4)

Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.3.2.B.4.a) **(where applicable)**

This project will be co-ordinated with the appropriate road authority such as the Township of Wilmot, the Region of Waterloo, Bell Canada and Rogers Cable TV.

Enabling of Future Technology and/or Future Operational Requirements (5.4.3.2.B.4.b)

Voltage conversion of the underground distribution plant will facilitate greater load transfer capability, permit higher DER penetration, reduce system losses, and improve voltage profile.

Environmental Benefits (5.4.3.2.B.2.B.5) **(where applicable)**

N/A

Conservation and Demand Management (5.4.3.2.B.2.B.6) **(where applicable)**

N/A

Project Name: Underground Voltage Conversion

System Renewal Specific Requirements (5.4.3.2.C.b)

Asset Performance Target and Asset Lifecycle Optimization (5.4.3.2.C.b.i.a)

1. Safety – by proactively installing conduit for future cable replacement, and/or replacing underground cables which have reached their EOL value, safety issues associated with cable failures are avoided.
2. Customer Focus – installing conduit for future planned cable replacement and/or replacing underground cables which have reached their EOL value will reduce the likelihood of a long duration outage due to failure.

Asset Condition Relative to Typical Life Cycle (5.4.3.2.C.b.i.b)

The existing direct buried primary cable located in Casselholme Crescent, Kenneth Fried Place, and Poth Drive ranges from 20 - 47 years old and has either reached it's EOL (30 years) or is near it.

Number of Customers Impacted (5.4.3.2.C.b.i.c)

For the work in New Dundee, there will be 81 customers that will be directly impacted from this program.

Quantitative Customer Impact and Risk (5.4.3.2.C.b.i.d)

For the work in New Dundee, there will be 81 customers that will be directly impacted from this program.

Qualitative Customer Impact and Risk (5.4.3.2.C.b.i.e)

If underground cables that have reached their EOL asset value are not replaced, the risk increases for unplanned outages resulting in lower customer satisfaction. One of the drivers for the project is reliability improvement.

Value of Customer Impact (5.4.3.2.C.b.i.f)

The value of customer impact is considered low. However, although the existing plant is working today, delaying its replacement may result in unplanned outages and decreased customer satisfaction.

Other Factors Affecting Project Timing (5.4.3.2.C.b.ii)

- Voltage Conversion – the pole line rebuild on Queen St is scheduled for 2019 construction and preparation for voltage conversion. If this gets delayed, the underground conversion will also be delayed.
- Weather – because this work involves underground excavation near existing energized cables, it will need to be scheduled outside of winter.

Impact on System O&M Costs (5.4.3.2.C.b.iii)

Not installing the conduit or replacing EOL cable could lead to poor system reliability and possible increasing OM&A costs if the cables need to be replaced on an emergency basis at premium rates.

Reliability and Safety Factors (5.4.3.2.C.b.iv)

By proactively installing conduit for future cable replacement, and/or replacing underground cables which have reached their EOL value, reliability and safety issues associated with cable failures are avoided.

Project Name: Underground Voltage Conversion

Analysis of Project Benefits, Costs, Alternatives, and Timing (5.4.3.2.C.b.v)

The replacement and conversion of the underground plant will avoid and/or reduce power outages. However, quantifying the financial benefit to customers impacted by this project is difficult. Maintaining the status quo ("Do Nothing") approach will result in possible future outages which will lead to customer dissatisfaction and unplanned work.

Like-for-Like Renewal Analysis (5.4.3.2.C.b.vi)

This program is considered a Like for Like replacement but will be upgraded to meet KWHI's current voltage supply standard.

Images

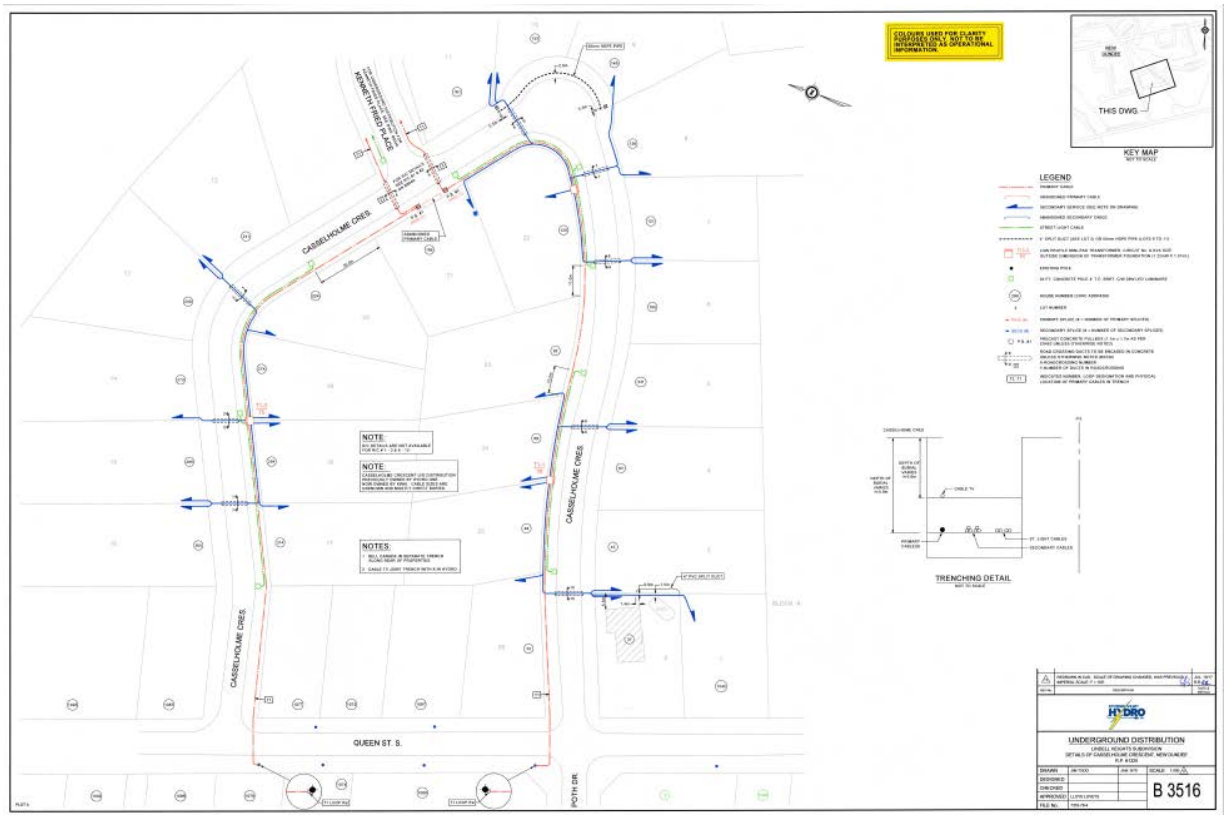


Figure 1: Underground Distribution, Casselholme Crescent

Project Name: Underground Voltage Conversion

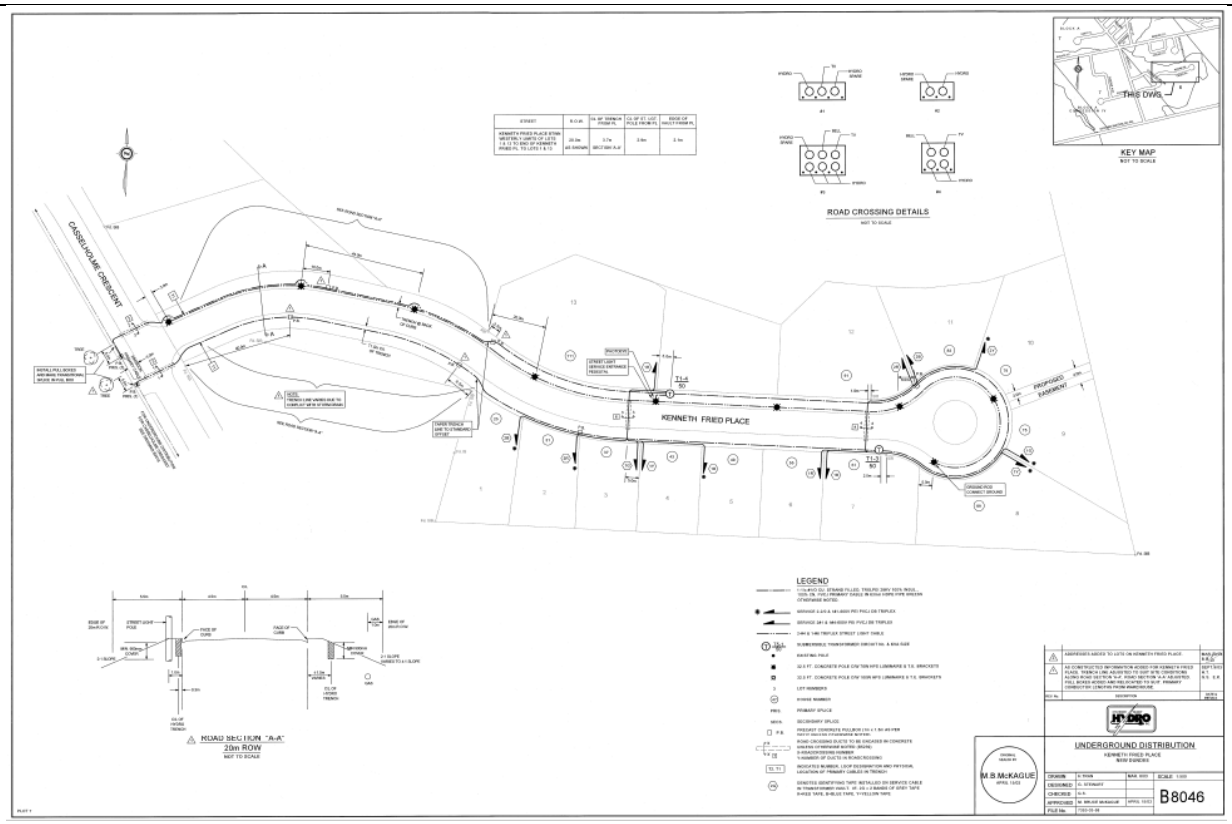


Figure 2: Underground Distribution, Kenneth Fried Place

Project Name: Underground Voltage Conversion

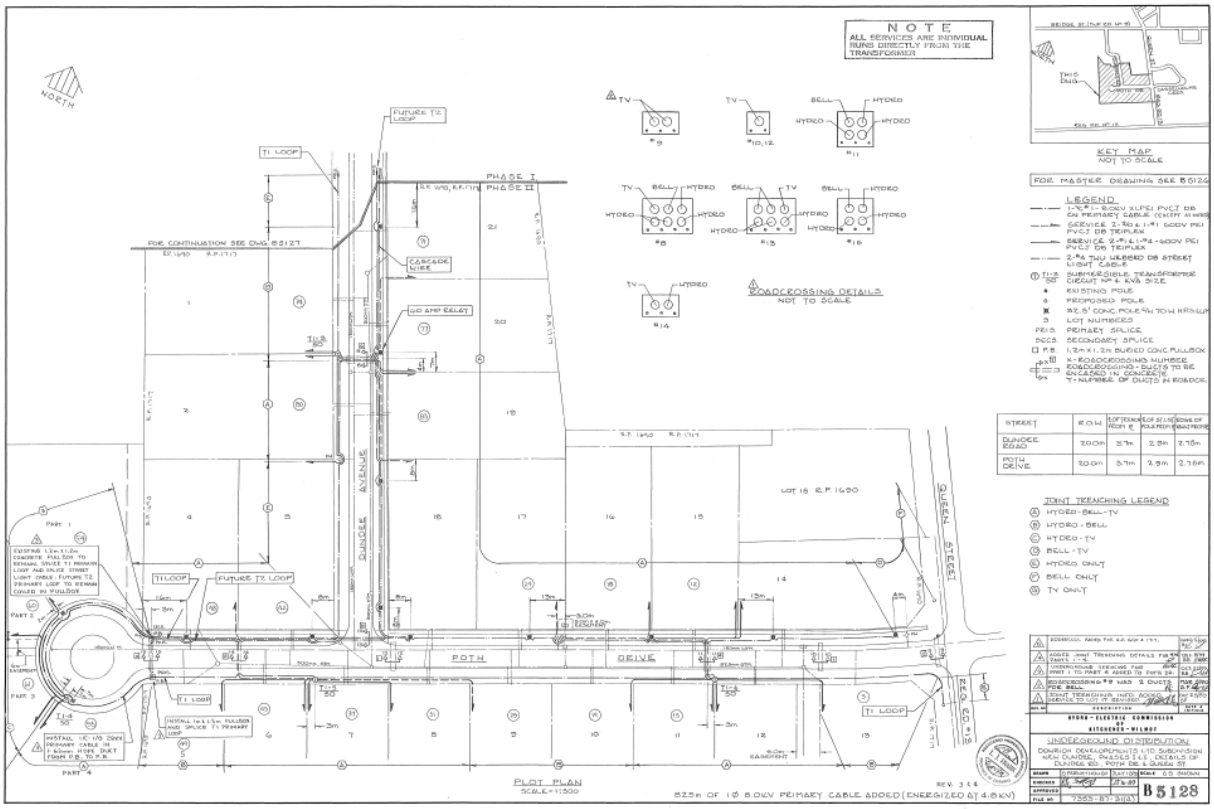


Figure 3: Underground Distribution, Poth Drive

Project Authorization

Prepared By: S. Ferneyhough

Date: January 22, 2019

Authorized By: G. Cameron

Date: April 5, 2019

Completion Date: _____

Capital Project Summary

Project Name: Underground System Renewal

Budget Year: 2020 **Budget Item No.:** 4-20-8

OEB Investment Category: System Renewal

General Information on Project (5.4.3.2.A)

Project Summary

This program consists of installation of ductbanks, vaults and cable to replace End of Life (EOL) underground distribution systems and conduit installation for future cable replacement. The program is prioritized based on condition of the assets from the 2018 ACA results and paced to maintain steady expenditures year over year. In 2020 the list of projects includes:

- Conduit installation in Westheights subdivision, Kitchener - This multi-phase project includes directional drilling approximately 1900 m of 50 mm HDPE conduit in the boulevard between existing submersible transformer vaults on various streets within the Westheights subdivision. This conduit is for future single phase 8 kV primary cable replacement, as the existing primary cable is direct buried and has reached or is approaching the end of its life. This may also include installation of small direct buried concrete pullboxes for future splices or installation of a drain from the existing transformer vaults to the city storm sewer.
- Replace failed and EOL feeder cables and services – The scope of this project is on an “As Needed” basis. Approximately 500 m of 3-phase cable will be identified and replaced in 2020.
- Underground transfers from pole line rebuilds – This project consists of splicing and extending or transferring existing underground distribution feeders or services complete with switches to new poles when needed as part of all pole line rebuild projects to suit KWHI.
- Scott St and Duke St E Rebuild Phase 2 – This project consists of installing approximately 500 m of network secondary bus from PB 1011 to PB32 in the new duct structure (installed in 2019 - Phase 1). This also includes removing the existing network secondary bus from PB32 to PB1011 from the old duct structure, breaking down 5 existing vault tops, filling in and abandoning the old structure.

Capital Investment (5.4.3.2.A.i)

Description	Estimated Cost
Labour:	$417,900
Materials:	$159,300
Contract:	$175,000
Engineering:	$97,800

Project Name: Underground System Renewal

Capital Contributions (5.4.3.2.A.ii)	**Total Estimated Cost:**	**$850,000**				
	Recoverable:	$0				
	KWHI Estimated Cost	**$850,000**				
Customer Attachments / Load (kVA) (5.4.3.2.A.iii) **(where applicable)**	The total number of customers impacted, and the connected load will be determined when the specific project scope is determined.					
Project Dates (5.4.3.2.A.iv)	**Start Date:** January 2020 **In Service Date:** December 2020					
Estimated Expenditure Timing (5.4.3.2.A.iv)	**Q1**	**Q2**	**Q3**	**Q4**		
	$25,000	$350,000	$350,000	$125,000		

Schedule Risk and Risk Mitigation (5.4.3.2.A.v)

1. Availability of resources may defer this project if others with a higher priority need attention. In the past, KWHI has had a Contractor complete the directional drilling, pipe and pull box installation up to the existing submersible transformer vaults with KWHI forces installing the conduit into the energized submersible transformer vaults.
2. If an existing cable was to fault and need to be replaced, this project, or a portion of this project might get moved up in the schedule.
3. Timing to transfer existing underground distribution feeders and services for a pole line rebuild will depend on the progress of the individual job. There will be an attempt to schedule work based on the need to not disrupt the schedule of the pole line rebuild.
4. If Phase 1 of the Scott St & Duke St project is delayed, the new duct structure may not be available for cabling in 2020.

Comparative Information from Equivalent Projects (5.4.3.2.A.vi) **(where available)**

- Installing conduit for future cable replacement in the Westheights subdivision area has been ongoing for several years. Costs for replacement in 2017-2018 were $126/m.
- Costs to replace failed primary feeder cables varies widely and depend on the extent of the cable damage.
- As part of the LRT relocation project, a number of secondary network cables were replaced. A similar job was completed in 2016 on Duke St between College St and Francis St where total costs were $77,427 ($685/m).
- The figure below shows the overall historical costs and forecasted future costs to implement this program. Based on the recently conducted ACA, KWHI is anticipating an increase in primary cable failure if no mitigating actions are taken. However, KWHI has not made any significant budget increase to replace primary cables but instead is implementing a cable testing program to evaluate the field conditions of the cables flagged for replacement.

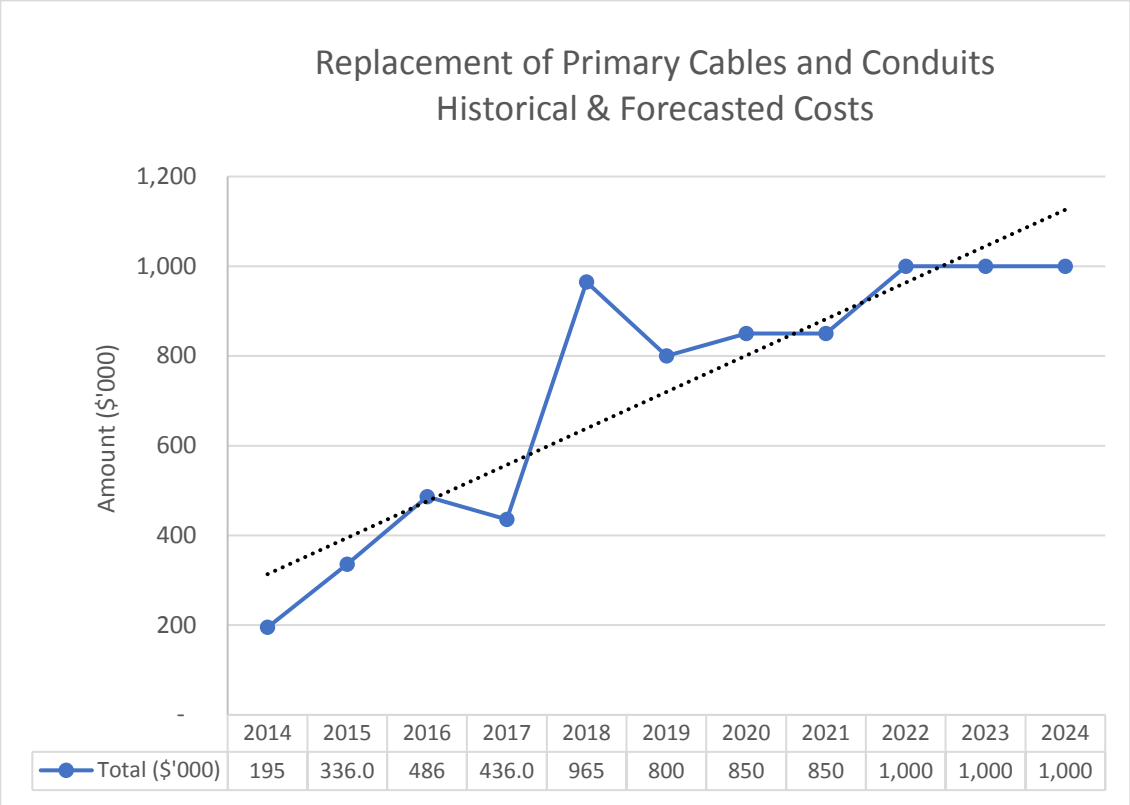


Figure 1: Historical costs for cables and conduits replacement

Cable Length	HI Condition	Recommendation
42 km	Very Poor	Require immediate attention. Need condition data to plan for replacement.
159.2 km	Poor	Require attention over the next five years. Need condition data to plan for replacement.
282.1 km	Fair	Some of these assets may fall into Poor condition over the next five years window and recommended to monitor these assets.

Figure 2: Asset Condition Assessment recommendation for underground primary cables

Total Capital and OM&A Costs Associated with REG Investments (5.4.3.2.A.vii)

N/A

Leave to Construct Approval (5.4.3.2.A.viii)

N/A

Evaluation Criteria and Information (5.4.4.2.B)

Efficiency, Customer Value, Reliability (5.4.3.2.B.1)

Project Name: Underground System Renewal

Investment Driver (5.4.3.2.B.1.a)

The primary investment driver for this program is failure risk, to replace the underground plant that has reached its end of life asset value and increase the reliability of our system.

- Installing conduit in the Westheights subdivision enables for future primary cable replacement. The existing primary cable was installed in the 1970's-1990's and as per the standard at that time, is direct buried. This does not allow for quick and easy replacement when the cable faults or reaches it's end of life value. There have been repeated incidents in the Westheights subdivision where transformers and cables have faulted due to the high-water table. Therefore in 2013 a program was started to install conduit and add drains from the existing submersible transformer vaults to the city storm sewer system.
- Replacing failed or EOL cables.
- Underground transfers from pole line rebuilds that have reached their EOL asset value.
- The existing network secondary buss on Scott St and Duke St E has reached it's EOL asset value.

Secondary Driver (5.4.3.2.B.1.a) **(where applicable)**

The secondary driver is to reduce unplanned outage time for our customers.

- With the conduit already installed, the outage time would be reduced when the primary cable needs to be replaced whether due to a fault or EOL.
- Outages can be planned to replace EOL feeder cables.
- Outages can be planned to transfer existing underground plant as part of a pole line rebuild.
- Outages can be planned to replace EOL network secondary cables.

Good Utility Practice (5.4.3.2.B.1.b)

Investment Priority (5.4.3.2.B.1.c)

The priority of this program compared to others is Medium. System Access (SA) projects have higher priority than System Renewal (SR) projects unless the condition of the assets associated with the SR project are in very poor condition. One of our asset management strategies is to replace assets before they reach a stage of critical condition. KWHI's project prioritization Tool was used to prioritize all materials projects for 2020 and this project was ranked 13 out or 31.

Analysis of Project and Project Alternatives – Effect of the investment on system operation efficiency and cost-effectiveness (5.4.3.2.B.1.d.i)

By planning the conduit installation and/or cable replacement, competitive bids can be received, and emergency replacement minimized or eliminated which will increase system operation efficiency and cost-effectiveness.

Analysis of Project & Alternatives – Net benefits accruing to customers (5.4.3.2.B.1.d.ii)

KWHI realizes that failures will begin to happen more frequently once cable has reached its EOL value in this project area resulting in unplanned customer outages. By having the conduit in place prior to the cable faulting or reaching it's EOL, work can be planned, and outages minimized and coordinated with the customers.

Analysis of Project & Alternatives – Impact of the investment on reliability performance including frequency and duration of outages (5.4.3.2.B.1.d.iii)

KWHI realizes that failures will begin to happen more frequently once cable has reached its EOL value in this project area resulting in unplanned customer outages. By having the conduit in place prior to the cable faulting or reaching it's EOL, work can be planned, and outages minimized and coordinated with the customers.

Project Name: Underground System Renewal

Project Alternatives (Design, Scheduling, Funding/Ownership (5.4.3.2.B.1.d.iii)

Project Design Alternatives:

Installing new conduit and/or cable once the plant fails – this is not a preferred alternative because it would take longer to complete the job, thus reducing customer satisfaction. It is also possible that the costs would be higher if the work needed to be completed after regular work hours at premium rates.

Scheduling Alternatives:

If an unplanned job arises that has significantly higher priority than this job, a decision can be made to defer this project to a later date. However, not installing the conduit or replacing EOL cable could lead to poor system reliability and possible increasing OM&A costs.

Ownership Alternatives:

This program consists solely of KWHI's assets and is constructed on the public right of way.

Safety (5.4.3.2.B.2)

This program will be completed in accordance with KWHI's standards and Ontario Regulation 22/04 to ensure no undue safety hazards. Work completed by a Contractor is inspected by KWHI.

Cyber-Security and Privacy (5.4.3.2.B.3) **(where applicable)**

This program does not impact cyber security or privacy.

Co-ordination and Interoperability (5.4.3.2.B.4)

Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.3.2.B.4.a) **(where applicable)**

This project will be co-ordinated with the appropriate road authority such as the City of Kitchener, the Region of Waterloo or the Township of Wilmot.

Enabling of Future Technology and/or Future Operational Requirements (5.4.3.2.B.4.b)

N/A

Environmental Benefits (5.4.3.2.B.2.B.5) **(where applicable)**

N/A

Conservation and Demand Management (5.4.3.2.B.2.B.6) **(where applicable)**

N/A

Project Name: Underground System Renewal

System Renewal Specific Requirements (5.4.3.2.C.b)

Asset Performance Target and Asset Lifecycle Optimization (5.4.3.2.C.b.i.a)

1. Safety – by proactively installing conduit for future cable replacement, and/or replacing underground cables which have reached their EOL value, safety issues associated with cable failures are avoided.
2. Customer Focus – installing conduit for future planned cable replacement and/or replacing underground cables which have reached their EOL value will reduce the likelihood of a long duration outage due to failure.

Asset Condition Relative to Typical Life Cycle (5.4.3.2.C.b.i.b)

The existing direct buried primary cable located in the Westheights area of Kitchener ranges from 30-45 years old and has either reached it's EOL (30 years) or is near it. Other assigned cables in concrete encased ductbanks to be replaced will have reached their EOL (40 years) or near it.

Number of Customers Impacted (5.4.3.2.C.b.i.c)

It is unknown at this time how many customers will be directly impacted from this program.

Quantitative Customer Impact and Risk (5.4.3.2.C.b.i.d)

It is unknown at this time how many customers will be directly impacted from this program with associated risk levels.

Qualitative Customer Impact and Risk (5.4.3.2.C.b.i.e)

If underground cables that have reached their EOL asset value are not replaced, the risk increases for unplanned outages resulting in lower customer satisfaction. One of the drivers for the project is reliability improvement.

Value of Customer Impact (5.4.3.2.C.b.i.f)

The value of customer impact is considered medium. Although the existing plant is working today, delaying its replacement may result in unplanned outages and decreased commercial and residential customer satisfaction.

Other Factors Affecting Project Timing (5.4.3.2.C.b.ii)

Already planned work by others may affect project timing. If the municipality, another utility or a new developer has work to do in the same area, a portion of the work may be delayed. Also, System Access (SA) projects have higher priority than System Renewal (SR) projects unless the condition of the assets associated with the SR project are in very poor condition or there is an unplanned equipment failure.

Impact on System O&M Costs (5.4.3.2.C.b.iii)

Not installing the conduit or replacing EOL cable could lead to poor system reliability and possible increasing OM&A costs if the cables need to be replaced on an emergency basis at premium rates.

Reliability and Safety Factors (5.4.3.2.C.b.iv)

By proactively installing conduit for future cable replacement, and/or replacing underground cables which have reached their EOL value, reliability and safety issues associated with cable failures are avoided.

Project Name: Underground System Renewal

Analysis of Project Benefits, Costs, Alternatives, and Timing (5.4.3.2.C.b.v)

This program to replace EOL underground assets is a constant in KWHI's yearly Capital Budget. It is recognized that waiting for EOL cable to fail and then replacing is not a preferred option. This work takes significant engineering, coordination and scheduling. The cost implication of completing this work on an emergency basis is high. The decrease in customer satisfaction due to unplanned outages is high. In order to sustain our reliability and eliminate the risk of safety hazards, it is imperative that this program is ongoing.

Like-for-Like Renewal Analysis (5.4.3.2.C.b.vi)
Yes, this program would be considered a Like of Like replacement. During rebuild, current design and equipment standards will be used.

Project Name: Underground System Renewal

Images

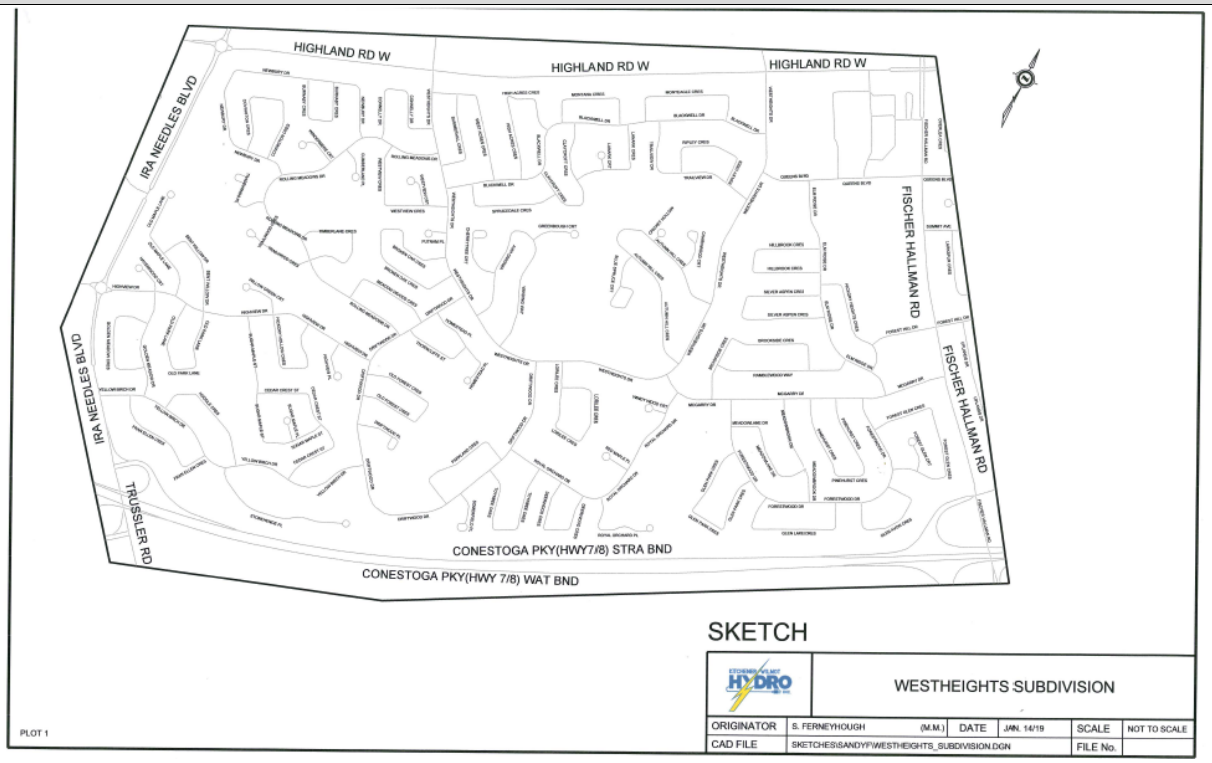


Figure 3: Layout of Westheights subdivision where conduits are being installed to replace direct buried primary cables

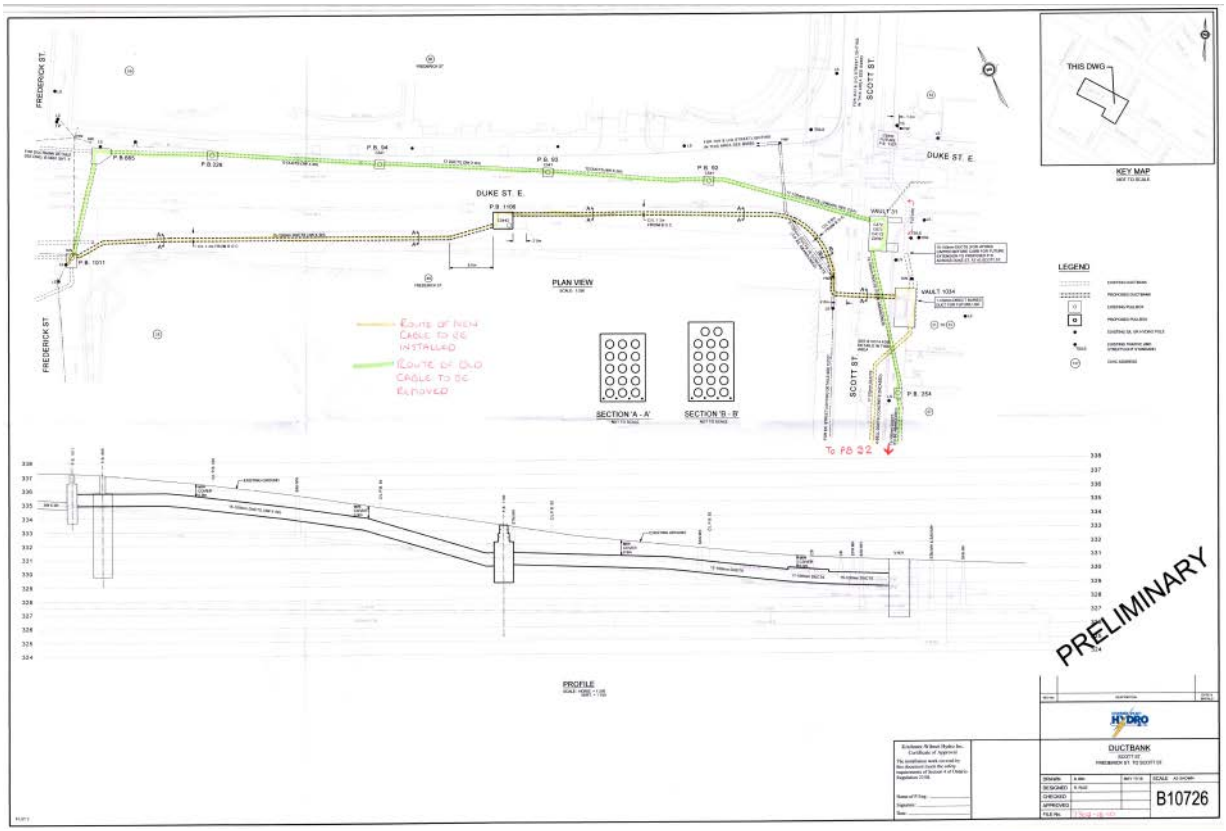


Figure 4: Duct bank design for replacement of civil infrastructure and network secondary cables on Scott St.

Project Name: Underground System Renewal

Project Authorization	
Prepared By: S. Ferneyhough	Authorized By: G. Cameron
Date: January 17, 2019	Date: April 5, 2019
	Completion Date: _____

Capital Project Summary

Project Name: Three Phase Transformer Vault Roof Replacements

Budget Year: 2020 **Budget Item No.:** 4-20-11

OEB Investment Category: System Renewal

General Information on Project (5.4.3.2.A)

Project Summary	This project is part of an ongoing program to replace 2 existing transformer vault roofs on an annual basis. This includes removal of the old concrete top, replacing any rotten steel beams, forming and pouring new reinforced concrete top. Exact locations will be determined from future conditions survey which are conducted annually. During the period when KWHI was focused on relocating its distribution plants to facilitate LRT, a number of transformer vaults were replaced as part of the LRT relocation project rather than the Transformer Vault Roof Replacement program.

	Description	Estimated Cost
Capital Investment (5.4.3.2.A.i)	**Labour:**	$113,800
	Materials:	$98,600
	Contract:	$0
	Engineering:	$27,600
Capital Contributions (5.4.3.2.A.ii)	**Total Estimated Cost:**	**$240,000**
	Recoverable:	$0
	KWHI Estimated Cost	**$240,000**

Customer Attachments / Load (kVA) (5.4.3.2.A.iii) **(where applicable)**	Each vault contains 1x500 kVA or 1x750 kVA 3-ph transformer. There are 38 network transformers that form part of a secondary grid network that serves approximately 632 customers (227 Residential, 367 GS<50, 38 GS>50). Each transformer supplies approximately 16 customers.
Project Dates (5.4.3.2.A.iv)	**Start Date:** **April 2020** **In Service Date:** **September 2020**

Estimated Expenditure Timing (5.4.3.2.A.iv)	Q1	Q2	Q3	Q4
	$0	$120,000	$120,000	$0

Project Name: Three Phase Transformer Vault Roof Replacements

Schedule Risk and Risk Mitigation (5.4.3.2.A.v)

The designs will be completed 1 month in advance of the scheduled construction date. KWHI will work closely with other 3rd parties such as the City of Kitchener and the Region of Waterloo to get their requirements for System Access projects 1 year in advance to reduce the potential for last minute design and construction changes.

Comparative Information from Equivalent Projects (5.4.3.2.A.vi) **(where available)**

In 2016, the top for transformer vault 290 (Young St at Ontario St) was rebuilt at a cost of $92,800. In 2018, the top of transformer vault 693 (Bell Lane) was rebuilt at a cost of $72,312. Also, in 2017/2018, the top of transformer vault 606 (Weber St W at Ontario St N) was rebuilt at a cost of $178,070. The variance in cost depends on the amount of work involved to repair the damage/deterioration. Detailed investigation and design will determine the scope of the work which is required for the 2 vaults chosen in this project. The estimated costs to rebuild two vaults in 2020 is based on average historical costs.

Total Capital and OM&A Costs Associated with REG Investments (5.4.3.2.A.vii)

There is no REG investment associated with this program.

Leave to Construct Approval (5.4.3.2.A.viii) **(where applicable)**

N/A

Evaluation Criteria and Information (5.4.4.2.B)

Efficiency, Customer Value, Reliability (5.4.3.2.B.1)

Investment Driver (5.4.3.2.B.1.a)

Condition – the main driver for this project is to replace the deteriorated tops of 2 transformer vault roofs. The tops have the greatest exposure to traffic, salt, and other corrosive elements, resulting in the tendency to deteriorate at a faster rate than the rest of the vault.

Secondary Driver (5.4.3.2.B.1.a) **(where applicable)**

Risk of failure – most of the network transformer vaults are installed with portion of their structure being below the travelled portion of roadways. If these structures are not repaired/replaced in a timely manner, there is a risk that they could suffer structure failure resulting in severe damage to people, property and vehicles.

Good Utility Practice (5.4.3.2.B.1.b)

The source of information used to justify this investment is field inspection of transformer vaults. In planning and designing the replacement for the vault roofs, considerations are given to existing reliability concerns such as the rusting of exposed I-beams used for support. The new design include support beams constructed from steel-reinforced concrete.

Investment Priority (5.4.3.2.B.1.c)

The priority of the project relative to others is Medium. System Access (SA) projects have a higher priority than System Renewal (SR) projects unless the condition of the assets associated with the SR project are in very poor condition. One of our asset management strategies is to replace assets before they reach a stage of critical condition. KWHI's project Prioritization Tool was used to prioritize all material projects for 2020 and this project was ranked as 21 out of 31.

Project Name: Three Phase Transformer Vault Roof Replacements

Analysis of Project and Project Alternatives – Effect of the investment on system operation efficiency and cost-effectiveness (5.4.3.2.B.1.d.i)

By planning the replacement of a transformer vault top rather than forced replacements at the time of failure, the cost can be managed utilising regular work hours and/or competitive bids and therefore not subject to overtime premiums. Proactive replacement also means that additional objectives can be achieved such as coordination with 3rd parties (e.g. The Region of Waterloo or the City of Kitchener) for future road alignment change.

Analysis of Project & Alternatives – Net benefits accruing to customers (5.4.3.2.B.1.d.ii)

By planning the replacement of a transformer vault top rather than forced replacements at the time of failure, the cost can be managed utilising regular work hours and/or competitive bids and therefore not subject to overtime premiums.

Analysis of Project & Alternatives – Impact of the investment on reliability performance including frequency and duration of outages (5.4.3.2.B.1.d.iii)

By planning the replacement of a transformer vault top rather than forced replacements at the time of failure, the cost can be managed utilising regular work hours and/or competitive bids and therefore not subject to overtime premiums. Also, if the state of a transformer vault top becomes critical, the transformer may have to be de-energized, thus affecting system reliability for customers.

Project Alternatives (Design, Scheduling, Funding/Ownership (5.4.3.2.B.1.d.iii)

Project Design Alternatives:

Patch or make minimum repairs to the vault top – This is not a preferred option. Patching of deteriorated concrete does not address the long-term structural damages.

Scheduling Alternatives:

If an unplanned job arises that has significantly higher priority than this job, a decision can be made to defer this project to a later date. Or if there is a large double vault that needs to be replaced, it is possible that only one (1) roof top may be replaced for this project. However, not replacing deteriorated plant is not an option due to public safety impacts, system reliability and possible increasing OM&A costs.

Ownership Alternatives:
None. This project consists solely of KWHI's assets and is constructed on the public right-of-way.

Safety (5.4.3.2.B.2)

Rebuilding the transformer vaults roof will be completed in accordance with KWHI's standards and Ontario Regulation 22/04 to ensure no undue safety hazards. This investment will ensure that the below grade structures continue to operate in a safe manner and reduces the probability of injuries to workers and the public.

Cyber-Security and Privacy (5.4.3.2.B.3) **(where applicable)**

This project does not impact cybersecurity or privacy.

Co-ordination and Interoperability (5.4.3.2.B.4)

Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.3.2.B.4.a) **(where applicable)**

This project will be co-ordinated with the Region of Waterloo and the City of Kitchener for their planned work.

Enabling of Future Technology and/or Future Operational Requirements (5.4.3.2.B.4.b)

This investment does not directly enable future technological functionality or operational requirements.

Environmental Benefits (5.4.3.2.B.2.B.5) **(where applicable)**

N/A

Conservation and Demand Management (5.4.3.2.B.2.B.6) **(where applicable)**

N/A

System Renewal Specific Requirements (5.4.3.2.C.b)

Asset Performance Target and Asset Lifecycle Optimization (5.4.3.2.C.b.i.a)

The life cycle for a transformer vault top is 30 years. All KWHI's transformer vault tops are surveyed on a yearly basis and those reaching their EOL value will be brought forward for possible replacement. Rebuilding the top of network transformer vaults extends the useful life for the overall structure.

Asset Condition Relative to Typical Life Cycle (5.4.3.2.C.b.i.b)

The life cycle for a transformer vault top is 30 years. All KWHI's transformer vault tops are surveyed on a yearly basis and those reaching their EOL value will be brought forward for possible replacement. If a vault top needs to be replaced prior to it's EOL value it can typically be because of its location. For example, if a vault is in the travelled road and subject to salt in the winter months, the steel beams may rot sooner than expected. Likewise, if the vault is subjected to frequent storm water run off, it may deteriorate faster than 30 years.

Number of Customers Impacted (5.4.3.2.C.b.i.c)

The actual number of customers impacted will be determined once the vault(s) has been decided. Typically, each network transformer services 16 customers.

Quantitative Customer Impact and Risk (5.4.3.2.C.b.i.d)

Outages that occur on the secondary network system are rare. However, when they do occur, they tend to last a long time (several hours) due to the complex nature of these systems. If the vaults are not rebuilt in a timely manner there could be structural failures which could have significant impact on reliability and safety. The risk of this occurring is minimized by proactive replacement or rebuilding of the transformer vaults roof and other structural elements.

Qualitative Customer Impact and Risk (5.4.3.2.C.b.i.e)

The secondary network that network transformer vaults support in terms of housing the network transformers, cables and accessories, has the highest reliability of all KWHI's distribution systems. The network has built-in redundancy and normally doesn't experience an outage with the failure of one piece of equipment. However, if there is a structural failure of the vault, a number of pieces of equipment could be damaged, such as the transformers, primary cables, and network secondary cables. This could result in a cascading outage that impacts the entire secondary network. Restoring power for these types of events could take several hours or days. If the primary cables for the other distribution subsystem is damaged, the

downtown loop system will also experience outages, albeit shorter in duration because of the ability to re-route power on this subsystem.

Value of Customer Impact (5.4.3.2.C.b.i.f)

If the secondary network is unavailable for a significant amount of time due to a structural failure of the vault, there will be a lot of dissatisfied customers and their clients since the network supplies mainly commercial loads in Kitchener's downtown core.

Other Factors Affecting Project Timing (5.4.3.2.C.b.ii)

Since transformer vaults are mainly located in the City's downtown core, this project may be delayed if other construction is scheduled in or near the same location such as new developments or City of Kitchener or Region of Waterloo road works.

Impact on System O&M Costs (5.4.3.2.C.b.iii)

Planned replacement of deteriorated structural elements of the transformer vaults will avoid unplanned failures which reduces O&M costs associated with possible forced outages and/or damage equipment.

Reliability and Safety Factors (5.4.3.2.C.b.iv)

If the project is not implemented, there is a strong likelihood that a transformer may have to be taken out of service to replace the deteriorated transformer vault top. If this is not completed prior to failure, this would become a safety hazard for the public and it may close a sidewalk or lane of traffic for an extended period until repairs can be completed. A transformer that is out of service effects the reliability of the network system.

Analysis of Project Benefits, Costs, Alternatives, and Timing (5.4.3.2.C.b.v)

Same as above.

Like-for-Like Renewal Analysis (5.4.3.2.C.b.vi)

This project is considered like for like replacement.

The Images



Figure 1: Sample of Transformer Vault Tops with rotting beams and deteriorated concrete.



Figure 2: Sample of Transformer Vault Tops with rotting beams and deteriorated concrete.

Project Name: Three Phase Transformer Vault Roof Replacements

Project Authorization	
Prepared By: S. Ferneyhough	Authorized By: G. Cameron
Date: January 21, 2019	Date: April 5, 2019
	Completion Date: _____

Capital Project Summary

Project Name: Distribution Transformer Installations and Replacement

Budget Year: 2020 **Budget Item No.:** 5-20-1, 5-20-3

OEB Investment Category: System Renewal

General Information on Project (5.4.3.2.A)

Project Summary	This project is to install new and replace failed overhead, underground and network transformers excluding those used in underground residential subdivisions, and underground commercial and industrial installations. This includes the labour to remove the old transformers and install all new transformers and all miscellaneous materials required to complete the job. It also includes the cost to purchase all overhead distribution transformers. Transformers are installed or replaced appurtenant to some other project (installing new services, rebuilding pole lines, replacing faulted units, etc.). Consequently, these expenditures are not discretionary. Specific expenditures are not always known at the time that the budget is set and total expenditures can vary from year to year.

	Description	Estimated Cost
Capital Investment (5.4.3.2.A.i)	**Labour:**	$543,800
	Materials:	$658,400
	Contract:	$ 50,000
	Engineering:	$ 97,800
Capital Contributions (5.4.3.2.A.ii)	**Total Estimated Cost:**	**$1,350,000**
	Recoverable:	$0
	KWHI Estimated Cost	**$850,000**

Customer Attachments / Load (kVA) (5.4.3.2.A.iii) **(where applicable)**	125 overhead transformers are budgeted for replacement ranging in size from 15 kVA to 225 kVA per transformer. The number of customers impacted varies.
Project Dates (5.4.3.2.A.iv)	**Start Date:** **January 2020** **In Service Date:** **December 2020**

Estimated Expenditure Timing (5.4.3.2.A.iv)	Q1	Q2	Q3	Q4
	$337,500	$337,500	$337,500	$337,500

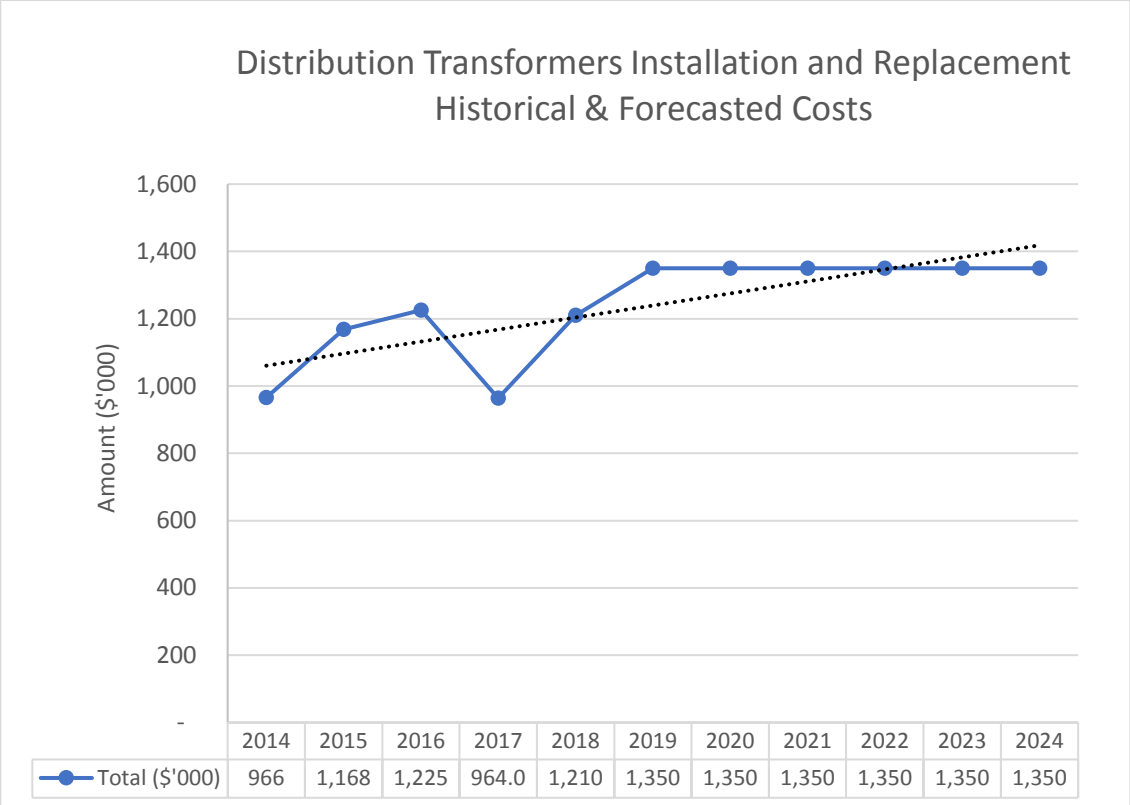
Project Name: Transformer Replacements

Schedule Risk and Risk Mitigation (5.4.3.2.A.v)

Manufacturers require 16-20 weeks for delivery for each unit, depending on the type. It is our practice to order transformers on a regular basis and have spares on hand. However; if the manufacturer's schedule is delayed, this could affect our scheduled installation of some transformers.

Comparative Information from Equivalent Projects (5.4.3.2.A.vi)

The total budget amount is determined by analyzing previous years installation expenditures combined with tendered pricing for purchasing of the transformers. The graph below shows the historical cost per year for this program along with the forecasted cost.



	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Total ($'000)	966	1,168	1,225	964.0	1,210	1,350	1,350	1,350	1,350	1,350	1,350

Total Capital and OM&A Costs Associated with REG Investments (5.4.3.2.A.vii)

There is no REG investment associated with this program.

Leave to Construct Approval (5.4.3.2.A.viii) **(where applicable)**

N/A

Evaluation Criteria and Information (5.4.4.2.B)

Efficiency, Customer Value, Reliability (5.4.3.2.B.1)

Project Name: Transformer Replacements

Investment Driver (5.4.3.2.B.1.a)

Age/Condition - the main driver for this investment is the age and condition of distribution transformers that are normally appurtenant to other distribution plant being replaced. As part of a pole line rebuild due to age and condition, the associated equipment installed on the poles are typically replaced including the transformers.

Secondary Driver (5.4.3.2.B.1.a) **(where applicable)**

Reliability – once this equipment has reached it's EOL, the reliability factor decreases, and the risk of unplanned outages increases.

Good Utility Practice (5.4.3.2.B.1.b)

The source of information used to justify this investment is record of past expenditures. Also, it is standard industry practice to replace transformers as part of pole line rebuild so that the same level of reliability exists for the entire pole line structure including the attached equipment. Replacing the transformers at the same time as the line rebuild is more cost effective than waiting until individual transformer fails or reach end of life.

Investment Priority (5.4.3.2.B.1.c)

The priority of the project relative to others is Low. System Access (SA) projects have a higher priority than System Renewal (SR) projects unless the condition of the assets associated with the SR project are in very poor condition. One of our asset management strategies is to replace assets before they reach a stage of critical condition. KWHI's project Prioritization Tool was used to prioritize all material projects for 2020 and this project was ranked as 28 out of 31.

Analysis of Project and Project Alternatives – Effect of the investment on system operation efficiency and cost-effectiveness (5.4.3.2.B.1.d.i)

By planning the replacement of a transformer rather than forced replacements at the time of failure, the cost can be managed utilising regular work hours and therefore not subject to overtime premiums.

Analysis of Project & Alternatives – Net benefits accruing to customers (5.4.3.2.B.1.d.ii)

By planning the replacement of transformers rather than forced replacements at the time of failure, the cost can be managed utilizing regular work hours and therefore not subject to overtime premiums. This will also reduce the risk of unplanned outages in the downtown core where there are many businesses.

Analysis of Project & Alternatives – Impact of the investment on reliability performance including frequency and duration of outages (5.4.3.2.B.1.d.iii)

By planning the replacement of transformers rather than forced replacements at the time of failure, the cost can be managed utilising regular work hours and therefore not subject to overtime premiums. This will also reduce the risk of unplanned outages in the downtown core where there are many businesses.

Project Alternatives (Design, Scheduling, Funding/Ownership (5.4.3.2.B.1.d.iii)

Project Design Alternatives:
Use existing transformation – where transformers are in relatively good condition, they can be re-used on the pole line rebuild. However, from an efficiency and work method perspective, this practice is not used. Instead, the transformer is replaced with a new unit on the new pole and the existing transformer, if in good condition, is returned to inventory for later re-use.

Scheduling Alternatives:
Replacement of transformers is dependent on replacement of the associated pole line or underground plant.

Ownership Alternatives:

None. This project consists solely of KWHI's assets.

Safety (5.4.3.2.B.2)

Replacing a network transformer will be completed in accordance with KWHI's standards and Ontario Regulation 22/04 to ensure no undue safety hazards.

Cyber-Security and Privacy (5.4.3.2.B.3) **(where applicable)**

This project does not impact cybersecurity or privacy.

Co-ordination and Interoperability (5.4.3.2.B.4)

Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.3.2.B.4.a) **(where applicable)**

The associated pole line projects will be co-ordinated with the Region of Waterloo, Wilmot Township and the City of Kitchener for their planned work and road closures. Network transformers are located in the downtown core and installation normally requires lane restriction or closure.

Enabling of Future Technology and/or Future Operational Requirements (5.4.3.2.B.4.b)

This investment does not directly enable future technological functionality or operational requirements.

Environmental Benefits (5.4.3.2.B.2.B.5) **(where applicable)**

N/A

Conservation and Demand Management (5.4.3.2.B.2.B.6) **(where applicable)**

N/A

System Renewal Specific Requirements (5.4.3.2.C.b)

Asset Performance Target and Asset Lifecycle Optimization (5.4.3.2.C.b.i.a)

The project supports the following asset performance and lifecycle optimization:

- Safety – by proactively replacing the end of life transformers, safety issues associated with equipment failures and oil spills are avoided.
- Operational Effectiveness – reliability indices (SAIDI and SAIFI) will be improved by not running the transformers to failure.
- Customer Focus – replacing poles and wires that are at end of life and in poor condition will reduce the likelihood of a long duration unplanned outage due to equipment failure.

Asset Condition Relative to Typical Life Cycle (5.4.3.2.C.b.i.b)

Overhead transformers are replaced as part of a pole line replacement. Since pole lines tend to be rebuilt after 40 years of being in service and based on their condition, the replacement of transformers follow the same schedule. Majority of transformers planned for replacement are at end of life. Those that have not reached their EOL, are in good condition, and are less than 30-years old are returned to inventory for restocking.

The life cycle for a network transformer is 40 years. All KWHI's network transformers are surveyed on a yearly basis and those reaching their EOL value will be brought forward for possible replacement. If a

network transformer needs to be replaced prior to it's EOL value, it can typically be because of its location. For example, if the vault is in the travelled road and subject to salt in the winter months, the transformer may rot sooner than expected. Likewise, if the vault is subjected to frequent storm water run off, the transformer may deteriorate faster than 40 years.

Number of Customers Impacted (5.4.3.2.C.b.i.c)

Typically, each overhead transformer services approximately12-16 residential customers. This is equivalent to 1,500 – 2,000 customers who are potentially impacted by the failure of the assets proposed for replacement.

Quantitative Customer Impact and Risk (5.4.3.2.C.b.i.d)
Assume that 1,500 customers are impacted by transformer outages lasting 4 hours in duration. This will equate to 6,000 customer-hours interrupted and SAIDI of 0.0625 hours.

Qualitative Customer Impact and Risk (5.4.3.2.C.b.i.e)

If these transformers are not replaced, the risk of unplanned outages and outage duration will increase resulting in lower customer satisfaction. Overhead transformers take between 3 and 4 hours to replace while underground transformers take between 4 and 6 hours to replace.

Value of Customer Impact (5.4.3.2.C.b.i.f)

- Replacement of transformers with new equipment reduces the cost of future repairs that may arise from potential equipment failures.
- If the project is not implemented, there is a strong likelihood that forced outages will occur due to equipment failure resulting in overtime required for response. Overhead transformers tend to fail during time of high demand which is usually outside regular business hours for residential customers.

Other Factors Affecting Project Timing (5.4.3.2.C.b.ii)

Since network transformers are mainly located in the City's downtown core, installation of network transformers may be delayed if other construction is scheduled in or near the same location such as new developments or City of Kitchener or Region of Waterloo road works.

Impact on System O&M Costs (5.4.3.2.C.b.iii)

If the project is not implemented, there is a strong likelihood that forced outages will occur due to equipment failure resulting in overtime required for response. Overhead transformers tend to fail during time of high demand which is usually outside regular business hours for residential customers.

Reliability and Safety Factors (5.4.3.2.C.b.iv)

By proactively replacing the end of life transformers, safety issues associated with equipment failures and oil spills are avoided.

Analysis of Project Benefits, Costs, Alternatives, and Timing (5.4.3.2.C.b.v)

- Replacement of transformers with new equipment will reduce the cost of future repairs that may arise from potential pole failures. New transformers are also designed to higher quality standards with lower losses. Reducing system losses is a direct customer benefit.
- If the project is not implemented, there is a strong likelihood that forced outages will continue to occur, resulting in possible overtime response.

Like-for-Like Renewal Analysis (5.4.3.2.C.b.vi)

Project Name: Transformer Replacements

Replacement of overhead transformers are like-for-like. An upgrade or downgrade in transformer size is undertaken during design based on historical loading.

Images



Figure 1: Overhead transformer at end of life

Project Authorization

Prepared By: S. Ferneyhough

Date: February 20, 2019

Authorized By: G. Cameron

Date: April 5, 2019

Completion Date: _____

Capital Project Summary

Project Name: Network Transformer Replacements

Budget Year: 2020 **Budget Item No.:** 5-20-6

OEB Investment Category: System Renewal

General Information on Project (5.4.3.2.A)

Project Summary	This project is to replace 2 existing 750 kVA network transformers with associated network protectors. The material cost to replace the equipment is captured here and installation cost is captured as part of budget item 5-20-1. The exact locations will be determined from the list of 14 transformers that are listed as being in poor condition and flagged for replacement. These assets are specialized in their use, costly to replace and should not run to failure because of the risk of a catastrophic failure in areas with high pedestrian traffic.

	Description	Estimated Cost
Capital Investment (5.4.3.2.A.i)	**Labour:**	$0
	Materials:	**$192,000**
	Contract:	$0
	Engineering:	$0
Capital Contributions (5.4.3.2.A.ii)	**Total Estimated Cost:**	**$192,000**
	Recoverable:	$0
	KWHI Estimated Cost	**$192,000**

Customer Attachments / Load (kVA) (5.4.3.2.A.iii) **(where applicable)**	Each network transformer is 750 kVA 3-ph 125/216V. There are 38 network transformers that form part of a grid secondary network in downtown Kitchener that serves approximately 632 customers (227 Residential, 367 GS<50, 38 GS>50). Each transformer supplies approximately 16 customers.
Project Dates (5.4.3.2.A.iv)	**Start Date: June 2020** **In Service Date: August 2020**

Estimated Expenditure Timing (5.4.3.2.A.iv)	Q1	Q2	Q3	Q4
	$0	$106,000	$86,000	$0

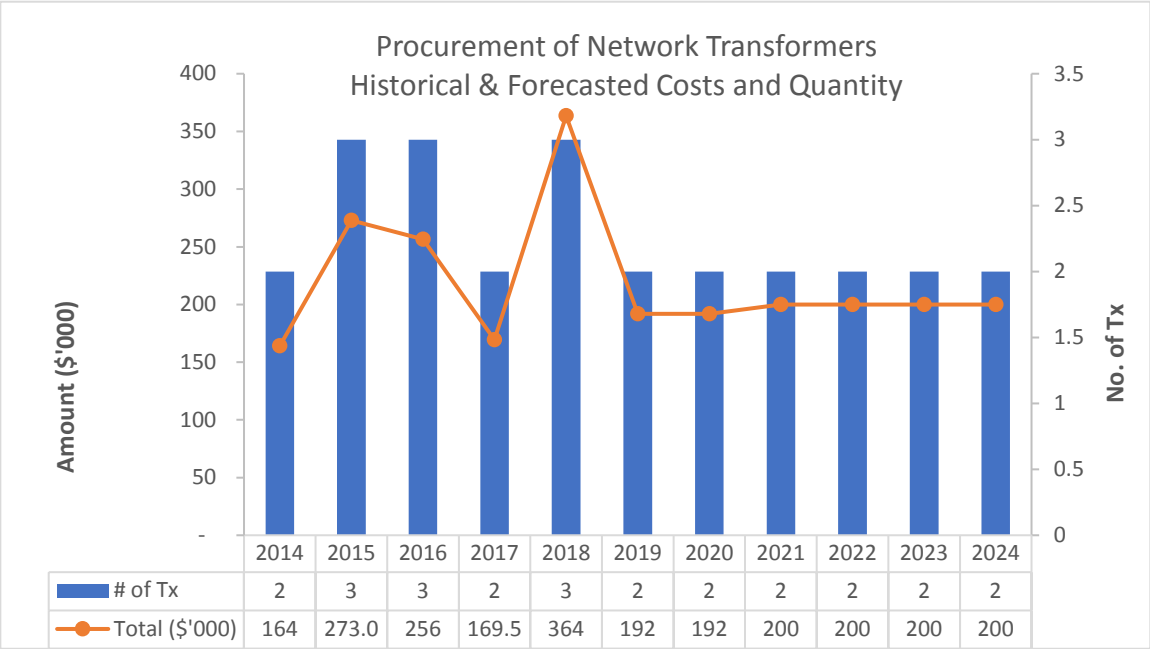
Project Name: Network Transformer Replacements

Schedule Risk and Risk Mitigation (5.4.3.2.A.v)

The manufacturer (Cartier International) requires 50 weeks for delivery for each unit so an order has been placed in 2019 in order to accommodate this lead time. However, if the manufacturers schedule is delayed, this would affect our scheduled installation date.

Comparative Information from Equivalent Projects (5.4.3.2.A.vi) **(where available)**

Historical cost to purchase one 750 kVA network transformer with protector is $95,000 per unit. The cost to install these devices is captured as part of KWHI's budget item 5-20-1, Installing Transformers. The figure below shows the historical (2014-2018) and forecasted (2019-2024) costs to purchase network transformers and the quantity purchased.



	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
# of Tx	2	3	3	2	3	2	2	2	2	2	2
Total ($'000)	164	273.0	256	169.5	364	192	192	200	200	200	200

Total Capital and OM&A Costs Associated with REG Investments (5.4.3.2.A.vii)

There is no REG investment associated with this program.

Leave to Construct Approval (5.4.3.2.A.viii) **(where applicable)**

N/A

Evaluation Criteria and Information (5.4.4.2.B)

Efficiency, Customer Value, Reliability (5.4.3.2.B.1)

Investment Driver (5.4.3.2.B.1.a)

Condition – the main driver for this project is to replace 2 network transformers which have reached their end of life asset value and are showing signs of deterioration. The 2018 ACA identifies 14 network transformers as being in poor condition.

Project Name: Network Transformer Replacements

Secondary Driver (5.4.3.2.B.1.a) **(where applicable)**

Reliability – Once this equipment has reached it's EOL, the reliability factor decreases, and the risk of unplanned outages increases.

Good Utility Practice (5.4.3.2.B.1.b)

The source of the information used to justify this investment is yearly visual inspection as well as annual oil sample testing.

Investment Priority (5.4.3.2.B.1.c)

The priority of the project relative to others is High. System Access (SA) projects have a higher priority than System Renewal (SR) projects unless the condition of the assets associated with the SR project are in very poor condition. One of our asset management strategies is to replace assets before they reach a stage of critical condition. KWHI's project Prioritization Tool was used to prioritize all material projects for 2020 and this project was ranked as 5 out of 31.

Analysis of Project and Project Alternatives – Effect of the investment on system operation efficiency and cost-effectiveness (5.4.3.2.B.1.d.i)

By planning the replacement of a network transformer rather than forced replacements at the time of failure, the cost can be managed utilising regular work hours and therefore not subject to overtime premiums.

Analysis of Project & Alternatives – Net benefits accruing to customers (5.4.3.2.B.1.d.ii)

By planning the replacement of a network transformer rather than forced replacements at the time of failure, the cost can be managed utilising regular work hours and therefore not subject to overtime premiums. This will also reduce the risk of unplanned outages in the downtown core where there are many businesses.

Analysis of Project & Alternatives – Impact of the investment on reliability performance including frequency and duration of outages (5.4.3.2.B.1.d.iii)

By planning the replacement of a network transformer rather than forced replacements at the time of failure, the cost can be managed utilising regular work hours and therefore not subject to overtime premiums. This will also reduce the risk of unplanned outages in the downtown core where there are many businesses.

Project Alternatives (Design, Scheduling, Funding/Ownership (5.4.3.2.B.1.d.iii)

Project Design Alternatives:

Repair Only – This is not a preferred option since the transformers flagged for replacement have all exceeded the typical useful life. Repairing the transformers would be a short-term measure.

Scheduling Alternatives:

If an unplanned job arises that has significantly higher priority than this job, a decision can be made to defer this project to a later date. However, not replacing deteriorated plant is not an option due to system reliability and possible increasing OM&A costs.

Ownership Alternatives:
None. This project consists solely of KWHI's assets and is constructed on the public right-of-way.

Safety (5.4.3.2.B.2)

Project Name: Network Transformer Replacements

Replacing a network transformer will be completed in accordance with KWHI's standards and Ontario Regulation 22/04 to ensure no undue safety hazards. Network transformers are installed below grade in the downtown core of Kitchener with high pedestrian and vehicular traffic. Failure of these transformers can lead to severe injuries or damages.

Cyber-Security and Privacy (5.4.3.2.B.3) **(where applicable)**

This project does not impact cybersecurity or privacy.

Co-ordination and Interoperability (5.4.3.2.B.4)

Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.3.2.B.4.a) **(where applicable)**

This project will be co-ordinated with the Region of Waterloo and the City of Kitchener for their planned work and road closures. Network transformers are located in the downtown core

Enabling of Future Technology and/or Future Operational Requirements (5.4.3.2.B.4.b)

New network transformers are fitted with microprocessor relays, dead-front network protectors, and remote racking breakers that enable remote monitoring and control, and safer operation of these equipment.

Environmental Benefits (5.4.3.2.B.2.B.5) **(where applicable)**

N/A

Conservation and Demand Management (5.4.3.2.B.2.B.6) **(where applicable)**

N/A

System Renewal Specific Requirements (5.4.3.2.C.b)

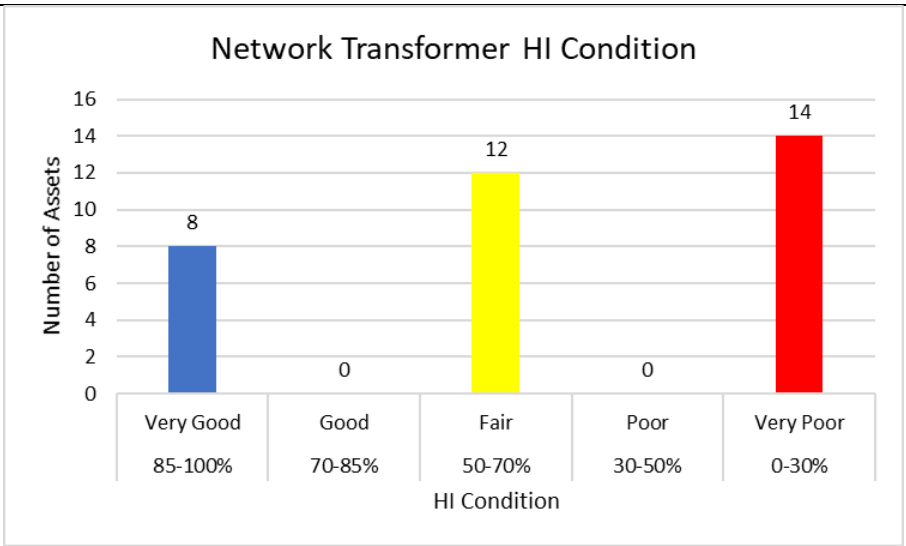
Asset Performance Target and Asset Lifecycle Optimization (5.4.3.2.C.b.i.a)

The life cycle for a transformer is 40 years. All KWHI's network transformers are surveyed on a yearly basis and those reaching their EOL value will be brought forward for possible replacement. These transformers are not allowed to run to failure because of the likelihood of a catastrophic failure and the impact on other assets in the network vault and the general public.

Asset Condition Relative to Typical Life Cycle (5.4.3.2.C.b.i.b)

The life cycle for a network transformer is 40 years. All KWHI's network transformers are surveyed on a yearly basis coupled with oil testing and those reaching their EOL value will be brought forward for possible replacement. If a network transformer needs to be replaced prior to it's EOL value, it can typically be because of its location. For example, if the vault is in the travelled road and subject to salt in the winter months, the transformer may rot sooner than expected. Likewise, if the vault is subjected to frequent storm water run off, the transformer may deteriorate faster than 40 years. The transformers scheduled for replacement are greater than 50 years old.

Project Name: Network Transformer Replacements



Number of Customers Impacted (5.4.3.2.C.b.i.c)

The actual number of customers impacted will be determined once the transformers have been decided. Typically, each network transformer services 16 customers.

Quantitative Customer Impact and Risk (5.4.3.2.C.b.i.d)

It is not KWHI's practice to run this equipment to failure due to the risk of catastrophic failure. However, in 2010, a 34-year old network transformer protector failed at a Provincial Courthouse resulting in a complete outage for the secondary network and its over 630 customers. The failure also resulted in overheating and melting of electrical equipment. To avoid these situations, network transformers and their associated network protectors are replaced on a proactive basis.

Qualitative Customer Impact and Risk (5.4.3.2.C.b.i.e)

The secondary network that network transformers supply has the highest reliability of all KWHI's distribution systems. The network has built-in redundancy and normally doesn't experience an outage with the failure of one transformer. However, if there is a catastrophic failure of the transformer or protector, the entire network may be impacted. If there is severe damage to the cables that form the highly interconnected network, restoring power could take hours or days.

Value of Customer Impact (5.4.3.2.C.b.i.f)

If the network is unavailable for a significant amount of time, there will be a lot of dissatisfied customers and their clients since the network supplies mainly commercial loads in Kitchener's downtown core.

Other Factors Affecting Project Timing (5.4.3.2.C.b.ii)

Since network transformers are mainly located in the City's downtown core, this project may be delayed if other construction is scheduled in or near the same location such as new developments or City of Kitchener or Region of Waterloo road works.

Impact on System O&M Costs (5.4.3.2.C.b.iii)

Planned replacement of network transformers will avoid unplanned failures which reduces O&M costs associated with possible forced outages and/or damage equipment.

Project Name: Network Transformer Replacements

Reliability and Safety Factors (5.4.3.2.C.b.iv)

If the project is not implemented, there is a strong likelihood that a deteriorated transformer may fault and then be out of service for an extended period of time before it can be replaced. A network transformer that is out of service affects the reliability of the entire network system.

Analysis of Project Benefits, Costs, Alternatives, and Timing (5.4.3.2.C.b.v)

Same as above.

Like-for-Like Renewal Analysis (5.4.3.2.C.b.vi)

This project is considered a Like for Like replacement. New equipment will be upgraded to meet KWHI's current standard.

Images



Figure 1 - Deteriorated network transformer with protector

Project Authorization

Prepared By: S. Ferneyhough

Date: February 20, 2019

Authorized By: G. Cameron

Date: April 5, 2019

Completion Date: _____

Capital Project Summary

Project Name: Strasburg Road between Rockcliffe Drive to Robert Ferrie Drive

Budget Year: 2020 **Budget Item No.:** 3-20-2 (part of)

OEB Investment Category: System Service

General Information on Project (5.4.3.2.A)

Project Summary	This project is part of a program for System Expansion to Supply New Development and represents Phase 2 of a multi-phase project. Phase 1 will be completed in 2019 and includes the construction of a pole line from the existing terminus of Strasburg Road to Rockcliffe Drive. This project includes building a new double circuit pole line (6-556 MCM ASC) complete with 21 poles along the extended Strasburg Road to accommodate future developments. There is an estimated 2,000+ customers that will be connected in the southwest portion of Kitchener within the next five years and over 6,000 in 10 – 20 years. Currently, there is no public road allowance or distribution circuit available to supply the future demand. With the extension of Strasburg to connect the future subdivisions, KWHI will be constructing a new distribution pole line to meet the demand.

	Description	**Estimated Cost**
Capital Investment (5.4.3.2.A.i)	**Labour:**	$146,700
	Materials:	$76,200
	Contract:	$6,100
	Engineering:	$29,800
Capital Contributions (5.4.3.2.A.ii)	**Total Estimated Cost:**	**$258,800**
	Recoverable:	$0
	KWHI Estimated Cost	**$258,800**

Customer Attachments / Load (kVA) (5.4.3.2.A.iii) **(if applicable)**	There are no existing customers on this section of pole line. The road work will enable the development of more than 5000 new single-family homes in Kitchener south area.
Project Dates (5.4.3.2.A.iv)	**Start Date:** **April 2020** **In Service Date:** **July 2020**

Estimated Expenditure Timing (5.4.3.2.A.iv)	**Q1**	**Q2**	**Q3**	**Q4**
	$0	**$129,400**	**$129,400**	$0

Project Name: Strasburg Road: Rockcliffe Drive to Robert Ferrie Drive

Schedule Risk and Risk Mitigation (5.4.3.2.A.v)

The scheduled risks for executing this program is primarily the timing of the municipality's roadway schedule and KWHI has limited authority over the timing of this project. KWHI maintains a high level of frequent communication with all municipalities in order to ensure a timely and efficient exchange of information. It is generally our intention to complete the construction within the assigned time window after grading is completed.

Comparative Information from Equivalent Projects (5.4.3.2.A.vi) **(where available)**

In 2017, a similar project was constructed in the City of Kitchener (Bullock St and Pearson St) that involved the building of a pole line by KWHI crews with 26 wood poles and stringing 6 spans of new 6-556 MCM Al. conductor and 18 spans of 3-556 MCM Al conductor. The project cost was $240,000 (approx. $9,200 per pole).

Total Capital and OM&A Costs Associated with REG Investments (5.4.3.2.A.vii)

There is no REG investment associated with this project.

Leave to Construct Approval (5.4.3.2.A.viii) **(where applicable)**

N/A

Evaluation Criteria and Information (5.4.3.2.B)

Efficiency, Customer Value, Reliability (5.4.3.2.B.1)

Investment Driver (5.4.3.2.B.1.a)

The main driver for this investment is customer service requests. KWHI is mandated to connect new customers or service upgrades within its distribution service area per the DSC and KWHI's Conditions of Service. The road work will enable the development of more than 5,000 new single-family homes in Kitchener south area. The pole line will be used to support the future development along the road extension.

Strasburg Road extension goes through areas which have been identified in the Kitchener Growth Plan 2017-2019. See the table below. Multiple subdivisions are expected to be serviced in the next 0 - 20 years. There are no existing distribution feeders to accommodate the proposed growth. Hence, the need to expand the distribution system along the Strasburg Road extension to supply the proposed future developments.

Development Subdivision Plan	Proposed Residential Units	In Service Schedule	KWHI Proposed feeder	Development Priority
Huron South	500	0-5 years	8M2	High
Brigadoon	600	5-10 years	8M2	Medium
Brigadoon South	800	5-10 years	8M2/8M7	Medium
Doon South Phase II	1500+	5-20 years	8M2/8M6	High
Dundee North	3000+	10-20 years	8M2/8M5	Low

Secondary Driver (5.4.3.2.B.1.a) **(where applicable)**

Efficiency and reliability improvement - the proposed upper circuit will be used to reconfigure the existing distribution feeder for Doon South area including Conestoga College which is sensitive to power outages.

Compared with the existing feeder configuration, the new supply feeder will be 3 km shorter than the existing feeder. This will reduce power loss and improve the feeder reliability.

Good Utility Practice (5.4.3.2.B.1.b)
The planning and designing of this new pole line will take into consideration existing reliability concerns and grid modernisation. The pole line will be designed to meet CSA Heavy design requirements, will utilise materials with high strength and capacity, and will have automated switch installed with remote monitoring and control capabilities.

Investment Priority (5.4.3.2.B.1.c)

The priority of this program relative to others is medium. KWHI is mandated to connect new customers or service upgrades within its distribution service area per the DSC and KWHI's Condition of Service. Without the pole line, KWHI could not support the future development along the road extension. There are no other cheaper alternatives. The project prioritization tool was used to prioritize all materials projects for 2020 and this project was ranked 9 out of 31.

Analysis of Project and Project Alternatives – Effect of the investment on system operation efficiency and cost-effectiveness (5.4.3.2.B.1.d.i)

KWHI is mandated to connect new customers or service upgrades within its distribution service area per the DSC and KWHI's Conditions of Service. Without the pole line, KWHI could not support the future development along the road extension. There are no other cheaper alternatives.

Analysis of Project & Alternatives – Net benefits accruing to customers (5.4.3.2.B.1.d.ii)

By planning the building of the pole line before the road is open to the public rather than after, the cost per pole can be reduced due to simpler traffic planning and safer working environment.

Analysis of Project & Alternatives – Impact of the investment on reliability performance including frequency and duration of outages (5.4.3.2.B.1.d.iii)

Efficiency and reliability improvement: the proposed upper circuit will be used to reconfigure the existing distribution feeder for Doon South area including important load customer Conestoga College. Compared with the existing feeder configuration, the new supply feeder will be 3km shorter than the existing feeder. The power loss will be reduced, and the feeder reliability will be improved.

Project Alternatives (Design, Scheduling, Funding/Ownership (5.4.3.2.B.1.d.iii)

Project Design Alternatives:

The overhead pole line will be constructed following the latest KWHI standards. There are no other cheaper alternatives.

Scheduling Alternatives:

The work will be carried out when the grading is completed, and the road is not yet open to the public. If the City of Kitchener changes their planned road work, KWHI will adjust the pole line work schedule accordingly.

Ownership Alternatives:

None. This project consists solely of KWHI's assets and is constructed on the public right-of-way.

Safety (5.4.3.2.B.2)

This project does not impact safety.

Cyber-Security and Privacy (5.4.3.2.B.3) **(where applicable)**

This project does not impact cyber security or privacy.

Co-ordination and Interoperability (5.4.3.2.B.4)

Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.3.2.B.4.a) **(where applicable)**

This project will be co-ordinated with the City of Kitchener road contractor, City of Kitchener Gas, Hydro One Networks, Bell Canada and Rogers Cable TV.

Enabling of Future Technology and/or Future Operational Requirements (5.4.3.2.B.4.b)

This pole line will have an automated switch (recloser) installed with remote monitoring and control capabilities. It will also have the space and capacity to add a second circuit for future load growth.

Environmental Benefits (5.4.3.2.B.2.B.5) **(where applicable)**

N/A

Conservation and Demand Management (5.4.3.2.B.2.B.6) **(where applicable)**

N/A

Category - Specific Requirements -System Service (5.4.3.2.SS - C)

Benefits to Customers vs. Cost Impact (5.4.3.2 SS – C.i)

KWHI is mandated to connect new customers or service upgrades within its distribution area per the DSC and KWHI's Condition of Service.

Regional Electricity Infrastructure Requirements (5.4.3.2 SS – C.ii) **(where applicable)**

N/A

Advanced Technology (5.4.3.2 SS – C.iii) **(where applicable)**

N/A

Reliability, Efficiency, Safety and Coordination Benefits (5.4.3.2 SS – C.iv)

Efficiency and reliability improvement: the proposed upper circuit will be used to reconfigure the existing distribution feeder for Doon South area including important load customers Conestoga College. Compared with the existing feeder configuration, the new supply feeder will be 3km shorter than the existing feeder. The power loss will be reduced, and the feeder reliability will be improved.

Factors Affecting Timing & Priority of Project (5.4.3.2 SS – C.v)

Factors affecting the timing and priority of this project include:

- Weather and road conditions.
- Change on road work schedule.

Project Name: Strasburg Road: Rockcliffe Drive to Robert Ferrie Drive

Analysis of Project Benefits and Costs ie. "Do Nothing" & "Technically Feasible Alternatives" (5.4.3.2 SS – C.vi)

Do Nothing – this is not an option since KWHI is mandated to connect new customers of service upgrades within its distribution service area per the DSC and KWHI's Conditions of Service. Without the pole line, KWHI could not support the future development along the road extension.

Feasible Alternatives – there are no feasible alternatives. New residential and commercial units will be constructed beginning in 2020 and KWHI is required to provide distribution service to all buildings within its service territory.

Images

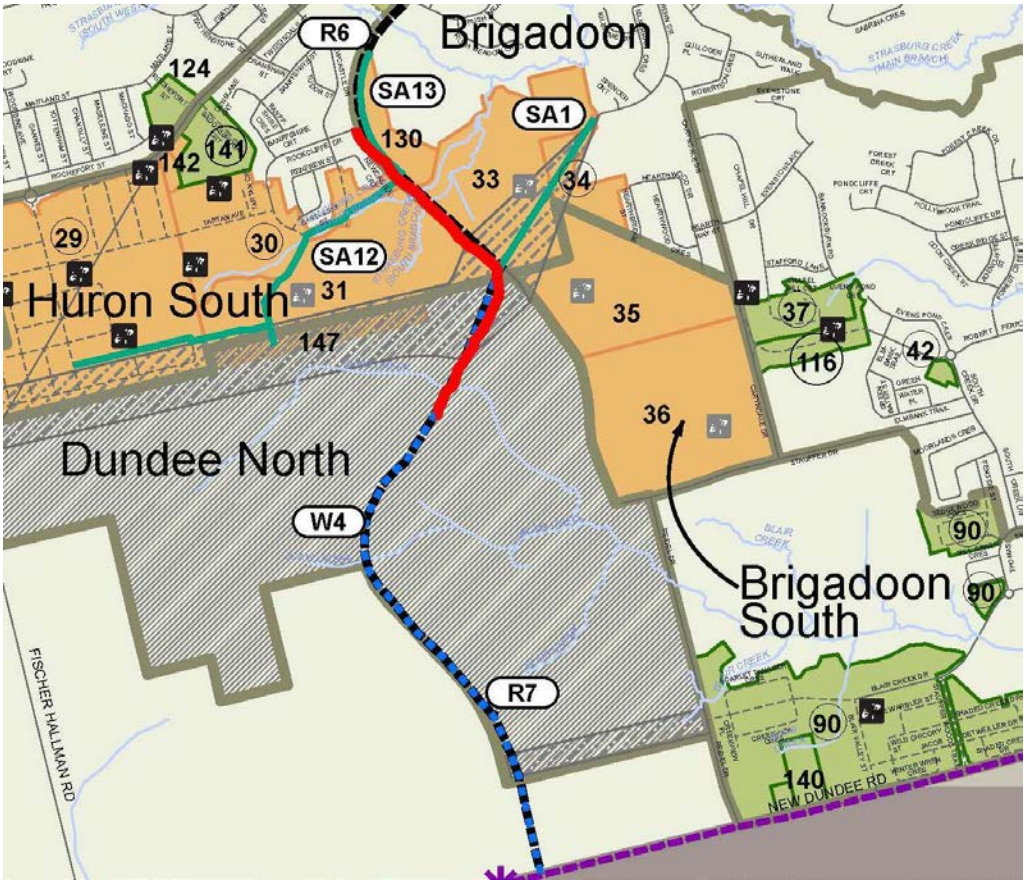


Figure 1: View of the proposed pole line project (marked by red line)



Figure 2: termination of existing pole line that will be extended

Project Authorization

Prepared By:	S. Ferneyhough	Authorized By:	G. Cameron
Date:	March 19, 2019	Date:	April 5, 2019
		Completion Date:	_____

Capital Project Summary

Project Name: Mannheim Road: Witmer Road to Huron Road

Budget Year: 2020 **Budget Item No.:** 3-20-2 (part of)

OEB Investment Category: System Service

General Information on Project (5.4.3.2.A)

Project Summary	This project is part of a program for System Expansion to Supply New Development and Load Growth or improve reliability. This project includes rebuilding the existing single circuit 1-ph/3ph pole line to a single 3-ph pole line with 35-45' wood poles, replacing the existing 3/0 ACSR conductor with 3-556 MCM Al. conductor to provide full load transfer capacity with adjacent feeders. The project will also include the installation of one new automated SCADA controlled recloser to provide remote monitoring and control of the switching device coupled with enabling fast response to fault isolation and outage restoration.

	Description	Estimated Cost
Capital Investment (5.4.3.2.A.i)	**Labour:**	$245,000
	Materials:	$113,400
	Contract:	$0
	Engineering:	$46,000
Capital Contributions (5.4.3.2.A.ii)	**Total Estimated Cost:**	**$402,500**
	Recoverable:	$0
	KWHI Estimated Cost	**$402,500**

Customer Attachments / Load (kVA) (5.4.3.2.A.iii) **(if applicable)**	7 customers- 540 kVA transformation
Project Dates (5.4.3.2.A.iv)	**Start Date: July 2020** **In Service Date: September 2020**

Estimated Expenditure Timing (5.4.3.2.A.iv)	Q1	Q2	Q3	Q4
	$0	**$0**	$402,500	$0

Project Name: Mannheim Road: Witmer Road to Huron Road

Schedule Risk and Risk Mitigation (5.4.3.2.A.v)

Availability of resources to design and construct the pole line in light of other priority jobs that were not known in advance. To mitigate this risk, the project will be designed at least 3 months in advance of the scheduled construction date. KWHI has access to external contractors who are often used to supplement the internal resources. Also, KWHI work closely with other 3rd parties such as the Region, Township of Wilmot to get their requirements for system access projects at least 1 year in advance so as to reduce the potential for last minute design and construction.

Comparative Information from Equivalent Projects (5.4.3.2.A.vi) **(where available)**

In 2017, a similar project was constructed in the City of Kitchener (Schweitzer Street between Bridge Street and Daniel Street) that involved the rebuilding of a pole line by KWHI crews with 25 wood poles and stringing new 3-556 MCM Al conductor. The project cost was $272,150 (approx. $11,200 per pole)

Total Capital and OM&A Costs Associated with REG Investments (5.4.3.2.A.vii)

There is no REG investment associated with this project.

Leave to Construct Approval (5.4.3.2.A.viii) **(where applicable)**

N/A

Evaluation Criteria and Information (5.4.3.2.B)

Efficiency, Customer Value, Reliability (5.4.3.2.B.1)

Investment Driver (5.4.3.2.B.1.a)

System Constraints, Reliability & Grid Flexibility – this pole line is a part of a 3 km long, 3-ph feeder lateral, supplying 319 customers including four (4) important Regional Water Wells (K22, K23, K24 & K26) which supplies tap water to the City of Kitchener. If there is an outage on this line section, the customers in this area will experienced longer that normal power outages due to lack of backup supply from the alternate feeders. By extending the 3-ph pole line to Huron Rd, this long section of pole line will be tied to another KWHI feeder (8M9) from a different transformer station. The customers in this area will be able to be transferred to an alternate supply during planned or unplanned outages and experience consistent service with other areas of KWHI's distribution system.

Secondary Driver (5.4.3.2.B.1.a) **(where applicable)**

Condition/Age/Failure Risk – the secondary driver for this project is the condition coupled with the age of the poles and the risk of failure. The majority of poles range in age from 43 to 55 years old and have health indices of Very Poor to Good based on results from the pole inspection survey conducted in 2017 and asset condition assessment done in 2018. The condition of the poles poses a failure risk that must be mitigated before a failure occurs. The old 3/0 ACSR conductor (50 years+) can only carry 400A current. By rebuilding this pole line and reconductoring with 3-556 MCM Al., it will facilitate the full load capacity of 600A which is KWHI's standard ampacity for distribution feeders.

	Age					
	0-10	11-20	21-30	31-40	41-50	>50
Condition	Quantity					
Very Good	1	-	-	-	-	-
Good	-	2	-	1	10	-
Fair	-	-	-	3	2	2

Poor	-	-	-	3	-	9
Very Poor	-	-	-	-	-	2

Good Utility Practice (5.4.3.2.B.1.b)
In planning and designing the replacement and upgrade of the pole line, considerations are given to existing reliability concerns and grid modernisation. The new pole line will be upgraded to provide a three-phase tie to another circuit so that reliability can be enhanced for three water wells currently being served. An automated circuit recloser will also be installed to provide remote monitor and control of the feeder section.

Investment Priority (5.4.3.2.B.1.c)

The priority of this program relative to others is high. System Access (SA) projects have higher priority than System Service (SS) projects unless the condition of assets associated with the SS project are in very poor condition. One of our asset management strategies is to replace assets before they reach a stage of critical condition. KWHI's project prioritization tool was used to prioritize all materials projects for 2020 and this project was ranked 9 out of 31.

Analysis of Project and Project Alternatives – Effect of the investment on system operation efficiency and cost-effectiveness (5.4.3.2.B.1.d.i)

By rebuilding the pole line and creating the backup tie, it will enhance the load transfer capacity for feeders from different transformer stations.

Analysis of Project & Alternatives – Net benefits accruing to customers (5.4.3.2.B.1.d.ii)

By planning the replacement of poles rather than forced replacement at the time of failure, the cost per pole can be managed utilising regular work hours and/or competitive bids and therefore not subject to overtime premiums. The line segment provides power supply to four water wells which provide clean drinking water for the citizens of Kitchener. Replacing aged assets and improving the load transfer capability will reduce the probability of a long duration outage to the wells.

Proactive replacement also means that additional objectives can be achieved such as coordination with 3rd parties (e.g. Township of Wilmot) for future road alignment changes and system expansion (conductor upgrading for load transfers).

Analysis of Project & Alternatives – Impact of the investment on reliability performance including frequency and duration of outages (5.4.3.2.B.1.d.iii)

By rebuilding the pole line and creating the backup tie, customers will experience an improvement in reliability (number of sustained outages and time of average outage duration). The risk associated with downed power lines will also be reduced with the installation of new poles, wires and associated hardware with higher structural strength.

Project Alternatives (Design, Scheduling, Funding/Ownership (5.4.3.2.B.1.d.iii)

Project Design Alternatives:

i. "Like for Like" replacement – i.e. replace poles and hardware only and transfer existing conductor – This is not a preferred option. The existing wire size is #3/0 ACSR which does not have the electrical characteristics to allow 600A current according to KWHI's maximum feeder load transfer requirements.
ii. Replace poles, hardware and associated hardware – this is the preferred option which will maximize benefits to the customer.

Scheduling Alternatives:

If an unplanned job arises that has significantly higher priority than this job, a decision can be made to defer this project to a later date. However, not replacing end of life assets is not a preferred option due to public safety impacts, system reliability and possible increasing OM&A costs.

Ownership Alternatives:

None. This project consists solely of KWHI's assets and is constructed on the public right-of-way.

Safety (5.4.3.2.B.2)

Replacement of these poles that are at their end of useful life and in poor/fair condition will reduce the likelihood for unexpected pole failures. The project will also replace old conductors (50+ years) with smaller cross-sectional area which tend to break due to metal fatigue. Metal fatigue is the application and release of small stresses which weakens the metal resulting in an accumulation of small cracks. These small cracks grow slowly and eventually the metal becomes permanently deformed or breaks. Having "downed" primary wires on the ground created a safety hazard for the public and workers.

Cyber-Security and Privacy (5.4.3.2.B.3) **(where applicable)**

This project does not impact cyber security or privacy.

Co-ordination and Interoperability (5.4.3.2.B.4)

Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.3.2.B.4.a) **(where applicable)**

This project will be co-ordinated with the Township of Wilmot, Bell Canada and Rogers Cable TV.

Enabling of Future Technology and/or Future Operational Requirements (5.4.3.2.B.4.b)

The pole line rebuild will facilitate more load transfer capacity of KWHI's distribution system. The section of pole line will also be fitted with a SCADA controlled electronic recloser which will enhance power restoration and reduce the extent of unplanned outages.

Environmental Benefits (5.4.3.2.B.2.B.5) **(where applicable)**

As part of the rebuild, KWHI will be replacing older poles which were predominately treated with chemicals that do not meet today's standards. As a result, rebuilding this pole line will replace older poles with poles that adhere to todays' current environmental standards.

Conservation and Demand Management (5.4.3.2.B.2.B.6) **(where applicable)**

N/A

Category - Specific Requirements -System Service (5.4.3.2.SS - C)

Benefits to Customers vs. Cost Impact (5.4.3.2 SS – C.i)

Although there are only 7 customers on this line section, failure of assets may cause an outage which will impact the entire 6M13 feeder serving approximately 1840 residential and general class customers (industrial and institutional).

Project Name: Mannheim Road: Witmer Road to Huron Road

Based on results from the pole inspection conducted in 2017 and asset condition assessment done in 2018, the majority of the pole line is in poor or very poor condition and at the end of life. If the pole line isn't rebuilt, the number of unplanned outages and outage duration may increase resulting in lower customer satisfaction.

Results from KWHI's Customer Engagement Survey suggests that commercial and industrial customers rank power quality and reliability as a high priority. See excerpt below.

> **Overall, low-volume customers are consistent on priorities related to reliability – reducing the number and length of outages, and improving restoration times during extreme weather. Mid-market and large business customers appear to prioritize reliability over price, with a focus on power quality and communications during outages in order to assist with operational planning.**

Regional Electricity Infrastructure Requirements (5.4.3.2 SS – C.ii) **(where applicable)**

N/A

Advanced Technology (5.4.3.2 SS – C.iii) **(where applicable)**

An automated recloser will be installed in this line section to enable load transfer capability during power outages. The reclosers utilized by KWHI have advanced technology built into them and meet cyber security standards for protection of data transfer.

The reclosers also have two integrated power modules on both sides of the interrupters, eliminating the need to install separate distribution transformers to supply power to the recloser.

Reliability, Efficiency, Safety and Coordination Benefits (5.4.3.2 SS – C.iv)

Reliability and efficiency – by rebuilding the pole line and creating the back-up tie, it will enhance the load transfer capability for feeders from different transformer stations.

Safety – replacing end of life assets (poles, hardware and conductors) will reduce the likelihood of failed equipment causing injury to person and property. New pole lines are constructed to higher standards and meet the requirements of Ontario Regulation 22/04.

Factors Affecting Timing & Priority of Project (5.4.3.2 SS – C.v)

Factors affecting the timing and priority of this project include:

- Weather and road conditions, as this is a rural road.
- Unplanned higher priority jobs.

Analysis of Project Benefits and Costs ie. "Do Nothing" & "Technically Feasible Alternatives" (5.4.3.2 SS – C.vi)

Do Nothing – this option has minimal cost associated with it, however considering the age and condition of the pole line and the customer experience, it is not a good option.

Feasible Alternatives – a technically feasible alternative is "like for like", i.e. replace poles and hardware only and transfer existing conductor. This is not the best option because the existing wire size is #3/0 ACSR primary which does not have the electrical characteristics to allow 600A current according to KWHI's standard feeder load transfer requirements.

Project Name: Mannheim Road: Witmer Road to Huron Road

Images



Scope of project: Mannheim Rd between Witmer Rd and Huron Rd



View of Existing Pole – 1963 vintage (ACA Health Index: Very Poor. Pole survey note: feathered pole top)

Project Name: Mannheim Road: Witmer Road to Huron Road

Project Authorization	
Prepared By: S. Ferneyhough	Authorized By: G. Cameron
Date: March 19, 2019	Date: April 5, 2019
	Completion Date: _____

Capital Project Summary

Project Name: Innovation and Reliability Improvement – Overhead Distribution

Budget Year: 2020 **Budget Item No.:** 3-20-7, 4-20-9

OEB Investment Category: System Service

General Information on Project (5.4.3.2.A)

Project Summary	This program includes a number of projects that seeks to improve the resiliency, flexibility and reliability of the distribution network. It utilises advanced distribution automation devices and technologies that communicate with KWHI's existing SCADA system via different communication networks (fibre, radio and cellular). Smart Grid activities (reclosers, sectionalizers, remotely controlled switching, fault sensing and monitoring, self-healing networks, etc.) will reduce the scope and duration of outages and crew travel time. The strategy being employed is to install Smart Grid devices on selected feeders that either have a large exposure to elements that cause outages (long lines) or feed customers critically sensitive to outage duration or have a history of poor reliability or service customers that are remote from the service centre. For 2020, seven (7) reclosers are budgeted for installation, four (4) in the City of Kitchener and three (3) in Wilmot Township. Two (2) 900 kVAR switched capacitor banks are also budgeted for installation in the City of Kitchener. KWHI intends to continue this program over the next 5 years with a goal of having a network of remote operable reclosers that can be incorporated into an automatic power restoration scheme such as FLISR (Fault Location, Isolation and Restoration).

	Description	Estimated Cost
Capital Investment (5.4.3.2.A.i)	**Labour:**	$154,000
	Materials:	$332,700
	Contract:	$0
	Engineering:	$63,300
Capital Contributions (5.4.3.2.A.ii)	**Total Estimated Cost:**	**$550,000**
	Recoverable:	$0
	KWHI Estimated Cost	**$550,000**

Customer Attachments / Load (kVA) (5.4.3.2.A.iii) **(if applicable)**	KWHI's philosophy for recloser installation is to install 1.5 reclosers per 13.8 kV feeder and 2.5 reclosers per 27.6 kV feeder. A typical 13.8 kV feeder has approximately 1,000 customers while a typical 27.6 kV feeder has approximately 2,500 customers.

Project Name: Innovation and Reliability Improvement – Overhead Distribution

Project Dates (5.4.3.2.A.iv)	**Start Date:** Q1, 2020 **In Service Date:** Q4, 2020				
Estimated Expenditure Timing (5.4.3.2.A.iv)	**Q1**	**Q2**	**Q3**	**Q4**	
	$	$150,000	$200,000	$200,000	

Schedule Risk and Risk Mitigation (5.4.3.2.A.v)

The following schedule risks and mitigation have been identified for the projects in this program.

Design, construction and material availability – the reclosers utilised by KWHI are highly specialised equipment and have very long lead times (16 – 20 weeks). To mitigate this risk, KWHI identifies the location that reclosers will be installed (whether new or replacing existing manual switches) during budget preparation in the prior year. The equipment used have been reviewed, approved and standardised and therefore reduce the processing time between KWHI and the suppliers. Engineering design and commissioning have also been standardised which reduces the effort to prepare a design and commission the devices once they have been installed. The installation of the projects are scheduled months in advance of when they are required, and the construction schedule is reviewed on a monthly basis by a cross-functional team at KWHI.

Lack of communication network coverage for parts or service areas – a private 900 MHz radio network and public cellular network are used as the main communication medium for the reclosers and line sensors. The cellular network has very high coverage and is designed to instantly self-reroute, which means signals are far less prone to a single-point failure. Signals can often reach their destination even if there's a problem with one tower en route. However, the 900 MHz network is being built out as reclosers and capacitor banks are installed, and coverage might not be available in a location where a recloser or capacitor bank is proposed to be installed. To address this concern, KWHI has secured two private sites (Region of Waterloo water tower and a tall residential building in downtown Kitchener) along with four KWHI-owned transformer station sites to provide the backbone coverage of the 900 MHz network. A number of radio repeaters are also kept in inventory to augment coverage when the existing infrastructure is insufficient. As the number of reclosers and capacitor banks installed increase, the network coverage improves.

Comparative Information from Equivalent Projects (5.4.3.2.A.vi) **(where available)**

Similar programs undertaken in 2014 - 2017 had the following cost:

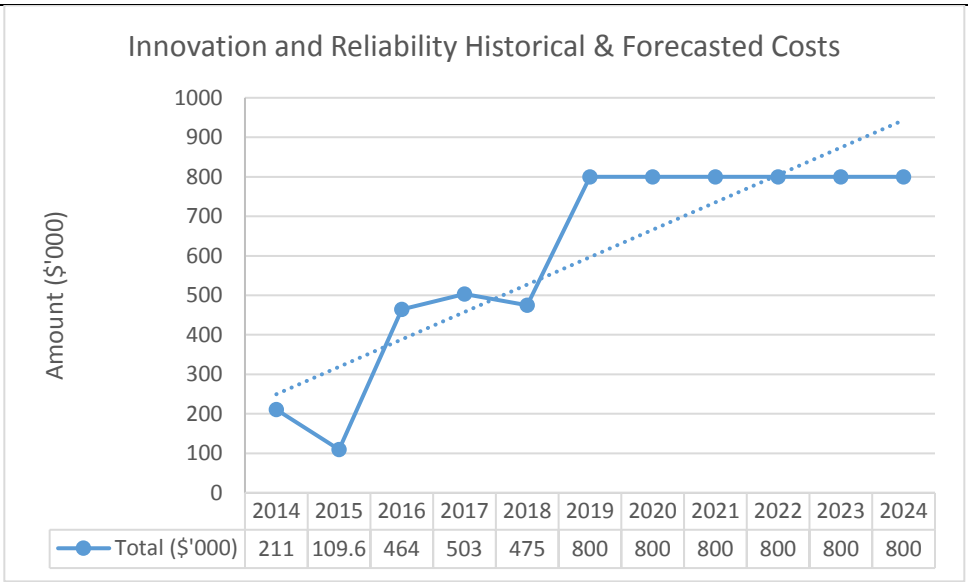
2014 - $211,050 – 4 reclosers and 20 automated line sensors

2015 - $109,616 – 3 reclosers

2016 - $464,118 – 7 reclosers and 1 remote supervisory capacitor bank

2017 - $503,000 – 8 reclosers and 1 remote supervisory capacitor bank

The cost to install each recloser varies, since it is dependent on whether the pole is replaced or not and the complexity of installing a recloser on an existing circuit. The graph below shows a comparison between the historical costs and the budgeted costs (2019-2024). 2019 and beyond includes additional work budgeted for to implement smart switches in the underground distribution system.



Total Capital and OM&A Costs Associated with REG Investments (5.4.3.2.A.vii)

This program doesn't have any direct REG investments cost. However, the installation of reclosers, capacitor banks and line sensors increase the flexibility of the distribution network which in turn allows for higher adoption of REG projects.

Leave to Construct Approval (5.4.3.2.A.viii) **(where applicable)**

N/A

Evaluation Criteria and Information (5.4.3.2.B)

Efficiency, Customer Value, Reliability (5.4.3.2.B.1)

Investment Driver (5.4.3.2.B.1.a)

The main drivers for this program are reliability improvement and grid flexibility. Electronic reclosers will automatically sectionalize a feeder for a fault that is downstream of the device resulting in less customers being impacted by a permanent or momentary outage (SAIFI and MAIFI reduction). For faults upstream of the recloser, the feeder circuit breaker will operate, initially creating an outage for all customers supplied by the feeder. However, since the reclosers can be controlled remotely from the Control Room, a downstream recloser can be remotely opened and another recloser remotely closed to transfer the healthy portion of the feeder to another feeder while isolating the faulted section. This can be done prior to a crew arriving on site using data from the reclosers and line sensors in the field. This action reduces the outage duration for some of the customers affected (SAIDI reduction) since the recloser will instantly isolate the only the section of feeder impacted by the outage and when required the Control Room Operator can make a decision and remotely operate the devices within 5 to 10 minutes. A manual process of dispatching crews to the field to find the fault and open a switch typically takes between 1 to 2 hours.

Secondary Driver (5.4.3.2.B.1.a) **(where applicable)**

Efficiency improvement and situational awareness – because the reclosers can be operated remotely, there is no need for a crew to drive to the location of these devices and perform manual operation. Also, by

integrating the reclosers within KWHI's OMS, our Control Room Operators have a greater situational awareness and customers can be quickly notified of the extent of an outage via the public outage map.

Good Utility Practice (5.4.3.2.B.1.b)

This project is a direct response to improve reliability and modernise the distribution grid, and therefore, considerations for reliability and grid modernisation are considered during design and planning.

Investment Priority (5.4.3.2.B.1.c)

The priority of this program relative to other programs and projects is medium. KWHI's project Prioritization Tool was used to prioritize all material projects for 2020 and this project was ranked as 24 out of 31. Results from the customer engagement survey conducted in 2018 shows that customers are generally supportive of KWHI's proposed investment in installing automated switches. See excerpt below.

Customer Engagement Activity	% who support proposed approach to spending on automated switches accelerated approach
Low-volume online workbook	89%
Residential telephone survey	88%
Small business telephone survey	84%

Analysis of Project and Project Alternatives – Effect of the investment on system operation efficiency and cost-effectiveness (5.4.3.2.B.1.d.i)

There is a positive impact on operating efficiency associated with this program. During both planned and unplanned outage situations, crews are not required to go to every switch location that is required to be operated. The locations that have remote monitored electronic reclosers can be controlled remotely from the Control Room. This is especially beneficial when the switching devices are remote from the service centre (e.g. Wilmot Township).

Analysis of Project & Alternatives – Net benefits accruing to customers (5.4.3.2.B.1.d.ii)

A recloser is designed to automatically close after opening to allow a temporary fault to clear and to stay open after two or more close attempts if the fault is permanent. The net benefits that accrue to customers are:

- Improve reliability (SAIDI and SAIFI reduction) – outage length and duration are reduced, number of customers impacted by an outage is reduced
- Reduction in overall OM&A cost
- Improve customer communication and situational awareness

Analysis of Project & Alternatives – Impact of the investment on reliability performance including frequency and duration of outages (5.4.3.2.B.1.d.iii)

Investment in this program will have a positive impact on system reliability. There will be an overall reduction in SAIDI and SAIFI, for feeders with reclosers installed, via the following actions:

- Reduction in outage duration
- Reduction in number of customers impacted by sustained outage (SAIFI) and momentary outages (MAIFI)
- Reduction in response time (devices can be operated remotely before a crew arrives on site)

Project Alternatives (Design, Scheduling, Funding/Ownership (5.4.3.2.B.1.d.iii)

Project Design Alternatives:

a) Retrofit existing manual switches with motor operators and remote control capabilities – this option is more cost effective (approximately $10,000 vs $50,000 for automated switches) but lacks the purpose built capability of a recloser. Retrofitting a manual switch will allow the switch to be emote operated by SCADA but the device would not have any reclosing capability since existing load interrupter switches do not have fault interrupting capability. This will mean that the device could not automatically open for a downstream fault resulting in the feeder breaker opening for all faults on the line and the control room operator taking a control action after the event to open the remote switch. While this solution improves reliability compared to the manual switch situation in which a crew need to drive to the location to operate the device, it doesn't provide the full benefit of reducing the number of customers impacted by an outage and also doesn't allow for future integration into self-healing grid schemes.

b) Reduce feeder length – reducing the length of feeders can eliminate or reduce the number of automated switches required for reliability and outage response purposes. However, this will increase the number of feeders and thereby increase transformer station capital and operating costs (additional switching and protection devices required). That is, additional breaker positions will be required with associated maintenance. Additional feeders will also be required. This initiative will reduce the number of customers impacted by an outage but will also increase cost compared to the marginal cost of adding reclosers and other automated devices on the line. Example, a typical 27.6 kV recloser costs approximately $50,000 to design and install while the average cost for a three-phase overhead line is $10K per pole ($200,000/km) excluding station equipment.

Scheduling Alternatives:

This project is part of an ongoing innovation and reliability program and investment is budgeted each year to pace the investment. There is the potential to defer the project from one year to another if projects with higher priority that were not budgeted arise during the budget year.

Ownership Alternatives:

There are no alternatives for ownership of these overhead distribution devices that are under the supervision and control of KWHI.

Safety (5.4.3.2.B.2)

Since there is no physical interaction required with a remote operable switch by an employee, the likelihood of an incident such as an arc flash occurring and causing injury to an employee is significantly reduced. That is, the remote operation of these devices provides a safety barrier for workers.

Cyber-Security and Privacy (5.4.3.2.B.3) **(where applicable)**

One of the key areas of this program is the communication network. Communication networks are susceptible to being intercepted by hackers if they are not adequately protected. Security measures are considered in both the software and hardware components of the devices and communication network utilised for the projects within this program. KWHI uses a wireless communication system (900 MHz radio network and cellular network) for the field devices. The cellular network is configured as a private access point name (APN) over a public network. This network encrypts traffic between the field devices and KWHI's SCADA system. The 900 MHz radio network utilise a frequency-hopping spread-spectrum transmission and data in transit is encrypted.

Co-ordination and Interoperability (5.4.3.2.B.4)

Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.3.2.B.4.a) **(where applicable)**

KWHI currently has two interconnection points with neighbouring utilities (WNH). One of these interconnecting switching points was replaced with a remote operable switch by WNH. The remaining switching point will be coordinated and replaced when KWHI or WNH rebuild the affected line section.

Enabling of Future Technology and/or Future Operational Requirements (5.4.3.2.B.4.b)

The communication network that is being built to facilitate remote operable switches can also be used to facilitate remote monitor and control of other devices such as capacitor banks (for voltage support and vars management) and line sensors (for fault identification).

Environmental Benefits (5.4.3.2.B.2.B.5) **(where applicable)**

There are no direct environmental benefits associated with this project.

Conservation and Demand Management (5.4.3.2.B.2.B.6) **(where applicable)**

There are no incremental conservation initiatives, over and above those established in cooperation with the IESO.

Category - Specific Requirements -System Service (5.4.3.2.SS - C)

Benefits to Customers vs. Cost Impact (5.4.3.2 SS – C.i)

The average cost of installing a remote operable (SCADA) overhead switch is $60,000. The switch has a typical useful life of 40 years with little maintenance activities over its lifetime (mainly battery replacement). The net benefit that customers will experience from installing these devices is reduced restoration time in the order of minutes versus hours. The crew time spent restoring outages will also reduced because crews do not need to travel to every switching point. This will reduce outage response cost especially those that occur after working hours. By installing reclosers midway along the length of a feeder and at the tie point between two feeders, outages on a feeder with these devices will typically have half as many customers impacted than if there were no reclosers installed.

A typical feeder outage takes approximately 60 minutes to respond, find the fault, and lasts approximately 120 minutes. The number of customers on a typical feeder is 1000. Feeders with reclosers installed will save the 60 minutes response and troubleshooting time for half the number of customers (500) resulting in 30,000 customer minutes saved.

Regional Electricity Infrastructure Requirements (5.4.3.2 SS – C.ii) **(where applicable)**

N/A

Advanced Technology (5.4.3.2 SS – C.iii) **(where applicable)**

The reclosers utilised by KWHI have advanced technology built into them and meet cyber security standards for protection of data in transit. One such advanced technology is a PulseClosing® feature that is proprietary to the manufacturer (S&C) of the reclosers used by KWHI. Pulse Closing Technology dramatically reduces the amount of force used during the reclosing action of the recloser when a fault is detected and significantly lessen momentary outages for customers on the main feeder. This strategy improves reliability and reduces costs for KWHI's customers since only 5% of available energy is used by the recloser to test a line segment for a fault before fully restoring power. By using a small amount of

energy to test the line segment that maybe faulted, transformers and cables upstream are not subjected to the damaging force caused when a traditional recloser closes in on a fault at 100% of the available fault energy.

The reclosers also have two integrated power modules on both sides of the interrupters, eliminating the need to install separate distribution transformers to supply power to the recloser.

Reliability, Efficiency, Safety and Coordination Benefits (5.4.3.2 SS – C.iv)

One of the main drivers for this program is reliability improvement. Electronic reclosers will automatically sectionalize a feeder for a fault that is downstream of the device resulting in fewer customers being impacted by a permanent or momentary outage (SAIFI and MAIFI reduction). For faults upstream of the recloser, the feeder circuit breaker will operate, initially creating an outage for all customers supplied by the feeder. However, since the reclosers can be controlled remotely from the Control Room, a downstream recloser can be remotely opened and another recloser remotely closed to transfer the healthy portion of the feeder to another feeder while isolating the faulted section. This can be done prior to a crew arriving on site using data from the reclosers and line sensors in the field. This action reduces the outage duration for some of the customers affected (SAIDI reduction) since the recloser will instantly isolate the only the section of feeder impacted by the outage and when required the Control Room Operator can make a decision and remotely operate the devices within 5 to 10 minutes. A manual process of dispatching crews to the field to find the fault and open a switch typically takes between 1 to 2 hours.

From a safety standpoint, the use of reclosers to remotely open and closed switching devices reduce the need for crews to operate the devices manually and therefore, reduces the chance of a safety incident such as arc-flash with a crew being in proximity.

Where practical, implementation of reclosers are coordinated with other planned jobs so as to optimise the labour effort required and reduce the number of planned outages required for installation.

Factors Affecting Timing & Priority of Project (5.4.3.2 SS – C.v)

Factors affecting the timing and priority of this project include:

- Availability of communication coverage – because the reclosers are monitored and controlled via SCADA, there needs to be communication coverage available either by 900 MHz radio or public cellular network. Identification of communication coverage is normally done ahead of time so that necessary mitigating measures can be put in place where there is lack of reliable network coverage.
- Unplanned high priority jobs – if another job that has higher priority utilises significantly more resources than budgeted for, this program or part of may be deferred or delayed.

Analysis of Project Benefits and Costs ie. "Do Nothing" & "Technically Feasible Alternatives"
(5.4.3.2 SS – C.vi)
Do Nothing – this option has minimal cost associated with it. Existing manual load break switches would be maintained and replaced as like-for-like during rebuild.

Feasible Alternatives – a technically feasible alternative to proactively replacing manual switches with automated reclosers is to wait until the line section is scheduled for rebuild based on asset condition assessment or other drivers. This option has the same cost (approx. $50,000 per recloser) but benefits that are accrued to customers will be delayed and could take many years before being realised.

Project Name: Innovation and Reliability Improvement – Overhead Distribution

Images



Figure 1: Automated recloser installed in the field

Project Authorization

Prepared By:	G. Cameron	Authorized By:	G. Cameron
Date:	February 28, 2019	Date:	April 5, 2019
		Completion Date:	_____

Capital Project Summary

Project Name: Underground System Expansion to Supply New Developments

Budget Year: 2020 **Budget Item No.:** 4-20-5

OEB Investment Category: System Service

General Information on Project (5.4.3.2.A)

Project Summary

This program consists of installing new underground feeders to supply new developments including the installation of conduit, pullboxes with racking, primary cables, splices, switchgear and service cables. This budget item includes Stage 1 of a multi-stage project to accommodate the future installation of a new primary feeder from Kitchener No. 4TS (West Ave) to downtown Kitchener via Victoria Street South. This is required to provide additional capacity for growth anticipated in the downtown core. The scope of work for Stage 1 includes the civil work to install approximately 900m of concrete encased ductwork, 4 precast pull boxes c/w chimney and lid, and an underground crossing of CN rail. Also included in this program are the costs to expand the underground distribution system (cable, conduits, switchgear, etc.) and connect commercial and industrial customers. There has been an influx of mix-use developments (3,000 - 4,000 new residential units and commercial units) occurring in the downtown core with estimated peak demand of 12 MVA. The existing electrical supply is unable to meet this demand and as such additional feeder capacity is required.

At the end of February 2019, the city of Kitchener had over 15 site plans approved for development. Each of which is required to have foundation in the ground by July 2019. Six of these proposed buildings are currently under construction and it is anticipated that within 3-years the existing feeders that supply downtown will be at capacity to reliably supply the demand. The flurry of developments has been described as “A tsunami of developments” by the local newspaper.

Capital Investment (5.4.3.2.A.i)

Description	Estimated Cost
Labour:	$357,000
Materials:	$447,400
Contract:	$700,000
Engineering:	$195,600

$1.0M estimated for Phase 1 of new underground feeder to downtown Kitchener.

$700K estimated to expand the underground distribution system and connect commercial/industrial customers.

Capital Contributions (5.4.3.2.A.ii)

Total Estimated Cost:	**$1,700,000**
Recoverable:	$170,000
KWHI Estimated Cost	**$1,530,000**

Project Name: Underground System Expansion to Supply New Developments

Customer Attachments / Load (kVA) (5.4.3.2.A.iii) **(if applicable)**	No existing customers will be directly affected by this new build. The new feeder will have nominal capacity of 10 MVA with peak load capability of 14 MVA.				
Project Dates (5.4.3.2.A.iv)	**Start Date:** May 2020 **In Service Date:** September 2020				
Estimated Expenditure Timing (5.4.3.2.A.iv)	**Q1**	**Q2**	**Q3**	**Q4**	
	$0	**$700,000**	**$1,000,000**	$0	

Schedule Risk and Risk Mitigation (5.4.3.2.A.v)

The schedule risks for execution of this program is completing the design and obtaining all necessary approvals. This design has several challenges including finding a running line for new ductwork and pullboxes in a busy right of way, crossing under a Canadian National Railway and obtaining geotechnical data. If these hurtles cannot be achieved in a timely manner, then the construction could be delayed. To mitigate these risks, KWHI is preparing the design at least one year ahead of the start of construction. This will allow for sufficient time to get the appropriate permits (railway crossing) and approvals (Municipal) required to construct the electrical plant.

Another schedule risk is the pace at which the new sites are developed. KWHI is anticipating a staggered implementation by the developers. However, if demands for the new residential and commercial units are high, we could see developers expediting their projects which will put a strain on KWHI to have the additional feeder capacity available. To mitigate this risk, KWHI is monitoring developments very closely and is arranging pre-construction meetings with each developer to understand their timelines.

Comparative Information from Equivalent Projects (5.4.3.2.A.vi) **(where available)**

A comparative job was completed in 2016 on Duke St W between Young St and Ontario St. The scope of work included installation of a new 15-duct structure (211m) and 2 vaults for a total cost of $455,508 ($2158/m).

Total Capital and OM&A Costs Associated with REG Investments (5.4.3.2.A.vii) Total Capital and OM&A Costs Associated with REG Investments (5.4.3.2.A.vii)

There is no REG investment associated with this project.

Leave to Construct Approval (5.4.3.2.A.viii)

N/A

Evaluation Criteria and Information (5.4.3.2.B)

Efficiency, Customer Value, Reliability (5.4.3.2.B.1)

Investment Driver (5.4.3.2.B.1.a)

System Capacity Constraint - the primary investment driver for this project is system capacity constraint at the feeder level. The existing feeders that supply downtown Kitchener are approaching their thermal load capacity due to the volume of new developments under construction and proposed for construction within a few years. KWHI's goal is to ensure that sufficient capacity is available to provide safe and reliable service

to all our existing and future commercial and residential customers located in the downtown core of Kitchener. It is also our goal to connect all new customers in a timely manner that meets the requirements of the DSC. The projected growth in the next 3-5 years includes 22 new developments with 15 of these developments already securing site plan approvals. In order to continue to provide exceptional service and increase the available feeder capacity to downtown Kitchener, a new underground feeder needs to be installed.

Secondary Driver (5.4.3.2.B.1.a) **(where applicable)**

Reliability - the secondary driver for this project is reliability. If the existing feeders are allowed to operate at their maximum loading capacity, there will be no contingency available to transfer load between the feeders during planned or unplanned outages. Installing the new feeder will alleviate this issue and permit load transfer from the existing feeders to this new feeder when needed for repairs or maintenance.

Good Utility Practice (5.4.3.2.B.1.b)
It is common practice among utilities to start plan for and construct new feeders when existing feeders are approaching their thermal load limit and/or there is forecasted load growth that will exceed the feeder capacity to reliable carry its existing load and loads from additional feeders during contingencies. Supplying loads in a dense downtown area with zero lot line set back zoning also requires the use of underground facilities to eliminate clearance and safety issues associated pole lines being in proximity to buildings.

Investment Priority (5.4.3.2.B.1.c)

The priority of this program is high since the developments have already begun. Deferral of this project will jeopardize KWHI's ability to provide a reliable service and connect customers in a timely manner as mandated by the DSC.

Analysis of Project and Project Alternatives – Effect of the investment on system operation efficiency and cost-effectiveness (5.4.3.2.B.1.d.i)

The installation of this new feeder will greatly increase the capacity and improve operational efficiency and flexibility of the system. The cost effectiveness of this solution will be further analysed in a non-wires alternative study commissioned by KWHI.

Analysis of Project & Alternatives – Net benefits accruing to customers (5.4.3.2.B.1.d.ii)

The installation of this new feeder will provide safe and reliable service to our new customers in the downtown core.

Analysis of Project & Alternatives – Impact of the investment on reliability performance including frequency and duration of outages (5.4.3.2.B.1.d.iii)

This installation of this new feeder will provide for future operational capabilities, adding more reliability to our downtown distribution system.

Project Alternatives (Design, Scheduling, Funding/Ownership (5.4.3.2.B.1.d.iii)

Project Design Alternatives:
The two existing feeders that supply the downtown core of Kitchener are projected to experience overloads of approximately 6.0 MW over the next 3-5 years. In order to permit the connection of new load and avoid feeder overload, relief is needed by the year 2022. The design alternatives are:

1. Traditional wires solution consisting of building additional underground distribution system to accommodate for the load growth – this includes the supply and installation of new equipment to connect loads to an existing transformer station. KWHI is currently studying the feasibility of this solution versus non-wires alternatives.
2. Non-wires solution – implementing DER solutions at the feeder level or behind the meter. This would include energy efficiency, demand response, distributed generation, or energy storage

resources that can provide load relief for the existing feeders. KWHI is currently studying the feasibility of this solution.

3. Install a new overhead feeder – this option is not viable in the downtown core. It is KWHI's mandate to provide underground service in order to continue with the existing underground system in the downtown core.

Scheduling Alternatives:

This project does not have any scheduling alternatives since construction for a number of the developments (6) have begun with additional buildings expected to be under construction by the end of 2019. It should be noted that the pace of these developments is not typical of what has been experienced in the past and there wasn't a lot of advanced notice provided to KWHI.

Ownership Alternatives:

None. This project consists solely of KWHI's assets and will be constructed on the public right-of-way.

Safety (5.4.3.2.B.2)

Installation of this new duct structure will be in accordance with KWHI's standards which in turn incorporates standards from groups such as the Canadian Standards Association (CSA) and the Institute of Electrical and Electronics Engineers (IEEE). This project applies the requirements of the Ontario Regulation 22/04 as overseen by the Electrical Safety Authority (ESA).

Cyber-Security and Privacy (5.4.3.2.B.3) **(where applicable)**

This project does not impact cyber security or privacy.

Co-ordination and Interoperability (5.4.3.2.B.4)

Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.3.2.B.4.a) **(where applicable)**

This project will be co-ordinated with the City of Kitchener, the Region of Waterloo, Bell Canada, Rogers Cable TV and Canadian National Railway.

Enabling of Future Technology and/or Future Operational Requirements (5.4.3.2.B.4.b)

This installation of this new feeder will provide for future operational capabilities such as the installation of DERs both on the distribution system and behind the meter for customers. It will also enhance the reliability of the downtown distribution system as new loads come online.

The new duct structure will also be used to route fibre optics cable that will form part of KWHI's communication infrastructure for switches, sensors, and transformer monitoring in the downtown core.

Environmental Benefits (5.4.3.2.B.2.B.5) **(where applicable)**

There are no direct environmental benefits associated with this project.

Conservation and Demand Management (5.4.3.2.B.2.B.6) **(where applicable)**

N/A

Project Name: Underground System Expansion to Supply New Developments

Category - Specific Requirements -System Service (5.4.3.2.SS - C)

Benefits to Customers vs. Cost Impact (5.4.3.2 SS – C.i)

The installation of a new feeder from our existing Kitchener No. 4 transformer station is more cost effective than to build a new transformer station in the downtown core. Existing and new customers will benefit from this new feeder that will improve reliability and system flexibility, reducing outage frequency and restoration time. The over 3,000 new customers/residents to be supplied will benefit directly from having a new feeder available to connect to.

The total project cost over three years is estimated at $2.5M. However, the forecasted peak load at full occupancy of the proposed developments is 10 MW. The revenue less operating costs equates to a 10 year break even period.

Regional Electricity Infrastructure Requirements (5.4.3.2 SS – C.ii) **(where applicable)**

N/A

Advanced Technology (5.4.3.2 SS – C.iii) **(where applicable)**

The switchgear that will be installed for this project will have remote supervisory and control capabilities and will be integrated into KWHI's SCADA system. This will permit remote operation of these devices and reduce the need for crews to operate the devices manually.

Reliability, Efficiency, Safety and Coordination Benefits (5.4.3.2 SS – C.iv)

Existing and new customers will benefit from this new feeder that will improve reliability and system flexibility, reducing outage frequency and restoration time.

Factors Affecting Timing & Priority of Project (5.4.3.2 SS – C.v)

The factors affecting the timing of this program is completing the design and obtaining all necessary approvals. This design has several challenges including finding a running line for new ductwork and pull boxes in a busy right of way, crossing under a Canadian National Railway and obtaining geotechnical data. If these hurdles cannot be achieved in a timely manner, then the construction could be delayed.

Analysis of Project Benefits and Costs ie. "Do Nothing" & "Technically Feasible Alternatives" (5.4.3.2 SS – C.vi)

- Do Nothing – this is not an option since KWHI is obligated to connect all new customers that lie along its distribution system.
- Feasible Alternatives - KWHI has commissioned a study to evaluate the feasibility of non-wires alternatives to defer this investment and/or offset the need for additional feeders after the first feeder is commissioned.

Project Name: Underground System Expansion to Supply New Developments

Images

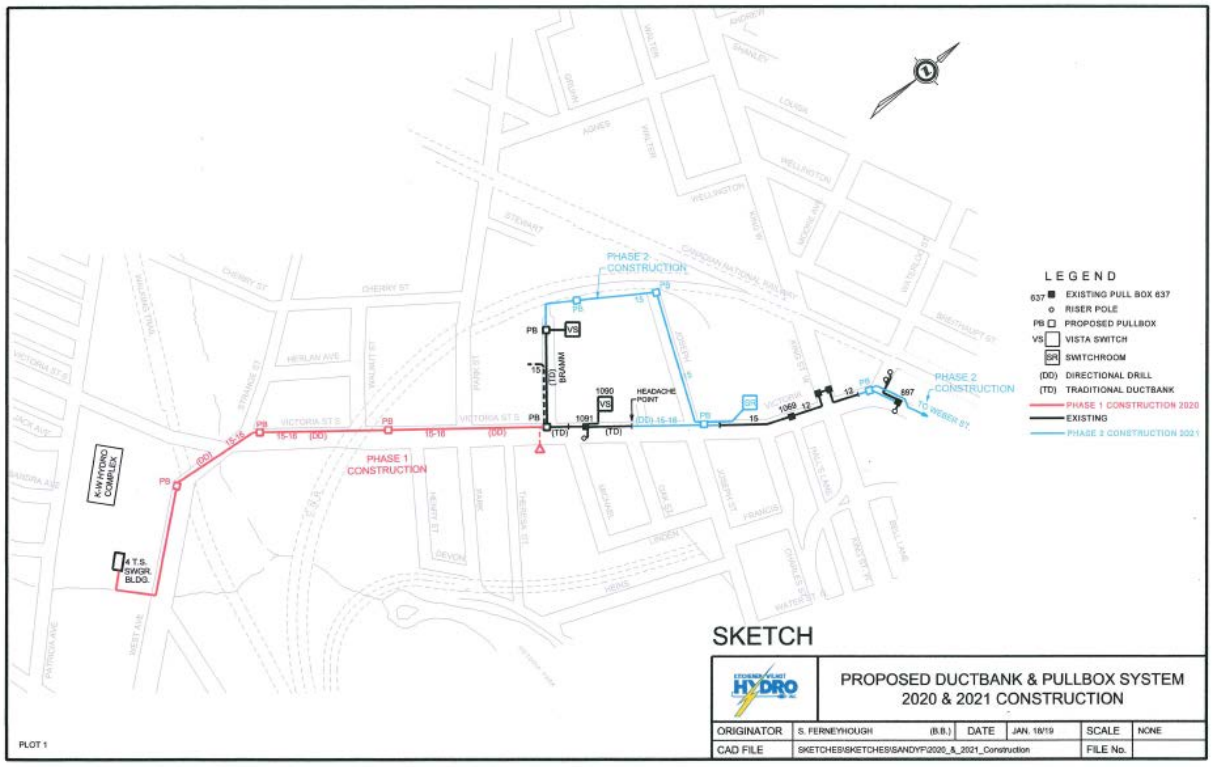
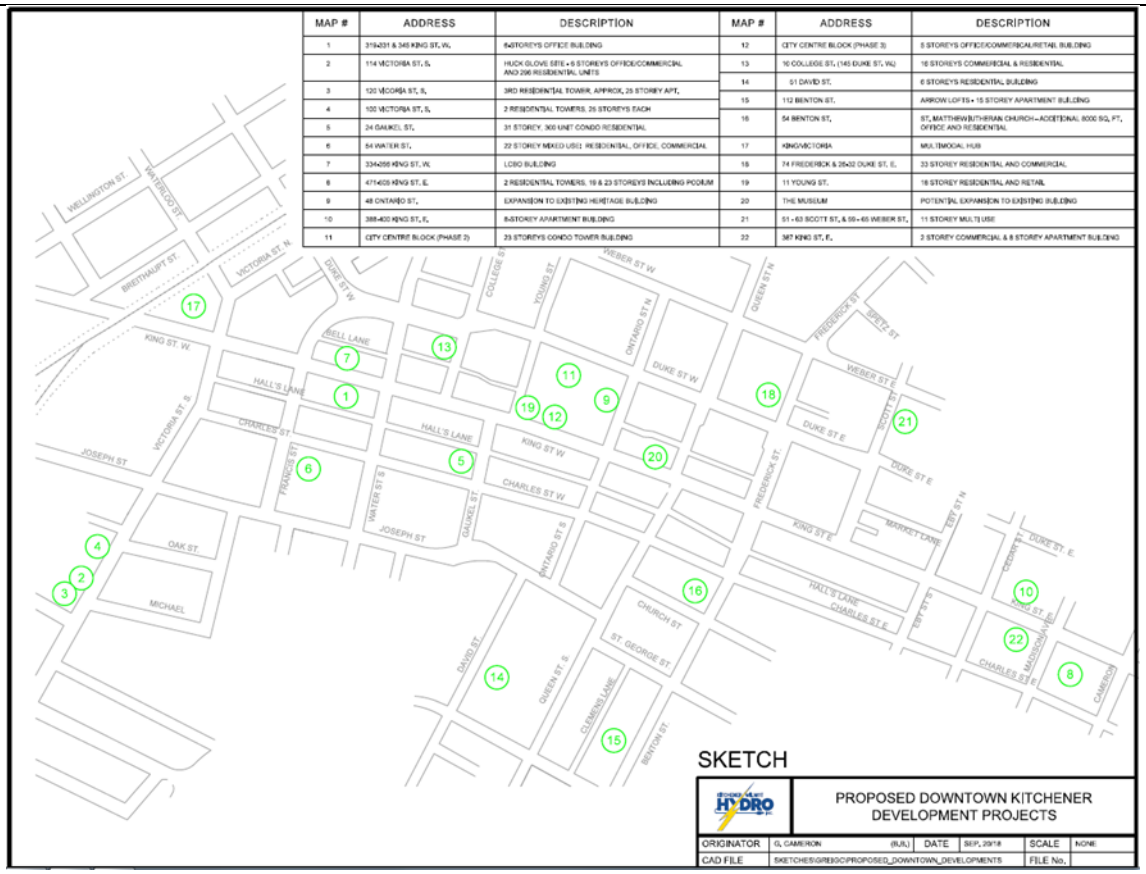


Figure 1: Proposed new duct structure to supply downtown Kitchener

Project Name: Underground System Expansion to Supply New Developments



MAP #	ADDRESS	DESCRIPTION	MAP #	ADDRESS	DESCRIPTION
1	319-331 & 345 KING ST. W.	6-STOREYS OFFICE BUILDING	12	CITY CENTRE BLOCK (PHASE 3)	5 STOREYS OFFICE/COMMERCIAL/RETAIL BUILDING
2	114 VICTORIA ST. S.	HUCK GLOVE SITE - 9 STOREYS OFFICE/COMMERCIAL AND 296 RESIDENTIAL UNITS	13	16 COLLEGE ST. (145 DUKE ST. W.)	16 STOREYS COMMERCIAL & RESIDENTIAL
3	120 VICORIA ST. S.	3RD RESIDENTIAL TOWER, APPROX. 25 STOREY APT.	14	51 DAVID ST.	6 STOREYS RESIDENTIAL BUILDING
4	100 VICTORIA ST. S.	2 RESIDENTIAL TOWERS, 25 STOREYS EACH	15	112 BENTON ST.	ARROW LOFTS - 15 STOREY APARTMENT BUILDING
5	24 GAUKEL ST.	31 STOREY, 300 UNIT CONDO RESIDENTIAL	16	54 BENTON ST.	ST. MATTHEW LUTHERAN CHURCH - ACCETIONAL 8000 SQ. FT. OFFICE AND RESIDENTIAL
6	64 WATER ST.	22 STOREY MIXED USE: RESIDENTIAL, OFFICE, COMMERCIAL	17	KING/VICTORIA	MULTIMODAL HUB
7	334-356 KING ST. W.	LOBO BUILDING	18	74 FREDERICK & 26-32 DUKE ST. E.	33 STOREY RESIDENTIAL AND COMMERCIAL
8	471-405 KING ST. E.	2 RESIDENTIAL TOWERS, 19 & 23 STOREYS INCLUDING PODIUM	19	11 YOUNG ST.	16 STOREY RESIDENTIAL AND RETAIL
9	48 ONTARIO ST.	EXPANSION TO EXISTING HERITAGE BUILDING	20	THE MUSEUM	POTENTIAL EXPANSION TO EXISTING BUILDING
10	388-400 KING ST. E.	8-STOREY APARTMENT BUILDING	21	51 - 63 SCOTT ST. & 59 - 65 WEBER ST.	11 STOREY MULTI USE
11	CITY CENTRE BLOCK (PHASE 2)	23 STOREYS CONDO TOWER BUILDING	22	387 KING ST. E.	2 STOREY COMMERCIAL & 8 STOREY APARTMENT BUILDING

Figure 2: Proposed developments in downtown Kitchener highlighted in green

Project Name: Underground System Expansion to Supply New Developments



Figure 3: Sample of new condominium being developed in downtown Kitchener

Project Authorization

Prepared By: S. Ferneyhough

Date: January 21, 2019

Authorized By: G. Cameron

Date April 5, 2019

Completion Date: _____

Capital Project Summary

Project Name: Emergency Backup Generator Replacement

Budget Year: 2020 **Budget Item No.:** 1-20-1

OEB Investment Category: General Plant

General Information on Project (5.4.3.2.A)

Project Summary	This project involves the replacement of an end of life emergency backup diesel generator that supplies backup power to sections of the main office during a power outage. The existing generator is over 34 years old (installed 1985) and has rated power output of 70 kW. The capacity is insufficient to supply the entire building load during an outage. KWHI is proposing to replace the generator with a modern, efficient, 300 kW unit and associated switchgear that will be able to provide backup power for the entire office and service centre located at 301 Victoria St. S, Kitchener. The new generator will be installed at ground level as opposed to the existing diesel generator that is installed on the building roof. The installation of a full-size generator will allow KWHI to continue operating equipment and devices such as elevators, mechanic shops, and equipment garages that are currently not supplied by the backup generator. The reliability of the generator and the standby power system is crucial to the continued operation of KWHI's day to day operations.

	Description	Estimated Cost
Capital Investment (5.4.3.2.A.i)	**Labour:**	$
	Materials:	$
	Contract:	$350,000
	Engineering:	$
Capital Contributions (5.4.3.2.A.ii)	**Total Estimated Cost:**	**$350,000**
	Recoverable:	$0
	KWHI Estimated Cost	**$350,000**

Customer Attachments / Load (kVA) (5.4.3.2.A.iii) **(if applicable)**	One customer (KWHI). Load served is 350 kVA (335 kW) peak demand with average peak of 305 kVA (277 kW).
Project Dates (5.4.3.2.A.iv)	**Start Date:** June 1, 2020 **In Service Date:** November 30, and 2020

Project Name: Emergency Backup Generator Replacement

Estimated Expenditure Timing	Q1	Q2	Q3	Q4	
			$250,000	$100,000	

Schedule Risk and Risk Mitigation (5.4.3.2.A.v)

The schedule risks that this project faces are mainly related to approvals from external agencies such as the city of Kitchener for site plan and Ministry of Environment (MOE) for Certificate of Air. The Certificate of Air will give clearance on the design for noise and exhaust plume mitigation on adjacent properties. To mitigate these risks, KWHI is commencing the design and approval process well in advance (6-12 months) of the anticipated project start date.

Comparative Information from Equivalent Projects (5.4.3.2.A.vi) **(where available)**

There is no comparative information from any similar project undertaken by KWHI. However, preliminary research shows that the cost for an emergency backup generator installed is approximately $1000/kW.

Total Capital and OM&A Costs Associated with REG Investments (5.4.3.2.A.vii)

There is no REG investment cost associated with this investment.

Leave to Construct Approval (5.4.3.2.A.viii) **(where applicable)**

N/A

Evaluation Criteria and Information (5.4.3.2.B)

Efficiency, Customer Value, Reliability (5.4.3.2.B.1)

Investment Driver (5.4.3.2.B.1.a)

Failure risk - the main driver for this investment is the risk of failure of the backup generator. The generator plays a critical role in KWHI's emergency response during a power outage. The existing generator is 34-years old, well past its typical useful life of 25-years.

Secondary Driver (5.4.3.2.B.1.a) **(where applicable)**

The secondary driver for this investment is environmental and safety. The existing generator uses diesel fuel and is installed on the roof of the main office building. The process of refuelling the generator includes the use of a 250 ft hose extended from a fuel tanker on the ground to the generator on the roof. This poses a safety and spill hazard. Replacement of the generator will include installation at ground level and a direct fuel line if natural gas option is selected.

Good Utility Practice (5.4.3.2.B.1.b)
New installations of emergency backup generators for mission critical facilities are fitted with automatic transfer switch, installed at ground level above flood plain, and provide full backup power capability for the entire business operation. These practices ensure that backup power is available during a power outage to the main distribution facility. Since the main site serves as the hub of the LDC's operations, having reliable and backup power available impacts the utility's ability to respond to outages in a timely manner which directly impacts system reliability.

Project Name: Emergency Backup Generator Replacement

Investment Priority (5.4.3.2.B.1.c)

The priority of this project relative to others is Medium. KWHI's project prioritization tool was used to prioritize all materials projects for 2020 and this project was ranked 26 out of 31. However, it is important to replace the standby generator in a timely manner since it is well beyond its typical useful life and plays a critical role in KWHI's business operations.

Analysis of Project and Project Alternatives – Effect of the investment on system operation efficiency and cost-effectiveness (5.4.3.2.B.1.d.i)

The installation of a new generator will reduce the likelihood that backup power is unavailable during a building power outage. This in turn will enable KWHI to continue providing service to its customers during a power outage and be able to respond in a timely and efficient manner.

Analysis of Project & Alternatives – Net benefits accruing to customers (5.4.3.2.B.1.d.ii)

Backup power is critical for facilities such as KWHI's main office that house the operations that provide essential services to its customer base. The availability of a reliable emergency backup generator allows KWHI to continue its operation during an unplanned power outage. Customers benefit from being able to; interact with customer service (such as bill query and payments), get information on outages, and have KWHI's crews respond to outages affecting customers.

Analysis of Project & Alternatives – Impact of the investment on reliability performance including frequency and duration of outages (5.4.3.2.B.1.d.iii)

This investment does not impact outage frequency. However, it has the potential to negatively impact the duration of outages if the main building loses power and there is no backup generator. That is, under this scenario, Control Room Operators may not be able to access system information required to provide direction to crews in the field. They may also lose complete control of the SCADA system that is used to monitor and control the distribution system including transformer stations.

Project Alternatives (Design, Scheduling, Funding/Ownership (5.4.3.2.B.1.d.iii)

Project Design Alternatives:

A consultant has been hired to evaluate the different design alternatives. This report is expected at the end of Q2 2019. Some of the options to investigate include; generator only (different fuel options), Combined Heat and Power (CHP), Battery Energy storage System (BESS), BESS and Solar PV.

Scheduling Alternatives:

The replacement of the generator is long overdue. While postponing replacement may seem like a worthwhile option, the risk of failure and unavailability of the generator during time of need will increase with each month/year of deferral.

Ownership Alternatives:

There are no feasible ownership alternatives that have been evaluated.

Safety (5.4.3.2.B.2)

KWHI operates a 24x7 control room that monitors the distribution system and provides outage response. The safety of operators working on the night shift is dependent on the availability of power for them to monitor not just the distribution system but also the building security where they work from. The ability to continuously monitor the safety of the distribution system is also dependent on power being able at the main office. The emergency backup generator plays a crucial role in ensuring continuous power availability.

Cyber-Security and Privacy (5.4.3.2.B.3) **(where applicable)**

N/A

Co-ordination and Interoperability (5.4.3.2.B.4)

Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.3.2.B.4.a) **(where applicable)**

N/A

Enabling of Future Technology and/or Future Operational Requirements (5.4.3.2.B.4.b)

This investment does not directly enable future technological functionality or operational requirements.

Environmental Benefits (5.4.3.2.B.2.B.5) **(where applicable)**

Depending on the solution implemented for emergency backup power, there might be additional environmental benefits. Example, if a CHP solution is implemented, heat that is normally wasted from a backup generator can be captured and reused. Similarly, if a BESS is implemented, there will be a reduction in greenhouse gases from not burning fossil fuel.

Conservation and Demand Management (5.4.3.2.B.2.B.6) **(where applicable)**

N/A

General Plant Specific Requirements (5.4.4.2.C.d)

General Plant Specific Requirements (5.4.3.2.C.d)

Results of quantitative and qualitative analyses, business case documenting the justifications for the expenditure (5.4.3.2.C.d.i)

KWHI's computer networks and building administration is supplied by the main distribution grid. While, KWHI distribution system is very reliable (availability of 99.97%), outages do occur. Currently, when a power outage occurs, most of the key office and administration departments are unable to access their computers which limits communication and productivity. Only critical systems are currently supplied by a backup generator. If the generator fails due to its age and condition, then no business function can continue during a grid power outage. To solve this potential issue, KWHI is recommending;

1. replacement of the existing 34-year-old backup generator – reduces the likelihood that the generator is unavailable when needed, and
2. replace the generator with a size that can supply the entire building load – this will ensure that all administrative functions can continue during a power failure.

Business Case Documenting the Justifications for the Expenditure, Alternatives Considered, Benefits for Customers (short/long term), and Impact on Distributor Costs (short/long term) (5.4.3.2.C.d.ii)

A separate business case was not prepared for this project as the proposed capital cost does not substantially exceed the materiality threshold of $225K.

Project Name: Emergency Backup Generator Replacement

Images



Figure 1: 70 kW diesel generator installed 1985

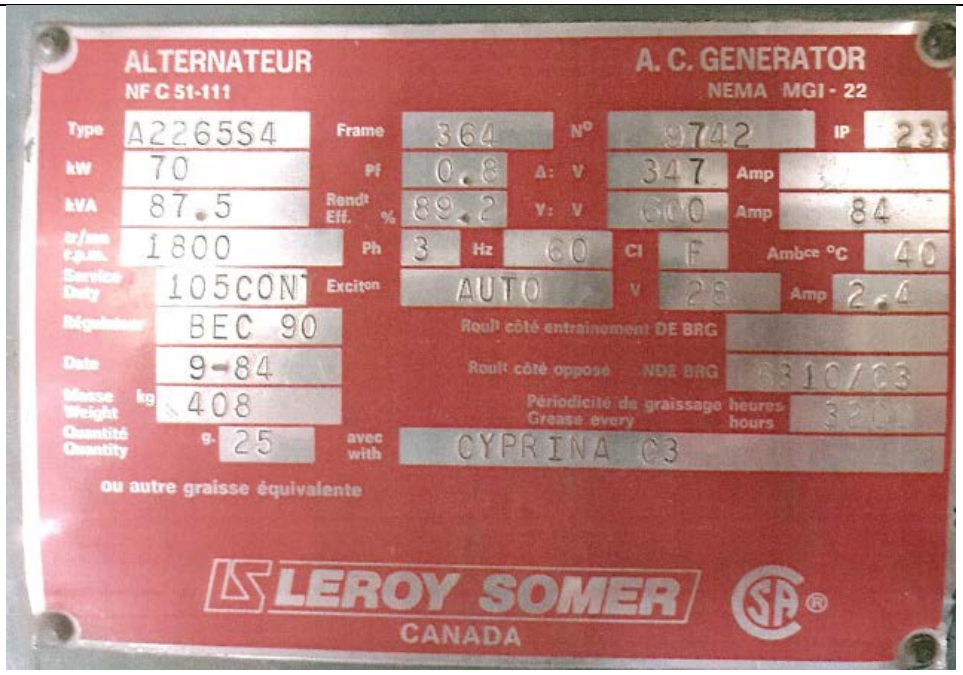


Figure 2: Generator nameplate

Project Authorization

Prepared By: Greig Cameron

Date: March 27, 2019

Authorized By: W. Meston

Date: April 2, 2019

Completion Date: _____

Capital Project Summary

Project Name: Pavement Replacement at Main Office – Phase 2

Budget Year: 2020 **Budget Item No.:** 1-20-2

OEB Investment Category: General Plant

General Information on Project (5.4.3.2.A)

Project Summary	This project includes the replacement of deteriorated pavement, curbs and sidewalk at KWHI's main office located at 301 Victoria Street South, Kitchener. The original pavement has been in service for 35 years. The project will occur in two phases and will include the replacement of 20,500 sq. m of pavement. Phase 1 (7,500 sq. m) will be completed in 2019 and Phase 2 (13,000 sq. m) is scheduled for completion in 2020. This investment is required to continue providing a safe environment for customers and staff to walk, ride, drive, and park.

	Description	Estimated Cost
Capital Investment (5.4.3.2.A.i)	**Labour:**	$0
	Materials:	$0
	Contract:	**$350,000**
	Engineering:	$0
Capital Contributions (5.4.3.2.A.ii)	**Total Estimated Cost:**	**$350,000**
	Recoverable:	$0
	KWHI Estimated Cost	**$350,000**

Customer Attachments / Load (kVA) (5.4.3.2.A.iii) **(if applicable)**	N/A
Project Dates (5.4.3.2.A.iv)	**Start Date:** August 2020 **In Service Date:** December 2020

Estimated Expenditure Timing (5.4.3.2.A.iv)	Q1	Q2	Q3	Q4
	$0	$0	$100,000	$250,000

Schedule Risk and Risk Mitigation (5.4.3.2.A.v)

This project will be completed by a contractor using a competitive tender process. If the prices are too high, this project or a portion of this project may get delayed. If grading changes are required, site plan approval from the City may be necessary. This additional process could also delay the completion of this project. These schedule risks will be mitigated by completing the design and the tender process early in the budget year.

Comparative Information from Equivalent Projects (5.4.3.2.A.vi) **(where available)**

There is no similar job to use for comparison, however KWHI is hiring a Consultant, who has more experience with these types of jobs, to assist with the tender and awarding process. The intention is to split the job into two phases. Phase 1 of Pavement Replacement will be completed in 2019.

Total Capital and OM&A Costs Associated with REG Investments (5.4.3.2.A.vii)

There is no REG investment cost associated with this investment.

Leave to Construct Approval (5.4.3.2.A.viii) **(where applicable)**

N/A

Evaluation Criteria and Information (5.4.3.2.B)

Efficiency, Customer Value, Reliability (5.4.3.2.B.1)

Investment Driver (5.4.3.2.B.1.a)

Condition – the existing pavement which was installed in 1984 is at end of life and has cracks and pot holes in many locations which makes it a safety hazard for both customers and employees. Poor grading and soft spots in some areas also present a safety hazard, in the presence of water or ice.

Secondary Driver (5.4.3.2.B.1.a) **(where applicable)**

Maintenance – the existing pavement is difficult to maintain, especially in the winter months.

Good Utility Practice (5.4.3.2.B.1.b)
The replacement of pavement and curbs does not directly impact reliability performance or grid modernisation challenges.

Investment Priority (5.4.3.2.B.1.c)

The priority of this project relative to others is Low. KWHI's project prioritization tool was used to prioritize all materials projects for 2020 and this project was ranked 31 out of 31. However, it is important from a liability stand point that the parking lots and grounds are well maintained.

Analysis of Project and Project Alternatives – Effect of the investment on system operation efficiency and cost-effectiveness (5.4.3.2.B.1.d.i)

The investment does not directly impact system operation efficiency and cost-effectiveness. It is required to continue providing a safe environment for customers and staff to walk, ride, drive, and park.

Analysis of Project & Alternatives – Net benefits accruing to customers (5.4.3.2.B.1.d.ii)

Project Name: Pavement Replacement at Main Office-Phase 2

Customers have a hassle-free experience visiting our main office if the parking lot is in good condition.

Analysis of Project & Alternatives – Impact of the investment on reliability performance including frequency and duration of outages (5.4.3.2.B.1.d.iii)

This project does not impact system reliability.

Project Alternatives (Design, Scheduling, Funding/Ownership (5.4.3.2.B.1.d.iii)

Project Design Alternatives:

- Resurfacing and patching existing cracks and potholes are a short-term repair, however it is difficult to maintain on an ongoing basis.
- Replace pavement with concrete - concrete pavement has longer lifespan and relatively low maintenance cost. However, the upfront capital cost is significantly higher than that of asphalt pavement and this material is more susceptible to freeze/thaw expansion and contraction.
- Replace pavement with asphalt – asphalt pavement can be installed in a relatively short period of time, has low installation cost, provides better drainage than concrete, and does not deteriorate with use of salt for melting snow/ice. If asphalt pavement is well maintained it can last as long or longer than concrete pavement.

Scheduling Alternatives:

If a more pressing repair becomes more apparent, this project may get deferred.

Ownership Alternatives:

N/A

Safety (5.4.3.2.B.2)

Risks increase for trip hazards when associated with aging and deteriorated pavement.

Cyber-Security and Privacy (5.4.3.2.B.3) **(where applicable)**

N/A

Co-ordination and Interoperability (5.4.3.2.B.4)

Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.3.2.B.4.a) **(where applicable)**

N/A

Enabling of Future Technology and/or Future Operational Requirements (5.4.3.2.B.4.b)

This investment does not directly enable future technological functionality or operational requirements.

Environmental Benefits (5.4.3.2.B.2.B.5) **(where applicable)**

NA

Conservation and Demand Management (5.4.3.2.B.2.B.6) **(where applicable)**

N/A

General Plant Specific Requirements (5.4.4.2.C.d)

General Plant Specific Requirements (5.4.3.2.C.d)

Results of quantitative and qualitative analyses, business case documenting the justifications for the expenditure (5.4.3.2.C.d.i)

Tendering for large expenses through the normal purchasing policy will enable quantitative and qualitative analysis for the pavement replacement.

Business Case Documenting the Justifications for the Expenditure, Alternatives Considered, Benefits for Customers (short/long term), and Impact on Distributor Costs (short/long term) (5.4.3.2.C.d.ii)

A separate business case was not prepared for this project as the proposed capital cost does not substantially exceed the materiality threshold of $225K.

Images

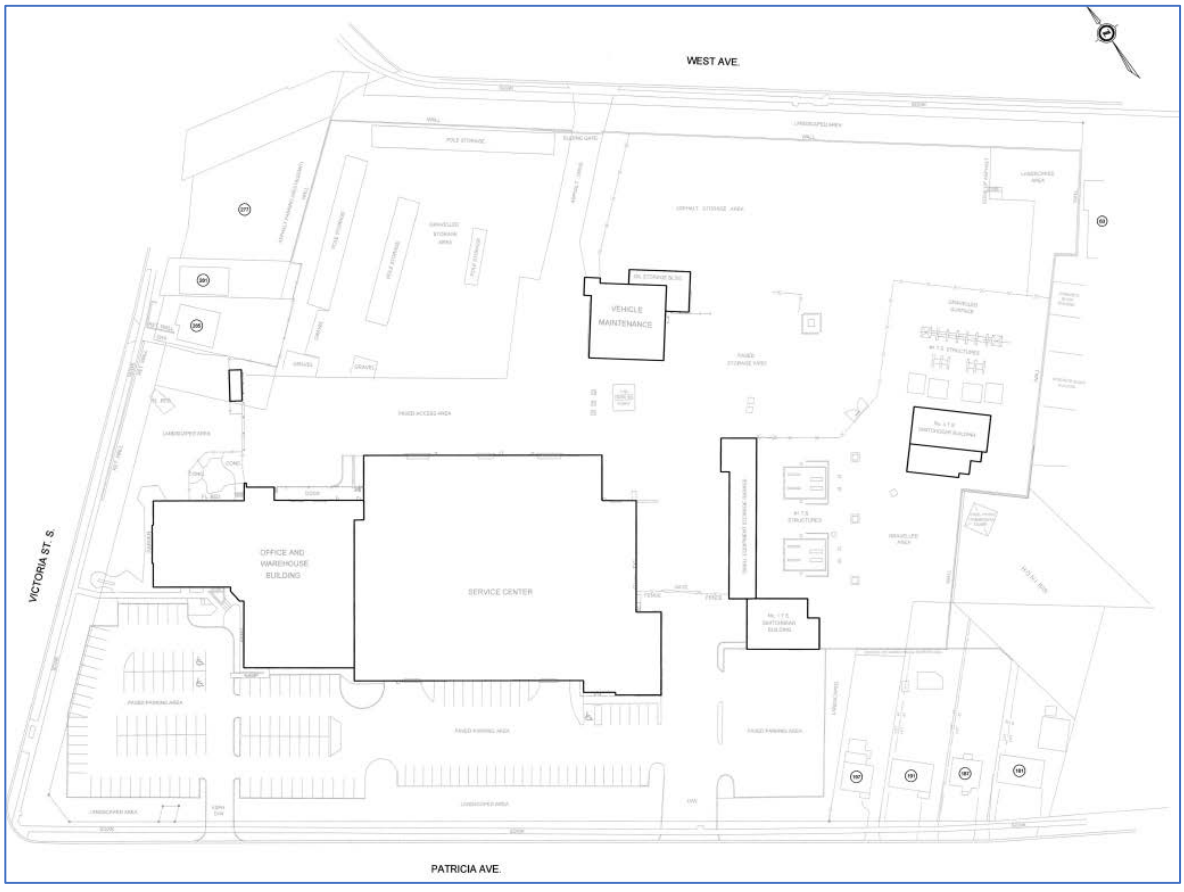


Figure 1: 301 Victoria St. S Site Layout

Project Name: Pavement Replacement at Main Office-Phase 2



Figure 2: Section of pavement showing deterioration

Project Authorization

Prepared By: S. Ferneyhough

Date: February 20, 2019

Authorized By: W. Meston

Date April 2, 2019

Completion Date: _____

Capital Project Summary

Project Name: Legacy Customer Information System (CIS) Replacement

Budget Year: 2020 **Budget Item No.:** 10-20-3

OEB Investment Category: General Plant

General Information on Project (5.4.3.2.A)

Project Summary	This project involves the replacement of an end of life, legacy Customer Information System (CIS) that was developed in-house and has been in service for more than 35 years. The existing CIS can no longer provide the features and functionalities required to interact with our customers in a timely manner. It also lacks the flexibility to make regulatory changes, update rate schedules, and other enhancements without modifying the underlying software code. The new CIS will feature a complete billing and customer relationship management engine with a modern web-based intuitive user interface, that will; reduce complexity, enable flexible business processes, increase customer communication channels, and improve customer service. The proposed system will enable future enhancements such as customer self-service, mobile workforce management, and business analytics. Oracle Utilities CC&B is being proposed for implementation which is a complete billing and customer care application. The project is a multi-year project with implementation schedule to start in Q2 of 2019 and continue into late Q4 of 2020.		
Capital Investment (5.4.3.2.A.i)	**Description**	**Estimated Cost**	Costs shown do not represent the entire project. They represent the forecasted expenditures for 2020 only. The estimated total project cost is $6.7M
	Labour:	$375,000	
	Materials:	$	
	Contract:	$1,300,000	
	Engineering:	$	
Capital Contributions (5.4.3.2.A.ii)	**Total Estimated Cost:**	**$1,675,000**	
	Recoverable:	$0	
	KWHI Estimated Cost	**$1,675,000**	
Customer Attachments / Load (kVA) (5.4.3.2.A.iii) **(if applicable)**	The CIS will serve KWHI's entire customer base of over 96,800 residential, commercial and industrial customers. Peak demand of the customer base is 367 MW (based on 2018 summer peak).		
Project Dates (5.4.3.2.A.iv)	**Start Date:** June 2019		

Project Name: Legacy Customer Information System (CIS) Replacement

	In Service Date: December 2020				
Estimated Expenditure Timing (5.4.3.2.A.iv)	**Q1**	**Q2**	**Q3**	**Q4**	
	500,000	500,000	350,000	325,000	

Schedule Risk and Risk Mitigation (5.4.3.2.A.v)

I. System Integrator (SI) Experience – the SI may fail to meet the program delivery obligations according to the agreed project schedule or in compliance with KWHI's specifications. This could lead to delays or cost overruns. To mitigate this risk, KWHI will establish a steering committee for the project and ensure that the vendor has the appropriate resources and subject matter experts before entering into a contractual agreement. KWHI will negotiate fixed price contracts where possible to avoid runaway project costs. KWHI will also agree to a well-defined project scope and endeavour to not deviate from the scope unless absolutely required.

II. Internal Resource Availability – significant internal resources will be required in terms of labour from KWHI's IT, customer service, metering, and finance departments to complement the System Integrator. There may be insufficient internal resources to complement the SI resources and participate fully in the implementation process. This in turn can result in project delay and/or escalation in project costs associated with procuring additional third-party resources. To mitigate this risk, KWHI will be hiring temporary resources to backfill internal skilled resources that will be assigned to the project on a full-time basis.

III. Regulatory Requirements – from time-to-time there are new regulatory requirements that require making changes to the existing CIS. These changes will require use of internal resources that are already assigned to the project. To mitigate this risk, KWHI will be requesting an exemption from certain regulatory changes while the CIS is being implemented and ask to only implement changes that are considered as emergency. In addition, KWHI will be reaching out to retired employees who have maintained the existing legacy CIS in the past, to assist with any emergency changes required. This is necessary because the legacy CIS was designed and built in-house.

IV. End User Acceptance – a key aspect of a successful CIS implementation is end user acceptance. Before the project can be considered completed, all end users must be fully trained and are comfortable using the new application. This is especially true for this project since users will be migrating from a "home grown" system that is highly customized to a commercial application that is based on industry best practices. To mitigate this risk, KWHI will be implementing organizational change management (OCM) throughout the project lifecycle which will perform a change impact assessment, identify the benefits of the new system, identify what will change and what will remain the same, and develop a training program for impacted staff.

Comparative Information from Equivalent Projects (5.4.3.2.A.vi) **(where available)**

There is no comparative information from any similar project undertaken by KWHI. It is also difficult to obtain comparative costs from other utilities who installed new CIS systems due to the nature of the contracts that are signed which tends to be confidential. Information that is available in the public domain through rate filings doesn't necessary identify whether internal labour costs are included or not and is typically budgeted costs, not actual costs. However, research shows that the average cost to replace a CIS is $85/customer with range from $60 to $120 per customer. This is a wide range and generating a more exact number is difficult as it is not clear what costs utilities include when providing a cost per customer.

Average cost of $85/customer is equivalent to total capital expenditures of $8.3M for a utility of KWHI's size. KWHI is budgeting $6.7M in capital expenditures ($75/customer) to replace its CIS application. The table below shows data from 6 Canadian utilities/municipalities CIS implementations over the last 10 years based on publicly available data.

Project Name: Legacy Customer Information System (CIS) Replacement

System	CIS Cost ($M)	Cost/Cust.
Oracle CC&B	25.20	$80
Oracle CC&B	35.00	$99
SAP	10.00	$68
SAP	180.00	$148
Northstar	7.00	$82
SAP	16.4	$117
Average	45.60	$99

Total Capital and OM&A Costs Associated with REG Investments (5.4.3.2.A.vii)

There is no REG investment cost associated with this investment.

Leave to Construct Approval (5.4.3.2.A.viii) **(where applicable)**

N/A

Evaluation Criteria and Information (5.4.3.2.B)

Efficiency, Customer Value, Reliability (5.4.3.2.B.1)

Investment Driver (5.4.3.2.B.1.a)

The main driver for this investment is functional obsolescence. The existing CIS is based on an outdated programming language (COBOL - designed and standardized in the 1960s) and business processes that no longer align with regulatory or KWHI's requirements. The application can also no longer be properly maintained or supported due to lack of adequate programmer analysts (PA). The application was developed in-house and only one PA remains in the organisation that can support/maintain the system. This PA is scheduled to retire within two years.

Secondary Driver (5.4.3.2.B.1.a) **(where applicable)**

The secondary driver for this investment is the risk of failure. Over the years, the CIS has become highly customized to meet ongoing regulatory requirements and market conditions. This has led to a lack of structured documentation to allow for adequate troubleshooting and enhancement of the application. Every modification to the existing code poses a risk of the system failing to continue meeting its obligations.

Good Utility Practice (5.4.3.2.B.1.b)

In planning the CIS replacement project, grid modernisation considerations were taken into account. Considerations such as availability of consumption data to customers in real-time or near real-time, availability of customer data to be downloaded and used by authorised third party applications, integration with outage management system to provide notification, and a platform to provide DER billing and compensation (e.g. net metering). The solution chosen has these capabilities to help KWHI in its journey to grid modernisation.

Investment Priority (5.4.3.2.B.1.c)

Project Name: Legacy Customer Information System (CIS) Replacement

Replacement of the CIS is a high priority item for KWHI. Failure of the existing system can result in KWHI being unable to bill its customers, customers unable to pay their bills, production of erroneous bills and erosion of trust in KWHI by its customers. KWHI's project Prioritization Tool was used to prioritize all material projects for 2020 and this project was ranked as 1 out of 31.

Analysis of Project and Project Alternatives – Effect of the investment on system operation efficiency and cost-effectiveness (5.4.3.2.B.1.d.i)

Currently several CIS activities are performed manually and outside of the application. IT specialists are required to provide information and modifications that should be readily available in a modern CIS such as ad hoc reports, batch processing, rates table update, etc. The following is a list of improvements in operation efficiency that is expected from a new CIS.

- Lower risk of CIS failure as obsolete technology will be removed
- Improved business continuity - retirement of aging staff will no longer be a factor
- Better analytics through improved access to data & reporting
- Easier input of regulatory changes to billing & customer service rules
- Integration with other systems (such as JDE) will reduce redundant input and other duplications of effort
- Improved ability for customer service representatives (CSRs) to provide meaningful information to customers in real-time. That is, the system will readily provide a 360-degree view of each customer.
- Better tracking of customers in collections/bad debts

The features mentioned above are part of a core modern CIS.

Analysis of Project & Alternatives – Net benefits accruing to customers (5.4.3.2.B.1.d.ii)

Implementation of the proposed Oracle CC&B CIS will provide the following customer benefits:

- Ensure bill accuracy by automatically identifying and resolving issues before sending out billing statements
- Tailor bill formats according to customer preferences
- Send consolidated bills to a central corporate office and individual bills to service outlets
- Help customers better understand their bills, by providing graphs that show how consumption varies over the course of the billing cycle
- Multiple communication channels - offer a choice of bill and payment methods, including e-mail, internet, direct debit, and postal service. Extend choice (e.g. SMS) for correspondence such as reminder notices, disconnection notices, deposit correspondence, etc.
- Reduce call times and significantly cutting down on call-backs by giving contact center staff members complete and immediate access to customer account histories

Analysis of Project & Alternatives – Impact of the investment on reliability performance including frequency and duration of outages (5.4.3.2.B.1.d.iii)

This project does not impact reliability (SAIFI and SAIDI).

Project Alternatives (Design, Scheduling, Funding/Ownership (5.4.3.2.B.1.d.iii)

Project Design Alternatives:

The following design alternatives were explored and are discussed further in the attached business case.

- Retool / Rebuild Existing CIS
- New Commercial Application
- Shared Services

Scheduling Alternatives:

Project Name: Legacy Customer Information System (CIS) Replacement

Implementation of a new CIS is long overdue and as such there isn't any feasible scheduling alternative to implementing the new application. As discussed earlier, there are real risks associated with the existing situation of having an obsolete system with minimal support available to continue keeping it functional and accurate.

Ownership Alternatives:

There are two options for owning the new CIS application;

1. KWHI owned, maintained and operated, or
2. complete SaaS solution.

Option 1 includes KWHI acquiring the license for the application, implementing the solution on premises or in a private cloud, and operating and maintaining the application. This option has a slightly higher initial capital cost and requires KWHI to make changes to the application when there are new regulatory requirements plus upgrade to new version release when they become available.

Option 2 would see KWHI incurring implementation costs while the vendor would hold the license for the application and have the solution installed on their private cloud platform. The vendor will provide all ongoing maintenance and application management support of the software. KWHI will be required to pay monthly fees for utilising the application. The monthly fees are significantly higher than option 1 and will have greater impact on OM&A costs. This in turn will have a higher customer bill impact.

Safety (5.4.3.2.B.2)

The CIS Replacement Project does not have any direct safety impact.

Cyber-Security and Privacy (5.4.3.2.B.3) **(where applicable)**

The proposed new CIS will include privacy by design. It will incorporate role-based access controls, encrypt data at rest and in transit, and permit the erasure (manual or automatic) of personal identifiable information that is no longer required to be stored in the application.

Co-ordination and Interoperability (5.4.3.2.B.4)

Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.3.2.B.4.a) **(where applicable)**

Due to the significant cost and complexity of implementing a new CIS application, a shared services model was explored by way of a Consortium. KWHI embarked on a joint RFP with two other LDCs for replacement of their individual CIS using a shared model. This was explored through the channels brought about through GridSmartCity, a co-operative of thirteen distribution utilities, Smart Grid innovators, industry regulators, government, academia and other electricity industry stakeholders. After developing joint requirements (over 2,000), an RFP was issued to fifteen (15) prospective vendors. Eight vendors responded and through a joint evaluation utilising a third-party consultant, a preferred vendor was selected. Unfortunately, all three LDCs were not able to move ahead with implementing the preferred solution resulting in the disbandment of the Consortium. KWHI then embarked on a KWHI-only solution due to the urgency of replacing its legacy system.

Enabling of Future Technology and/or Future Operational Requirements (5.4.3.2.B.4.b)

From the standpoint of both "efficiency" and security (and cybersecurity, in particular), aging legacy systems create more liabilities over time. They are a major roadblock to making timely, efficient and cost-effective changes and enhancements. Commercial CIS software offers greater functionality, improved data security, better transaction processing in real-time, improved user interfaces, and greater access to data. Utilising commercial software will also provide the ability to easily integrate to future applications such as asset management systems, workforce management systems, and business analytics solutions.

Other future technology/operational requirements that can be accommodated includes; charging for electric vehicle pricing events, energy conservation programs, time varying pricing, and demand response programs.

Project Name: Legacy Customer Information System (CIS) Replacement

Environmental Benefits (5.4.3.2.B.2.B.5) **(where applicable)**

There are no direct environmental benefits associated with this project. However, because of the flexibility and capability of a next generation CIS, KWHI would be able to offer more self-service options to customers which may result in less paper bills being produced and reduction in the need for customers to drive to the office to complete transactions.

Conservation and Demand Management (5.4.3.2.B.2.B.6) **(where applicable)**

The proposed solution has the capability to support conservation and demand management programs. However, the initial implementation will not include this module.

General Plant Specific Requirements (5.4.4.2.C.d)

General Plant Specific Requirements (5.4.3.2.C.d)

Results of quantitative and qualitative analyses, business case documenting the justifications for the expenditure (5.4.3.2.C.d.i)

See attached business case in Appendix P.

Business Case Documenting the Justifications for the Expenditure, Alternatives Considered, Benefits for Customers (short/long term), and Impact on Distributor Costs (short/long term) (5.4.3.2.C.d.ii)

See attached business case in Appendix P.

Images

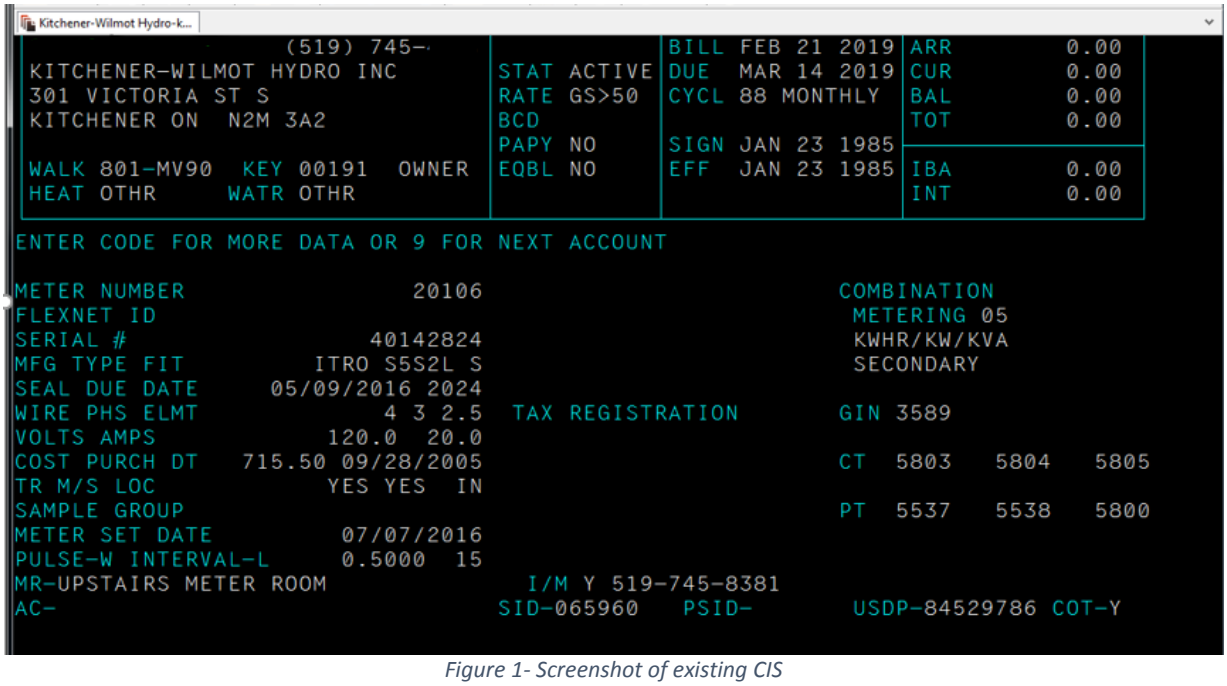


Figure 1- Screenshot of existing CIS

Project Name: Legacy Customer Information System (CIS) Replacement

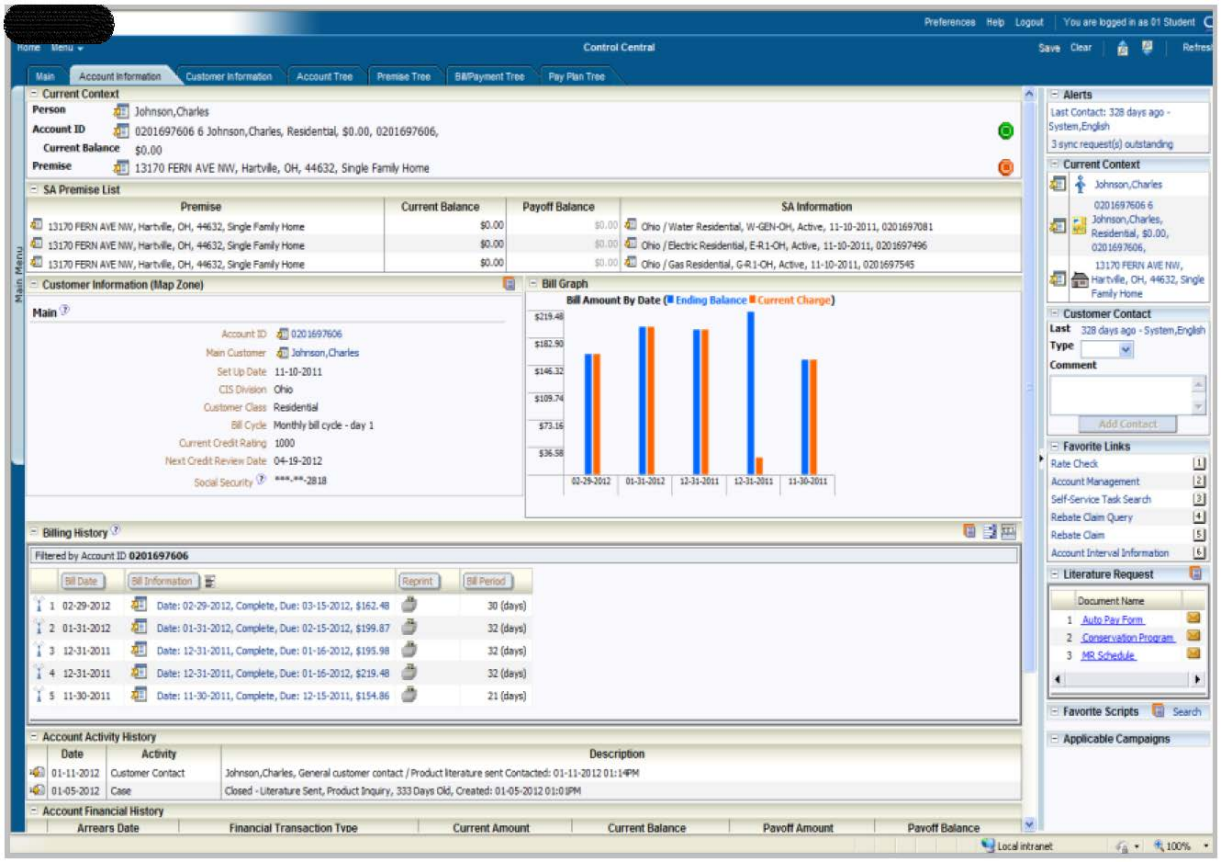


Figure 2-- Screenshot of proposed CIS

Project Authorization

Prepared By: Greig Cameron

Date: February 14, 2019

Authorized By: M. Nanninga

Date: April 20, 2019

Completion Date: _____

Capital Project Summary

Project Name: Vehicle Replacement

Budget Year: 2020 **Budget Item No.:** 11-20-1, 11-20-2, 11-20-3, 11-20-4

OEB Investment Category: General Plant

General Information on Project (5.4.3.2.A)

Project Summary	The vehicle replacement program includes the replacement of Truck 35, Truck 80, Truck 56 and various small vehicles, tractors and/or other equipment that are at end of life.	
Capital Investment (5.4.3.2.A.i)	**Description** / **Estimated Cost** **Labour:** $0 **Materials:** $1,000,000 **Contract:** $0 **Engineering:** $0	
Capital Contributions (5.4.3.2.A.ii)	**Total Estimated Cost:** **$1,000,000** **Recoverable:** $0 **KWHI Estimated Cost** **$1,000,000**	
Customer Attachments / Load (kVA) (5.4.3.2.A.iii) **(if applicable)**	N/A	
Project Dates (5.4.3.2.A.iv)	**Start Date:** April 2020 **In Service Date:** December 2020	

Estimated Expenditure Timing (5.4.3.2.A.iv)	**Q1**	**Q2**	**Q3**	**Q4**
	$0	$250,000	$500,000	$250,000

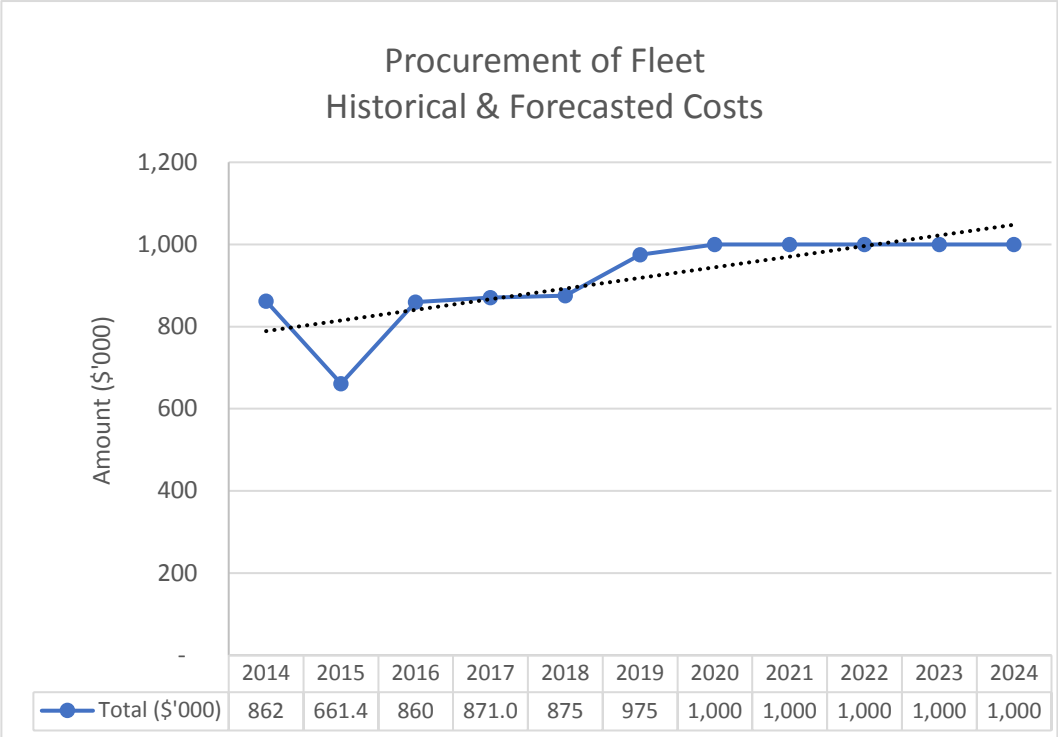
Schedule Risk and Risk Mitigation (5.4.3.2.A.v)

The process involved in tendering, ordering and receiving a new large vehicle can take up to 18 months. Planning well ahead, preparing detailed specifications for each vehicle to be included with the tendering process, having a pre-construction meeting with the manufacturer and frequent correspondence during

construction helps to minimize last minute changes before final inspection and ultimate scheduled delivery.

Comparative Information from Equivalent Projects (5.4.3.2.A.vi) **(where available)**

The figure below shows the historical expenditures for procuring vehicles and the forecasted expenditures. The increase in costs is associated with inflation and types of vehicles budgeted for purchasing. In building the budget, actual costs for comparable vehicles are used to forecast the costs for each vehicle type.



	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Total ($'000)	862	661.4	860	871.0	875	975	1,000	1,000	1,000	1,000	1,000

In 2015, a similar 50' reach single bucket aerial device was purchased for $346,054 which would be comparative to new truck 35. In 2017, a similar forestry single bucket aerial device was purchased for $278,036 which would be comparative to new truck 80. In 2019, a similar dump truck was purchased for $160,000 which would be comparative to new truck 56.

Total Capital and OM&A Costs Associated with REG Investments (5.4.3.2.A.vii) **(where applicable)**

N/A

Leave to Construct Approval (5.4.3.2.A.viii) **(where applicable)**

N/A

Evaluation Criteria and Information (5.4.3.2.B)

Efficiency, Customer Value, Reliability (5.4.3.2.B.1)

Investment Driver (5.4.3.2.B.1.a)

Project Name: Vehicle Replacement

Age and Condition – KWHI's policy is to replace large and small vehicles and equipment on a 10-12 year schedule. Trailers and other power operated equipment are kept for longer periods of time and are scheduled for replacement when annual maintenance repair costs escalate. Heavy use power operated equipment, such as backhoes, are budgeted to be replaced on a 7 to 8 year interval. Existing truck 35 is a 2007 50' reach single bucket materials handler (12 years old), existing truck 80 is a 2009 Terex Hi-Ranger tree trimming aerial device (10 years old), existing truck 56 is a dump truck (11 years old). When finalizing replacements for a particular year, an overall assessment of the vehicle's mileage, engine hours, age, repair history, vehicle condition and future intended use is considered. The replacement of several small vehicles, trailers and equipment will be determined based on need.

Secondary Driver (5.4.3.2.B.1.a) **(where applicable)**

Reliability – The reliability of large vehicles in the fleet impact several areas including construction projects and response time to trouble calls. Equipment availability directly impacts crew productivity and scheduled replacements reduces the risk of unplanned vehicle and equipment failures.

Good Utility Practice (5.4.3.2.B.1.b)

Investment Priority (5.4.3.2.B.1.c)

It is important that all fleet vehicles are maintained properly and replaced in a timely manner, keeping overall costs in mind. This requires balancing new vehicle costs against excessive repair bills and operational downtimes that occurs when vehicles are kept for too long. KWHI's project Prioritization Tool was used to prioritize all material projects for 2020 and this project was ranked low as 30 out of 31.

Analysis of Project and Project Alternatives – Effect of the investment on system operation efficiency and cost-effectiveness (5.4.3.2.B.1.d.i)

The reliability of large vehicles in the fleet impact several areas including construction projects and response time to trouble calls. Equipment availability directly impacts crew productivity and scheduled replacements reduces the risk of unplanned vehicle and equipment failures.

Analysis of Project & Alternatives – Net benefits accruing to customers (5.4.3.2.B.1.d.ii)

Net benefits to customers include maintaining and improving response times to outages, system reliability and crew effectiveness.

Analysis of Project & Alternatives – Impact of the investment on reliability performance including frequency and duration of outages (5.4.3.2.B.1.d.iii)

Net benefits to customers include maintaining and improving response times to outages, system reliability and crew effectiveness.

Project Alternatives (Design, Scheduling, Funding/Ownership (5.4.3.2.B.1.d.iii)

Project Design Alternatives:

When the age of a vehicle approaches its end of life, a case by case evaluation is done to determine whether or not replacement is an option ahead of or later than the vehicles normal life expectancy. The life expectancy for vehicles is based on long-term experience with residual values at times of sale and are driven by odometer readings, engine hours, maintenance records and depreciation policy.
It has been our recent practice to consider purchasing electric or hybrid vehicles for small vehicle replacements.

Scheduling Alternatives:

It is important that all fleet vehicles are maintained properly and replaced in a timely manner, keeping overall costs in mind. This requires balancing new vehicle costs against excessive repair bills and operational downtimes that occurs when vehicles are kept for too long.

Ownership Alternatives:

Not applicable as KWHI owns their own fleet.

Safety (5.4.3.2.B.2)

Risks increase when associated with aging vehicles and equipment, including ergonomic impacts, employee safety and efficiency.

Cyber-Security and Privacy (5.4.3.2.B.3) **(where applicable)**

N/A

Co-ordination and Interoperability (5.4.3.2.B.4)

Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.3.2.B.4.a) **(where applicable)**

N/A

Enabling of Future Technology and/or Future Operational Requirements (5.4.3.2.B.4.b)

This investment does not directly enable future technological functionality or operational requirements.

Environmental Benefits (5.4.3.2.B.2.B.5) **(where applicable)**

Newer vehicles are generally more fuel efficient and have less emissions which are both environmental benefits.

Conservation and Demand Management (5.4.3.2.B.2.B.6) **(where applicable)**

N/A

General Plant Specific Requirements (5.4.4.2.C.d)

General Plant Specific Requirements (5.4.3.2.C.d)

Results of quantitative and qualitative analyses, business case documenting the justifications for the expenditure (5.4.3.2.C.d.i)

Tendering for larger expenses through the normal purchasing policy enables quantitative and qualitative analysis for truck replacements.

Business Case Documenting the Justifications for the Expenditure, Alternatives Considered, Benefits for Customers (short/long term), and Impact on Distributor Costs (short/long term) (5.4.3.2.C.d.ii)

A separate business case was not prepared for this program as the proposed individual projects that make up the program have capital cost that does not substantially exceed the materiality threshold ($225K). Also, the replacement of vehicles is a routine activity.

Project Name: Vehicle Replacement

Images



Existing Truck 35-vintage 2007, Freightliner 50’ Posi-Plus Single Bucket

Project Name: Vehicle Replacement



Existing Truck 80-Vintage 2009, Sterling 70" Hi Ranger Single Bucket

Project Name: Vehicle Replacement



Existing Truck 56-Dump Truck, 11 years old

Project Authorization

Prepared By: S. Ferneyhough

Date: February 13, 2019

Authorized By: W. Meston

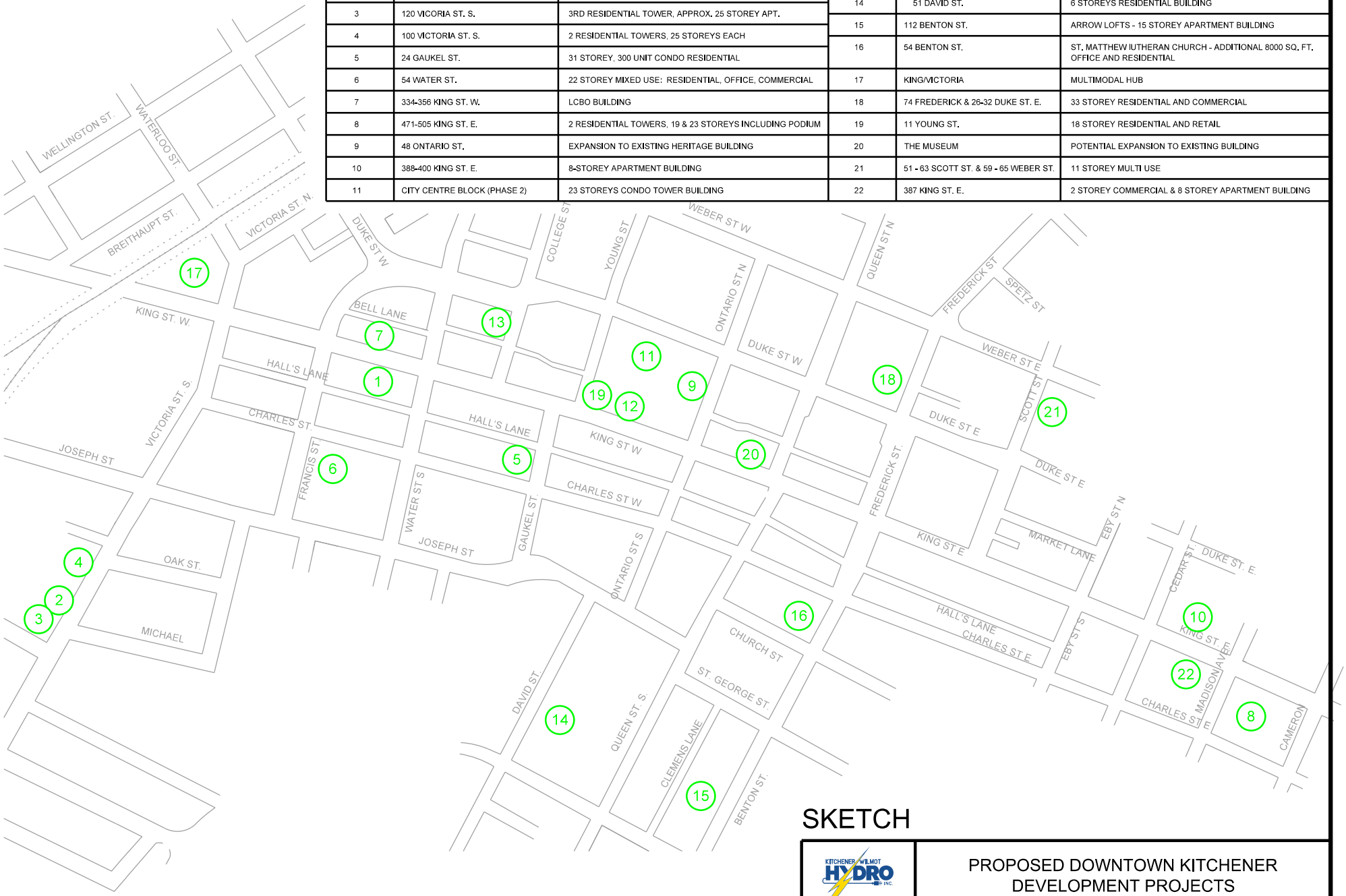
Date April 2, 2019

Completion Date: _____

Appendix B:
Visualization of Proposed Downtown Developments

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MAP #	ADDRESS	DESCRIPTION	MAP #	ADDRESS	DESCRIPTION
1	319-331 & 345 KING ST. W.	6-STOREYS OFFICE BUILDING	12	CITY CENTRE BLOCK (PHASE 3)	5 STOREYS OFFICE/COMMERICAL/RETAIL BUILDING
2	114 VICTORIA ST. S.	HUCK GLOVE SITE - 6 STOREYS OFFICE/COMMERCIAL AND 296 RESIDENTIAL UNITS	13	10 COLLEGE ST. (145 DUKE ST. W.)	16 STOREYS COMMERICIAL & RESIDENTIAL
3	120 VICORIA ST. S.	3RD RESIDENTIAL TOWER, APPROX. 25 STOREY APT.	14	51 DAVID ST.	6 STOREYS RESIDENTIAL BUILDING
4	100 VICTORIA ST. S.	2 RESIDENTIAL TOWERS, 25 STOREYS EACH	15	112 BENTON ST.	ARROW LOFTS - 15 STOREY APARTMENT BUILDING
5	24 GAUKEL ST.	31 STOREY, 300 UNIT CONDO RESIDENTIAL	16	54 BENTON ST.	ST. MATTHEW IUTHERAN CHURCH - ADDITIONAL 8000 SQ. FT. OFFICE AND RESIDENTIAL
6	54 WATER ST.	22 STOREY MIXED USE: RESIDENTIAL, OFFICE, COMMERCIAL	17	KING/VICTORIA	MULTIMODAL HUB
7	334-356 KING ST. W.	LCBO BUILDING	18	74 FREDERICK & 26-32 DUKE ST. E.	33 STOREY RESIDENTIAL AND COMMERCIAL
8	471-505 KING ST. E.	2 RESIDENTIAL TOWERS, 19 & 23 STOREYS INCLUDING PODIUM	19	11 YOUNG ST.	18 STOREY RESIDENTIAL AND RETAIL
9	48 ONTARIO ST.	EXPANSION TO EXISTING HERITAGE BUILDING	20	THE MUSEUM	POTENTIAL EXPANSION TO EXISTING BUILDING
10	388-400 KING ST. E.	8-STOREY APARTMENT BUILDING	21	51 - 63 SCOTT ST. & 59 - 65 WEBER ST.	11 STOREY MULTI USE
11	CITY CENTRE BLOCK (PHASE 2)	23 STOREYS CONDO TOWER BUILDING	22	387 KING ST. E.	2 STOREY COMMERCIAL & 8 STOREY APARTMENT BUILDING



SKETCH

KITCHENER WILMOT HYDRO INC.

PROPOSED DOWNTOWN KITCHENER DEVELOPMENT PROJECTS

ORIGINATOR	G. CAMERON (B.B.)	DATE	SEP. 20/18	SCALE	NONE
CAD FILE	SKETCHES\GREIGC\PROPOSED_DOWNTOWN_DEVELOPMENTS			FILE No.	

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Appendix C:
Needs Assessment Report - Kitchener-Waterloo-Cambridge-Guelph

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Hydro One Networks Inc.
483 Bay Street
Toronto, Ontario
M5G 2P5

NEEDS ASSESSMENT REPORT

Kitchener - Waterloo - Cambridge - Guelph (KWCG) Region

Date: December 19, 2018

Prepared by: KWCG Region Study Team

Disclaimer

This Needs Assessment Report was prepared for the purpose of identifying potential needs in the KWCG Region and to recommend which need may require further assessment and/or regional coordination to develop a preferred plan. The results reported in this Needs Assessment are based on the input and information provided by the Study Team.

The Study Team participants, their respective affiliated organizations, and Hydro One Networks Inc. (collectively, "the Authors") shall not, under any circumstances whatsoever, be liable to each other, to any third party for whom the Needs Assessment Report was prepared ("the Intended Third Parties") or to any other third party reading or receiving the Needs Assessment Report ("the Other Third Parties"). The Authors, Intended Third Parties and Other Third Parties acknowledge and agree that: (a) the Authors make no representations or warranties (express, implied, statutory or otherwise) as to this document or its contents, including, without limitation, the accuracy or completeness of the information therein; (b) the Authors, Intended Third Parties and Other Third Parties and their respective employees, directors and agents (the "Representatives") shall be responsible for their respective use of the document and any conclusions derived from its contents; (c) and the Authors will not be liable for any damages resulting from or in any way related to the reliance on, acceptance or use of the document or its contents by the Authors, Intended Third Parties or Other Third Parties or their respective Representatives.

Executive Summary

REGION	Kitchener - Waterloo - Cambridge - Guelph (KWCG) Region		
LEAD	Hydro One Networks Inc. ("HONI")		
START DATE	September 17, 2018	**END DATE**	December 19, 2018

1. INTRODUCTION

The first cycle of the Regional Planning process for the KWCG Region an Integrated Regional Resource Plan ("IRRP") was published in April 2015 which identified a number of near- and mid-term needs in the KWCG region. The planning process was completed in December 2015 with the publication of the Regional Infrastructure Plan ("RIP") which provided a description of needs and recommendations of preferred wires plans to address near-term needs. The RIP also identified some near- and mid-term needs that will be reviewed during this Regional Planning cycle.

The purpose of this Needs Assessment ("NA") is to identify any new needs and to reaffirm needs identified in the previous KWCG Regional Planning cycle.

2. REGIONAL ISSUE/TRIGGER

In accordance with the Regional Planning process, the regional planning cycle should be triggered at least every five years. In light of the timing of the needs identified in the previous Integrated Regional Resource Plan ("IRRP") and RIP reports as well as new replacement/ refurbishment needs in the KWCG Region, the 2nd Regional Planning cycle was triggered for this Region.

3. SCOPE OF NEEDS ASSESSMENT

The scope of this NA includes:

- Review and reaffirm needs/plans identified in the previous RIP; and
- Identification and assessment of system capacity, reliability, operation, and aging infrastructure needs.

The Study Team may also identify additional needs during the next phases of the planning process, namely Scoping Assessment ("SA"), IRRP and RIP, based on updated information available at that time.

4. INPUTS/DATA

The Study Team representatives from Local Distribution Companies ("LDC"), the Independent Electricity System Operator ("IESO"), and Hydro One provided input and relevant information for the KWCG Region regarding capacity needs, reliability needs, operational issues, and major assets/facilities approaching end-of-life ("EOL"). In addition, community energy plans in the region have also been scanned and reviewed.

5. ASSESSMENT METHODOLOGY

The assessment's primary objective is to identify the electrical infrastructure needs, recommend further mitigation or action plan(s) to address these needs, and determine whether further regional coordination or broader study would be beneficial.

The assessment reviewed available information including load forecasts, conservation and demand management ("CDM") and distributed generation ("DG") forecasts, reliability needs, operational issues, and major high

voltage equipment identified to be at or near the end of their useful life and requiring replacement/refurbishment. A technical assessment of needs was undertaken based on:

- Current and future station capacity and transmission adequacy;
- Reliability needs and operational concerns; and
- Any major high voltage equipment reaching the end of its useful life.

6. NEEDS

I. Station & Transmission Supply Capacity

- Campbell TS (T3/T4) DESN Overloading is forecasted in the 2021-2022.
- Future need for Waterloo North Hydro MTS #4
- Future need for Energy+ MTS #2

A contingency analysis was performed and due to reduced forecasts no issues were found.

II. System Reliability & Operation

- D10H 115 kV line reliability and restoration of Elmira TS loads.

III. Aging Infrastructure – Transformer Replacements and line Section Refurbishment

- Projects in execution:
  - i. Campbell TS – T1 (2018)
  - ii. Detweiler TS -Auto T2 &T4 (2021-2022)
  - iii. 115 kV B5C/ B6C Circuits (2019-2020) [1]
- New projects:
  - i. 115 kV D7F/ D9F Circuits (2019-2020)[2]
  - ii. 230 kV D6V/ D7V Circuits (2019- 2020)[3]
  - iii. Hanlon TS - T1 & T2 (2023-2024)
  - iv. Kitchener MTS #5 - T9 & T10 (2023-2024)
  - v. Cedar TS - T7 & T8 (2024-2025)
  - vi. Scheifele MTS - T1 & T2 (2024-2026)
  - vii. Preston TS - T3 & T4 (2025-2026)

IV. Other Planning Considerations

The local municipalities in the region are extremely engaged and actively pursuing innovative ways to manage and/or reduce their energy needs over the next 10-20 Years. For example, several community energy plans have been developed in the region.

[1] Burlington TS to a CTS Line Section
[2] Tower 157 to Freeport Switching Station Line Section
[3] Guelph North Junction to Fergus TS Line Section

7. RECOMMENDATIONS

The Study Team's recommendations for the above identified needs are as follows:

a) The replacement of EOL station supply transformers at Campbell TS, Hanlon TS, Cedar TS, Kitchener MTS #5 and Preston TS along with the EOL auto transformers at Detweiler to proceed. Hydro One and the concerned LDCs will coordinate replacement of above equipment and develop replacement plans.

b) The refurbishment of EOL line sections 115 kV B5C/ B6C, D7F/ D9F and 230 kV D6V/ D7V to proceed. Hydro One will coordinate refurbishment of these line sections with affected LDCs/ Customer.

c) Hydro One will continue to work with Waterloo North Hydro Inc. to address the supply reliability issue at Elmira TS.

d) The Study Team has recommended that Hydro One Transmission and the Guelph Hydro Electric System Inc. to closely monitor the loading at the T3/T4 Campbell TS DESN and to balance the loads between these DESNs when required.

e) The Study Team recommends that the supply capacity needs with regards to Energy + MTS #2 and WNH MTS #4 be further assessed for optimization in the SA phase of regional planning. Once the optimization options are complete, Waterloo North Hydro and Energy+ shall conduct a technical and economic assessment in consultation with Hydro One.

f) The Study Team has recommended that community energy plans will be further considered in the SA phase of the regional planning process.

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1 INTRODUCTION

The first cycle of the Regional Planning process for the KWCG Region was completed in December 2015 with the publication of the Regional Infrastructure Plan ("RIP"). The RIP provided a description of needs and recommendations of preferred wires plans to address near- and medium-term needs. Waterloo North Hydro MTS #4 was the only need to be reviewed in this planning cycle.

The purpose of this Needs Assessment ("NA") is to identify new needs and to reconfirm needs identified in the previous KWCG regional planning cycle. Since the previous regional planning cycle, some new needs in the region have been identified.

This report was prepared by the KWCG Region Study Team ("Study Team"), led by Hydro One Networks Inc. Participants of the Study Team are listed below in Table 1. The report presents the results of the assessment based on information provided by the Hydro One, the Local Distribution Companies ("LDC") and the Independent Electricity System Operator ("IESO").

Table 1: KWCG Region Study Team Participants

Company
Centre Wellington Hydro
Energy+
Guelph Hydro Electric System Inc.
Halton Hills Hydro
Hydro One Networks Inc. (Lead Transmitter)
Hydro One Networks Inc. (Distribution)
Independent Electricity System Operator ("IESO")
Kitchener Wilmot Hydro Inc.
Milton Hydro
Waterloo North Hydro Inc.
Wellington North Power Inc.

2 REGIONAL ISSUE/TRIGGER

In accordance with the Regional Planning process, the Regional Planning cycle should be triggered at least every five years. In light of the timing of the needs identified in the previous IRRP and RIP reports as well as new replacement/ refurbishment identified needs in the KWCG Region, the 2nd Regional Planning cycle was triggered for the KWCG region.

3 SCOPE OF NEEDS ASSESSMENT

The scope of this NA covers the KWCG Region and includes:

- Identification of new needs based on latest information provided by the Study Team; and,
- Confirmation/updates of existing needs and/or plans identified in the previous planning cycle.

The Study Team may identify additional needs during the next phases of the regional planning process, namely Scoping Assessment ("SA"), Local Planning ("LP"), IRRP, and/or RIP.

4 REGIONAL DESCRIPTION AND CONNECTION CONFIGURATION

The KWCG Region covers the cities of Kitchener, Waterloo, Cambridge and Guelph, portions of Oxford and Wellington counties and the townships of North Dumfries, Puslinch, Woolwich, Wellesley and Wilmot. Electrical supply to the Region is provided from eleven 230 kV and thirteen 115 kV step-down transformer stations. The summer 2018 non-coincident regional loads were about 1390 MW. The approximate boundaries of the KWCG Region are shown below in Figure 1.

The main sources of electricity into the KWCG Region are from five Hydro One stations: Middleport TS, Buchanan TS, Detweiler TS, Orangeville TS and Burlington TS. At these stations electricity is transformed from 500 kV and 230 kV to 230 kV and 115 kV levels, respectively. Electricity is then delivered to the end users of LDCs and directly-connected industrial customers through 26 (TS/ MTS/ CTS) step-down transformer stations. Figure 2 illustrates these stations as well as the four major regional sub-systems: Waterloo-Guelph 230 kV sub-system, Cambridge-Kitchener 230 kV sub-system, Kitchener-Guelph 115 kV sub-system and South-Central Guelph 115 kV sub-system.

The summer non-coincident regional load forecast is provided as Appendix A. Appendix B lists all step-down transformer stations, Appendix C transmission circuits and Appendix D LDCs in the KWCG Region.

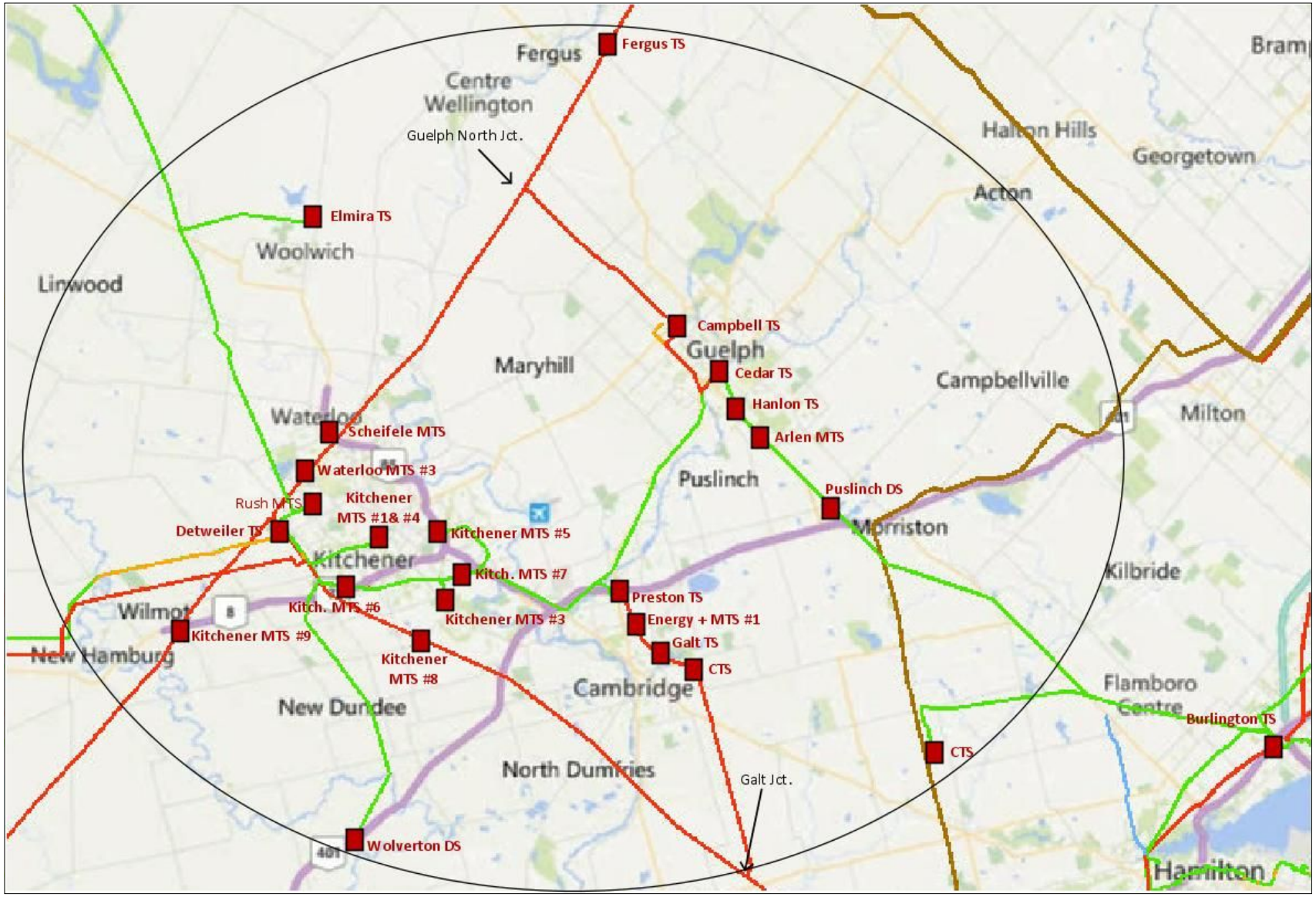


Figure 1: Geographical Area of the KWCG Region with Electrical Layout

An electrical single line diagram for the KWCG Region facilities is shown below in Figure 2.

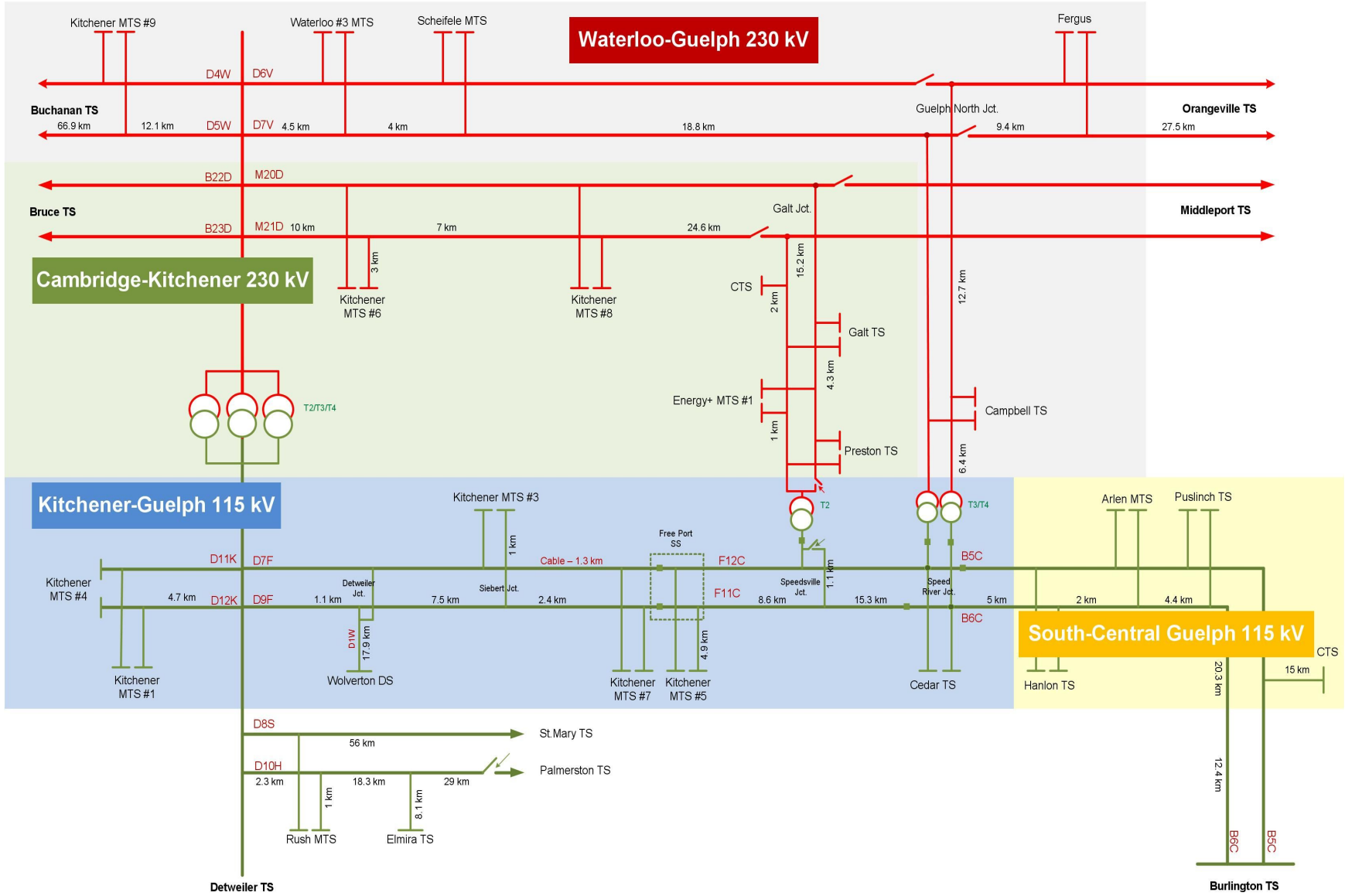


Figure 2: KWCG Region (Single Line Diagram)

5 INPUTS AND DATA

Study Team participants, including representatives from LDCs, IESO, and Hydro One provided information and input for the KWCG Region NA. The information provided includes the following:

- KWCG Load Forecast for all supply stations;
- Known capacity and reliability needs, operating issues, and/or major assets approaching the end of their useful life ("EOL"); and
- Planned/foreseen transmission and distribution investments that are relevant to regional planning for the KWCG Region.

6 ASSESSMENT METHODOLOGY

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

Information gathering included:

i. Load forecast: The relevant LDCs provided load forecasts for all the stations supplying their loads in the KWCG region for the 10 year study period. The IESO provided a Conservation and Demand Management ("CDM") and Distributed Generation ("DG") forecast for the KWCG region. The region's extreme summer non-coincident peak gross load forecast for each station were prepared by applying the LDC load forecast load growth rates to the actual 2018 summer peak extreme weather corrected loads. The extreme summer weather correction factors were provided by Hydro One. The net extreme weather summer load forecasts were produced by reducing the gross load forecasts for each station by the % age CDM and then by the amount of effective DG capacity provided by the IESO for that station. These extreme weather summer load forecast for the individual stations in the KWCG region is given in Appendix A;

ii. Relevant information regarding system reliability and operational issues in the region; and

iii. List of major HV transmission equipment planned and/or identified to be refurbished and/or replaced due to the end of their useful life which is relevant for regional planning purposes. This includes HV transformers, autotransformers, HV Breakers, HV underground cables and overhead lines.

A technical assessment of needs was undertaken based on:

- Current and future station capacity and transmission adequacy;
- System reliability and operational concerns; and
- Any major high voltage equipment reaching the end of its useful life.

In addition, Hydro One has reviewed the Community Energy Plans in the region. It is worth noting that there are several community energy plans in the region and some of them are meant to sustain at the

current level or reduce the community's reliance on the provincial electric system by meeting future electricity needs with local, distributed resources and/or community-based solutions. These plans may have potential to supplement and/or defer future transmission infrastructure development needs.

7 NEEDS

This section describes emerging needs identified in the KWCG Region, and also reaffirms the near, mid, and long-term needs already identified in the previous regional planning cycle.

The recent load forecast prepared for this report is lower than that of the previous cycle of regional planning. A contingency analysis was performed for the region and due to reduced load forecasts, as expected; no new system needs were identified.

The newly identified/emerging needs pertaining to this NA will be discussed further in the following sub-sections, while the status of the previously identified needs is summarized in Table 2 below.

Table 2: Needs Identified in the Previous Regional Planning Cycle

Type of Needs identified in the previous RP cycle	Needs Details	Current Status
115kV System Supply Capacity	**GATR Project** Two new additional 230/115kV autotransformers at Cedar TS to reinforce supply to both 115kV sub-systems in the region.	Completed
230kV Load Restoration Needs	**GATR Project** Two new additional 230 kV in-line switches on D6V/D7V circuits to improve restoration capability of Waterloo-Guelph 230 kV sub-system.	Completed
	Galt Junction Two new additional 230kV in-line switches on M20D/M21D circuits to improve restoration capability of the Cambridge-Kitchener 230 kV sub-system.	Completed
Station Short Circuit Capacity	**Arlen MTS** Install 13.8 kV series reactors to mitigate LV bus short circuit levels.	Completed
Station Transformation Capacity	New Waterloo North Hydro: MTS #4 (2024).	Need is now expected beyond 2029.

7.1 End-Of-Life (EOL) Equipment Needs

Hydro One and LDCs have provided high voltage asset information under the following categories that have been identified at this time and are likely to be replaced over the next 10 years:

- Autotransformers
- Power transformers
- HV breakers
- Transmission line requiring refurbishment where an uprating is being considered for planning needs and require Leave to Construct (i.e., Section 92) application and approval
- HV underground cables where an uprating is being considered for planning needs and require EA and Leave to Construct (i.e., Section 92) application and approval

Accordingly, following major high voltage equipment has been identified as approaching its end of useful life over the next 10 years.

Table 3: End-of-Life Equipment – KWCG Region

EOL Asset Replacement/ Refurbishment	Replacement/ Refurbishment Timing	Details
Projects in Execution		
Campbell TS (T1/T2 DESN): T1 Supply Transformer	2018	These Project are discussed further in Section 7.1.1
Detweiler TS: 230/ 115 kV T2/ T4 Auto-transformers	2021-2022	
115 kV B5C/ B6C: Burlington TS to Westover CTS Line Sections	2019-2020	
New Identified Projects		
115 kV D7F/ D9F : Tower #157 to Freeport SS Line Section	2019-2020	These Project are discussed further in Section 7.1.2
230 kV D6V/ D7V: Guelph North Jct. to Fergus Jct. Line Section	2019-2020	
Kitchener MTS #5[1]: T9/T10 Supply Transformers	2023-2024	
Hanlon TS: T1/T2 Supply Transformers	2023-2024	
Cedar TS: T7/T8 Supply Transformers	2024-2025	
Scheifele MTS[1]- T1/T2 Supply Transformers	2024-2026	
Preston TS: T3/T4 Supply Transformers	2025-2026	

[1] LDC owned assets

The end-of-life assessment for the above high voltage equipment typically included consideration of the following options:

1. Maintaining the status quo;
2. Replacing equipment with similar equipment of lower ratings and built to current standards;
3. Replacing equipment with lower ratings and built to current standards by transferring some load to other existing facilities;
4. Eliminating equipment by transferring all of the load to other existing facilities;
5. Replacing equipment with similar equipment and built to current standards (i.e., "like-for-like" replacement);
6. Replacing equipment with higher ratings and built to current standards; and
7. Station reconfiguration

Maintaining status quo is not an option for any of the above EOL autotransformer, station transformer or line sections due to risk of equipment failure, would result in increased maintenance cost and customer outages. Replacing "Like-for-Like" with nonstandard transformers would result in complexity with failures and difficulty in getting similar spare equipment along with their installation. Nonstandard equipment also poses serious safety risk for employees under normal and emergency situations.

No other lines or HV station equipment in the KWCG region have been identified for major replacement/ refurbishment at this time. If and when new and/or additional information is available, it will be provided during the next planning phase underway at the time.

7.1.1 Projects in Execution

The following end-of-life refurbishment needs are under execution. This region was deemed to be in transition and NA for this region was deemed complete. Hence, following projects were not listed or discussed in the first cycle of regional planning and are currently in execution:

Campbell TS – T1 Transformer

Campbell TS is located in the city of Guelph supplying Guelph Hydro Electric System Inc. loads. Campbell TS has two 230/ 13.8 kV DESNs T1/T2 and T3/T4 of 75 MVA transformers with an LTR of 105 MVA (94 MW @ 0.9 PF) and 63 MVA (56 MW @ 0.9 PF) respectively. The loads on these two DESNs are currently forecasted to be about 87 MW and 66 MW respectively by the end of study period.

The 75 MVA T1/T2 DESN transformer T2 failed in 2017 and was replaced with a new standard 100 MVA unit and transformer T1 is also being replaced with a similar unit. In 2021-2022, Hydro One in addition plans to replace the secondary equipment limiting the station LTR. This will result in sufficient LTR of about 130 MVA for T1/T2 DESN, over the study period.

The replacement of T1 transformer is currently in execution and expected to be completed by the end of year 2018.

Detweiler TS - T2 & T4 Autotransformers

Detweiler TS is a Bulk System, major switching and autotransformer station located in the city of Kitchener. Detweiler TS facilities include a 230 kV switchyard, three 230/115 kV autotransformers (T2/T3/T4) and a 115 kV switchyard.

The Detweiler TS autotransformers T2/T3/ T4 were built in 1959, 2004 and 1963 respectively. The condition assessment has identified T2 and T4 autotransformers as EOL requiring replacement. At this time none of other HV equipment at this station has been identified as approaching EOL over the next 5-10 years.

Not replacing these auto transformers would increase risk of failure due to asset condition, maintenance expenses and reduce supply reliability to the customers. The replacement of both the EOL Detweiler TS T2 and T4 autotransformers with similar units is in execution expected to be completed in 2021-22. This will address the 230/ 115 kV transformation needs at Detweiler TS and maintain station's operability and reliability of supply.

Any Detweiler TS 230 kV system reconfiguration needs will be studied under bulk system planning expected to commence in early 2019.

115 kV B5C/ B6C Line Sections

The 115 kV B5C/B6C circuits consist of about 45 km of double circuit line and 15 km of single circuit line supplying South-Central Guelph 115 kV loads. About 12 km of double circuit line section from Burlington TS to Harper's Jct. and about 15 km B5C 115 kV line tap from Harper's Jct. to a Westover Jct. requires refurbishment.

Not refurbishing these line sections would increase risk of failure due to asset condition, maintenance expenses and reduce supply reliability to the customers.

The refurbishment of this 27 km long 115 kV B5C/B6C line sections from Burlington TS to a CTS is currently under execution and the work is planned to be completed by the end of year 2019.

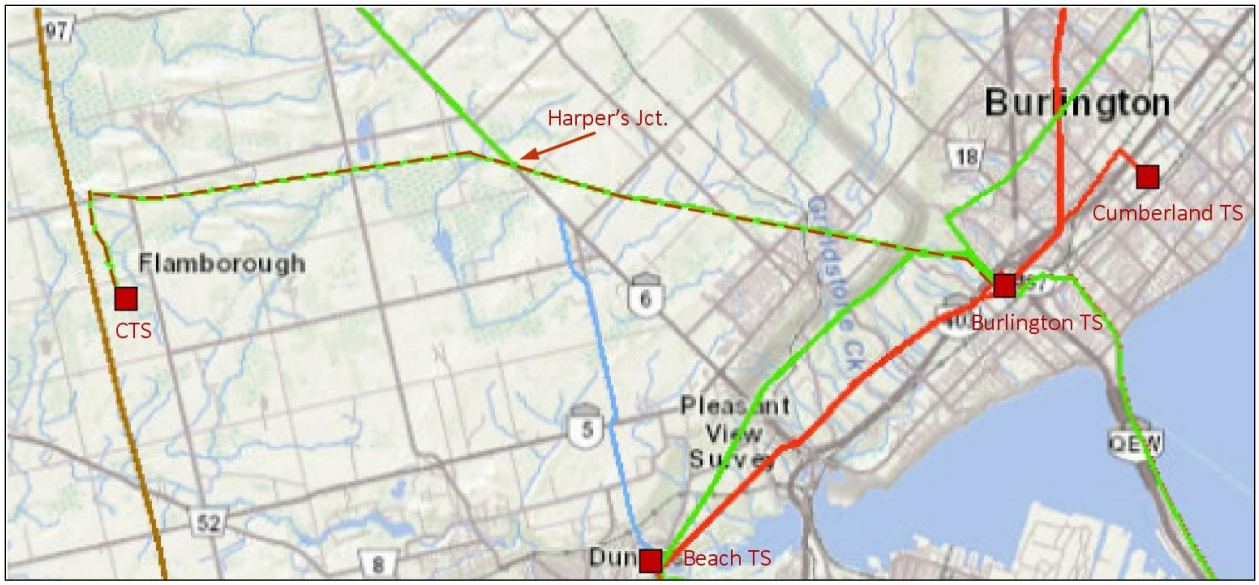


Figure 3: Burlington TS to Harper's Jct. to CTS B5C/ B6C Line Sections

7.1.2 New Needs

The following end-of-life refurbishment needs have been identified in this regional planning cycle:

115 kV D7F/D9F Line Section

The 115 kV D7F/ D9F double circuit line is about 12 km long supplying Kitchener- Guelph 115 kV loads. The 115 kV D7F/ D9F double circuit 450 meter line section from Tower 157 to Freeport Switching Station was built in 1951. It is approaching end of life and requires refurbishment.

Not refurbishing this line section would increase risk of failure due to asset condition, maintenance expenses and reduce supply reliability to the customers.

Therefore the Study Team recommends Hydro One to continue with refurbishment of the 450 meter long 115 kV D7F/ D9F end of life line section from Tower 157 to Freeport Switching Station. This project is currently under estimating and is planned to be completed by the end of year 2019.

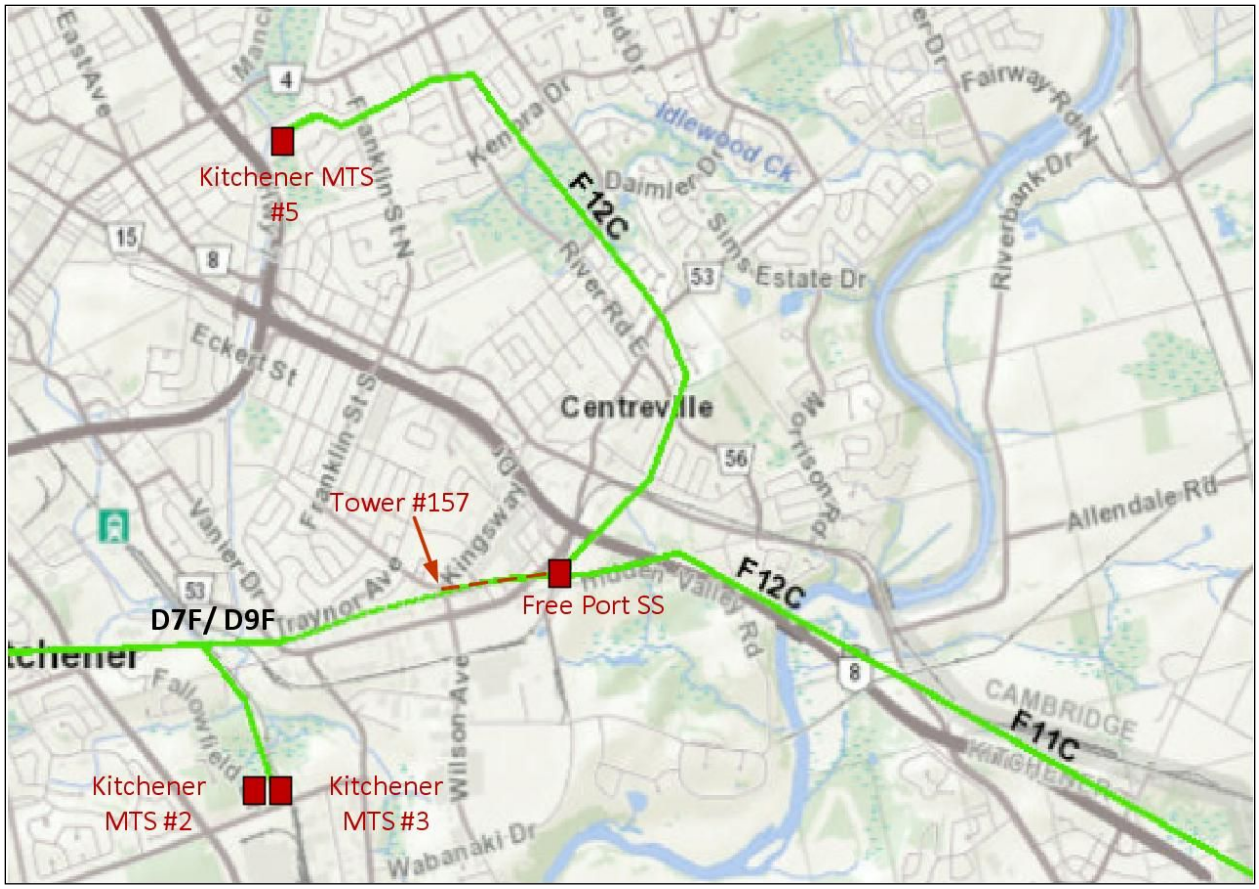


Figure 4: Tower #157 Jct. to Freeport SS F11C/ F12C Line Section

230 kV D6V/D7V Line Section

The 230 kV D6V/D7V double circuit line is about 84 km long and is part of bulk power system supplying loads in the Waterloo Guelph 230kV and South Central Guelph 115 kV loads. A 230 kV D6V/ D7V 9.5 km double circuit line section from Guelph North junction to Fergus TS was built in 1950's and its conductor is approaching end of life. It requires refurbishment.

Not refurbishing this line section would increase risk of failure due to asset condition, maintenance expenses and reduce supply reliability to the customers.

Therefore the Study Team recommends to refurbish this the 9.5 km long 230 kV D6V/D7V end of life line section from Guelph North Junction to Fergus TS. This project is currently under estimating and is planned to be completed by the end of year 2019.



Figure 5: Guelph North Jct. to Fergus TS D6V/ D7V Line Section

Kitchener MTS #5 T9/T10 Transformers

Kitchener MTS #5 is located in the city of Kitchener supplying Kitchener-Wilmot Hydro Inc. loads. Kitchener MTS #5 is a 115/ 13.8 kV single T9/T10 DESN station of 83 MVA nonstandard transformers having a LTR of 89 MVA (80 MW @ 0.9 PF), currently supplying 67 MW of peak load. The loads at Kitchener MTS #5 are currently forecasted to remain flat over the entire study period. The supply capacity of this station is therefore expected to be sufficient over and beyond the study period.

Both the T9/T10 transformers at this station have been identified as approaching end of life requiring replacement. At this time none of other HV/LV equipment at this station has been identified as approaching EOL over the next 5-10 years.

The station cannot be downsized or eliminated because there is no nearby supply station/s to Kitchener MTS #5 having surplus capacity where this station's loads can be transferred. The Study Team recommends replacing the T9/T10 nonstandard transformers with standard units of similar size is the preferred option. Kitchener-Wilmot Hydro Inc. and Hydro One will coordinate the replacement plan of these transformers. The replacement of the EOL equipment is expected to be completed by 2023-2024.

Hanlon TS T1/T2 Transformer

Hanlon TS is located south of the city of Guelph supplying Guelph Hydro Electric System Inc. loads. Hanlon TS is a single T1/T2 DESN station of 33 MVA nonstandard transformers having a LTR of 48

MVA (43 MW @ 0.9 PF). This station is currently supplying about 27 MW of peak load. The loads at Hanlon TS are currently forecasted to remain flat over the entire study period. The supply capacity of this station is therefore expected to be sufficient over and beyond the study period.

The T1/T2 transformers are of 1955/ 56 built and have been identified as EOL requiring replacement. At this time none of other HV/LV equipment at this station has been identified as approaching EOL over the next 5-10 years.

There is no nearby supply station/s to Hanlon TS having surplus capacity where this station's loads can be transferred therefore Hydro One plans to replace these EOL transformers with standard size units of 42 MVA in 2023-2024.

Cedar TS – T7/ T8 Transformers

Cedar TS is located in the city of Guelph supplying Guelph Hydro Electric System Inc. loads. Cedar TS has two 115/ 13.8 kV DESN units T1/T2 and T7/T8 of 75 MVA with a LTR of 115 MVA (103 MW @ 0.9 PF) and 37 MVA with a LTR of 44 MVA (40 MW @ 0.9 PF), currently supplying 67 MW and 36 MW of peak loads respectively. The loads at both Cedar TS DESNs are currently forecasted to remain almost flat over the entire study period. The supply capacity of this station is therefore expected to be sufficient over and beyond the study period.

The T7/T8 DESN 38 MVA nonstandard transformers are of 1958 built have been identified for replacement. The T1/T2 transformers are relatively newer and were built in early 1990s. At this time none of other HV/LV equipment at this station has been identified as approaching EOL over the next 5-10 years.

The station cannot be downsized or eliminated because there is no nearby supply station/s to Cedar TS having surplus capacity where this station's loads can be transferred therefore Hydro One plans to replace these EOL transformers with standard size units of 42 MVA in 2024-2025 timeframe.

Cedar TS and Hanlon TS Optimization with Neighbouring Stations

After performing an analysis of the current distribution situation, it was determined that there are not enough spare feeder positions at HONI and GHESI stations to reallocate DESN loads in the sub-system without significant distribution system and neighboring station upgrades.

Over loading of Campbell DESN T3/T4 will be effectively managed by load transfer to DESN T1/T2 after 2021/22. Following that there will be no additional capacity at these two DESNs.

Secondly, Hanlon TS DESN has eight (8) feeders with three (3) being dedicated underground infrastructure to existing customers, two (2) feeders supplying the industrial load in the Hanlon Industrial Park, two (2) feeder circuits supplying residential load north of Hanlon TS and one (1) feeder to be utilized for planned future load growth at Gordon/ Clair. In addition, due to technical limitations at 13.8 kV distribution voltage and density of load on certain feeders sections, it is not possible to supply existing

loads from any other station without significant transmission and distribution investments. Therefore there are little or no significant optimization opportunity is present at this point in time. Option considered for load transfer will require significant new investment; for example:

- The two residential distribution feeders supplying loads north of Hanlon TS could be transferred to existing feeders out of Cedar TS. These load transfers will result in increased line losses and reduced capacity (due to voltage drop)
- Another option could be transferring remaining Hanlon TS load to Arlen MTS. This load transfer will require an additional DESN and underground infrastructure at Arlen MTS.

Hence, the Study Team recommends that Hydro One undertakes replacement of Cedar TS T7/T8 and Hanlon TS T1/T2 transformers with 42 MVA standard size units, being technically and economical most suitable solution. The replacement of EOL equipment is expected to be completed by 2023-2025 timeframe for both stations.

Scheifele MTS – T1/ T2 Transformers

Scheifele MTS is located in the city of Waterloo supplying Waterloo North Hydro Inc. loads. Scheifele MTS has four 230/ 13.8 kV transformers T1 and T2 of 67 MVA, and T3 and T4 of 83 MVA currently supplying 145 MW of peak loads. The load at this station is forecasted to remain almost flat over the entire study period. The total supply capacity of Scheifele MTS is 161 MW expected to be sufficient over the study period.

The T1/T2 transformers based on their age have been identified by Waterloo North Hydro Inc. as approaching end of life potentially requiring replacement in the 2024- 2026 timeframe. Waterloo North Hydro will be monitoring the condition of these transformers to assess their replacement need. At this time none of other HV/LV equipment at this station has been identified as approaching EOL over the next 5-10 years.

The station cannot be downsized or eliminated because there is no nearby supply station/s to Scheifele MTS having surplus capacity where this station's loads can be transferred. The Study Team recommends that Waterloo North Hydro continue monitoring the condition of these T1/T2 transformers at Scheifele MTS and this need to be reassessed in the next regional planning cycle.

Preston TS T3/T4 Transformers

Preston TS (DESN) is located in the city of Cambridge supplying Energy+ loads. Preston TS is a single T3/T4 DESN station of 125 MVA transformers with no additional LTR capability available i.e. 125 MVA (113 MW @ 0.9 PF). This station is currently supplying about 92 MW of peak load. The loads at Preston TS are currently forecasted to peak at about 102 MW during the study period.

The T3/T4 transformers are almost 50 years old, having been built in 1968. Condition assessment has identified that both T3/T4 transformers at their EOL requiring replacement. At this time none of other HV/LV equipment at this station has been identified as EOL over the next 5-10 years.

The station cannot be downsized or eliminated because there is no nearby supply station/s to Preston TS having spare supply capacity where this station's loads can be transferred. The Study Team recommends replacing the existing 125 MVA 230/ 27.6 kV T3/T4 transformers at Preston TS with 125 MVA standard units. This will also result in an increased supplying capacity at Preston TS required to meet the future Energy+ needs in the Cambridge distribution area. The replacement plan for the equipment will be developed by Hydro One and coordinated with the affected LDC and/or customers and it is expected to be completed by 2025-2026.

7.2 Supply Reliability Needs

Supply reliability of Elmira TS –D10H 115 kV Line

The 115 kV D10H circuit between Detweiler TS and Hanover TS supplies loads at Rush MTS, Elmira TS and Palmerston TS. The D10H circuit has a normally open point just south of Palmerston TS through a motorized disconnect switch. The northern section of D10H is supplied from Hanover TS radially supplying Palmerston TS loads. The southern section of D10H supplied from Detweiler TS radially supplies Waterloo North Hydro's 34 MW Elmira TS peak loads. D10H also supplies Rush MTS which is also supplied by 115 kV D8S circuit from Detweiler TS.

The normally open motorized switch near Palmerston TS helps restore the loads at Elmira TS from Hanover TS in-case supply from Detweiler TS is interrupted and similarly helps restoring Palmerston TS loads from Detweiler if supply from Hanover is interrupted.

In last three years, supply to Elmira TS from Detweiler TS resulted in 3 outages due to faults on the D10H line section between Elmira TS tap and Detweiler TS. The Elmira TS load restoration from Hanover TS is slower due to manually operated disconnect switches at Elmira TS tap location.

Hydro One is currently assessing the condition of line and will continue to work with Waterloo North Hydro to address the supply reliability at Elmira TS. The developed mitigation plan to improve supply reliability of Elmira TS loads will be included in the final RIP report.

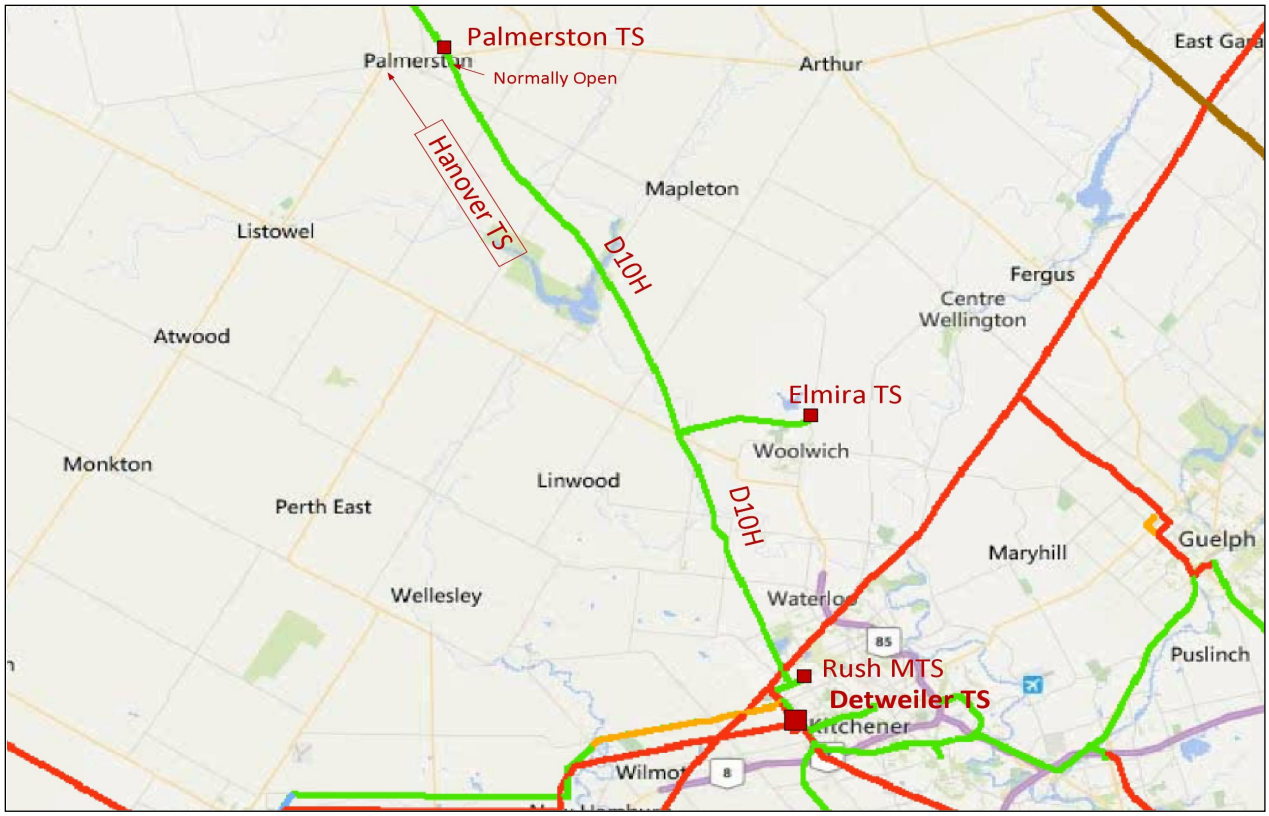


Figure 6: D10H 115 kV Line (Burlington TS to Elmira TS)

7.3 Station and Transmission Capacity Needs in the KWCG Region

The following Station and Transmission supply capacities needs have been identified in the KWCG region during the study period of 2019 to 2028.

7.3.1 Campbell TS (T3/T4) DESN Overloading

There are two DESN stations inside Campbell TS boundary. Both the T1/T2 and T3/T4 DESNs are 230 kV/ 13.8 kV having supply capacities of 94 MW and 56 MW, currently supplying 84 MW and 52 MW of loads respectively. The 75 MVA transformer T2 recently failed and was replaced with a Hydro One standard 100 MVA unit. The transformer T1 is also being replaced with a similar 100 MVA unit by the end of 2018. The load at T3/T4 DESN is forecasted to exceed its supply capacity of 56 MW in the 2021-2022 timeframe.

At Campbell TS, after replacement of T1 transformer and secondary equipment there will be sufficient spare supply capacity on T1/T2 DESN where excess T3/T4 DESN loads can be transferred. Hydro One Transmission and the Guelph Hydro Electric System Inc. will monitor the loading at the T3/T4 Campbell TS DESN and will balance the loads between the two DESNs, when required. The Study Team therefore recommends that no further action is required at this time.

7.3.2 Waterloo North Hydro MTS #4

During the last regional planning cycle a need for a new MTS #4 DESN was identified in the 2024 timeframe. The current load forecast defers this need beyond the needs assessment study period.

7.3.3 Energy+ MTS #2

Energy+ has initially identified a future need for a new DESN station (MTS #2) in the city of Cambridge near Preston TS. This station need is due to a potential new load center growth in their service territory. The additional supply capacity due to EOL transformer replacement and available new feeder positions at Preston TS, will defer this new MTS need beyond the study period of current regional planning cycle.

WNH MTS #4 and Energy+ MTS #2 Optimization

The Preston TS like-for-like transformer replacement is critical for local supply needs and will proceed according to the current plan. However, study team recommends that the supply capacity needs with regards to Energy + MTS #2 and WNH MTS #4 be further assessed for optimization in the next phases of regional planning. Once the optimization options are complete, Waterloo North Hydro and Energy+ shall conduct a technical and economic assessment in consultation with Hydro One.

7.4 Other Planning Considerations in the KWCG Region

Municipalities in KWCG region have developed their community energy plans with a primary focus to reduce their energy consumption by local initiatives over next 25 to 30 years. With respect to electricity, these communities are planning for an increased reliance on community energy sources such as distributed generation, generation behind the meters like rooftop solar systems and local battery storage systems to reduce cost and for improved reliability of electricity supply.

There are situations where behind the meter battery storage cannot be connected due to technical constraints. The LDCs in this region and Hydro One, outside the regional planning forum, can undertake the task of exploring the issue to assess technical constraints and /or other solutions that can facilitate connection of additional battery storage.

Communities are also working towards self-sufficiency by improving efficiencies of existing local energy systems i.e. reducing energy consumption and losses by means of utilizing smarter buildings, houses, efficient heating, cooling, appliances, equipment, and processes for all community needs. Ultimately, the objective of these energy plans in the region is to be a net zero carbon community.

Community energy plans may have potential to supplement and/or defer future transmission infrastructure development needs. The Study Team therefore recommends reviewing the community energy plans in the SA phase.

8 CONCLUSION AND RECOMMENDATIONS

Hydro One and Waterloo North Hydro Inc. will develop a supply reliability improvement plan for Elmira TS loads. The developed local plan to improve supply reliability of Elmira TS loads will be included in the final RIP report.

At Campbell TS, after replacement of T1 transformer and addressing the secondary equipment limitations there will be sufficient spare supply capacity on T1/T2 DESN to accommodate T3/T4 DESN overloading. Hydro One and the LDC will work together to balance loads between the two Campbell TS DESNs, when required.

The distribution system in the Cedar TS, Hanlon TS and Arlen MTS supply area is already optimized and there are not enough spare feeder positions at any of the stations to reallocate DESN loads without significant distribution system investments and upgrades at neighboring stations.

The Study Team's recommendations for the above identified needs are as follows:

a) The replacement of EOL station supply transformers at Campbell TS, Hanlon TS, Cedar TS, Kitchener MTS #5 and Preston TS along with the EOL auto transformers at Detweiler to proceed. Hydro One and the concerned LDCs will coordinate replacement of above equipment and develop replacement plans.

b) The refurbishment of EOL line sections 115 kV B5C/ B6C, D7F/ D9F and 230 kV D6V/ D7V to proceed. Hydro One will coordinate refurbishment of these line sections with affected LDCs/ Customer.

c) Hydro One will continue to work with Waterloo North Hydro Inc. to address the supply reliability issue at Elmira TS.

d) The Study Team has recommended that Hydro One Transmission and the Guelph Hydro Electric System Inc. to closely monitor the loading at the T3/T4 Campbell TS DESN and to balance the loads between these DESNs when required.

e) The Study Team recommends that the supply capacity needs with regards to Energy + MTS #2 and WNH MTS #4 be further assessed for optimization in the SA phase of regional planning. Once the optimization options are complete, Waterloo North Hydro and Energy+ shall conduct a technical and economic assessment in consultation with Hydro One.

f) The Study Team has recommended that community energy plans will be further considered in the SA phase of the regional planning process.

9 REFERENCES

[1] KWCG Regional Infrastructure Plan - December 2015

[2] Planning Process Working Group Report to the Ontario Energy Board - May 2013

[3] Ontario Resource and Transmission Assessment Criteria (ORTAC) – Issue 5.0 -August 2007

Appendix A: KWCG Region Non-Coincident Summer Load Forecast

* LTR based on 0.9 power factor

Transformer Station		Summer 10 Day LTR*	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Arlen MTS	Gross	45	24.44	25.17	25.92	26.70	27.50	28.33	29.18	30.05	30.95	31.88	32.84	33.82
	CDM		0.00	0.22	0.28	0.44	0.57	0.79	1.12	1.50	2.05	2.71	3.40	3.99
	DG		0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
	Net		24.42	24.94	25.64	26.25	26.92	27.53	28.04	28.54	28.89	29.16	29.43	29.83
Campbell TS (T1/T2)	Gross	94	83.46	84.71	85.98	87.27	88.58	89.91	91.26	92.63	94.02	95.43	96.86	98.31
	CDM		0.00	0.72	0.91	1.44	1.83	2.50	3.51	4.63	6.22	8.11	10.03	11.59
	DG		0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
	Net		83.45	83.98	85.06	85.82	86.75	87.40	87.74	87.99	87.78	87.30	86.82	86.72
Campbell TS (T3/T4)	Gross	56	51.62	53.42	55.29	57.23	59.23	61.30	63.45	65.67	67.97	70.35	72.81	75.36
	CDM		0.00	0.46	0.59	0.94	1.22	1.70	2.44	3.28	4.50	5.98	7.54	8.88
	DG		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Net		51.62	52.97	54.71	56.28	58.01	59.60	61.01	62.39	63.47	64.37	65.27	66.48
Cedar TS (T1/T2)	Gross	103	67.35	67.69	68.03	68.37	68.71	69.05	69.40	69.75	70.09	70.44	70.80	71.15
	CDM		0.00	0.58	0.72	1.13	1.42	1.92	2.67	3.49	4.64	5.99	7.33	8.38
	DG		0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
	Net		67.30	67.06	67.26	67.19	67.24	67.09	66.68	66.21	65.40	64.41	63.42	62.72
Cedar TS (T7/T8)	Gross	40	35.63	35.80	35.98	36.16	36.34	36.53	36.71	36.89	37.08	37.26	37.45	37.63
	CDM		0.00	0.31	0.38	0.60	0.75	1.01	1.41	1.85	2.45	3.17	3.88	4.44
	DG		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Net		35.63	35.50	35.60	35.57	35.59	35.51	35.29	35.05	34.62	34.09	33.57	33.20
Elmira TS	Gross	55	34.19	34.62	35.04	35.38	35.73	36.06	36.39	36.71	37.05	37.40	37.75	38.10
	CDM		0.00	0.30	0.37	0.58	0.74	1.00	1.40	1.84	2.45	3.18	3.91	4.49
	DG		0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
	Net		34.17	34.31	34.65	34.78	34.98	35.04	34.97	34.86	34.58	34.20	33.83	33.60
Energy+ MTS #1	Gross	102	84.03	84.87	85.72	86.58	87.44	88.53	89.64	90.76	91.90	93.05	94.21	95.39
	CDM		0.00	0.73	0.91	1.43	1.80	2.46	3.45	4.54	6.08	7.91	9.75	11.24
	DG		0.32	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49
	Net		83.71	83.65	84.31	84.65	85.15	85.58	85.70	85.73	85.32	84.64	83.96	83.65
Fergus TS	Gross	154	87.52	88.57	89.62	90.27	90.96	91.52	92.07	92.62	93.20	93.83	94.45	95.05
	CDM		0.00	0.76	0.95	1.49	1.87	2.54	3.54	4.63	6.17	7.98	9.78	11.20
	DG		0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
	Net		87.47	87.77	88.62	88.73	89.03	88.92	88.48	87.94	86.98	85.80	84.62	83.80
Galt TS	Gross	169	113.56	114.69	115.84	117.00	118.17	119.64	121.14	122.65	124.19	125.74	127.31	128.90
	CDM		0.00	0.98	1.23	1.93	2.44	3.32	4.66	6.14	8.22	10.69	13.18	15.19
	DG		0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21
	Net		113.35	113.51	114.40	114.86	115.53	116.11	116.27	116.31	115.76	114.84	113.93	113.51
Hanlon TS	Gross	43	26.85	27.25	27.66	28.08	28.50	28.93	29.36	29.80	30.25	30.70	31.16	31.63
	CDM		0.00	0.23	0.29	0.46	0.59	0.80	1.13	1.49	2.00	2.61	3.23	3.73
	DG		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Net		26.85	27.02	27.37	27.62	27.91	28.12	28.23	28.31	28.25	28.09	27.94	27.90
Kitchener MTS # 1	Gross	54	31.31	33.64	34.72	35.81	36.90	37.76	38.60	39.46	40.31	41.16	42.02	42.87
	CDM		0.00	0.29	0.37	0.59	0.76	1.05	1.49	1.97	2.67	3.50	4.35	5.05
	DG		0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
	Net		31.28	33.33	34.33	35.19	36.11	36.68	37.09	37.47	37.62	37.64	37.65	37.79
Kitchener MTS # 3	Gross	108	46.73	45.03	45.34	46.05	46.78	47.49	48.22	48.93	49.64	50.37	51.08	51.81
	CDM		0.00	0.38	0.48	0.76	0.96	1.32	1.86	2.45	3.29	4.28	5.29	6.11
	DG		0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
	Net		46.71	44.63	44.83	45.27	45.79	46.15	46.34	46.46	46.34	46.06	45.77	45.68

Transformer Station		Summer 10 Day LTR*	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Kitchener MTS # 4	Gross	90	58.39	59.76	60.63	61.49	62.36	63.05	63.73	64.41	65.09	65.77	66.46	67.13
	CDM		0.00	0.51	0.64	1.01	1.29	1.75	2.45	3.22	4.31	5.59	6.88	7.91
	DG		0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
	Net		58.34	59.19	59.93	60.43	61.02	61.24	61.22	61.14	60.73	60.12	59.52	59.17
Kitchener MTS #5	Gross	80	66.56	67.94	68.82	69.70	70.58	71.28	71.96	72.66	73.35	74.03	74.73	75.42
	CDM		0.00	0.58	0.73	1.15	1.45	1.98	2.77	3.63	4.86	6.29	7.74	8.89
	DG		0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06
	Net		66.50	67.31	68.03	68.49	69.07	69.24	69.14	68.97	68.43	67.68	66.94	66.47
Kitchener MTS #6	Gross	90	64.17	62.22	62.97	63.71	64.47	65.21	65.96	66.70	67.44	68.19	68.93	69.68
	CDM		0.00	0.53	0.67	1.05	1.33	1.81	2.54	3.34	4.46	5.80	7.14	8.21
	DG		0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09
	Net		64.08	61.60	62.21	62.57	63.04	63.30	63.33	63.27	62.88	62.30	61.70	61.38
Kitchener MTS #7	Gross	54	42.79	43.98	44.69	45.38	46.08	46.77	47.47	48.16	48.85	49.55	50.24	50.95
	CDM		0.00	0.38	0.48	0.75	0.95	1.30	1.83	2.41	3.23	4.21	5.20	6.00
	DG		0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
	Net		42.77	43.59	44.19	44.61	45.11	45.45	45.63	45.73	45.60	45.32	45.03	44.92
Kitchener MTS #8	Gross	54	38.68	39.94	41.18	42.44	43.70	45.62	47.53	49.45	51.38	53.30	55.21	57.13
	CDM		0.00	0.34	0.44	0.70	0.90	1.27	1.83	2.47	3.40	4.53	5.71	6.73
	DG		0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06
	Net		38.62	39.54	40.69	41.68	42.74	44.30	45.65	46.92	47.92	48.71	49.44	50.34
Kitchener MTS #9	Gross	90	30.16	30.72	31.28	31.83	32.39	32.94	33.50	34.05	34.61	35.17	35.73	36.27
	CDM		0.00	0.26	0.33	0.52	0.67	0.92	1.29	1.70	2.29	2.99	3.70	4.27
	DG		0.23	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50
	Net		29.94	29.96	30.45	30.80	31.22	31.53	31.71	31.85	31.82	31.68	31.53	31.50
Preston TS	Gross	113	92.38	95.15	98.00	100.94	103.97	105.27	106.59	107.92	109.27	110.63	112.02	113.42
	CDM		0.00	0.81	1.04	1.67	2.14	2.92	4.10	5.40	7.23	9.41	11.60	13.37
	DG		0.00	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19
	Net		92.38	94.14	96.76	99.08	101.63	102.15	102.29	102.33	101.84	101.03	100.23	99.86
Puslinch DS	Gross	56	28.49	29.24	30.01	30.45	30.92	31.30	31.68	32.05	32.45	32.88	33.31	33.72
	CDM		0.00	0.25	0.32	0.50	0.64	0.87	1.22	1.60	2.15	2.80	3.45	3.97
	DG		0.02	0.02	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15
	Net		28.47	28.98	29.54	29.80	30.14	30.29	30.31	30.30	30.16	29.94	29.71	29.60
Rush MTS	Gross	68	45.33	46.24	47.16	48.11	49.07	50.05	51.05	52.07	53.11	54.17	55.26	56.36
	CDM		0.00	0.40	0.50	0.79	1.01	1.39	1.97	2.60	3.52	4.61	5.72	6.64
	DG		0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
	Net		45.30	45.81	46.63	47.28	48.03	48.63	49.06	49.44	49.57	49.54	49.51	49.69
Scheifele MTS	Gross	161	144.78	146.96	149.16	151.39	153.67	155.98	158.32	160.69	163.11	165.55	168.04	170.56
	CDM		0.00	1.26	1.59	2.50	3.17	4.33	6.10	8.04	10.80	14.08	17.39	20.10
	DG		0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08
	Net		144.70	145.62	147.49	148.81	150.42	151.56	152.14	152.57	152.23	151.40	150.56	150.38
WNH MTS #3	Gross	77	56.29	57.42	58.57	59.74	60.93	62.15	63.39	64.66	65.95	67.27	68.62	69.99
	CDM		0.00	0.49	0.62	0.99	1.26	1.73	2.44	3.23	4.37	5.72	7.10	8.25
	DG		0.06	0.06	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15
	Net		56.23	56.87	57.80	58.61	59.53	60.28	60.81	61.28	61.44	61.41	61.37	61.60
Wolverton DS	Gross	54	18.42	18.73	19.05	19.19	19.35	19.47	19.59	19.71	19.83	19.98	20.12	20.25
	CDM		0.00	0.16	0.20	0.32	0.40	0.54	0.75	0.99	1.31	1.70	2.08	2.39
	DG		0.00	0.00	0.00	0.00	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19
	Net		18.41	18.57	18.84	18.87	18.76	18.74	18.64	18.53	18.33	18.08	17.84	17.67
CTS	Net		9.80	9.80	9.80	9.80	9.80	9.80	9.80	9.80	9.80	9.80	9.80	9.80

Appendix B: Lists of Step-Down Transformer Stations

Sr. No.	Transformer Stations
1.	Arlen MTS
2.	Campbell TS (T1/T2)
3.	Campbell TS (T3/T4)
4.	Cedar TS (T1/T2)
5.	Cedar TS (T7/T8)
6.	Elmira TS
7.	Energy+ MTS #1
8.	Fergus TS
9.	Galt TS
10.	Hanlon TS
11.	Kitchener MTS # 1
12.	Kitchener MTS # 3
13.	Kitchener MTS # 4
14.	Kitchener MTS #5
15.	Kitchener MTS #6
16.	Kitchener MTS #7
17.	Kitchener MTS #8
18.	Kitchener MTS #9
19.	Preston TS
20.	Puslinch DS
21.	Rush MTS
22.	Scheifele MTS
23.	Waterloo North MTS 3
24.	Wolverton DS
25.	CTS - 1
26.	CTS - 2

Appendix C: Lists of Transmission Circuits

Sr. No.	Circuit ID	From Station	To Station	Voltage (kV)
1.	D6V/ D7V	Detweiler TS	Orangeville TS	220
2.	M20D/ M21D	Detweiler TS	Middleport TS	220
3.	D4W/ D5W	Detweiler TS	Buchanan TS	220
4.	B22D/ B23D	Detweiler TS	Bruce TS	220
5.	D7F/ D9F	Detweiler TS	Free Port SS	115
6.	F11C/ F12C	Free Port SS	Cedar TS	115
7.	B5C/ B6C	Cedar TS	Burlington TS	115
8.	D11K/ D12K	Detweiler TS	Kitchener MTS #4	115
9.	D8S	Detweiler TS	St. Mary TS	115
10.	D10H	Detweiler TS	Hanover TS	115

Appendix D: Lists of LDCs in the KWCG Region

Sr. No.	Company	Connection Type (TX/DX)
1.	Centre Wellington Hydro	Dx
2.	Energy+	Tx/ Dx
3.	Guelph Hydro Electric System Inc.	Tx/ Dx
4.	Halton Hills Hydro	Dx
5.	Hydro One Networks Inc. (Distribution)	Tx/ Dx
6.	Kitchener Wilmot Hydro Inc.	Tx
7.	Milton Hydro	Dx
8.	Waterloo North Hydro Inc.	Tx/ Dx
9.	Wellington North Power Inc.	Dx

Appendix E: Acronyms

Acronym	Description
A	Ampere
BES	Bulk Electric System
BPS	Bulk Power System
CDM	Conservation and Demand Management
CIA	Customer Impact Assessment
CGS	Customer Generating Station
CSS	Customer Switching Station
CTS	Customer Transformer Station
DESN	Dual Element Spot Network
DG	Distributed Generation
DS	Distribution Station
GS	Generating Station
HV	High Voltage
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	Kilovolt
LDC	Local Distribution Company
LP	Local Plan
LTE	Long Term Emergency
LTR	Limited Time Rating
LV	Low Voltage
MTS	Municipal Transformer Station
MW	Megawatt
MVA	Mega Volt-Ampere
MVAR	Mega Volt-Ampere Reactive
NA	Needs Assessment
NERC	North American Electric Reliability Corporation
NGS	Nuclear Generating Station
NPCC	Northeast Power Coordinating Council Inc.
NUG	Non-Utility Generator
OEB	Ontario Energy Board
OPA	Ontario Power Authority
ORTAC	Ontario Resource and Transmission Assessment Criteria
PF	Power Factor
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Plan
SA	Scoping Assessment
SIA	System Impact Assessment
SPS	Special Protection Scheme
SS	Switching Station
STG	Steam Turbine Generator
TS	Transformer Station

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Appendix D:
INNOVATIVE Customer Survey Reports

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CUSTOMER ENGAGEMENT REPORT

Cost of Service Rate Application

December 14, 2018

Prepared for:

Kitchener-Wilmot Hydro Inc.

301 Victoria St S

Kitchener, ON N2G 4L2

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Customer Engagement

Cost of Service Rate Application

December 14, 2018

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Confidentiality

This Report and all of the information and data contained within it may not be released, shared or otherwise disclosed to any other party, without the prior, written consent of Kitchener-Wilmot Hydro Inc. (KW Hydro).

Acknowledgement

This report has been prepared by Innovative Research Group Inc. (INNOVATIVE) for KW Hydro. The conclusions drawn and opinions expressed are those of the authors.

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1. Customer Engagement Executive Summary

Customer Needs

There does not appear to be a gap between the services that KW Hydro are currently providing, and the services that customers expect. There is, however, an opportunity for KW Hydro to improve its role as a business partner amongst larger business customers.

Outcome Preferences

Distribution rates are the top priority for low-volume customers, and an important priority for larger business customers. That said, ensuring reliable day-to-day electrical service remains an important priority, especially for business customers who are negatively impacted by outages and power quality issues.

Reliability Preferences

Low-volume customers are consistent on priorities related to reliability – reducing the number and length of outages, and improving restoration times during extreme weather. Mid-market and large business customers appear to prioritize reliability over price, with a focus on power quality and communications during outages in order to assist with operational planning.

Capital Plan Priorities

Low-volume customers are strongly supportive of accelerating the speed in which poles and power transformers are replaced, as well as the instillation of more automated switches and software. Mid-market and large business customers appear to more supportive of investments that directly improve services for their organization, rather than system-wide improvements.

The majority of low-volume customers support a basic CIS solution. As KW Hydro is generally seen to be meeting the needs of customers, there does not appear to be strong interest in additional customer service offerings, including the enhanced benefits of a new customer information system.

Assessment of KW Hydro's Proposed Plan

Overall, there is strong support for KW Hydro's proposed plan, or even one that exceeds current spending levels in order to improve service further. A larger proportion of residential customers feel that the utility should be spending more, rather than spending less. Small business customers are generally less supportive of a plan that spends beyond what's currently proposed, and more think that the utility should spend less compared to spend more.

Mid-market and large business customers generally trust KW Hydro, however, expect to understand how this plan specifically impacts them, especially provided they feel the rate impact is significant.

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2. Introduction

A key requirement for any rate application is active engagement between a utility and its customers. Under the *Renewed Regulatory Framework for Electricity Distributors* (RRFE), a utility must:

1. Engage customers in a meaningful, on-going process;
2. Engage customers in its planning process by identifying customer **priorities**, **needs** and **preferences**; and
3. Demonstrate that utility services will be provided in a manner that responds to identified customer **needs, preferences** and **expectations**.

Starting in February 2018, INNOVATIVE worked with Kitchener-Wilmot Hydro Inc. (KW Hydro) staff to design a multi-faceted customer engagement program to collect feedback from various customer classes across its service territory. Considering the various challenges of engaging a representative group of customers, INNOVATIVE developed a process built on six key principles.

1. Create open voluntary processes that allow anyone who wants to be heard an opportunity to express themselves (**Online workbook**).
2. Use random-sampling research elements to ensure a representative sample of customers are engaged in order to ensure the generalizability of the findings (**Telephone surveys**).
3. Provide customers with the context they require to make informed decisions that are articulated in transparent and accessible language.
4. Create an opportunity for customers to learn the basics of the distribution system so they can provide a more informed point of view.
5. Focus on fundamental value choices. Look for questions that ask people to choose between key outcomes rather than focus on the technical questions of how to reach those outcomes.
6. Give customers an opportunity to "colour outside the lines" through qualitative feedback. (**Focus groups and workshops**)

The table below summarizes the scope of the various customer engagement activities.

Customer Engagement Activity	Methodology	Customers Engaged
Low-volume focus groups	In-person	**14**
Mid-Market and Large Business Workshops	In-person	TBC
Low-volume online workbook	Online	**1,749**
Low-volume telephone surveys	Telephone	**715**
Total number of customers who participated in the engagement:		**2,478**

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3. Customer Engagement Overview

The OEB expects a utility's rate application to provide an overview of customer needs, preferences and expectations learned through the utility's customer engagement activities (Handbook to Utility Rate Applications, October 13, 2016, p. 12)

This section summarizes the various feedback gathered throughout KW Hydro's customer engagement in support of their Cost of Service Rate Application. *Detailed findings can be found in the attached customer engagement appendices.*

3.1.1 Customer Needs

Throughout the engagement, customers were asked **"needs questions"**, which focus on understanding the gap between the services and experience customers want, and the services and experience customers are receiving.

The first element of understanding customer needs is related to **overall satisfaction**.

Customer Engagement Activity	% Satisfied with KW Hydro
Low-volume online workbook	**84%**
Residential telephone survey	**88%**
Small business telephone survey	**81%**

When asked in the telephone survey how satisfied they are with the services provided by KW Hydro, between 81% and 88% of low-volume customers are either very or somewhat satisfied. Overall satisfaction is highest amongst residential customers in Wilmot Township (91%) and lowest amongst small business customers in Kitchener (80%).

Similarly, as seen in the qualitative workshop sessions amongst mid-market and large business customers, most are satisfied with the services offered and received from KW Hydro. That said, these larger business customers expect KW Hydro to be a business partner, offering more proactive communications when it comes to outages and cost-saving measures.

Furthermore, when asked whether there is anything in particular that KW Hydro can do to improve services, the majority of low-volume customers say either "nothing" or "reduced rates". About 1-in-4 low-volume customers say, "reduced rates", while a majority say either nothing, or don't know what could be improved.

For mid-market and large business customers, consumption analytics are important and drive many important business decisions. There is a general sense that KW Hydro should be involved in providing these analytics, however, only if they are providing measurable, accurate and timely information.

Overall, there does not appear to be a gap between the services that KW Hydro are currently providing, and the services that customers expect. There is, however, an opportunity for KW Hydro to improve its role as a business partner amongst larger business customers.

3.1.2 Customer Preferences

To better understand customer preferences, questions are asked that focus on customer views in three areas: outcomes the utility should focus on; priorities among those outcomes; and, trade-offs illustrated by choices on specific programs or the pacing of investments.

3.1.2.1 Customer Outcome Priorities

For low-volume customers, delivering electricity at reasonable distribution rates is the number one priority which they believe the utility should be focused on. This is the most important priority for 37% of residential customers and 42% of small business customers.

The majority of low-volume customers also believe that KW Hydro should be focusing on ensuring reliable day-to-day electrical service. This is the number one priority for 20% of both residential and small business customers.

The third most important outcome, as ranked by low-volume customers, is related to pursuing collaboration with other LDCs, in order to find efficiencies and reduce costs.

Beyond the seven priorities listed below, close to 70% of low-volume customers do not believe that there are any other priorities that KW Hydro should be focusing on.

1. *Delivering electricity at reasonable distribution rates*
2. *Ensuring reliable day-to-day electrical service*
3. *Pursuing collaboration with other electricity distributors to find efficiencies and reduce costs*
4. *Preventing or reducing the length of power outages caused by extreme weather*
5. *Helping customers reduce and better manage their electricity consumption*
6. *Safely delivering electricity to homes and businesses*
7. *Providing new electrical services like electric vehicle charging stations*

For mid-market and large business customers, electricity rates can be a competitive advantage or disadvantage. While KW Hydro's rates are seen to be competitive, some customers are skeptical as to what services are being bypassed to keep rates low. For these customers, the impact of an outage or power quality fluctuations can be very costly. As such, despite a desire to focus on investment prudence, it appears that reliability remains a top priority for these customers.

Overall, distribution rates are the top priority for low-volume customers, and an important priority for larger business customers. That said, ensuring reliable day-to-day electrical service remains an important priority, especially for business customers who are negatively impacted by outages and power quality issues.

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3.1.2.2 Customer Reliability Priorities

With regards to system reliability priorities, low-volume customers rank "reducing extreme weather restoration times", the overall "number of outages" and the "length of outages" as their top three priorities. In terms of total priority, extreme weather restoration times is the top priority for residential customers (55%), while reducing the overall length of outages is number one for small business customers (51%).

That said, reducing the overall number of outages is the top priority for a plurality of low-volume customers – 26% of residential and 23% of small business customers.

For mid-market and large business customers, outages and power quality issues can be significant, both in terms of lost productivity and potential equipment failure or damage. Proactive communications during outages is seen to be an important priority for larger business customers, as it allows them to prepare and make important operational decisions.

Overall, low-volume customers are consistent on priorities related to reliability – reducing the number and length of outages, and improving restoration times during extreme weather. Mid-market and large business customers appear to prioritize reliability over price, with a focus on power quality and communications during outages in order to assist with operational planning.

3.1.3 Planning Principles and Approach to Pacing Investments

Based on initial and ongoing customer feedback, legal and regulatory obligations, and internal business planning, KW Hydro developed a plan with three core aims: to improve reliability and customer service; to implement a new customer information system; and to ensure new customers are accommodated.

This approach was explained to customers throughout the customer engagement, along with proposed rate impacts which totaled **$2.36** for residential customers and **$11.01** for small business customers over the course of the proposed 5-year plan.

In the telephone surveys, when asked if this was seen to be the right approach, 68% of residential customers agreed, while a plurality (37%) of small business customers felt the same. One-in-three small business customers feel that they don't know whether KW Hydro's proposed approach is the right approach to planning for the next five years, and 29% do not support the proposed approach.

With regards to planning, mid-market and large business customers generally trust KW Hydro. Many of these customers feel that the utility is an expert in the field, and trust them to make prudence investments decisions, especially given the utility's track record as a cost-effective utility.

In terms of KW Hydro's approach to pacing investments, the majority of low-volume customers believe that the utility should keeping spending levels consistent year-over-year, even if that means deferring investments to other years, in order to lessen the impact of any bill increase. This preferred approach to pacing investments is most strongly held by residential customers who are LEAP qualified, as well as small businesses who's bottom line is significantly impacted by their electricity bill.

Overall, residential and small business customers are generally split on KW Hydro's approach to planning for the next five years, however, are consistent in supporting the utility's approach to pacing investments, including keeping spending consistent year-over-year to lessen bill impacts.

3.1.4 Capital Plan Priorities

Another element in understanding customer preferences is in relation to trade-offs, as illustrated by choices regarding specific programs and the pacing of investments.

Throughout KW Hydro's initial planning, the utility identified four areas where it could accelerate investments. A significant portion of this customer engagement focused on soliciting feedback on these investments, and whether customers valued them – acknowledging that there is a tradeoff between customer costs and the value delivered by these specific investments.

Overall, when it comes to capital plan priorities and a willingness or desire to spend beyond what is currently being proposed, opinions differ somewhat based on rate class. In general, residential customers are more supportive of an approach that spends beyond what is currently being proposed than small business customers.

That said, a majority of customers in both rate classes support a capital investment approach that either sticks to what is currently being proposed or accelerates investment at an incremental rate increase.

Unlike low-volume customers, many mid-market and large business customers want to understand how specific investments and grid upgrades will impact their organizations' service, especially power quality and reliability. It's less about stewardship of the electricity grid, and more about individual value.

Overall, low-volume customers are strongly supportive of accelerating the speed in which poles and power transformers are replaced, as well as the instillation of more automated switches and software. Mid-market and large business customers appear to be more supportive of investments that directly improve services for their organization, rather than system-wide improvements.

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3.1.4.1 System Renewal | KW Hydro's Pole Replacement Program

Half (50%) of residential customers are willing to pay an additional $0.12 per month annually so KW Hydro can accelerate its pole replacement plan and replace 1,500 more at-risk poles by 2024. Among these customers, this sentiment is strongest amongst those whose electricity bill has no impact on their personal finances, while strongest opposition comes from those whose finances are significantly impacted. Two-in-ten (19%) residential customers who are LEAP qualified feel that KW should slow its pace of pole replacement in order to lower rate impacts.

Customer Engagement Activity	% who support proposed approach to pole replacement or accelerated approach
Low-volume online workbook	**84%**
Residential telephone survey	**81%**
Small business telephone survey	**75%**

Small business customers are generally split with regards to KW Hydro's pole replacement program. A plurality (40%) believe that the utility should stick with its proposed approach, while 35% would like to see this investment accelerated. As with residential customers, two-in-ten small business customers believe that KW Hydro should reduce spending. Support for either sticking with the proposed plan or accelerating investment is strongest amongst higher consumption small businesses.

Overall, support for investments in KW Hydro's pole replacement program are strong, especially amongst residential customers, where a majority believe that the utility's investment pace should be accelerated. Nevertheless, between 75% and 81% of low-volume customers support KW Hydro's current approach to pole replacement, or one that replaces 1,500 more at-risk poles by 2024.

3.1.4.2 System Renewal | KW Hydro's Power Transformer Replacement Program

The second system renewal investment discussed in the engagement was with regards to KW Hydro's power transformer replacement program.

Residential customers are divided on how they feel the utility should respond to pacing the replacement of two end-of-life power transformers. A plurality (43%) would like to see them replaced sooner, while 41% think KW Hydro should stick with its proposed replacement plan which would see the transformers replaced over the next five years. Residential customers in Kitchener (44%) are more likely to support an accelerated timeline, compared to those in Wilmot County (34%).

Customer Engagement Activity	% who support proposed approach to transformer replacement or accelerated approach
Low-volume online workbook	**87%**
Residential telephone survey	**84%**
Small business telephone survey	**79%**

Close to a majority of small business customers (49%) believe that the utility should stick with its proposed plan, while nearly one-in-three (31%) are willing to pay more to accelerate the pace of investment. Close to one-in-ten (14%) small business customers are willing to risk equipment failure in order to minimize bill impacts. Higher consumption businesses are more likely to support the power transformer replacement program as currently paced, or the accelerated option.

Overall, about eight-in-ten low-volume customers support KW Hydro's transformer replacement plan, with a plurality of small business customers favouring the current approach, and residential customers supporting an approach that would accelerate replacement by three years. Residential customers in Wilmot County are most supportive of these types of investments.

3.1.4.3 System Service | Spending on Automated Switches

In general, as gleaned from the online workbook, low-volume customers are split when to comes to investing in the benefits of grid modernization now vs. as part of normal system renewal. It appears that support for specific programs, including spending on automated switches, could exceed general support for grid modernization. When discussed generally, 46% of low-volume customers support KW Hydro's current approach to modernizing the grid as part of normal renewal and 45% support increased investment even if it costs more.

When looking at specific spending on automated switches, however, customer support becomes clearer.

Nearly an equal portion of residential customers (43% install more vs. 45% stick with current pace) are supportive of the utility's current plan, or one that spends more to increase the pace of

investment. This feedback was generally consistent within residential segments, including both in Kitchener and Wilmot County, as well as with lower income households.

Customer Engagement Activity	% who support proposed approach to spending on automated switches accelerated approach
Low-volume online workbook	**89%**
Residential telephone survey	**88%**
Small business telephone survey	**84%**

As consistent with the other investments discussed throughout the engagement, small business customers are generally less supportive of any approach that goes beyond what is currently being proposed. That said, more than half are supportive of the current pace of spending on automated switches, and close to one-in-three are willing to pay more to accelerate investments. Again, higher consumption businesses are most supportive of an accelerated approach.

Overall, when not tied to specific program benefits, low-volume customers are split on investments in grid modernization. In the context of reducing outage lengths through automated switches, low-volume customers are supportive of the utility's proposed approach, and in many cases, one that focuses on spending more.

3.1.4.4 General Plant | KW Hydro's Customer Information System (CIS)

The final specific program discussed in the customer engagement was in relation to KW Hydro's Customer Information System (CIS). In both the telephone surveys and online workbook, customers were provided the context that the utility's 30+ year old CIS is beyond its useful life and requires replacement. Customers in both cases were presented with two options – a basic CIS or an advanced CIS.

As explained, the basic solution provides the features needed to ensure that customers continue to receive a bill on time. The enhanced solution provides more features, including text or email alerts and a self-service customer portal.

In both the online workbook and telephone surveys, the majority of low-volume customers support a basic CIS solution. In the telephone surveys, 70% of residential and 75% of small business customers supported the basic CIS solution with minimal additional features. As such, there does not appear to be a strong appetite amongst low-volume customers for an enhanced solution and the associated benefits if it means an increase to bills.

Customer Engagement Activity	% who selected basic CIS solution
Low-volume online workbook	**56%**
Residential telephone survey	**70%**
Small business telephone survey	**75%**

When discussed with mid-market and large business customers, opinions regarding the utility's CIS are generally split. Some saw the value of implementing the enhanced system now, recognizing that it could save future costs. Others felt that it would be most effective to move to the enhanced CIS more gradually, allowing utility staff the opportunity to become familiar with the software before committing to one with advanced functionality. That said, as previously mentioned, these customers generally trust the utility, but still expect them to be prudent with their spending and investment decisions.

In the online workbook, where there was additional bandwidth to ask questions, the engagement presented customers with a number of additional services offerings to gauge interest. These service offerings included:

- *Customer Portal*
- *Online Customer Service*
- *Extended Call Centre Hours*
- *Consumption Notification*
- *Detailed Electricity Use Information*
- *Interactive Voice Response (IVR)*

None of the additional service offerings received a majority of low-volume customer support. A customer portal, at a cost of between **$0.11 and $0.58** per month received the strongest support, with about one-in-three saying they would be willing to pay for this service offering. As such, it appears that there is little appetite for new customer service offerings if they will increase customer bills beyond what is currently being proposed.

Overall, the majority of low-volume customers support a basic CIS solution. As KW Hydro is generally seen to be meeting the needs of customers, there does not appear to be strong interest in additional customer service offerings, including the enhanced benefits of a new customer information system.

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3.1.5 Assessment of KW Hydro's Proposed Plan

Upon weighing the details and information provided in both the online workbook and telephone surveys, low-volume customers were asked to assess KW Hydro's proposed plan.

More than three-in-four (77%) of residential customers support KW Hydro's current proposed plan, or one that improves services beyond current level. 26% of this figure accounts for those who support the accelerated approach; which is nearly twice as large as the proportion who believe the utility should be spending below the current plan (14%).

In fact, a further breakdown shows that LEAP qualified residential customers overwhelmingly support (75%) the current proposed plan or one that improves service, even if bills increase beyond the current proposed **$2.36**.

Residential LEAP Qualification	% who support current proposed plan or one that improves service
LEAP Qualified	**75%**
Not LEAP Qualified (*Household income **less** than $52,000)*	**76%**
Not LEAP Qualified (*Household income **more** than $52,000)*	**81%**

- A plurality (34%) of residential customers who say that KW Hydro should improve services say so because they feel service quality is essential and should be improved.
- Most residential customers who are opposed to the proposed plan feel that they don't want any increase, as electricity bills are already too high.

Consistent with findings throughout the engagement, small business customers are less supportive of a plan that exceeds the current proposed rate increase, yet 61% still believe the utility should to continue with its plan or spend beyond. That said, more than one-in-three (36%) small business customers believe that the utility should keep spending below the current proposed **$11.01** increase, even if that could mean a reduction in service. In fact, a majority of the lowest consumption small businesses believe that the utility should be spending below what it currently being proposed.

With small business customers, there is a direct correlation between support for the proposed plan, and the significance of strain the customers electricity bill presents.

Small Business Electricity Bill Impact on Finances	% who support current proposed plan or one that improves service
Significant Impact	**48%**
Impact	**68%**
No Impact	**84%**

- Small business customers who support the current proposed plan do so because they generally feel that it is the best plan, and do not want to pay beyond the currently proposed $11.01.
- Those small businesses who oppose the plan do so because they generally feel the increase is too much, they already pay too much, or the utility should find other ways to keep their own costs down through efficiencies.

Again, mid-market and large business customers generally trust KW Hydro to make prudent investments in the system. While there is a high level of trust, given the utility's track record as a cost-effective utility, prudence remains an important priority. Some customers in this group feel that the proposed rate increase and associated bill impacts are excessive and could negatively impact business competitiveness.

Overall, there is strong support for KW Hydro's proposed plan, or even one that exceeds current spending levels in order to improve service further. A larger proportion of residential customers feel that the utility should be spending more, rather than spending less. Small business customers are generally less supportive of a plan that spends beyond what's currently proposed, and more think that the utility should spend less compared to spend more.

Mid-market and large business customers generally trust KW Hydro, however, expect to understand how this plan specifically impacts them, especially provided they feel the rate impact is significant.

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4. About this Consultation

4.1.1 Customer Engagement Process Overview

Based on the engagement principles outlined in the introduction, INNOVATIVE worked with KW Hydro to design and execute a multi-faceted engagement program that aligns with both OEB expectations and provides meaningful input for the utility's business planning.

4.1.1.1 Pre-Consultation

The first phase of this program is known as **pre-consultation**, wherein INNOVATIVE and KW Hydro worked together to understand what was already known about customer needs and preferences, as well as how best to engage with these customers.

In this phase, INNOVATIVE worked closely with KW Hydro staff to understand the challenges which the system is facing, how the utility is planning to address those challenges and what value these plans will provide customers.

This pre-consultation included both a review of existing customer feedback and research, as well as structured interviews with various business departments of the utility, including customer service, engineering, communications and senior management.

4.1.1.2 Workbook Development

Based on the information gleaned from the pre-consultation phase, INNOVATIVE and KW Hydro staff worked to develop a workbook that was to be used throughout both the qualitative and quantitative phases of the customer engagement. In order to ensure that the workbook provided meaningful, balanced and comprehensive information, the workbook development phase included two feedback sessions: one workshop with OEB and intervenor stakeholders and another series of focus groups with low volume customers. Based on feedback from these two sessions, the workbook was edited to more closely align with customer and stakeholder recommendations.

- The **OEB and intervenor stakeholder workshop session** was held on July 17th, 2018 at the Ontario Energy Board. The purpose of this workshop was to present KW Hydro's proposed customer consultation process, share the draft workbook, solicit stakeholder feedback and answer any outstanding questions related to the engagement process.
- The **workbook testing focus groups** were completed amongst residential customers on July 18th, 2018. These groups were intended to gauge whether the draft workbooks provided an appropriate amount and substance of information, in order to enable customers to provide an informed opinion of KW Hydro's proposed plan.

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4.1.1.3 Customer Engagement

The core of KW Hydro's customer engagement encompassed five elements, covering every type of customer across the service territory – from residential to large business.

Customer Engagement Activity	Customers Engaged	Timeframe (2018)
Low-volume focus groups	**14**	**Sep. 19**
Mid-market and large business workshops	TBC	**Sep. 20**
Low-volume online workbook	**1,749**	**Oct. 10 – Nov. 11**
Low-volume telephone surveys	**715**	**Oct. 31 – Nov. 14**

1. The **low-volume focus groups** provided customers an opportunity to "colour outside the lines" through qualitative feedback. This qualitative phase of the customer engagement was designed to provide customers with some education about KW Hydro's distribution system, and then to gather their feedback on KW Hydro's proposed investment and spending plan going forward. The focus groups were formatted around the themes in the customer engagement workbook, and were led by a professional moderator. The feedback gleaned from these focus groups helped inform the subsequent phases of the customer engagement, including the online workbook and telephone surveys.
2. The **mid-market and large business workshops** provided a unique opportunity to directly engage with larger business customers in small groups, to better understand their needs and preferences as they relate generally to KW Hydro, as well as the current proposed plan. The workshops were structured in two phases; the first portion was a presentation from KW Hydro's senior management, followed by smaller breakout sessions led by INNOVATIVE staff. This format allowed customers to both ask questions directly of KW Hydro staff, as well as provide anonymous feedback on the utility and their proposed plans.
3. The **low-volume online workbook** created an open, voluntary process that allowed any low-volume KW Hydro customer who wanted to be heard an opportunity to express themselves. This online workbook, which was based on the earlier developed workbook, was accessible for one month (between October 10th and November 11th, 2018), and allowed the opportunity to provide customers with an interactive platform to both educate and allow for them to provide detailed feedback on a wide-range of topics, focusing on KW Hydro's proposed plans. KW Hydro effectively promoted the online workbook using a comprehensive approach, which resulted in **1,749** unique respondents. Feedback gleaned from the online workbook helped inform the design of the telephone surveys
4. The **low-volume telephone surveys** used a random-sampling approach to ensure a representative sample of KW Hydro customers were engaged ensuring the generalizability of the findings. The telephone surveys followed a stratified random sampling methodology. This is a method of sampling that involves the division of a "population" (in this case, the entire KW Hydro customer base) into smaller groups known as strata. In stratified random sampling, the

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strata are formed based on members' shared attributes or characteristics (in this case: customer class, region, and electricity usage). A random sample from each stratum is taken in a number proportional to the stratum's size when compared to the customer population. These subsets of the strata are then pooled to form a random sample. **This phase of the engagement provided low-volume customers the "final say" on the topics discussed with thousands of customers over the course of the consultation.**

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Kitchener-Wilmot Hydro 2018 Customer Engagement

Online Workbook Report

Low-Volume Report

NOVEMBER 2018

STRICTLY PRIVILEGED AND CONFIDENTIAL

Online Workbook Methodology

Kitchener-Wilmot Hydro (KW Hydro) commissioned INNOVATIVE to develop an online workbook to provide all customers an opportunity to learn more about KW Hydro and provide an opportunity to tell KW Hydro how best they can serve them moving forward. Also, to gather and incorporate feedback to ensure decisions are aligned with customers' priorities, preferences, and needs.

Field Dates & Completes

The online workbook was accessible to KW Hydro customers from **October 10 to November 11 2018**.

	Residential	Small Business	Total
Kitchener	1,562	22	**1,584**
Wilmot Township	162	3	**165**
Total	**1,724**	**25**	**1,749**

Promoting the Online Workbook

Promoting the online workbook included a comprehensive approach, including:

- A media release
- Customer website and customer portal links
- Email news letters to 25,506 customers
- Newspaper ads in all local newspapers
- Social media posts

Publishing the Online Workbook

INNOVATIVE hosted the online portal at the following URL: *KWHydroSurvey.ca*

The website prevented customers from completing questions repeatedly and saved their progress as they answered each question. Upon completion, the site was no longer accessible at the web address given.

Validating Consumer Responses

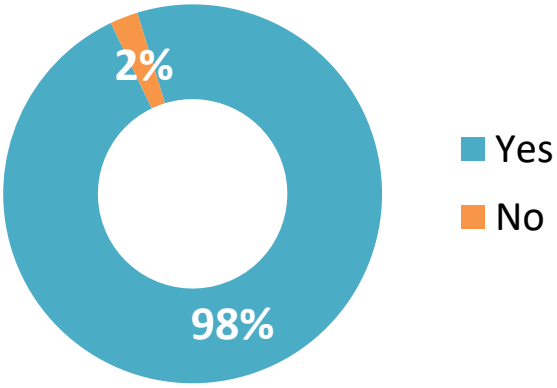
Customers who filled out the online workbook were tagged with an identification number based on their postal code and their response as a residential or business customer. Postal codes were checked against lists provided by KW Hydro for validity and those deemed invalid were removed from the final sample.

Graphs and tables may not always total 100% due to rounding values rather than any error in data. Sums are added before rounding numbers. Caution interpreting results with small n-sizes.

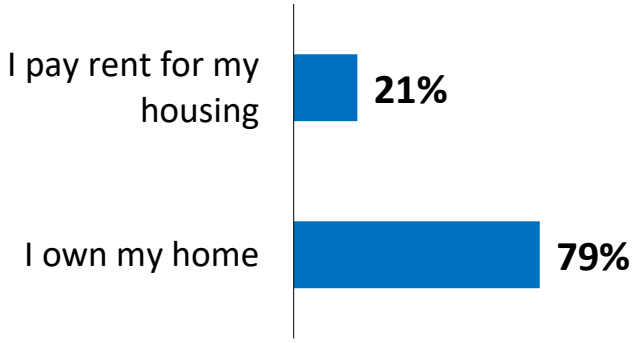
Residential Customers

Segmentation & Demographics

Responsible for Paying Electricity Bill

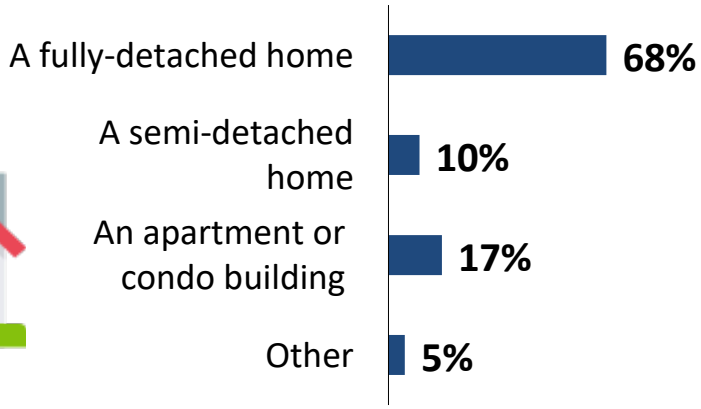


Living Situation

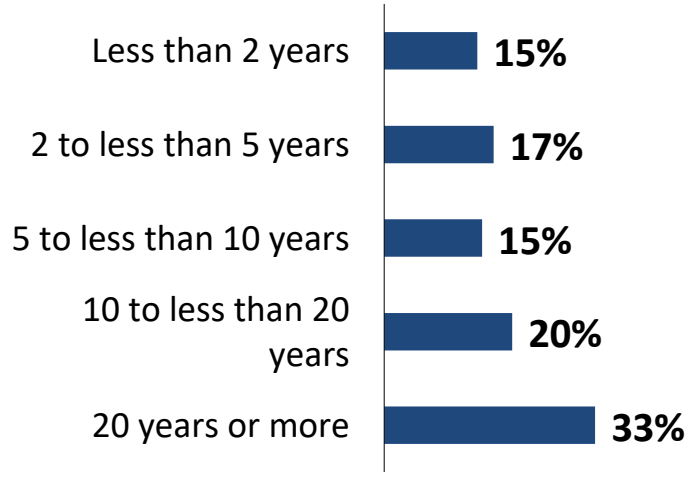


Primary Residence





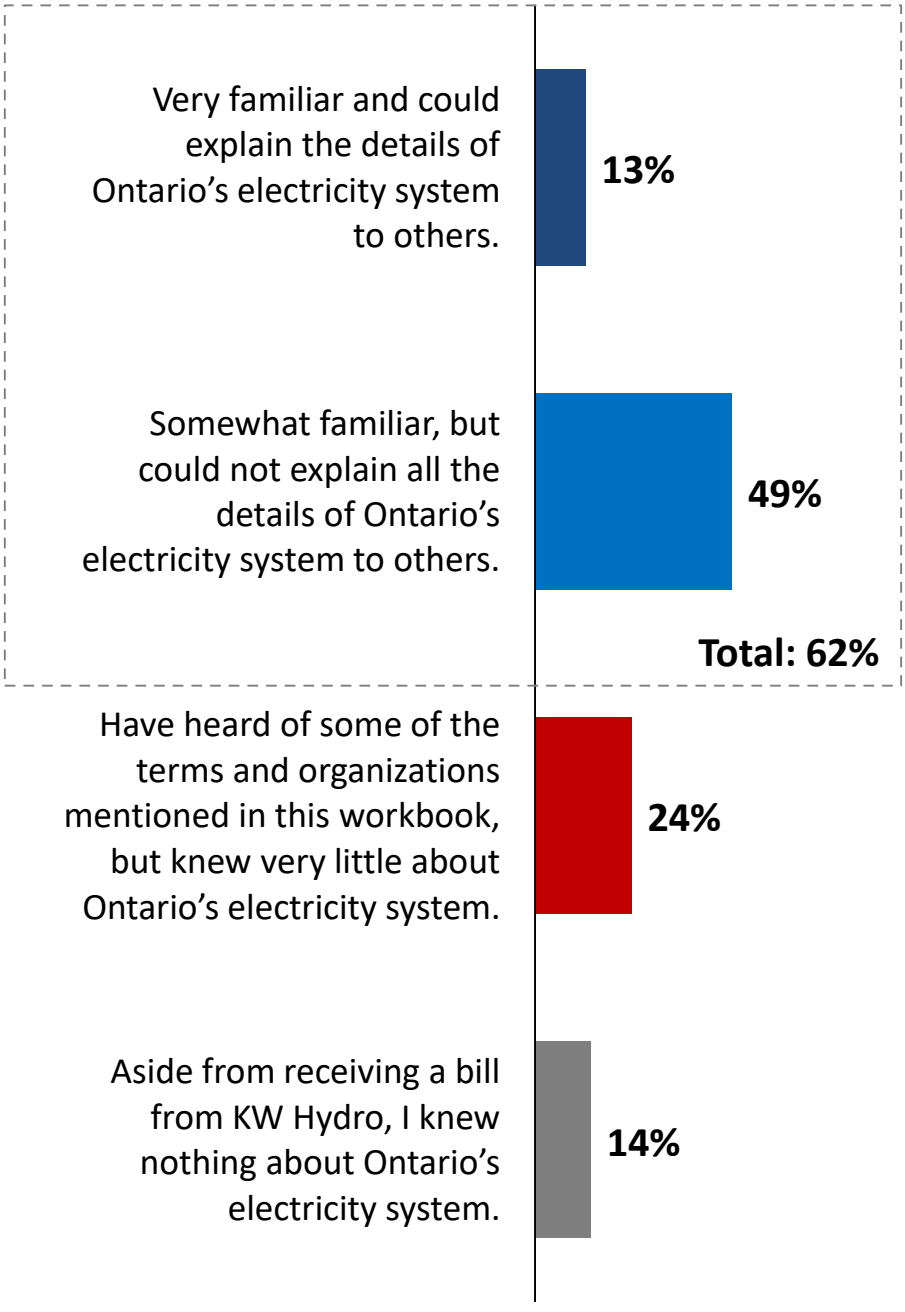
Years as a KW Hydro Customer

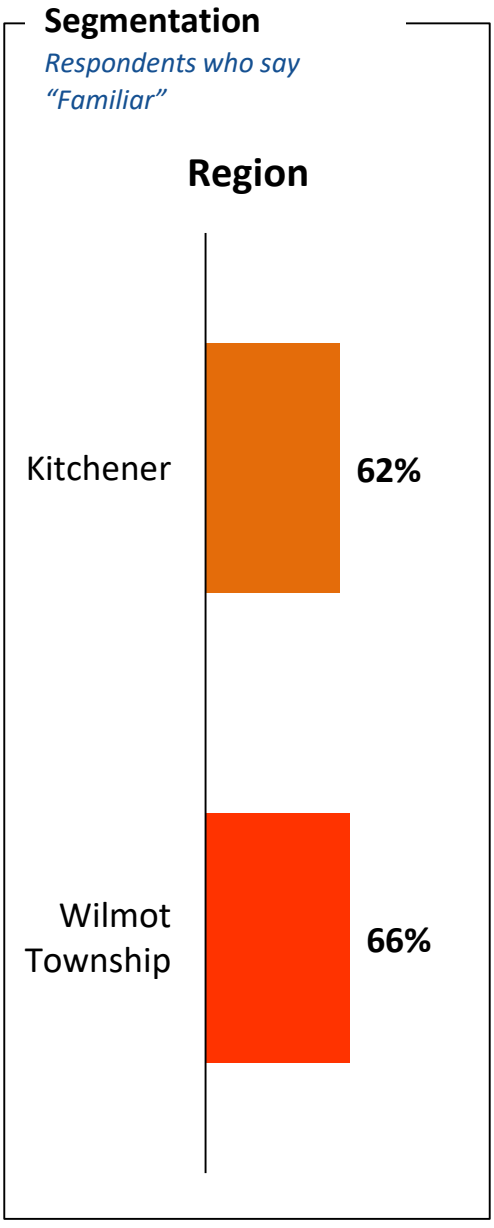


Familiarity with Electricity System

Q Before this consultation, how familiar were you with the various parts of the electricity system and how they work together?

[asked all respondents, n=1,749]





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Satisfaction Preamble



“

KW Hydro operates and maintains the local electricity distribution system, delivers electricity throughout the community, reads meters, calculates and collects customer electricity bills, answers customer calls, responds during outages, clears trees from power lines and delivers electricity conservation programs.

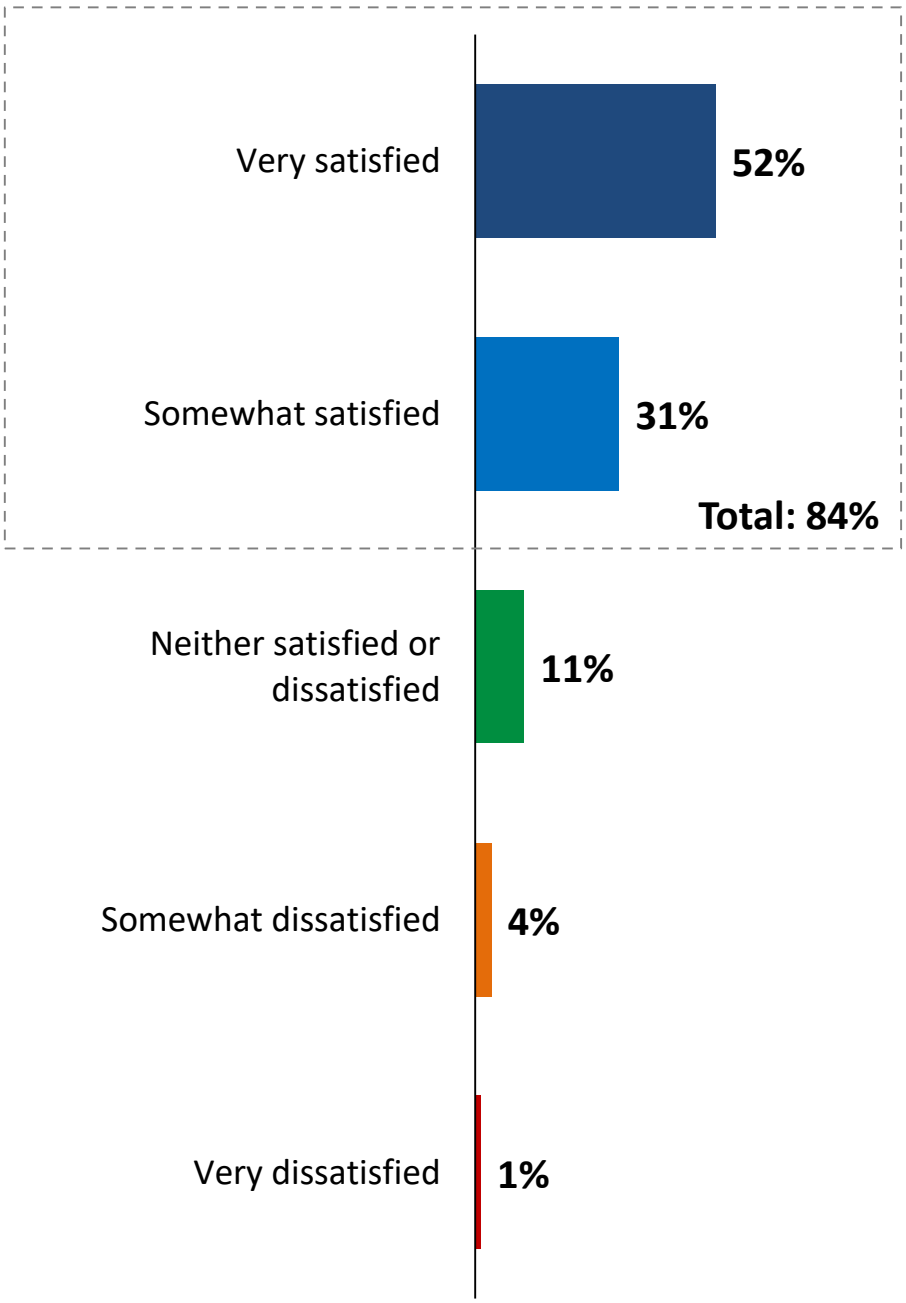
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Satisfaction with Services

Q Generally, how satisfied or dissatisfied are you with the services you receive [your organization receives] from **KW Hydro**?

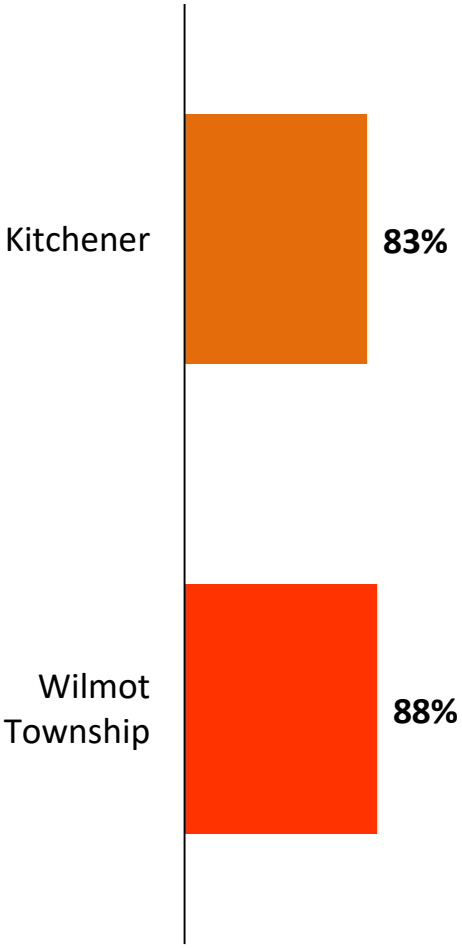
[asked all respondents, n=1,749]



Segmentation

Respondents who say "Satisfied"

Region

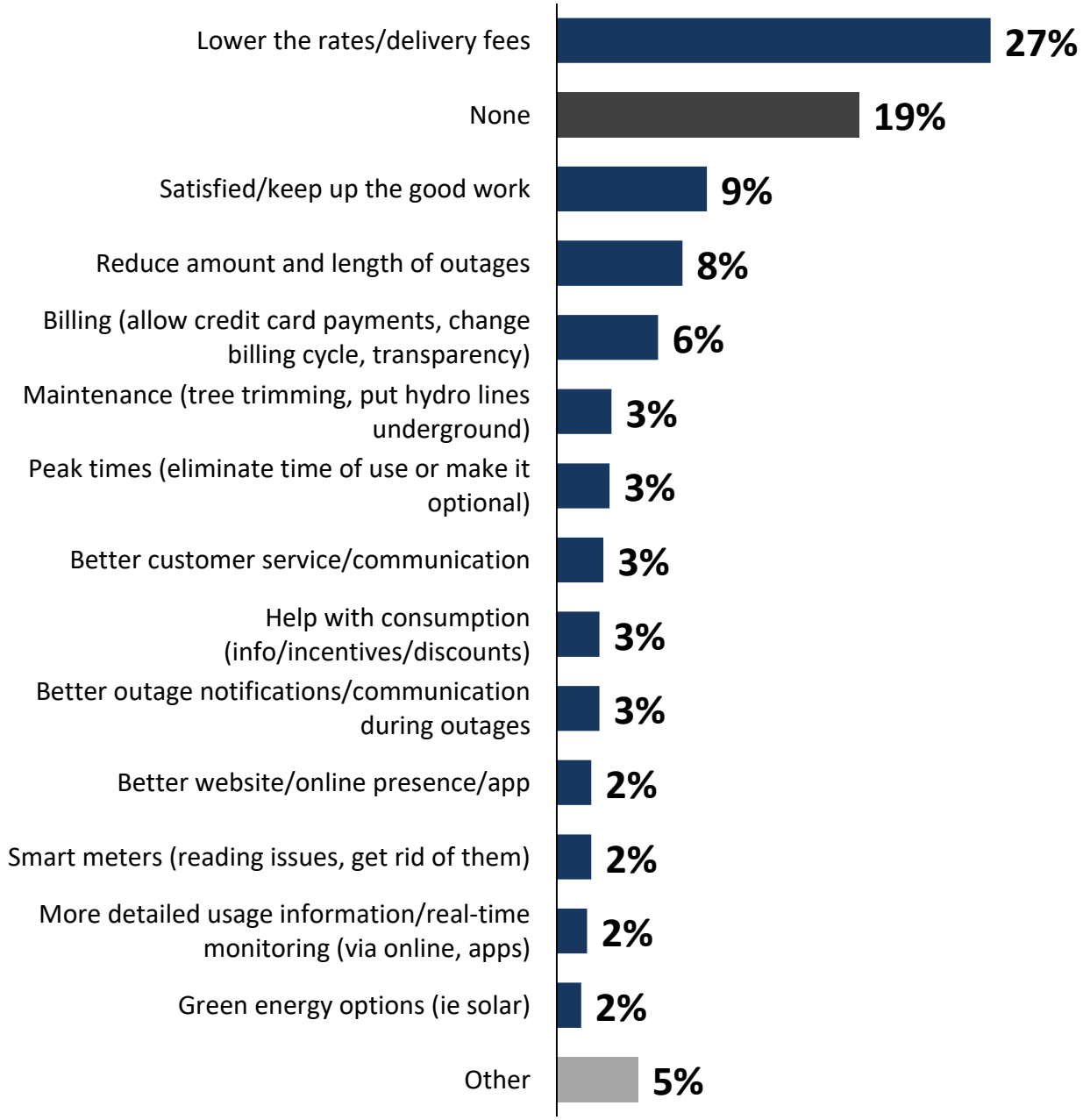


Note: 'Don't Know' (1%) not shown.

Suggestions for Improved Services

Q Is there anything in particular that KW Hydro can do to improve its services to you [your organization]?

[OPEN; asked all respondents (Optional), n=795]

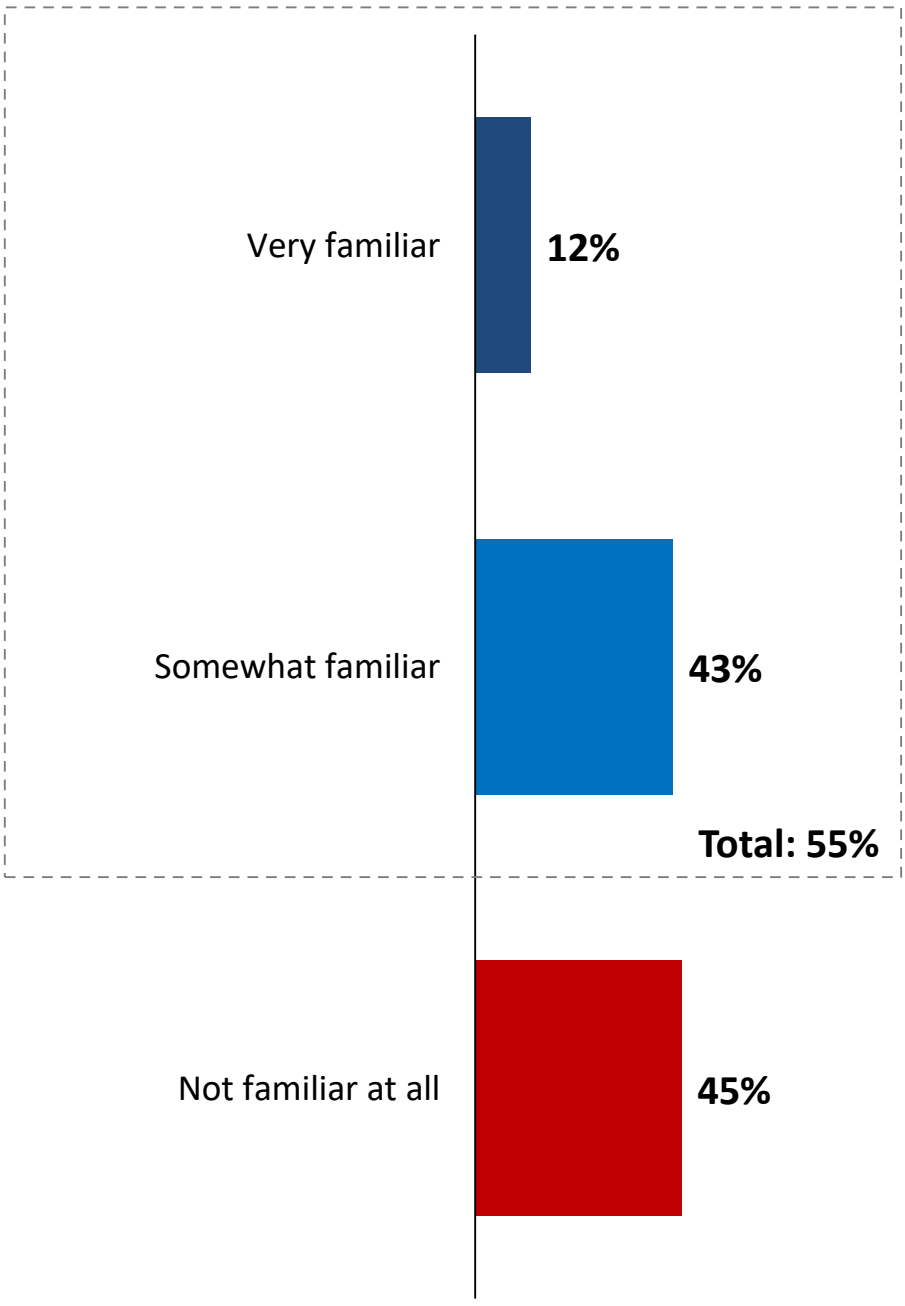


Note: 'Don't Know' (1%) and 'Refused' (3%) not shown.

Bill Knowledge

Q Before this consultation, how familiar were you with the percentage of your [organization's] electricity bill that is retained by **KW Hydro**?

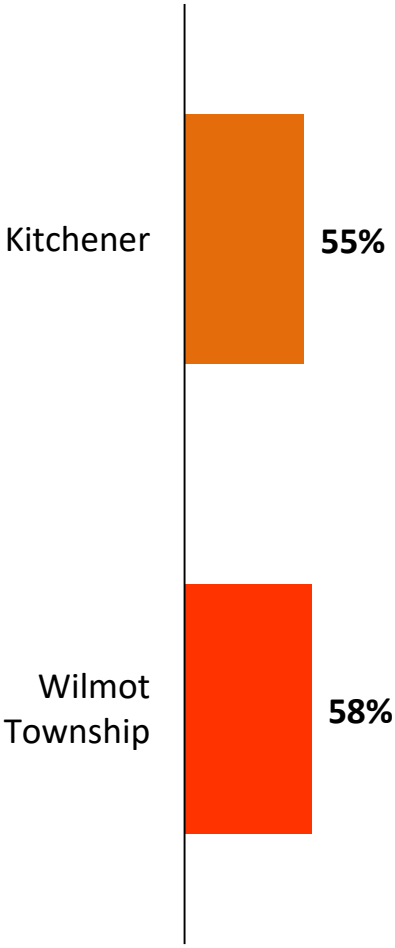
[asked all respondents, n=1,749]



Segmentation

Respondents who say "Familiar"

Region

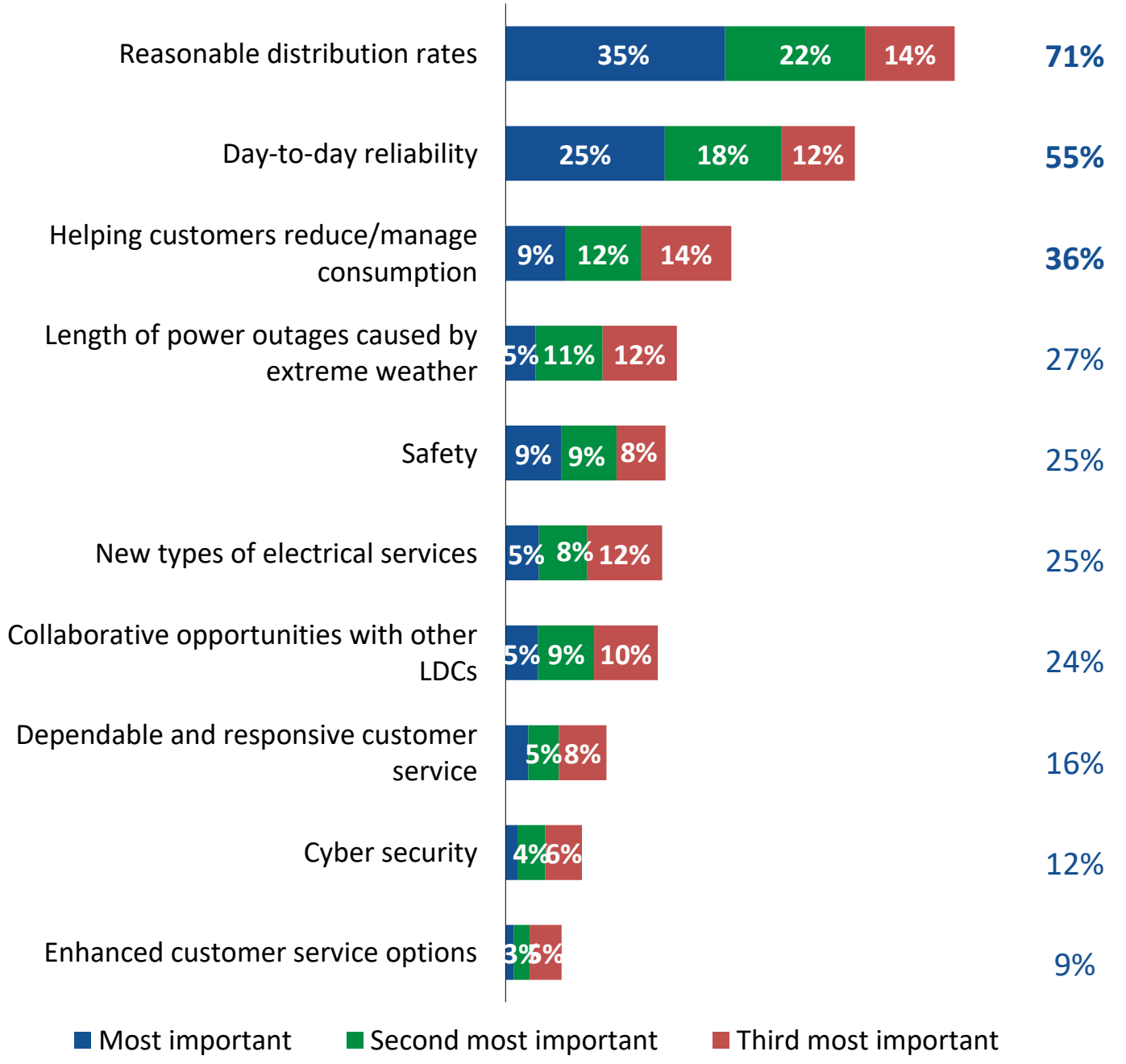


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Customer Priorities

Q While all of these priorities may be important to you, please rank your top 3 priorities – where "1" would be most important, "2" the second most important, "3" the third most important.

[asked all respondents, n=1,749]

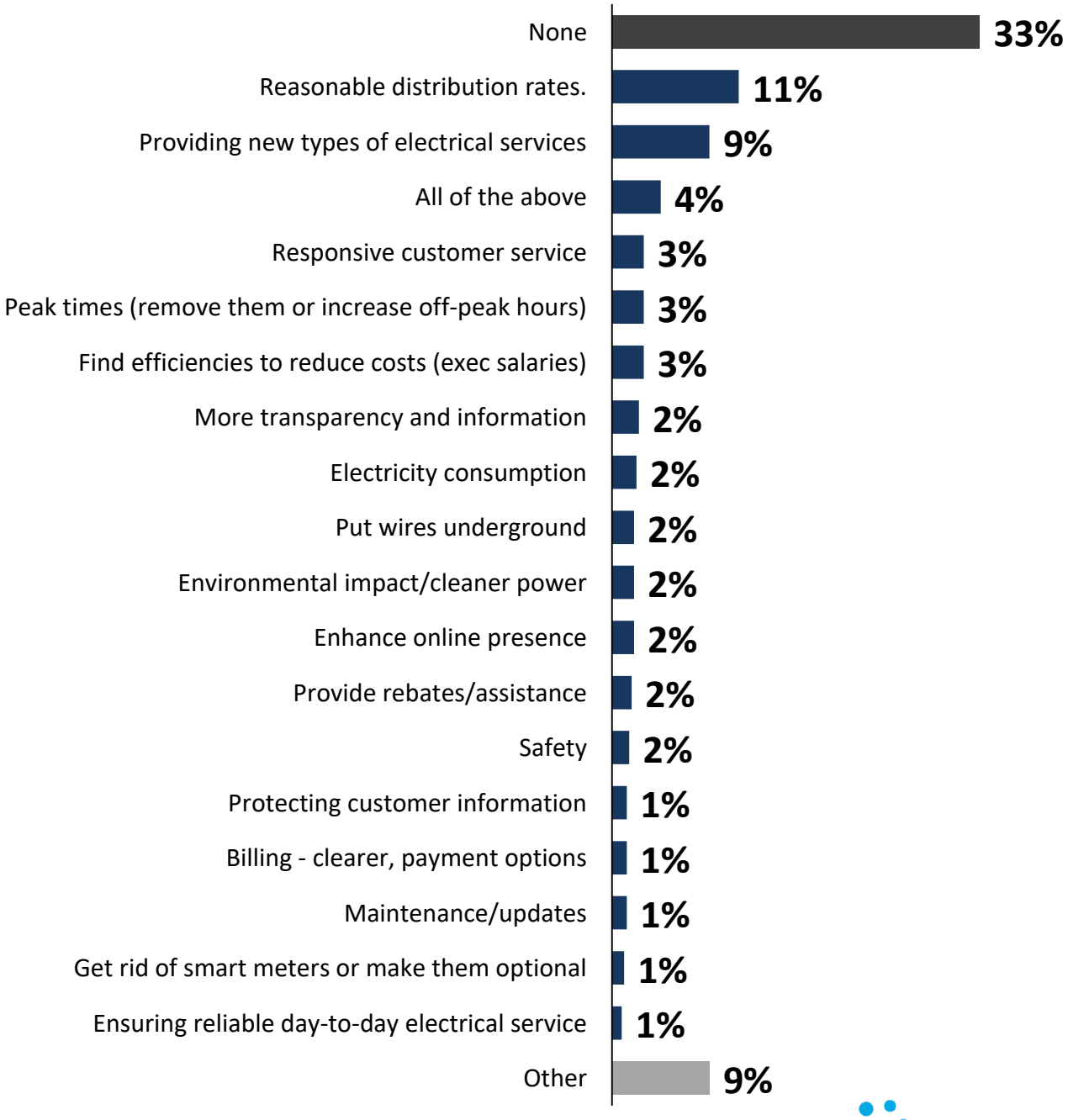


Note: Options have been abbreviated. See **Appendix XX** for complete list of options presented in the online workbook.

Additional Customer Priorities

Q Are there any other important priorities that **KW Hydro** should be focusing on, not mentioned above?

[OPEN; asked all respondents (Optional), n=460]



Note: 'Don't Know' (6%) and 'Refused' (5%) not shown.

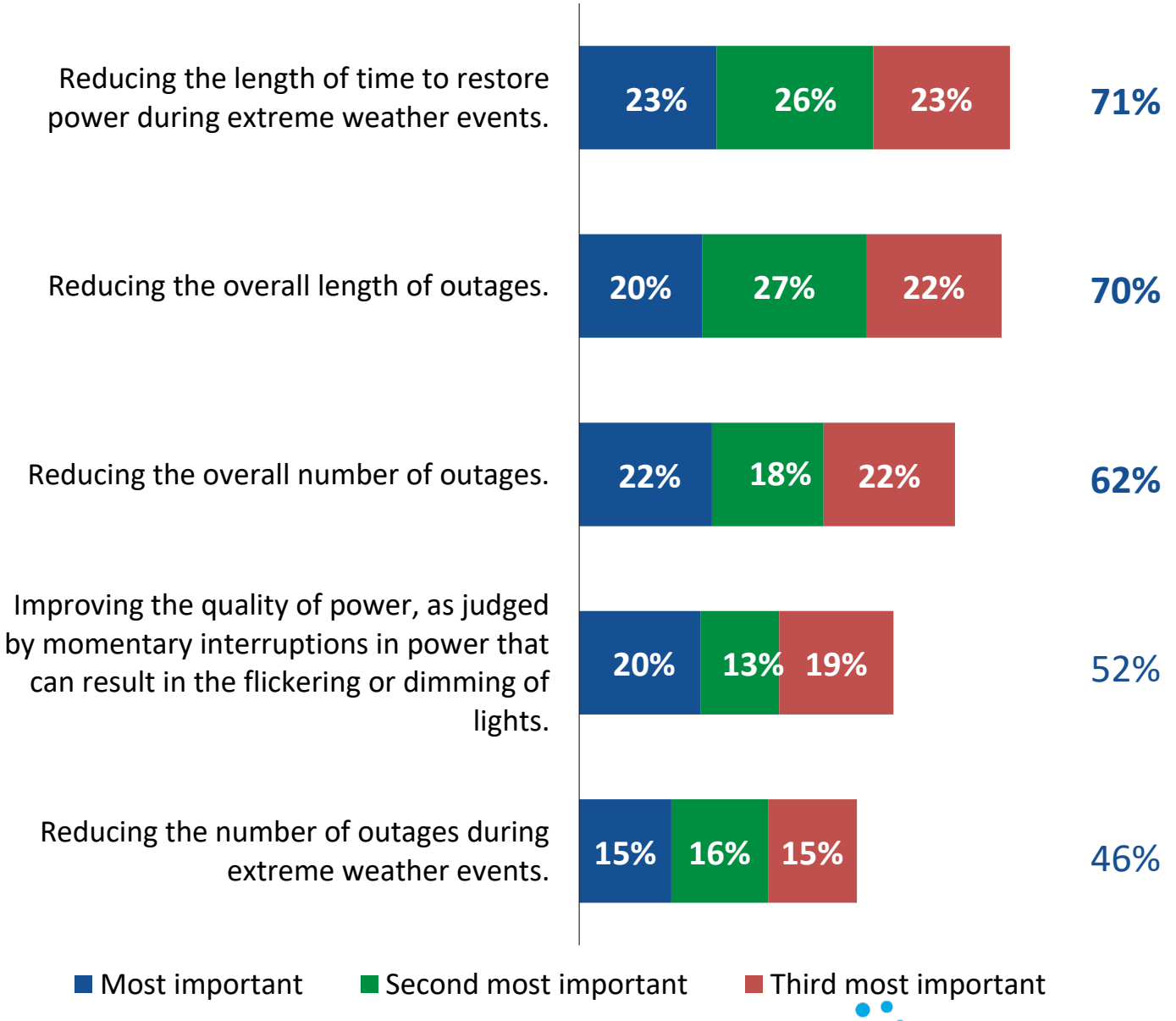
System Reliability Priorities

Q

Among the following reliability outcomes, which are most important to you?

While all of these priorities may be important to you, please rank your top 3 priorities – where "1" would be most important, "2" the second most important, "3" the third most important.

[asked all respondents, n=1,749]



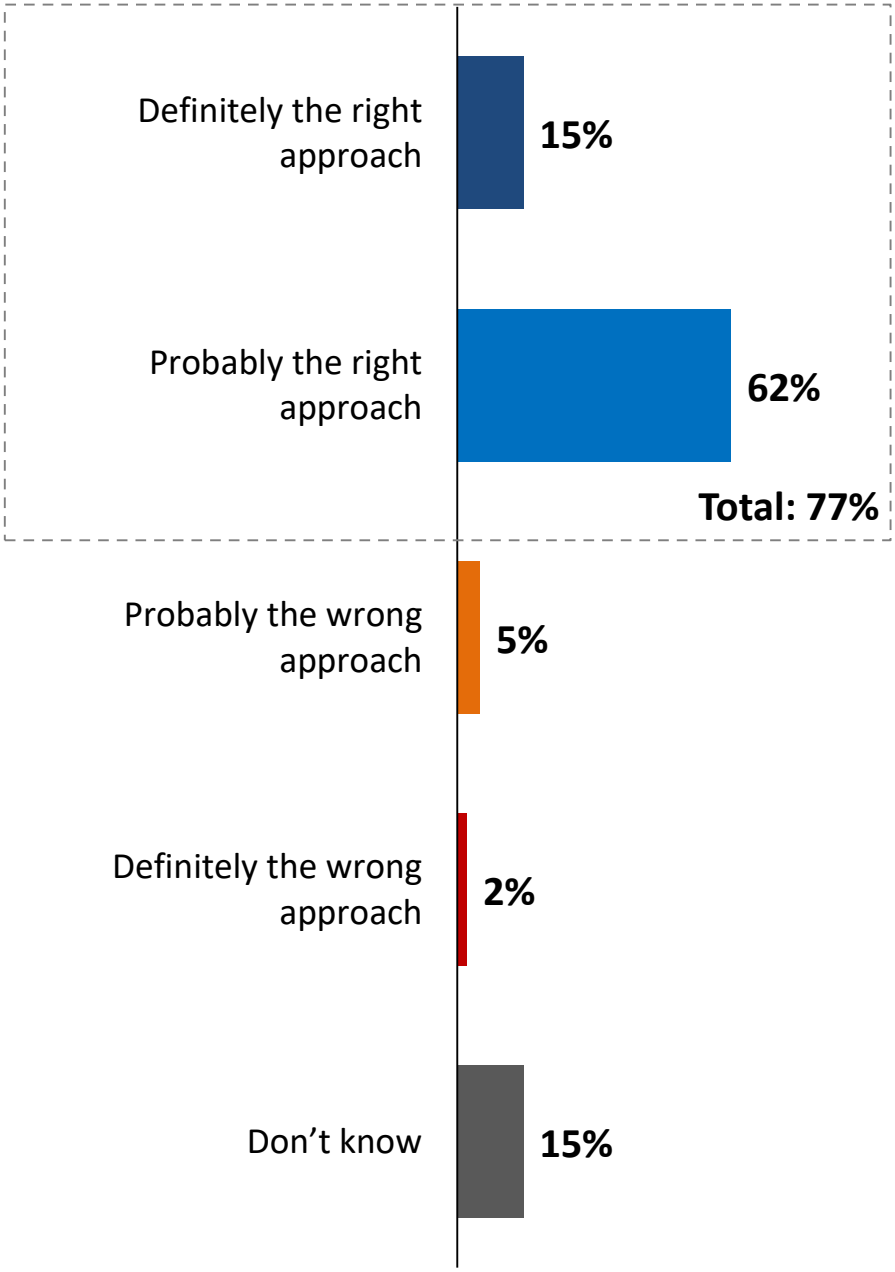
Proposed Operating Budget

Q

This workbook leaves detailed discussion of **KW Hydro's** operating budget to experts from the OEB and intervenors in the formal rate application review; the workbook focuses on collecting your view on competing trade-offs in capital investments.

Does this seem like the right approach or the wrong approach to you?

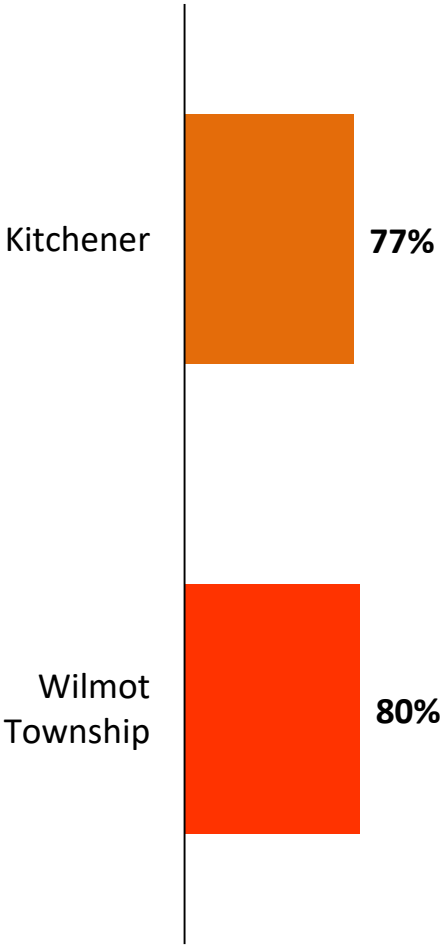
[asked all respondents, n=1,749]



Segmentation

Respondents who say "Right Approach"

Region

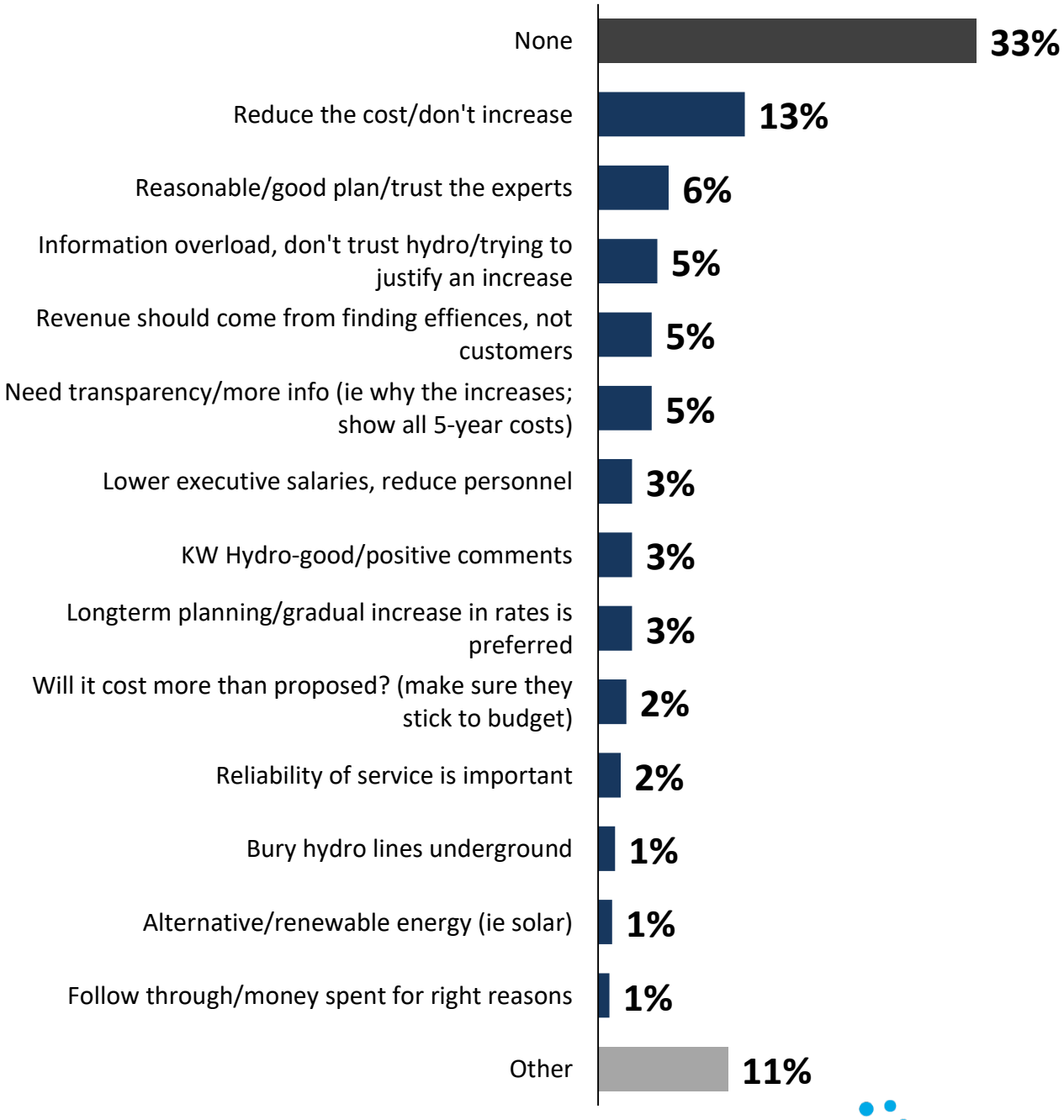


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Additional Feedback on Approach to Operating Budget

Q Is there is anything in particular you would change about this approach or any other comments you would like to make?

[OPEN; asked all respondents (Optional), n=407]



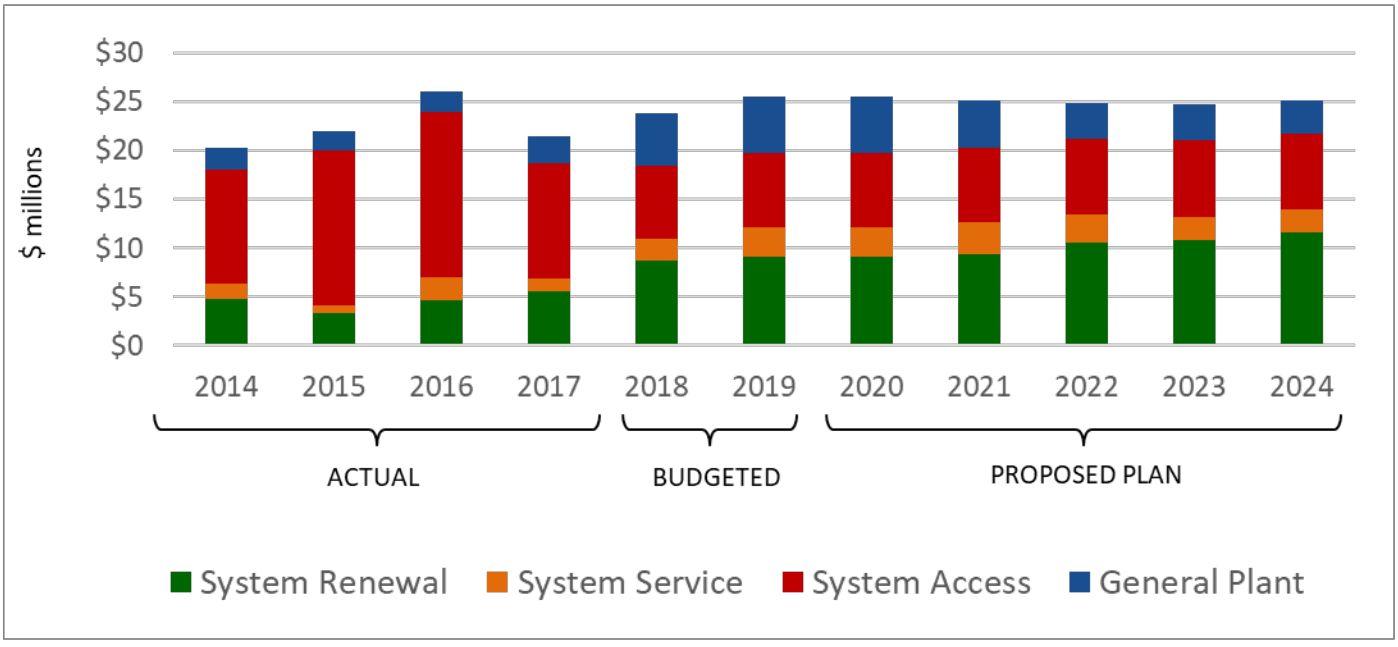
Note: 'Don't Know' (5%) and 'Refused' (4%) not shown.

Pacing Investments Preamble

Pacing Investments

The overall amount KW Hydro invests in capital projects remains generally the same year over year, but what does change is where these investments are made. KW Hydro carefully paces spending to ensure it stays as consistent as possible so the impact to customer rates is minimal.

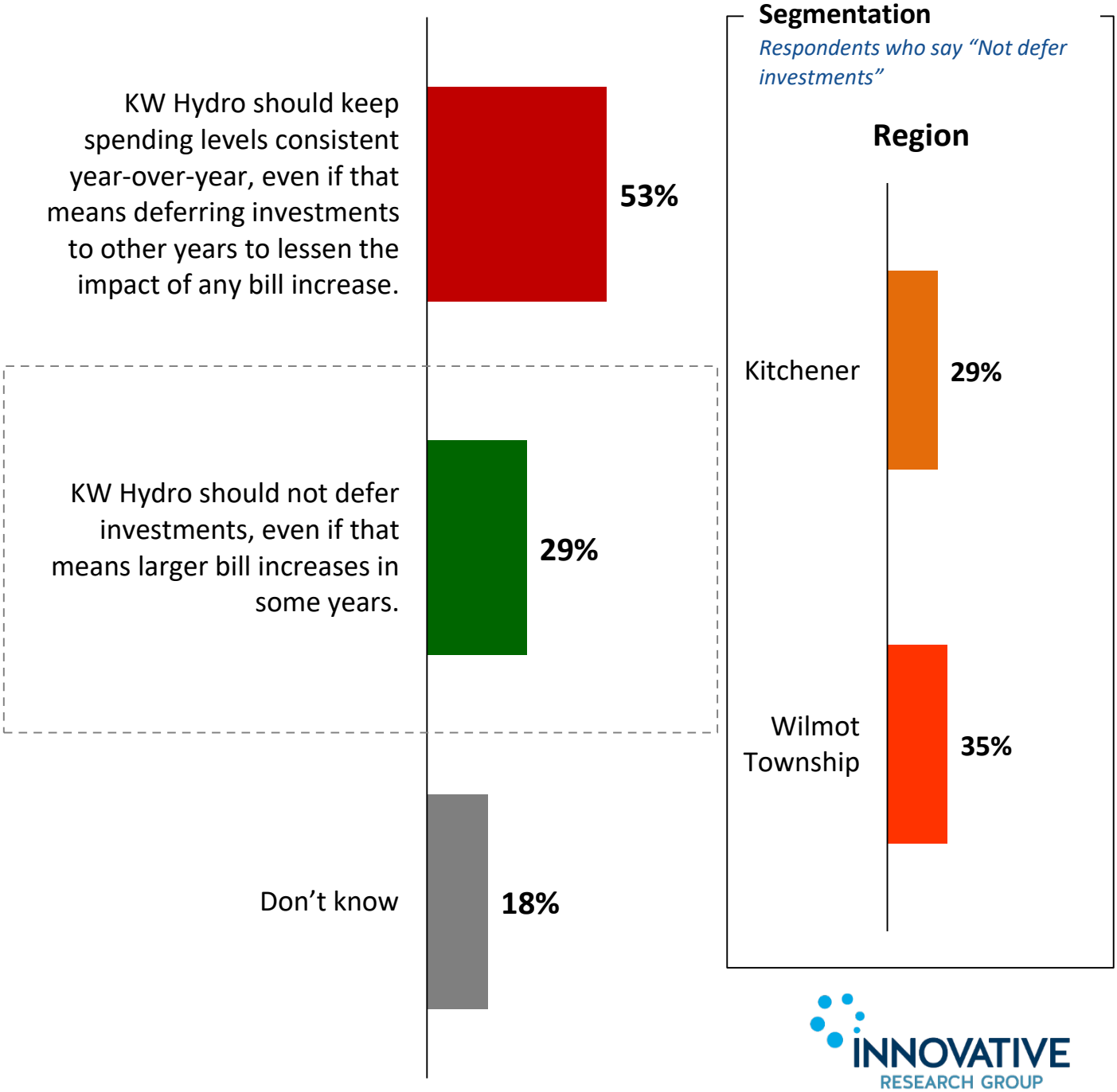
The chart below outlines KW Hydro's spending in past years, and proposed spending for the 5-year period 2020 to 2024. The colours on the chart help identify the categories in which KW Hydro makes its spending investments.



Pacing Investments

Q Which of the following statements best represents your point of view regarding KW Hydro's approach to pacing investments?

[asked all respondents, n=1,749]



System Access Preamble



“

KW Hydro’s practice is to adjust all “non-mandatory” investing to allow for mandatory (system access) investments. Generally, KW Hydro keeps its investment budget the same year over year. As such, when more mandatory spending is needed, money is taken from other investment categories, instead of the utility spending beyond its “cap”.

This approach helps minimize customer bill impacts, but results in some important, but non-mandatory investments being deferred – which in some cases could result in longer and more frequent power outages.

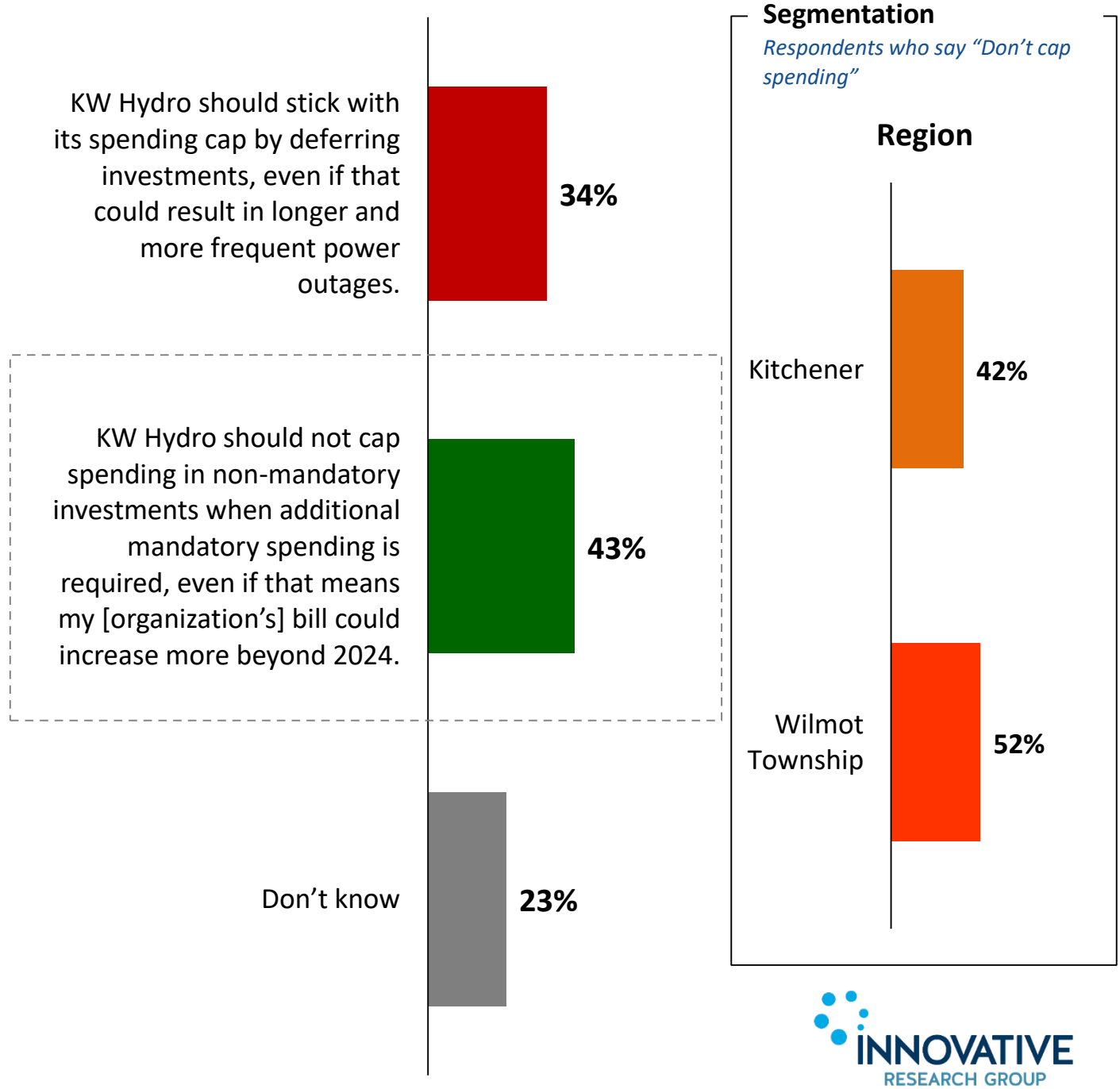
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KW Hydro's Spending "Cap"

Q Which of the following statements best represents your point of view regarding KW Hydro's approach to mandatory (system access projects) and non-mandatory spending?

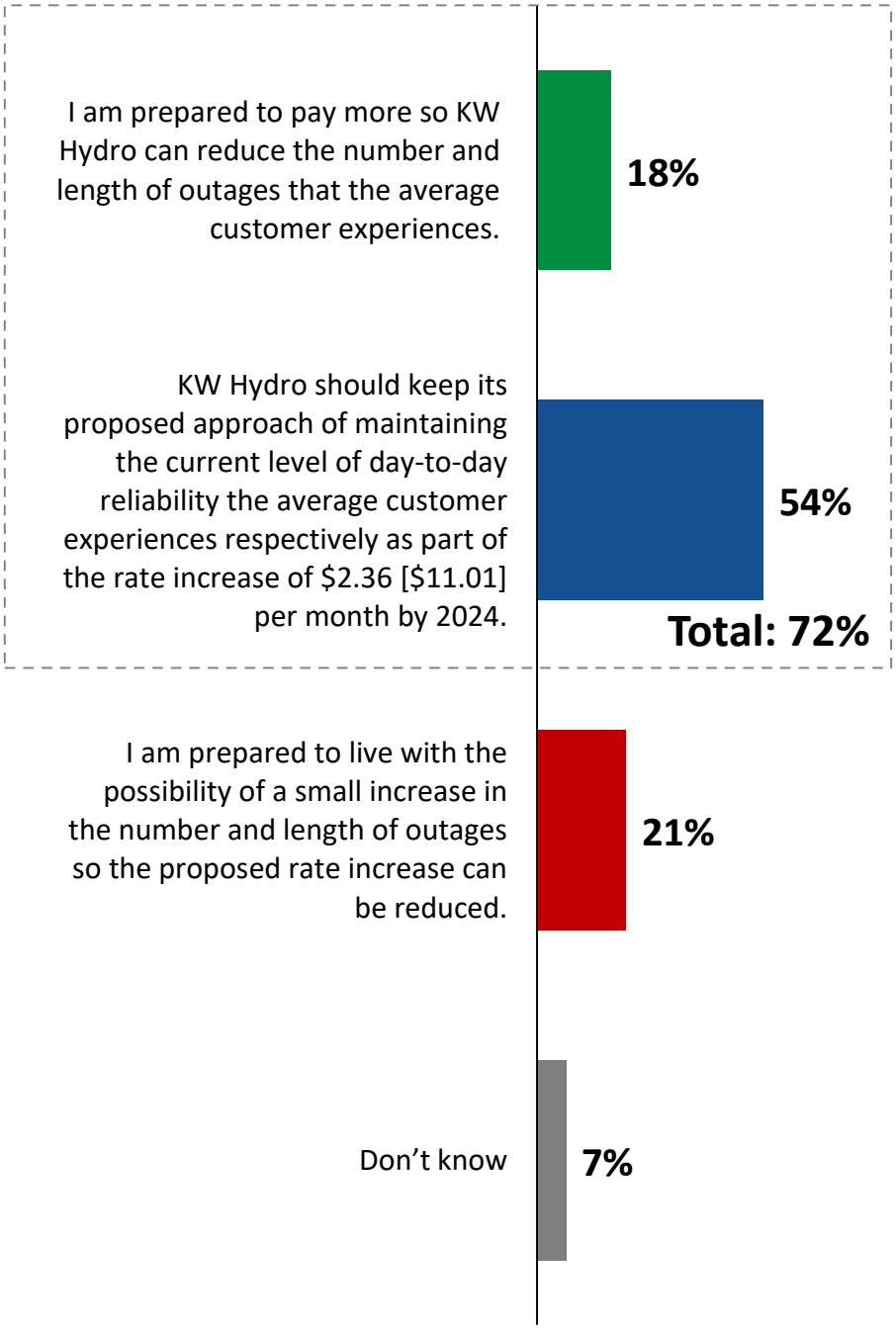
[asked all respondents, n=1,749]



Approach to Addressing Reliability

Q Which of the following is closest to your point of view regarding KW Hydro's approach to addressing reliability?

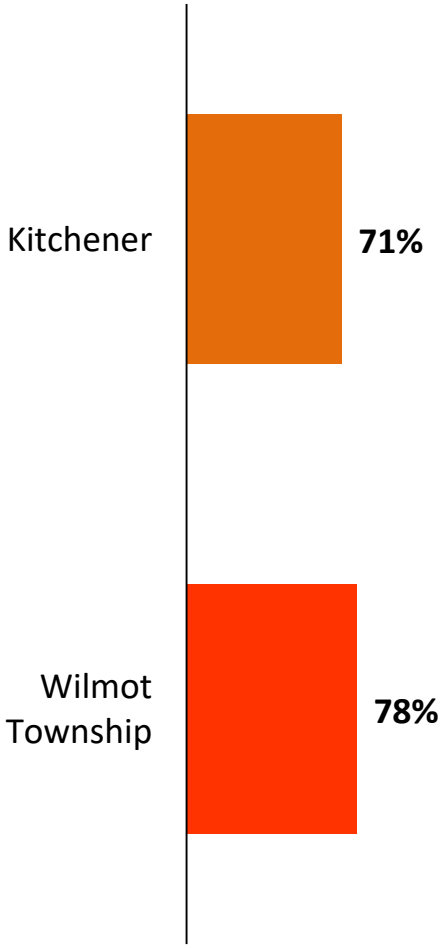
[asked all respondents, n=1,749]



Segmentation

Respondents who say "Stick with approach or spend more"

Region



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Pole Replacement Preamble



A recent asset health condition assessment shows that 15% of the poles in KW Hydro's distribution system are in poor or very poor condition. Customers served by these lines are more likely to experience power outages, and when they do, those outages are more likely to last longer and be more expensive to fix.

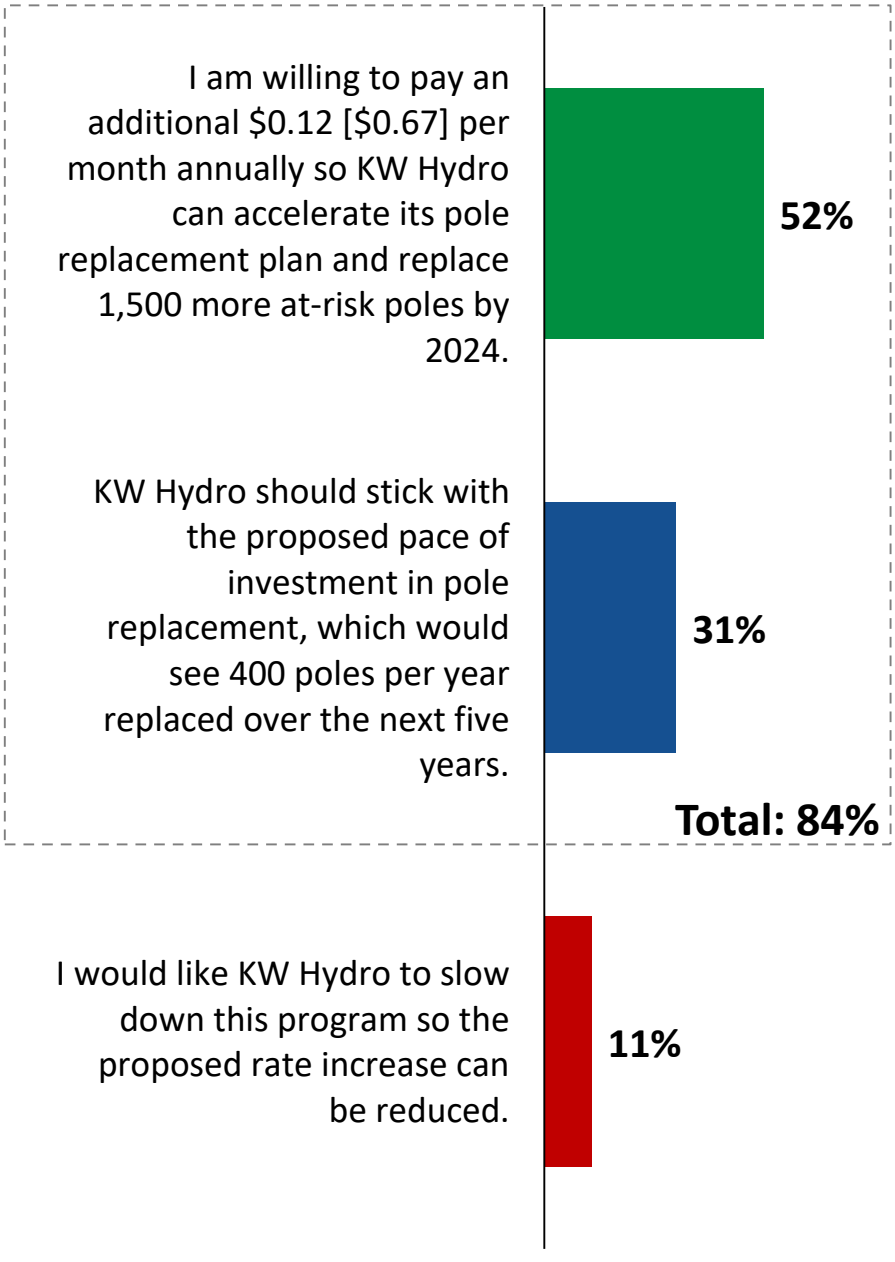
KW Hydro is proposing to replace these poles over the course of the next five years, however, there is an opportunity to replace these poles more quickly, improving reliability for customers served by this type of equipment.

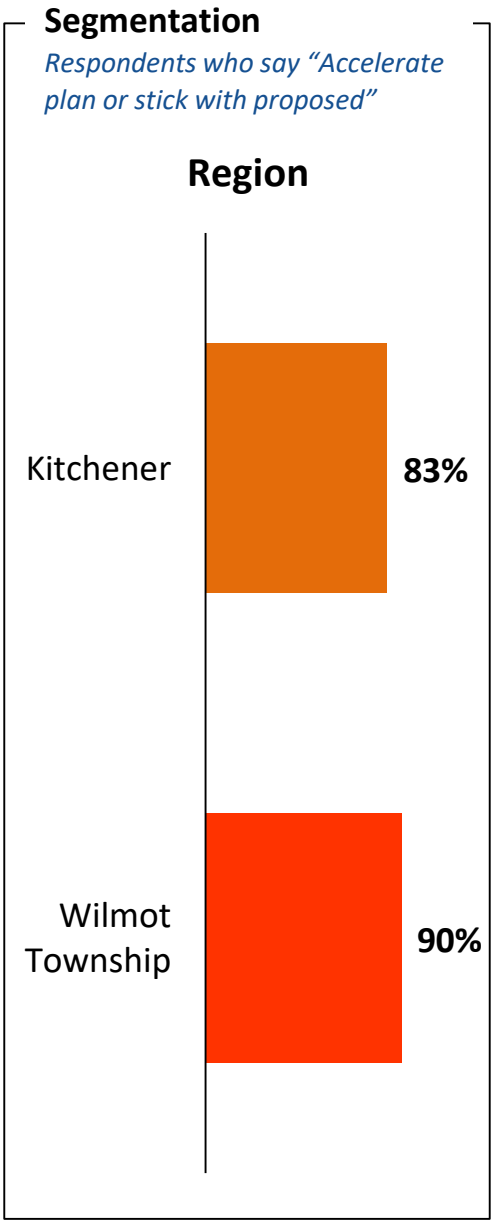
INNOVATIVE RESEARCH GROUP

Pole Replacement

Q Which of the following is closest to your point of view regarding KW Hydro's pole replacement program?

[asked all respondents, n=1,749]





Note: 'Don't Know' (5%) not shown.

Power Transformer Replacement Preamble

Utilities are required to inspect and monitor distribution assets and ensure appropriate follow up and corrective action regarding problems identified. After analyzing data for transformer stations, it was determined that two power transformers are nearing end of life.

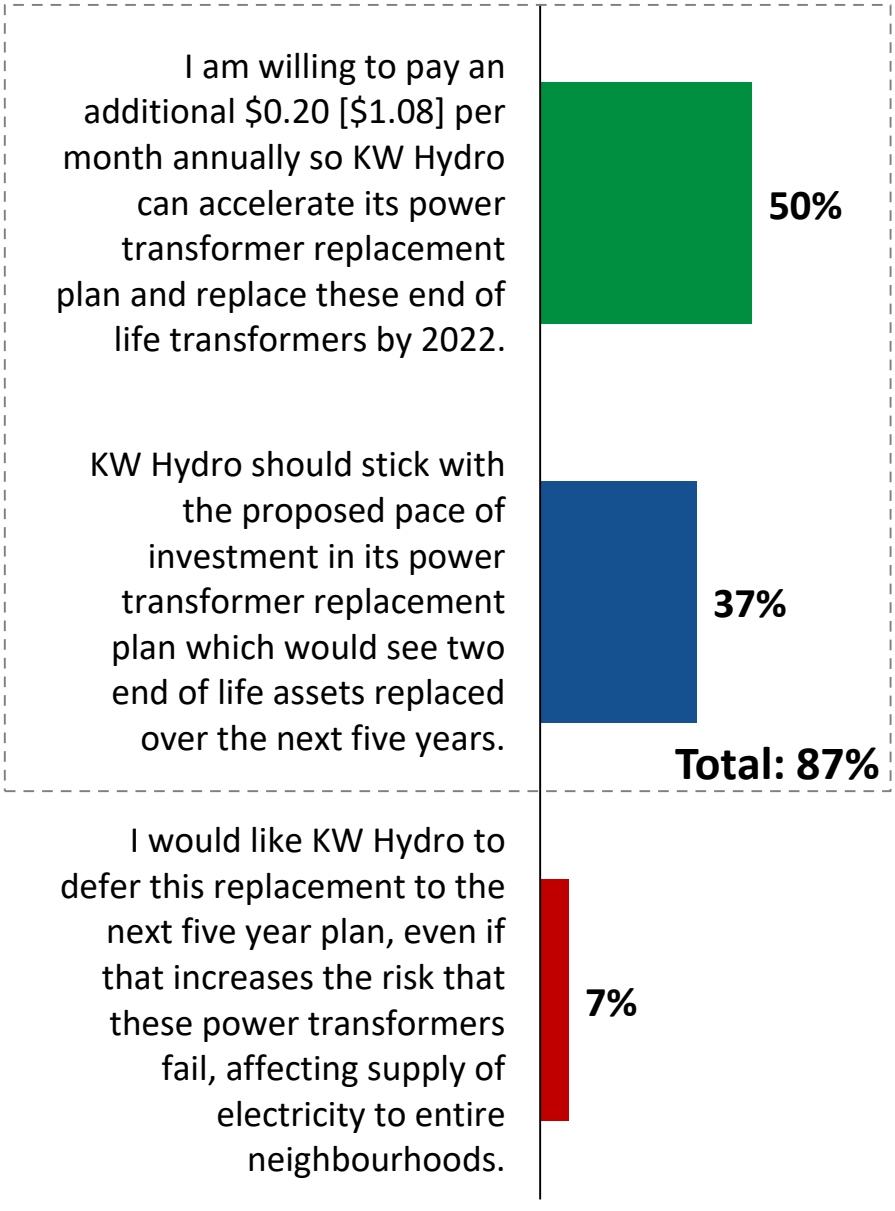
These are assets that have been in use for more than 40 years and require a long time to proactively plan for their replacement. While initially they served KW Hydro customers well, they now pose reliability concerns. These transformers feed entire neighbourhoods in the KW Hydro service territory. Should either of these transformers fail, it could cause prolonged outages and result in more costly reactive costs. That said, they have been in service for more than 40 years, and could continue to operate even longer.

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Power Transformer Replacement

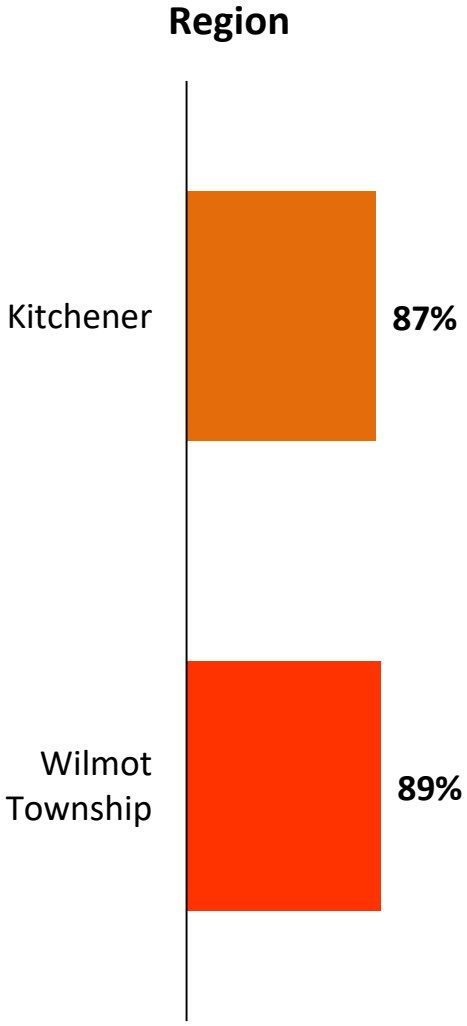
Q Which of the following is closest to your point of view regarding KW Hydro's power transformer replacement program?

[asked all respondents, n=1,749]



Segmentation

Respondents who say "Accelerate plan or stick with proposed"



Note: 'Don't Know' (6%) not shown.

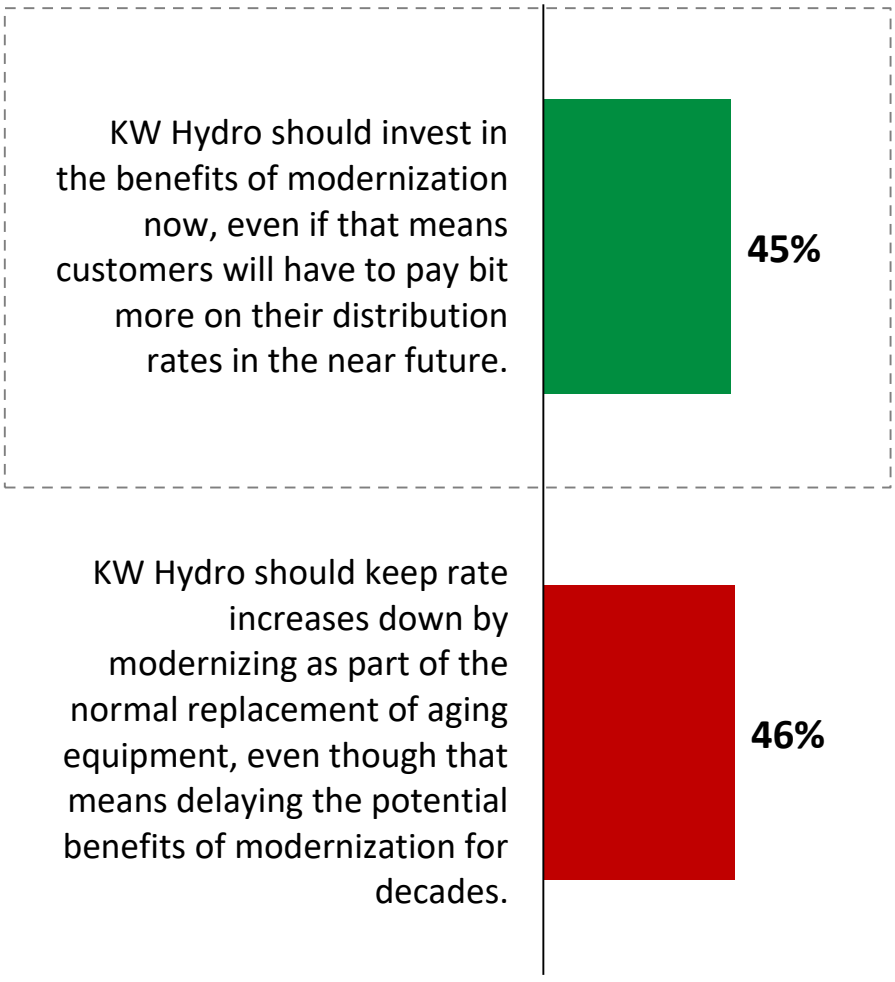
Modernizing the Distribution System

There are proven technologies that KW Hydro can implement such as electricity storage and automatic switches that can give customers more choices, improve reliability or reduce the impact on the environment.

Under KW Hydro's current plan to pace capital spending, these investments would create a more robust distribution system, and are required to maintain the reliability that KW Hydro customers experience today.

Which of the following statements best represents your point of view?

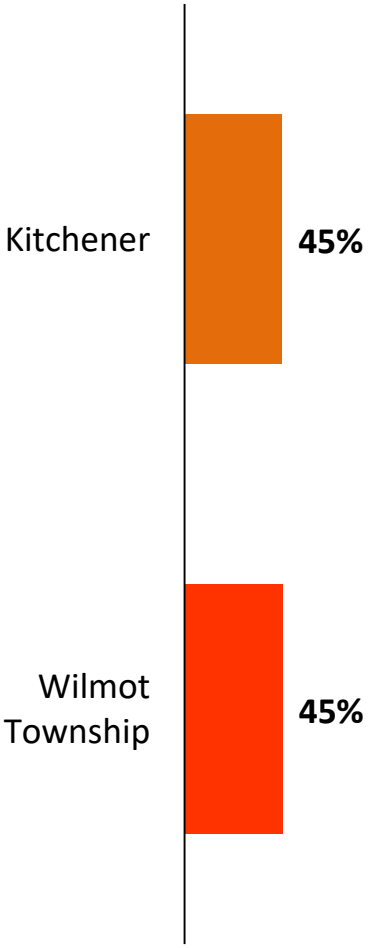
[asked all respondents, n=1,749]



Segmentation

Respondents who say "Invest in benefits of modernization now"

Region



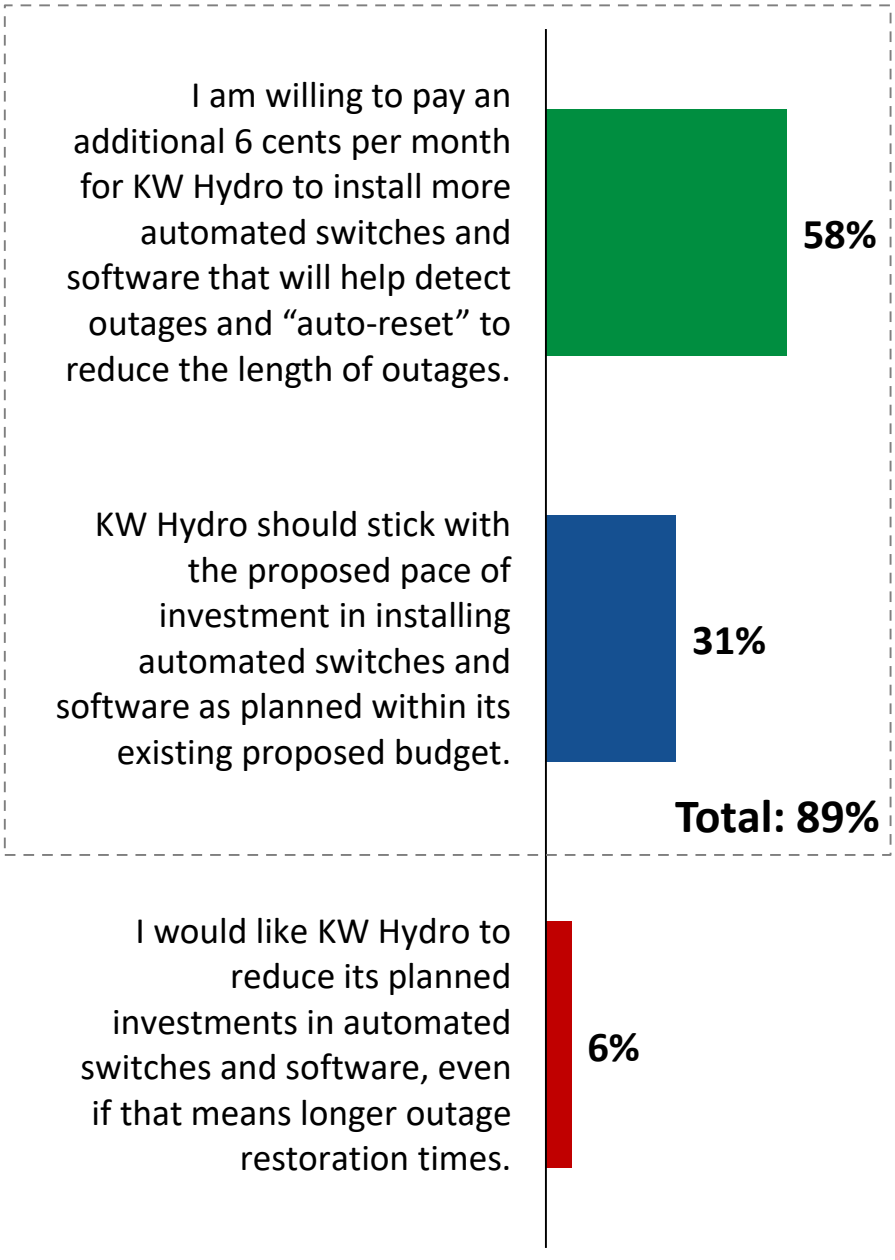
Note: 'Don't Know' (10%) not shown.

System Service

Spending on Automated Switches

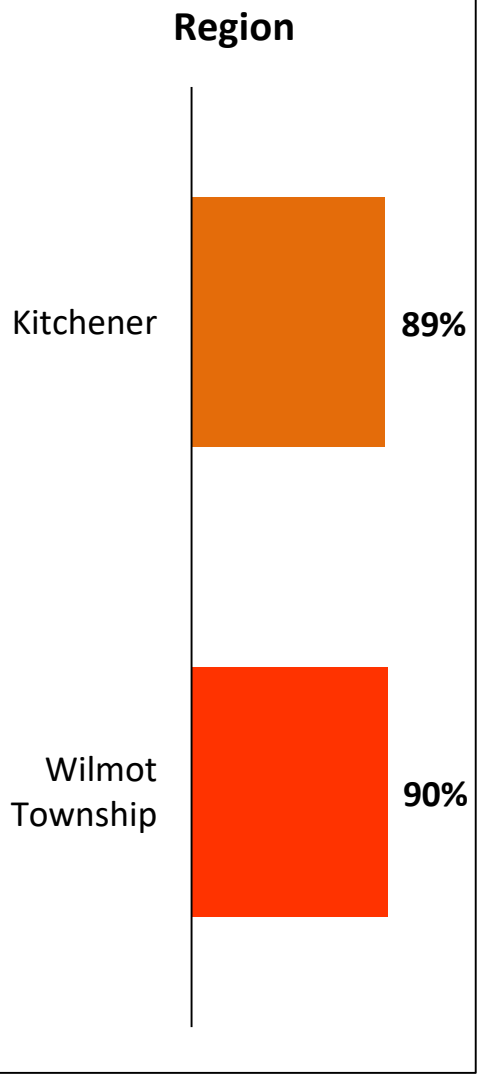
Q With regards to spending on automated switches and software designed to remotely detect an outage and "auto-reset" to reduce the length of outages, which of the following statements best represents your point of view?

[asked all respondents, n=1,749]



Segmentation

Respondents who say "Install more or stick with proposed"



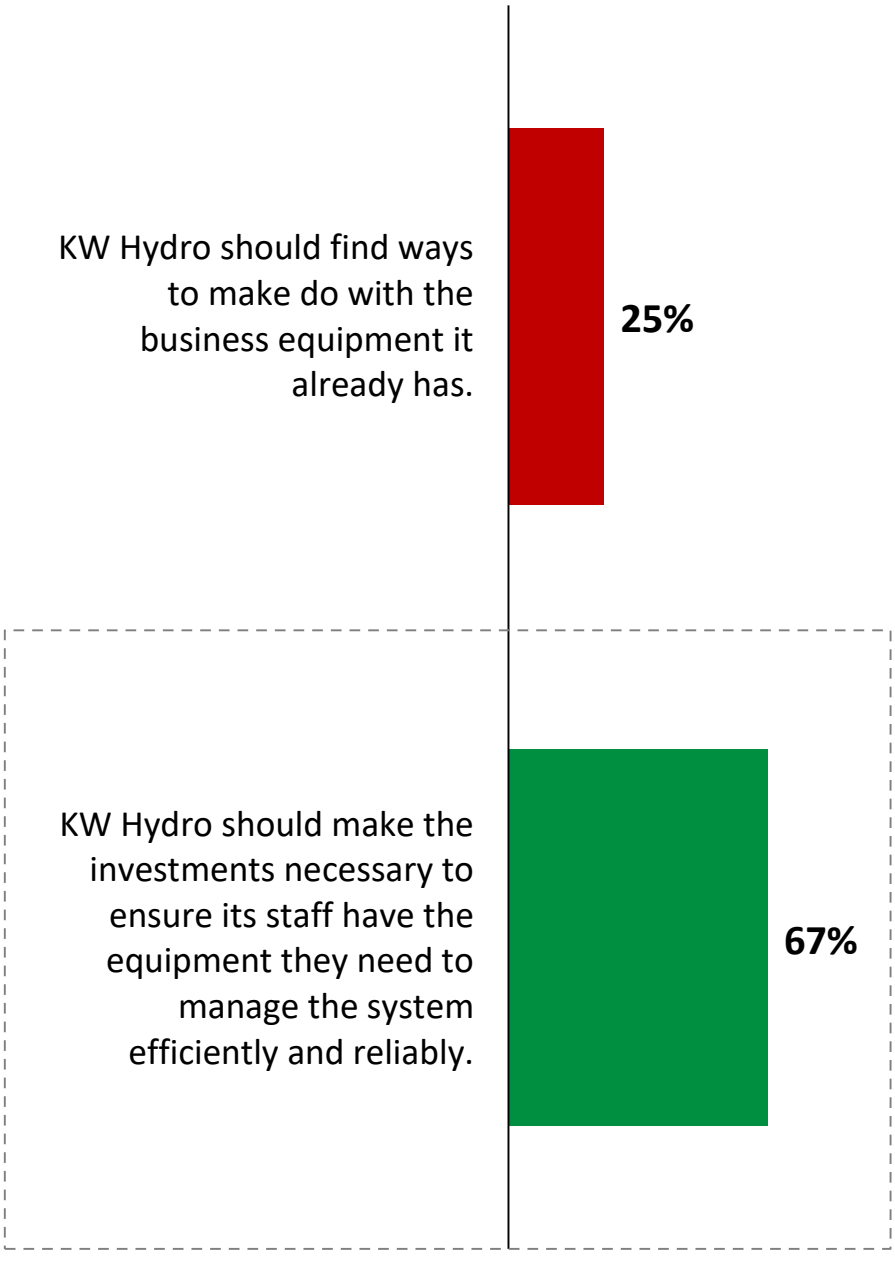
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Note: 'Don't Know' (5%) not shown.

Vehicles and Equipment

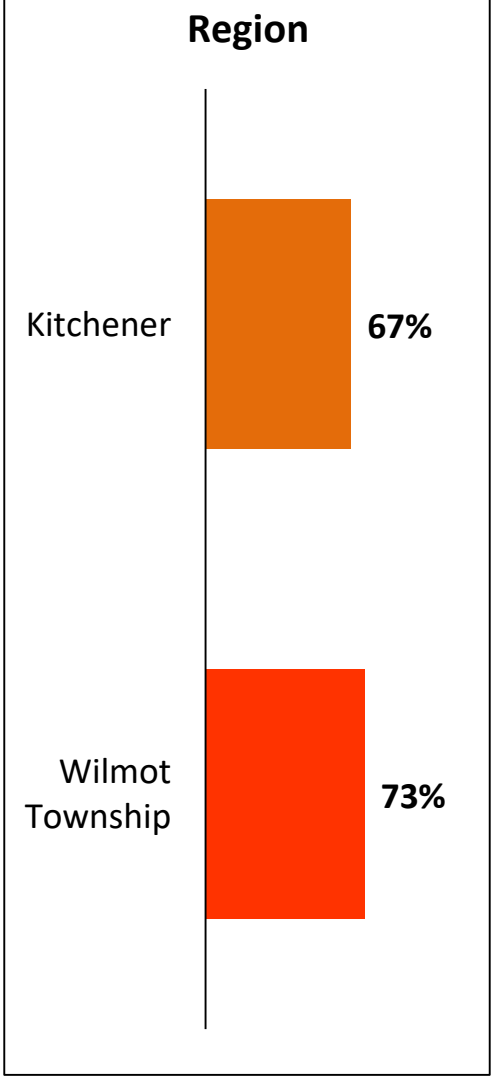
Q As a company, KW Hydro needs vehicles and equipment to maintain its distribution system and IT systems to manage the system and customer information. Which of the following statements best represents your point of view?

[asked all respondents, n=1,749]



Segmentation

Respondents who say "Make the investments necessary"



Note: 'Don't Know' (8%) not shown.

Customer Information System (CIS) Preamble

Several of KW Hydro's **information technology systems** have exceeded their useful lives and no longer meet the needs of the business and must be replaced.

One of the most important replacements is a 30+ year-old **customer information system (CIS)** that no longer has vendor support and cannot be maintained, posing a risk to KW Hydro's ability to deliver timely and accurate bills and limiting enhanced service options that customers may value. There is no other option but to replace the CIS.

KW Hydro conducted an extensive two-year procurement process to find a suitable vendor to build its new CIS.

The current plan includes the purchase of a basic CIS solution that will cost the typical residential [small business] customer $0.78 [$4.29] on the distribution portion of their electricity bill starting in 2020 and provides features needed to ensure customers continue to receive a bill on time.

An enhanced CIS system will allow KW Hydro to streamline and automate many processes that are currently manual and provide greater online options for customers. An enhanced CIS system will cost the typical residential [small business] customer an additional $0.46 [$2.57] per month.

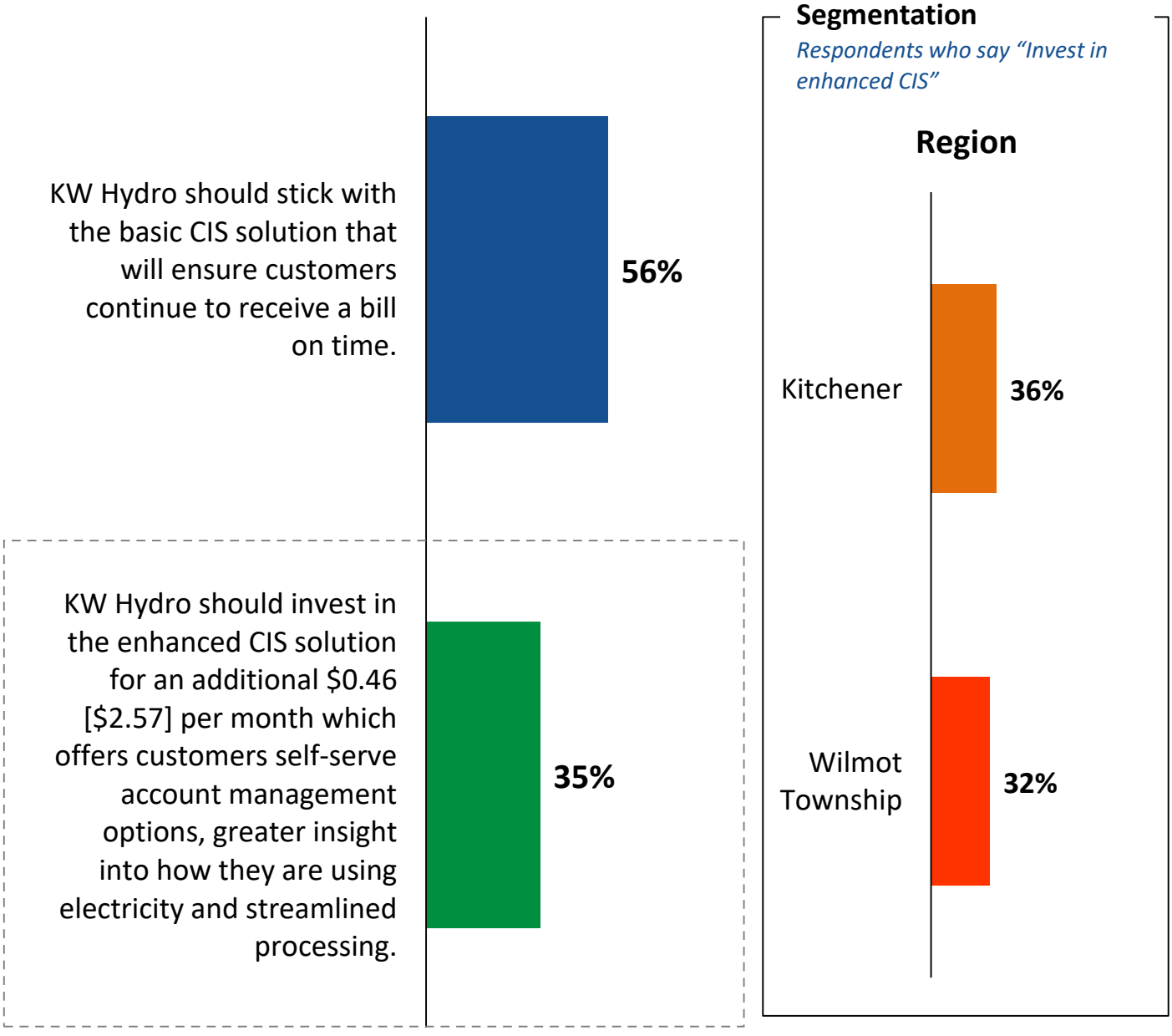
FEATURE	BASIC CIS	ENHANCED CIS
Receive bill on time	✓	✓
Email or text alerts Notify customers when their electricity consumption has reached a certain limit	X	✓
Insight into electricity consumption Insight into how and when electricity is being used in customer homes and businesses	X	✓
Self-service customer portal A customer portal that offers customers self-service account management without the need to speak to KW Hydro staff	X	✓
Automated and streamlined processing Greater administrative efficiencies in KW Hydro's back office.	X	✓

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Customer Information System

Q Which of the following statements best represents your point of view?

[asked all respondents, n=1,749]



Note: 'Don't Know' (8%) not shown.

Assessment of Proposed Plan Preamble

Throughout its planning process, KW Hydro has identified four potential investments that could be made beyond the $2.36 increase that is currently being proposed. Those four investments have been discussed throughout, and are summarized below. These incremental investments would offer benefits to customers ranging from improved reliability to enhanced customer service offerings.

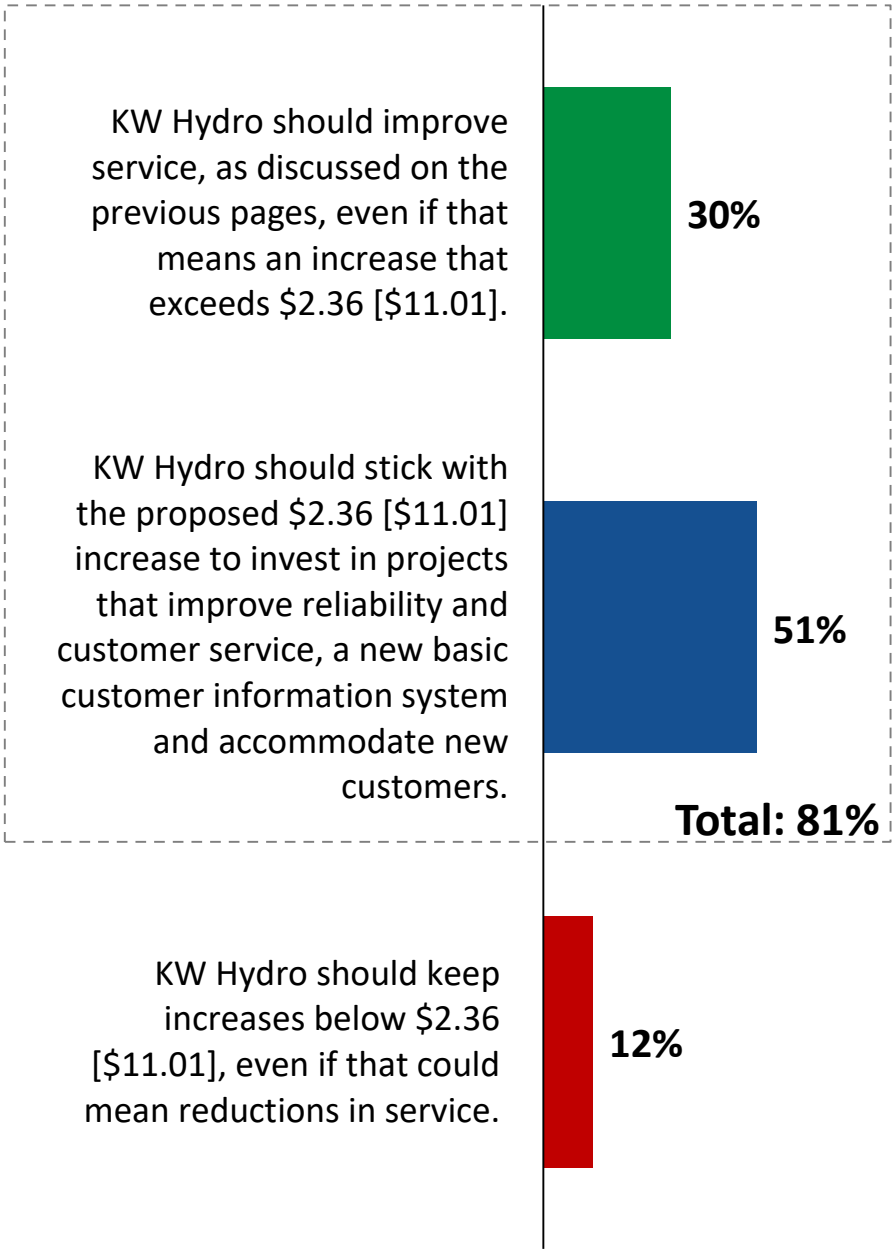
INCREMENTAL INVESTMENT	CUSTOMER BENEFITS	ADDITIONAL COST
Accelerate its pole replacement plan	Improved reliability for impacted customers	+ $0.12 [+ $0.67]
Accelerate its power transformer replacement plan	Reduced risk of widespread outages	+ $0.20 [+ $1.08]
Install more automated switches and software	Reduced length of outages	+ $0.05 [+ $0.31]
Enhanced Customer Information System	Self-serve account management options, greater insight into electricity usage and streamlined processing.	+ $0.46 [+ $2.57]

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Assessment of Proposed Plan

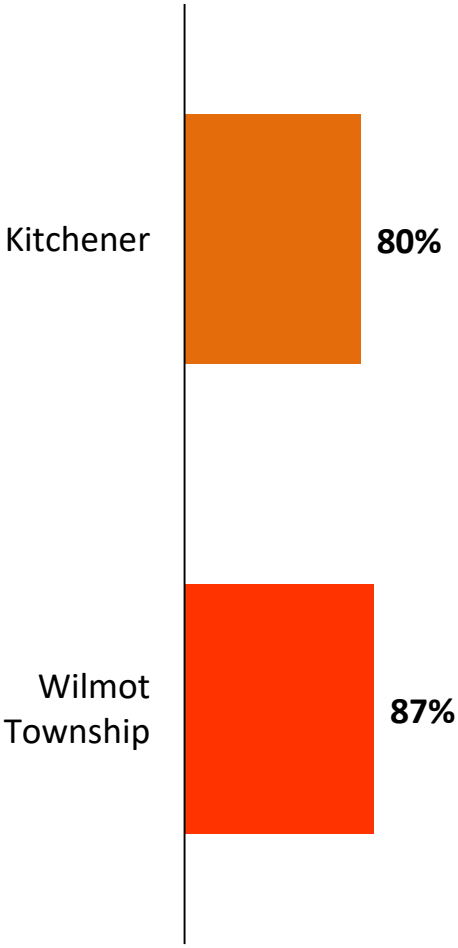
Q Considering what you know about KW Hydro's proposed plan – which would see the typical residential [small business] customer's distribution portion of their bill increase by $2.36 [$11.01] over the 5-year period – which of the following best represents your point of view?

[asked all respondents, n=1,749]



Segmentation

Respondents who say "Improve services or stick with plan"



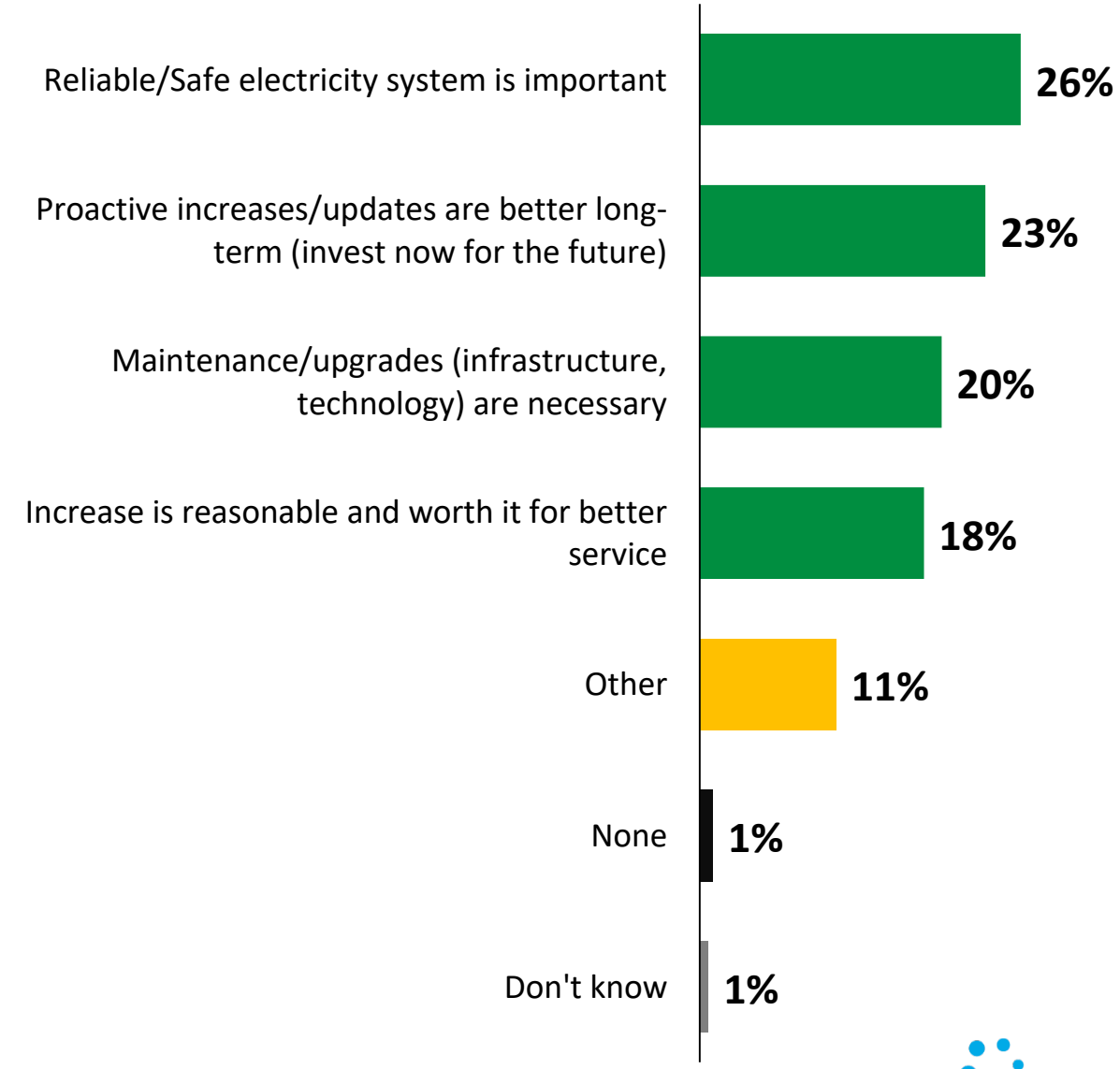
Note: 'Don't Know' (7%) not shown.

Opinion of KW Hydro's Proposed Plan

Q Thinking about your answer to the previous question, why do you either think KW Hydro should improve services beyond what is being proposed, stick with what is being proposed, or keep increases below what is being proposed?

[asked all respondents, n=530]

Amongst those who answered: KW Hydro should improve service, as discussed on the previous pages, even if that means an increase that exceeds $2.36 [$11.01]. (n=530)



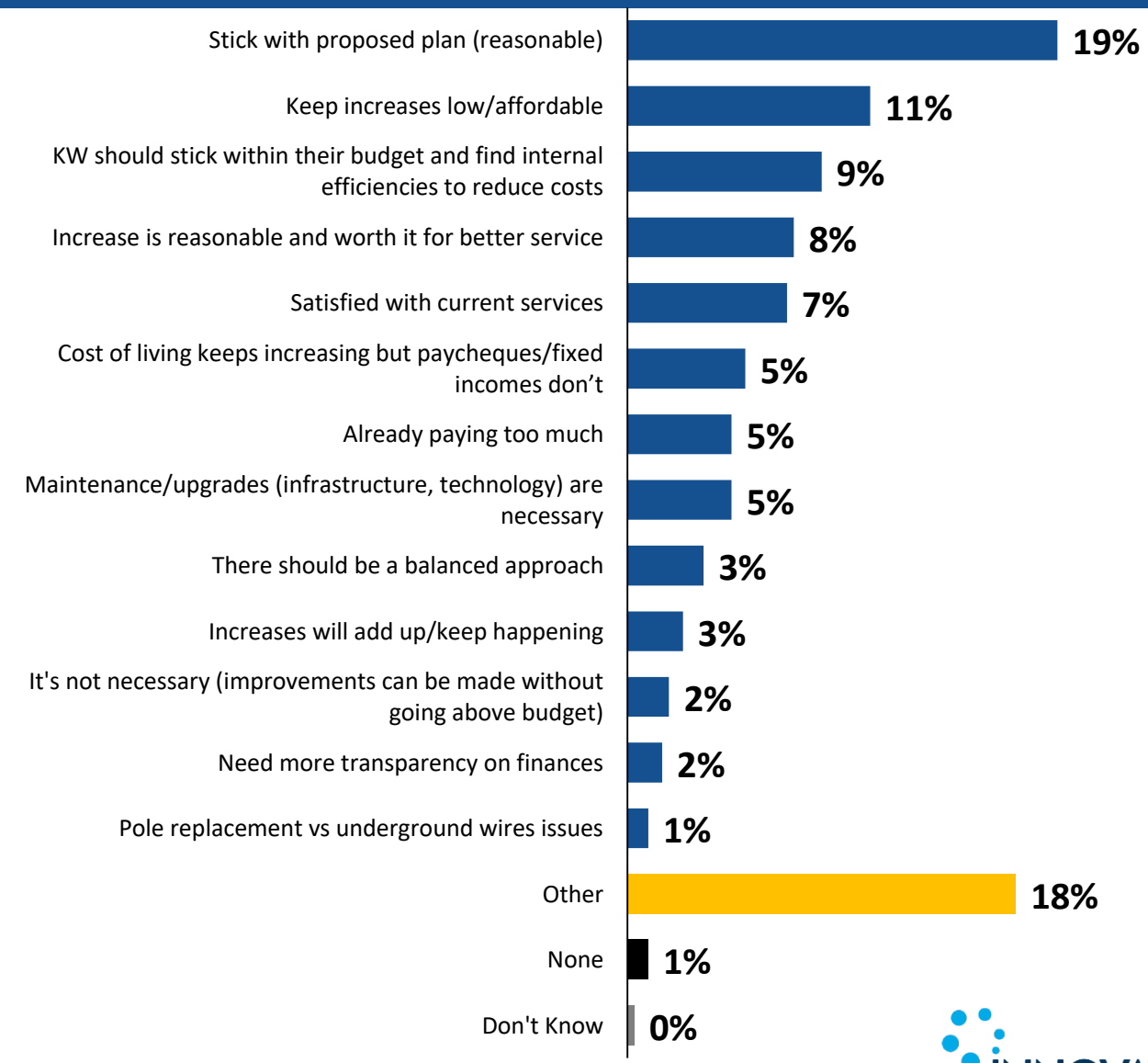
Note: 'Refused' (<1%) not shown.

Opinion of KW Hydro's Proposed Plan

Q Thinking about your answer to the previous question, why do you either think KW Hydro should improve services beyond what is being proposed, stick with what is being proposed, or keep increases below what is being proposed?

[asked all respondents, n=887]

Amongst those who answered: KW Hydro should stick with the proposed $2.36 [$11.01] increase to invest in projects that improve reliability and customer service, a new basic customer information system and accommodate new customers. (n=887)



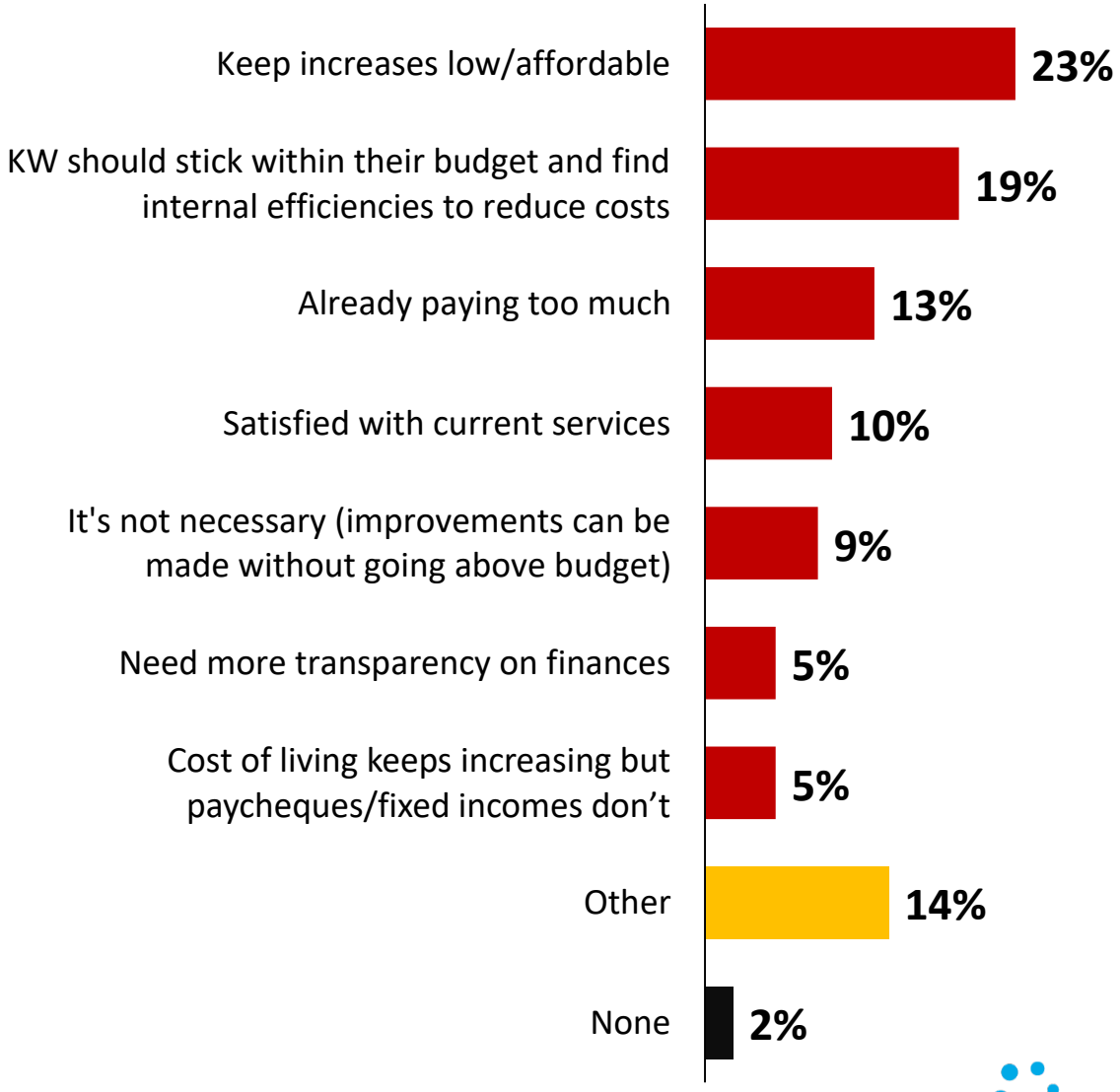
Note: 'Refused' (3%) not shown.

Opinion of KW Hydro's Proposed Plan

Q Thinking about your answer to the previous question, why do you either think KW Hydro should improve services beyond what is being proposed, stick with what is being proposed, or keep increases below what is being proposed?

[asked all respondents, n=206]

Amongst those who answered: KW Hydro should keep increases below $2.36 [$11.01], even if that could mean reductions in service. (n=206)



Note: 'Don't know' (0%) and 'Refused' (0%) not shown.

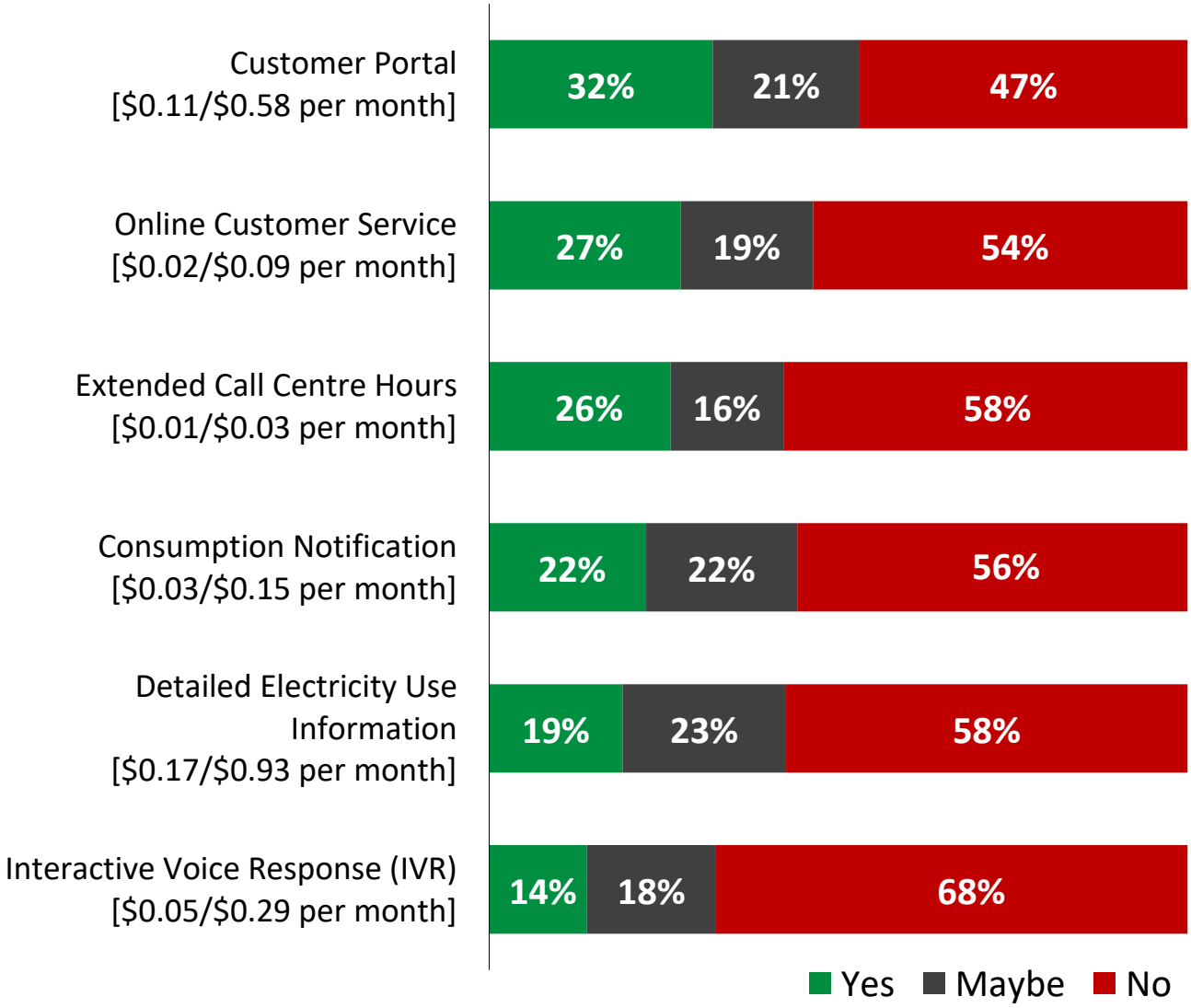
Specific Initiatives

Q

Some customers have expressed interest in additional service offerings that are not included in KW Hydro's proposed investment plan. The following section is intended to gather your feedback on some potential investments that are not currently included in the proposed plan previously discussed.

In addition to the amount you currently pay on your electricity bill, would you be willing to pay for the following customer services?

[asked all respondents, n=1,749]

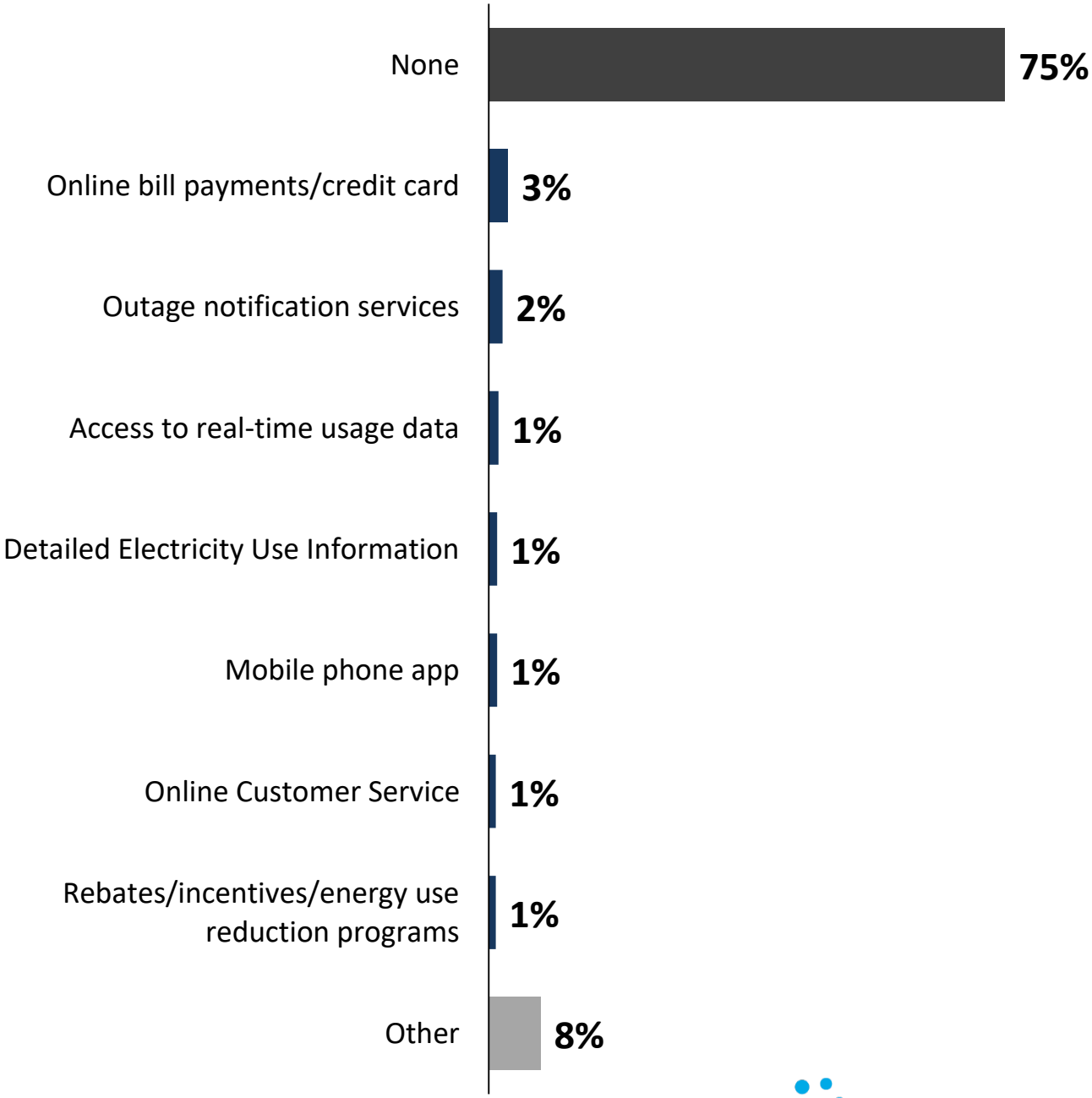


Note: Options have been abbreviated. See **Appendix XX** for complete list of options presented in the online workbook.

Additional Customer Services

Q Are there any other customer services, not mentioned above, that you would be willing to pay for?

[OPEN; asked all respondents (Optional), n=504]

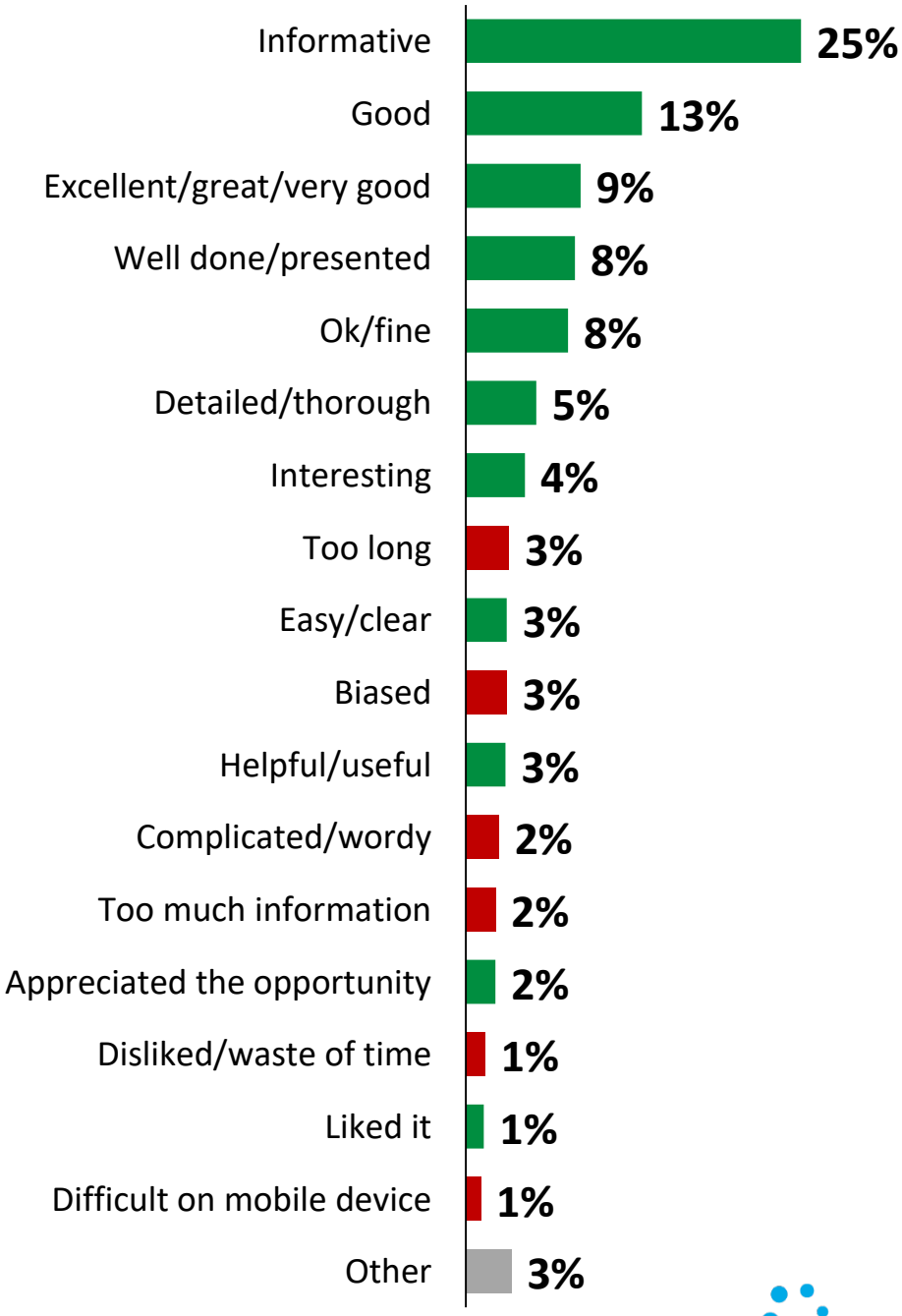


Note: 'Refused' (4%) and 'Don't Know' (2%) not shown.

Overall Impression of Workbook

Overall Impression: What did you think about the workbook?

[OPEN; asked all respondents (Optional), n=1,175]

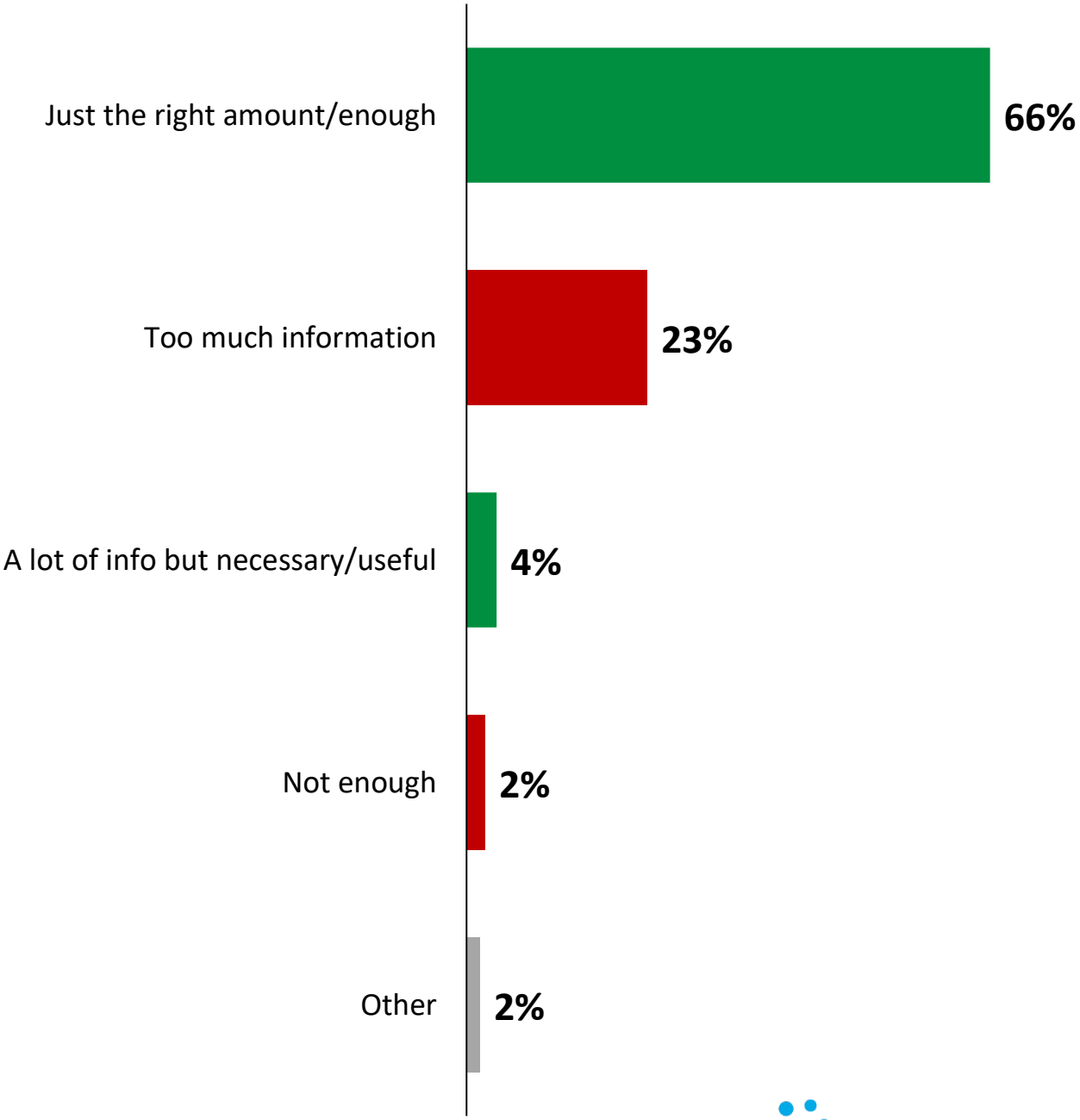


Note: 'None' (<1%), 'Don't Know' (<1%) and Refused' (<1%) not shown.

Volume of Information

Volume of Information: Did KW Hydro provide too much information, not enough, or just the right amount?

[OPEN; asked all respondents (Optional), n=1,178]

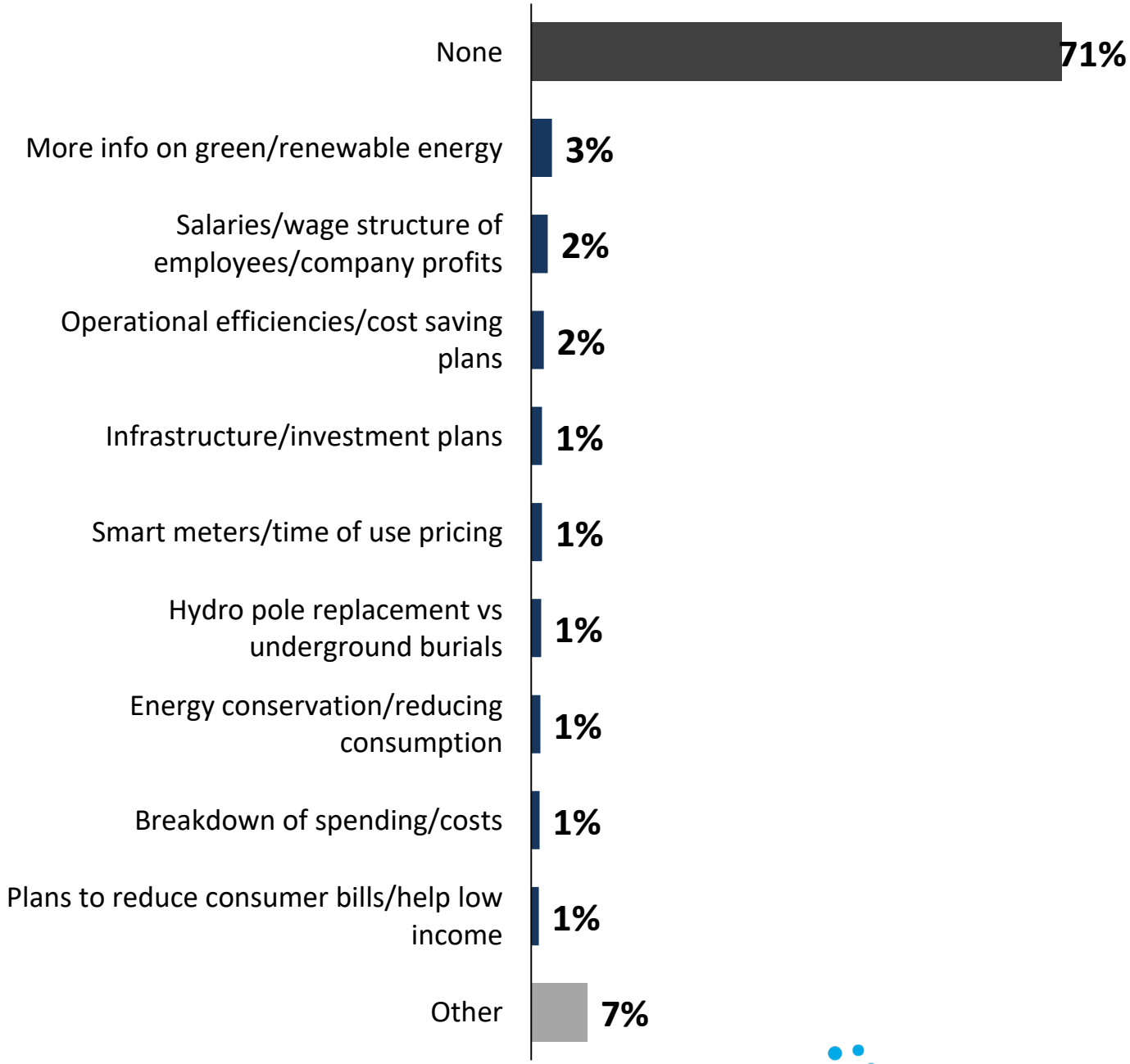


Note: 'Don't Know' (1%) and 'Refused' (2%) not shown.

Content Covered

Content Covered: Was there any content missing that you would have liked to have seen included?

[OPEN; asked all respondents (Optional), n=907]

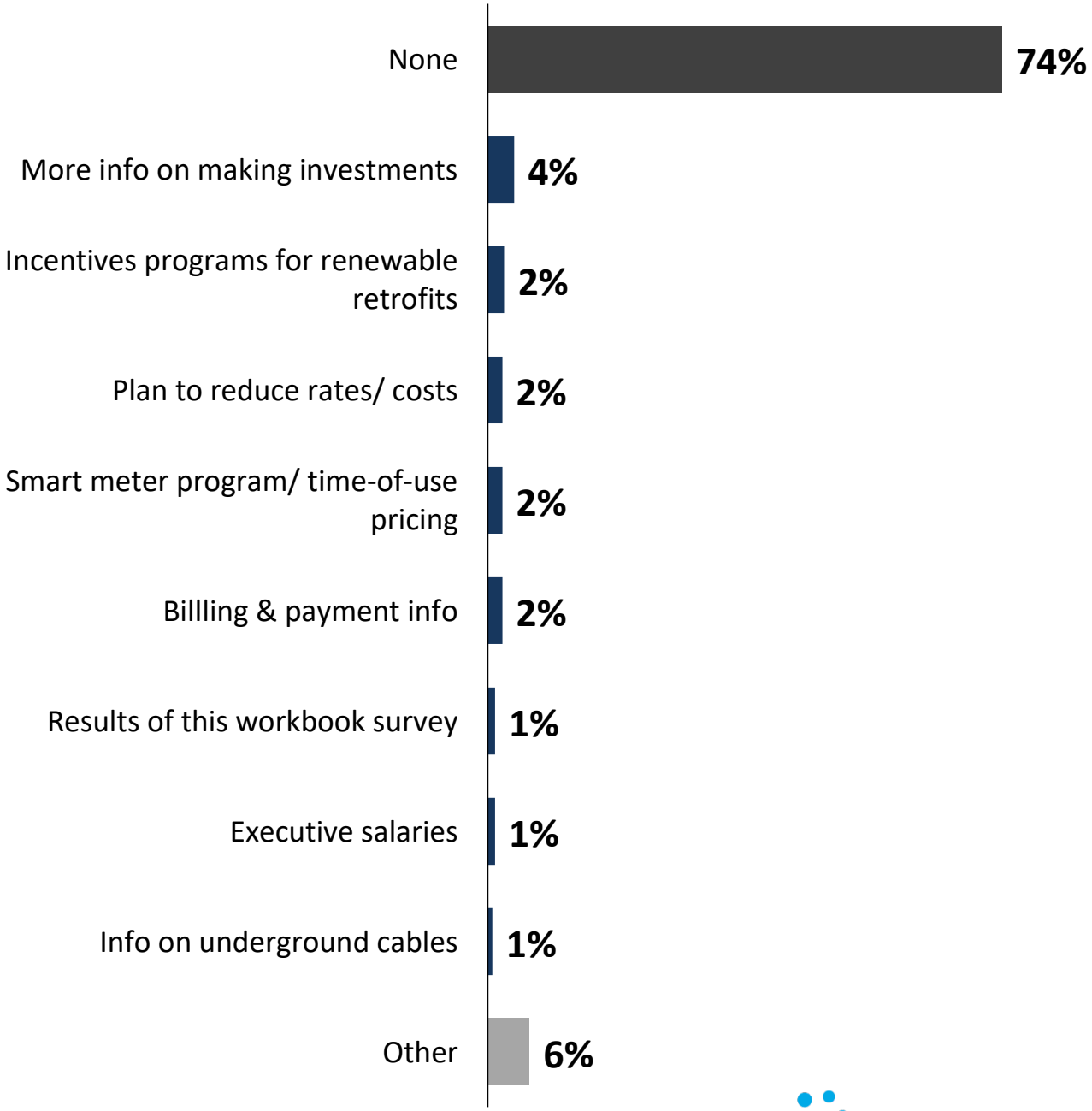


Note: 'Don't Know' (4%) and 'Refused' (3%) not shown.

Outstanding Questions

Content Covered: Was there any content missing that you would have liked to have seen included?

[OPEN; asked all respondents (Optional), n=763]

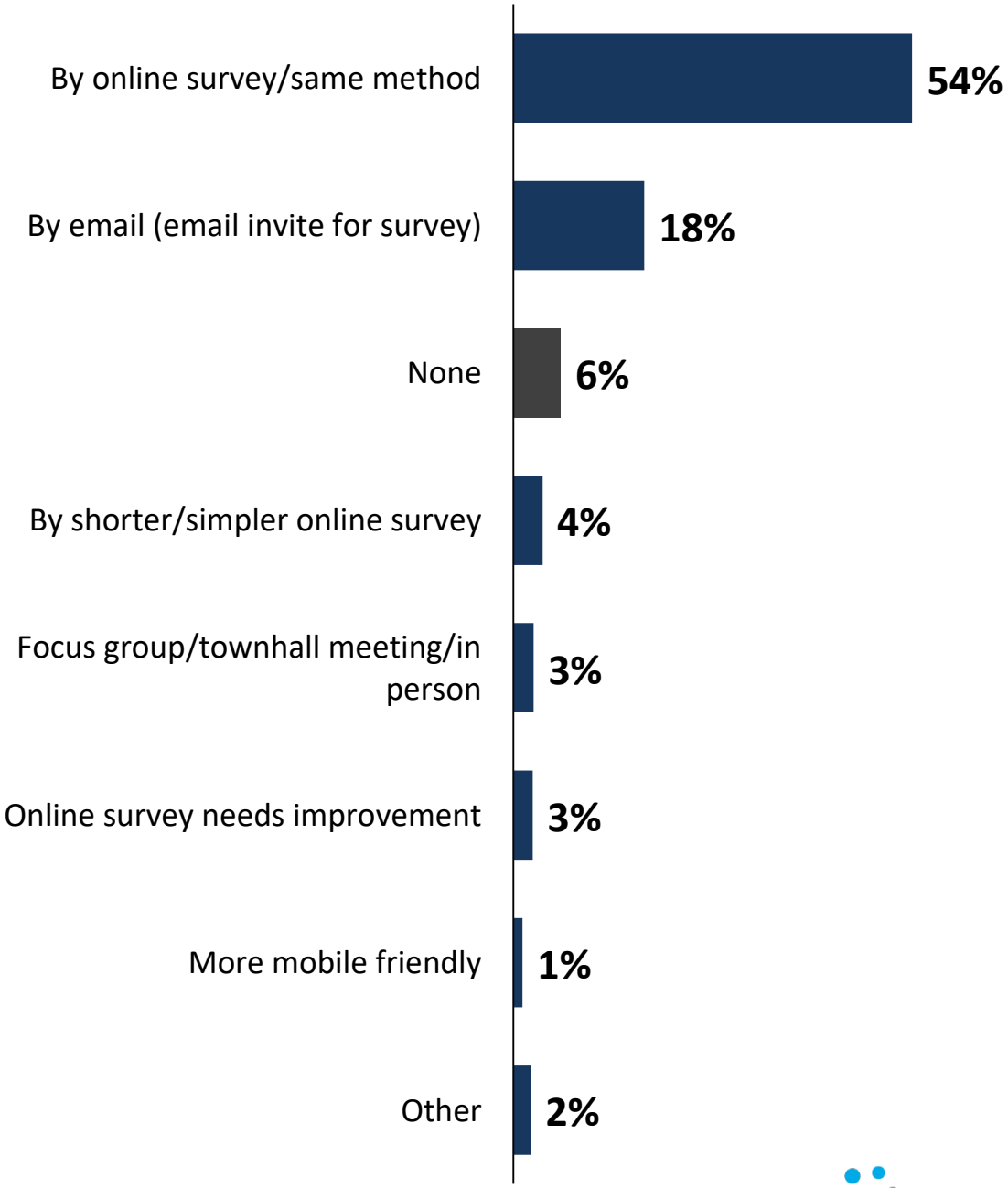


Note: 'Don't Know' (1%) and 'Refused' (4%) not shown.

Suggestions for Future Consultations

Content Covered: Was there any content missing that you would have liked to have seen included?

[OPEN; asked all respondents (Optional), n=818]



Note: 'Don't Know' (2%) and 'Refused' (7%) not shown.

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Personalized research to connect you and your audiences.

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Kitchener-Wilmot Hydro 2018 Customer Engagement

Telephone Survey Report

Low-Volume Report

NOVEMBER 2018

STRICTLY PRIVILEGED AND CONFIDENTIAL

Survey Methodologies



Field and Design

These are the findings of two Innovative Research Group (INNOVATIVE) telephone surveys conducted amongst Kitchener-Wilmot Hydro residential and small business customers between **October 31 and November 14, 2018.**

- The **residential** survey fielded from **October 31 – November 5, 2018** amongst **n=511** residential customers, with a margin of error of ±4.3%, 19 times out of 20.
- The **small business** survey fielded from **November 1-14, 2018** amongst **n=204** small business customers, with a margin of error of ±6.9%, 19 times out of 20.

INNOVATIVE conducted all interviews through its computer assisted telephone interviewing (CATI) system.

This generalizable telephone survey used a stratified random sampling approach based on known characteristics of customers including region and consumption by rate class (residential and GS<50kW).

Sample lists were provided by Kitchener-Wilmot Hydro. Screening questions were designed to ensure only customers who received an electricity bill from Kitchener-Wilmot Hydro were included. In addition, residential customers needed to have primary or shared responsibility over their household's electricity bill and only the organization's decision makers on electricity use were included in the business completes.

Quotas were set by electricity consumption levels and geographic considerations from within the Kitchener-Wilmot Hydro service territory in order to obtain a representative customer sample.

Note: *Graphs and tables may not always total 100% due to rounding values rather than any error in data. Sums are added before rounding numbers. Caution interpreting results with small n-sizes.*

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Consumption Quartiles

Dividing customer sample into quartiles based on known characteristics, including region and annual consumption, was used to develop accurate quotas to ensure the sample was representative of Kitchener-Wilmot Hydro's customer base.

Residential Sample Strata Divisions

Region	Low	Medium-Low	Medium-High	High	Total
Kitchener	114	116	117	117	**464**
Wilmot Township *Including Baden, New Dundee, New Hamburg, Petersburg & St. Agatha*	13	12	11	11	**47**
Total	**127**	**128**	**128**	**128**	**511**

Small Business Sample Strata Divisions

Region	Low	Medium-Low	Medium-High	High	Total
Kitchener	42	43	43	43	**171**
Wilmot Township *Including Baden, New Dundee, New Hamburg, Petersburg & St. Agatha*	8	8	8	9	**33**
Total	**50**	**51**	**51**	**52**	**204**

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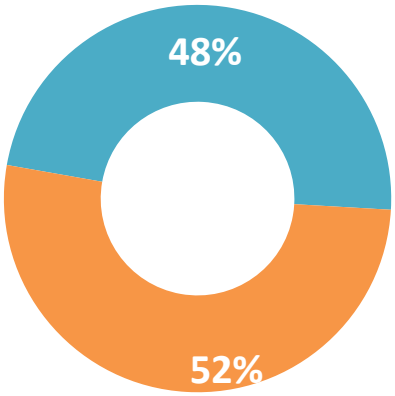
Segmentation and Demographics



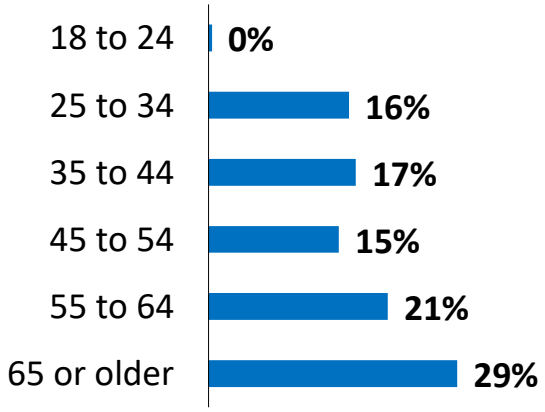
Segmentation & Demographics

Residential

Age-Gender



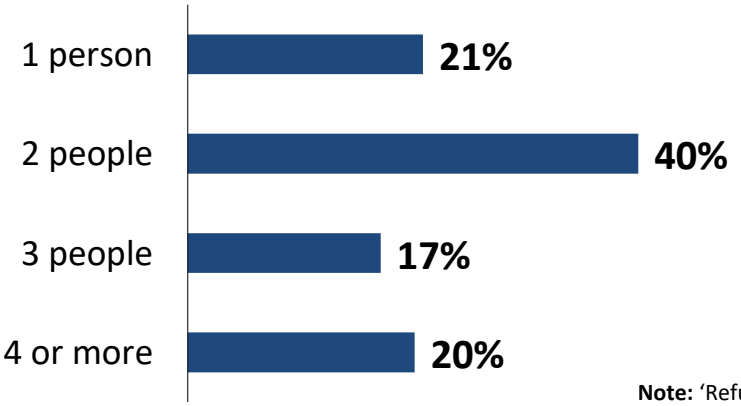




Note: 'Refused' (2%) not shown.

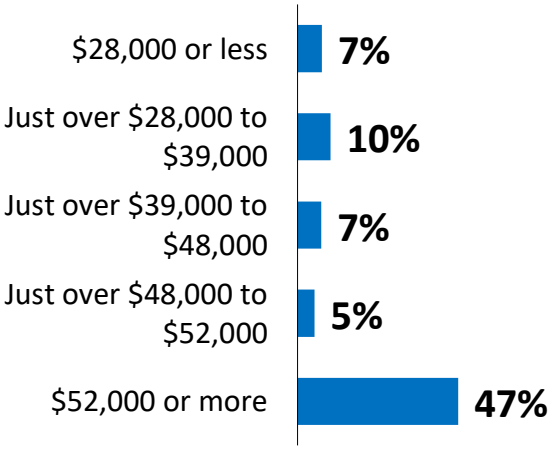
Household Size





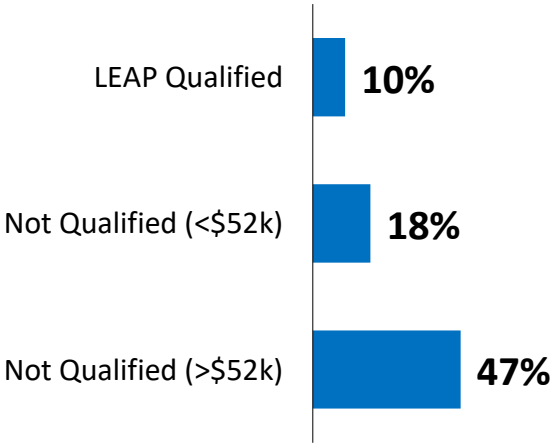
Note: 'Refused' (2%) not shown.

Household Income (After Tax)



Note: 'Refused' (22%), 'Not sure' (3%) not shown.

LEAP Qualification



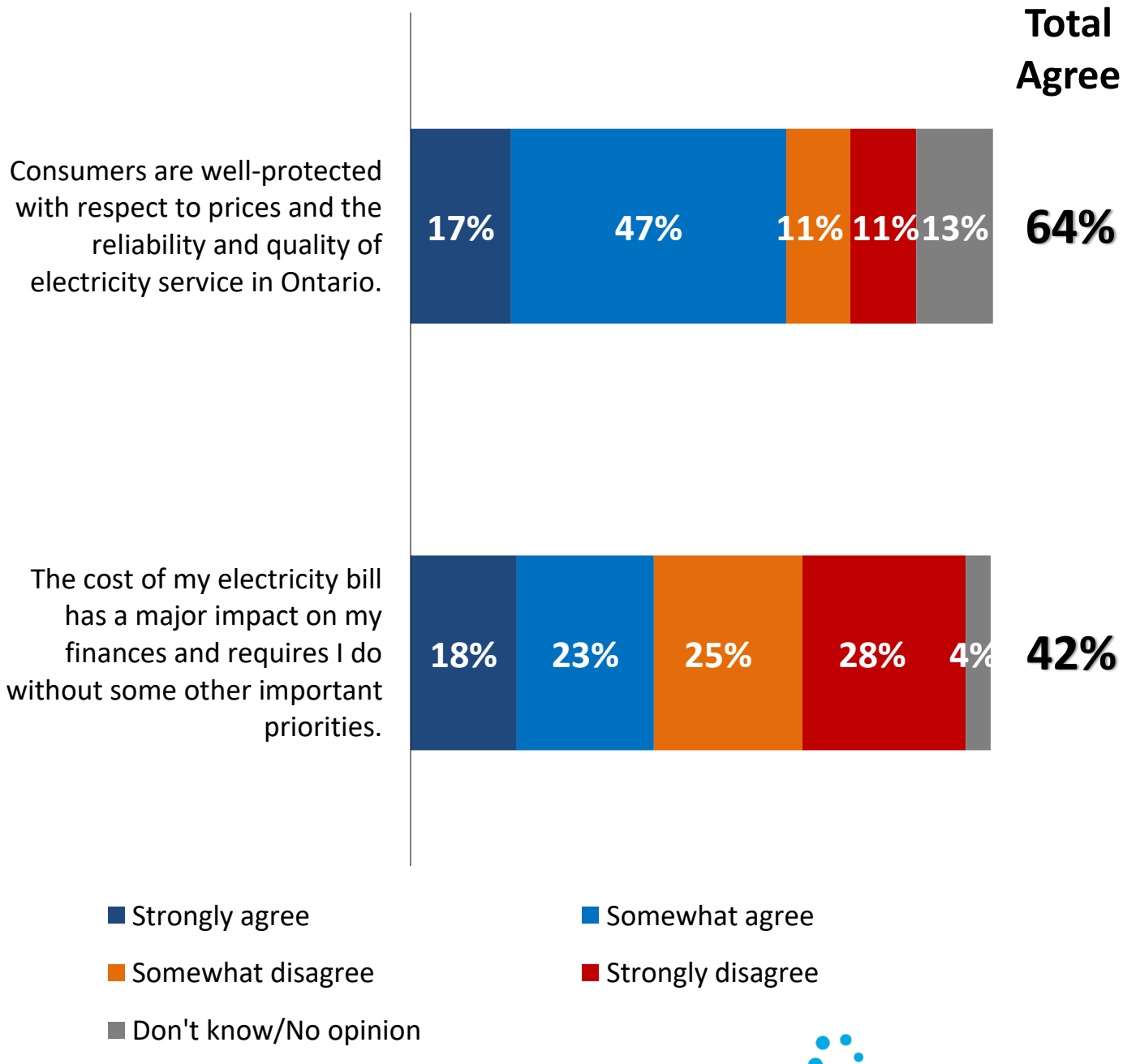
Note: 'Refused' (22%), 'Not sure' (2%) not shown.

Segmentation & Demographics

Residential

Q For each statement please tell me if you would strongly agree, somewhat agree, somewhat disagree or strongly disagree. If you don't know enough to say or don't have an opinion just let me know.

[asked all respondents, n=511]



Note: 'Refused' not shown.

Familiarity Preamble



“

As you may know, **KW Hydro** operates and maintains the local electricity distribution system, delivers electricity throughout the community, reads meters, calculates and collects customer electricity bills, answers customer calls, responds during outages, clears trees from power lines and delivers electricity conservation programs.

”

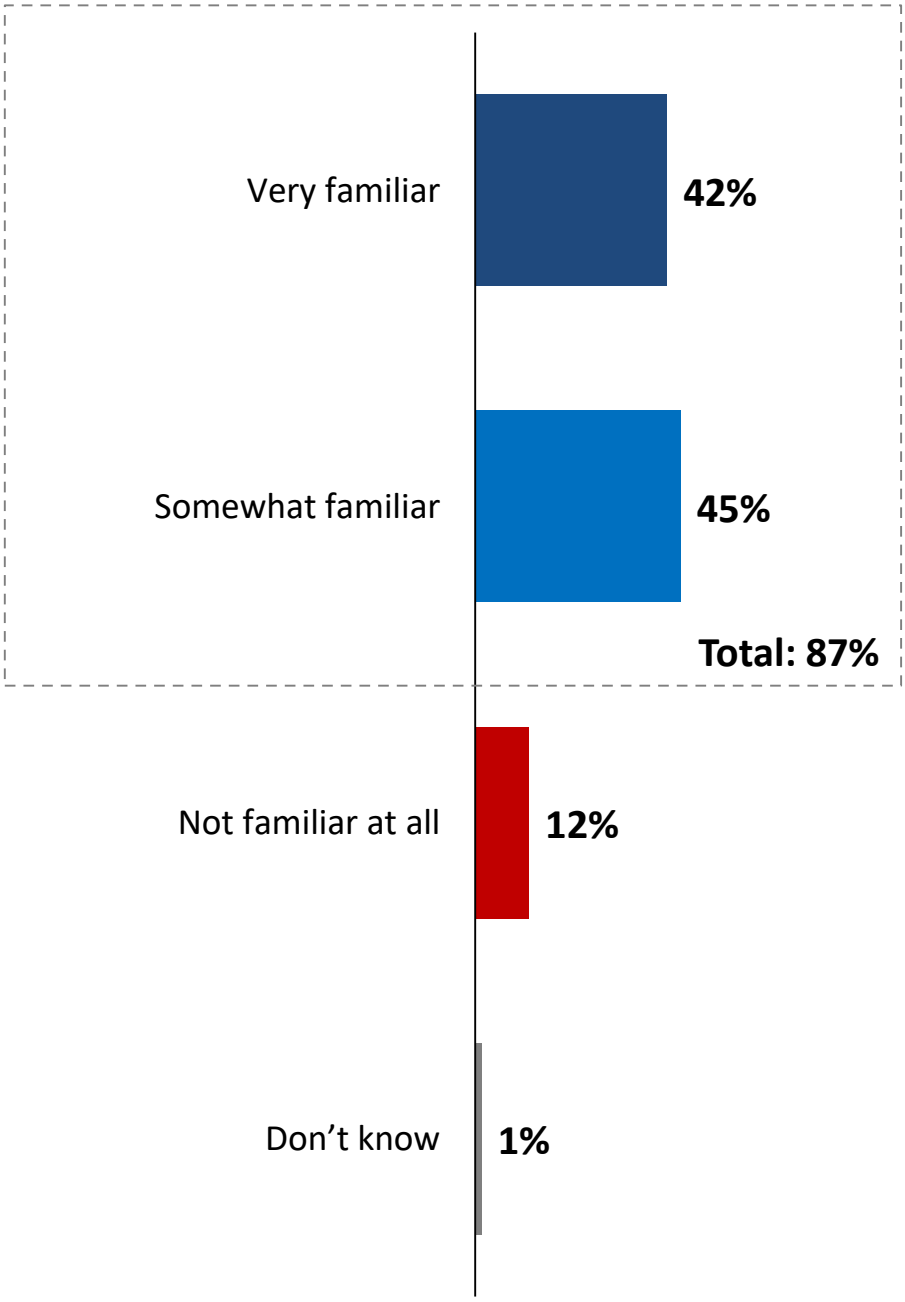
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Familiarity with Kitchener-Wilmot Hydro

Residential

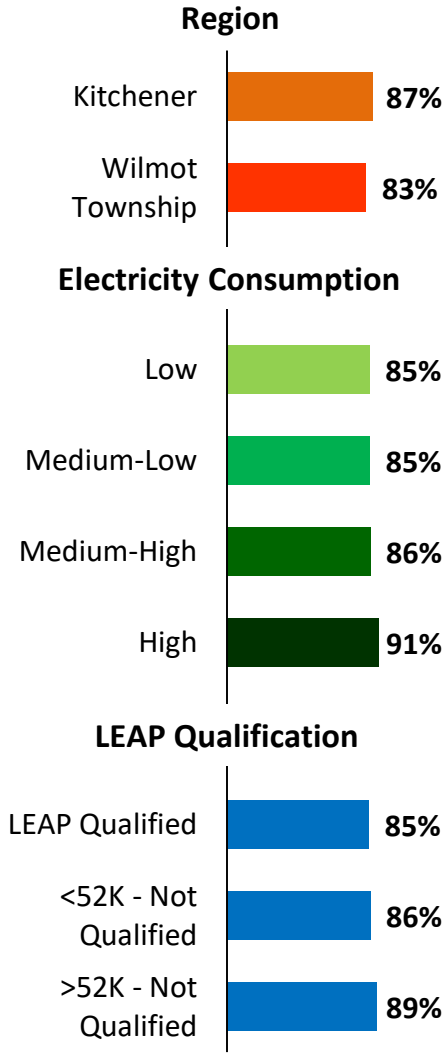
Q In general, how familiar are you with KW Hydro as your local distribution company?

[asked all respondents, n=511]



Segmentation

Respondents who say "Familiar"



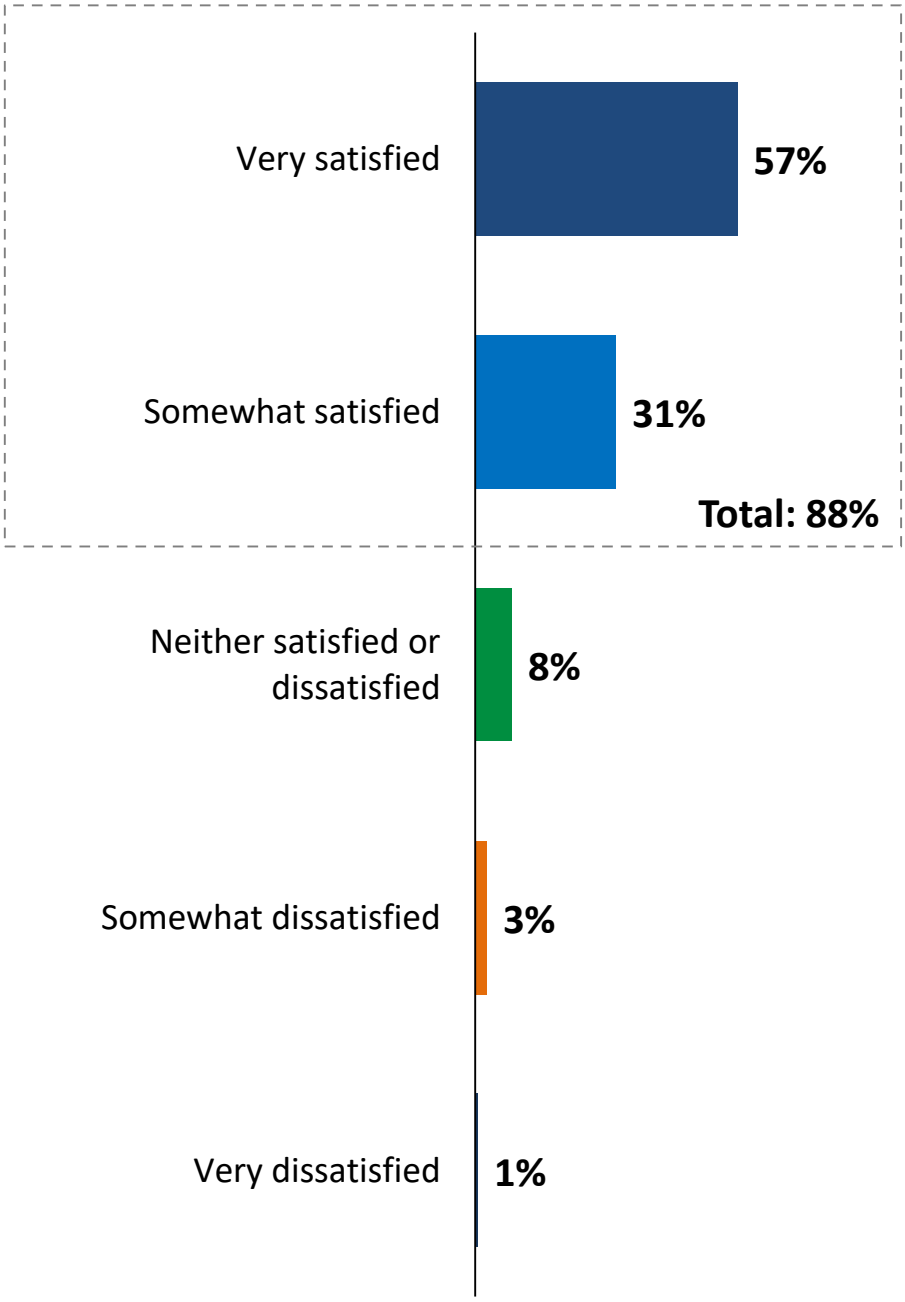
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Satisfaction with Services

Residential

Q Generally, how satisfied or dissatisfied are you with the services you receive from **KW Hydro**?

[asked all respondents, n=511]



Segmentation

Respondents who say "Satisfied"

Region

Kitchener	88%
Wilmot Township	91%

Electricity Consumption

Low	88%
Medium-Low	91%
Medium-High	87%
High	86%

LEAP Qualification

LEAP Qualified	83%
<52K - Not Qualified	91%
>52K - Not Qualified	87%

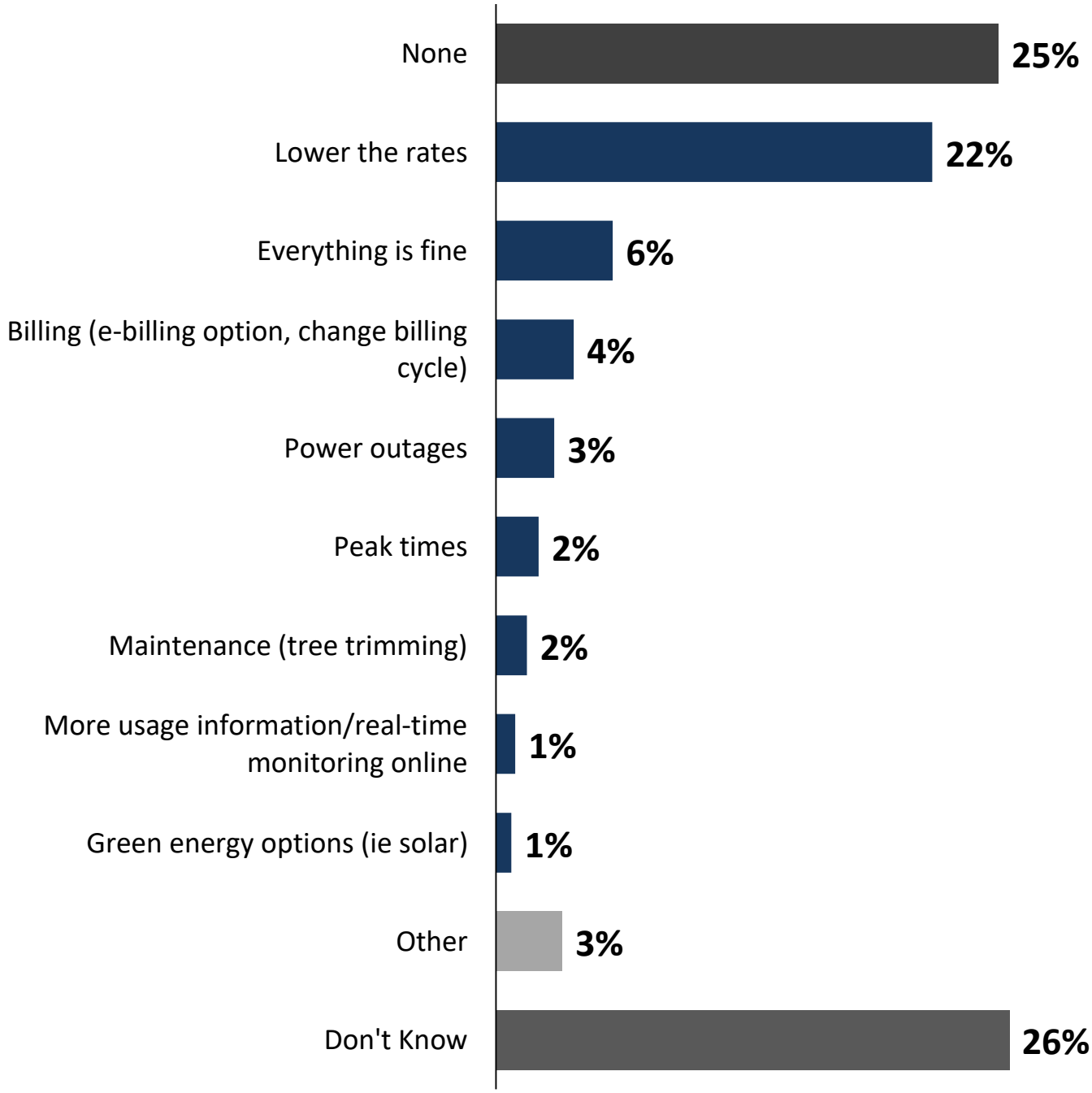
Note: 'Don't Know' (1%) not shown.

Suggestions for Improved Services

Residential

Q Is there anything in particular KW Hydro can do to improve its services to you?

[OPEN; asked all respondents, n=511]



Note: 'Refused' (5%) not shown.

Bill Knowledge

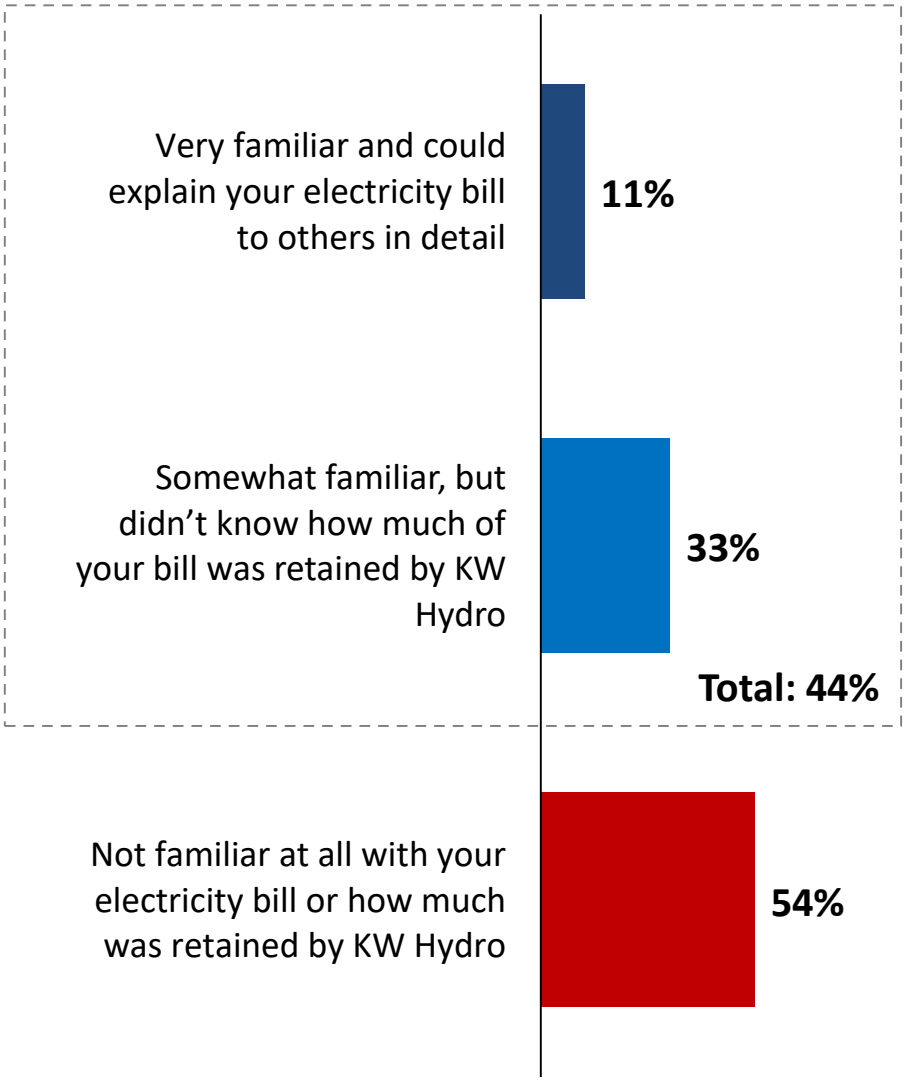
Residential

Q While **KW Hydro** is responsible for billing customers for the entire electricity bill, about 23% of the electricity bill pays for KW Hydro's distribution system. This is about **22 dollars and 75 cents** on an average **$101** monthly residential electricity bill.

The rest of the bill goes to power generation companies, transmission companies, regulatory agencies, and government taxes.

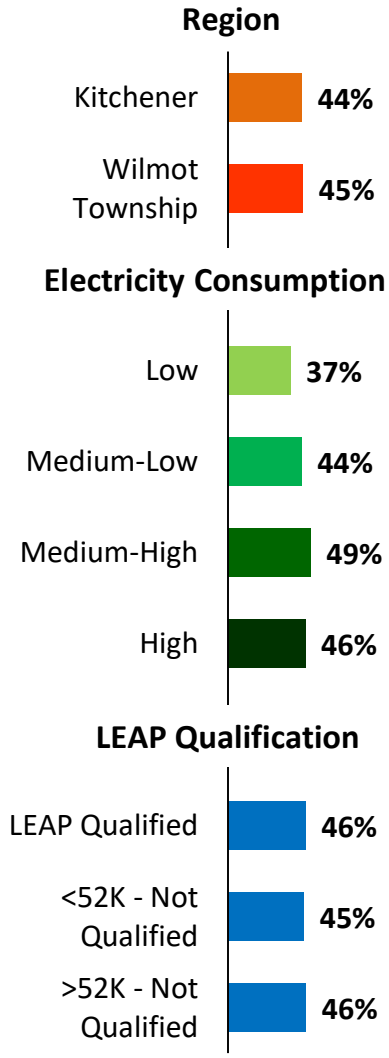
Before this survey, how familiar were you with the percentage of your electricity bill that is retained by KW Hydro?

[asked all respondents, n=511]



Segmentation

Respondents who say "Familiar"



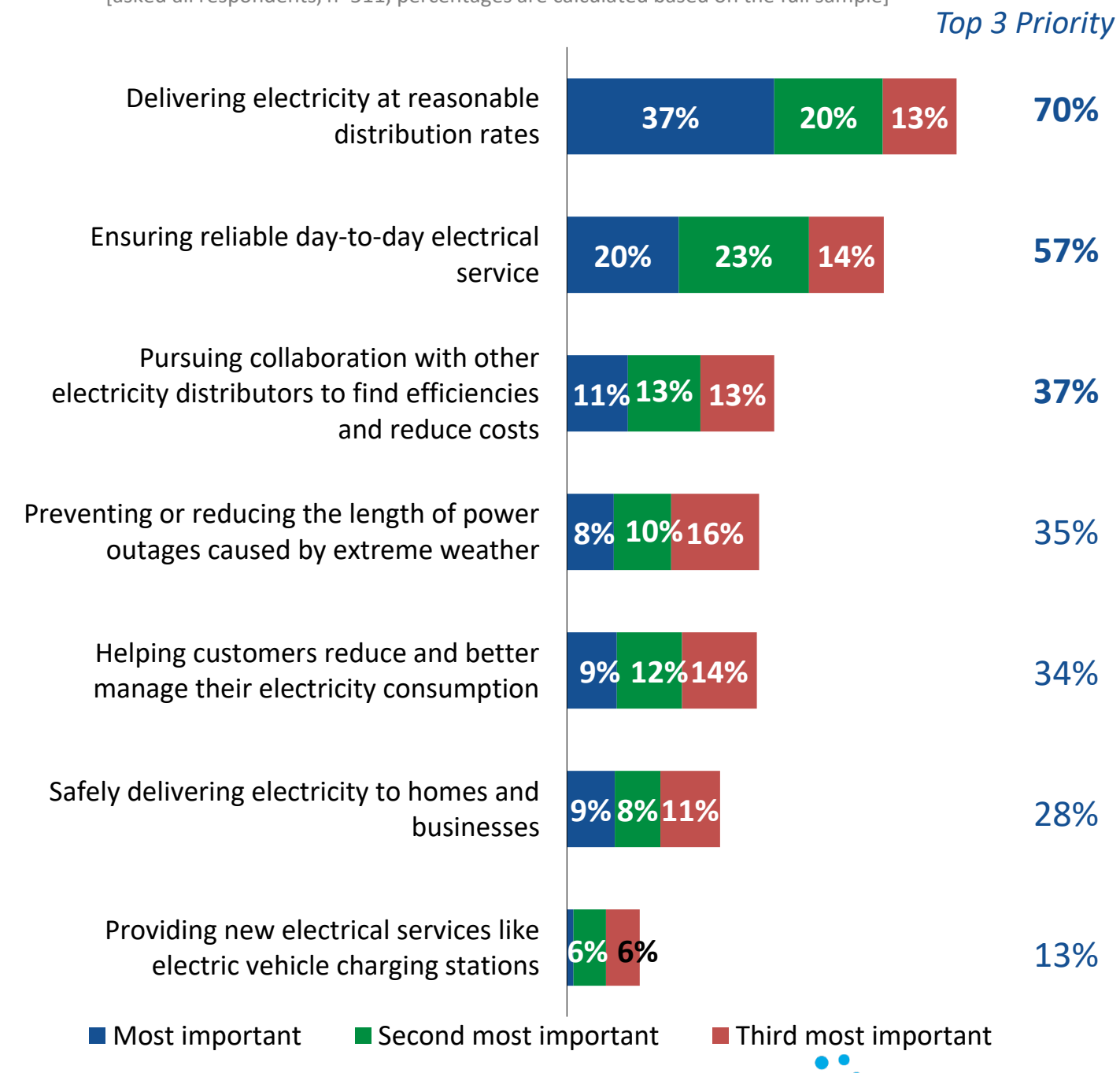
Note: 'Don't Know' (2%) not shown.

Customer Priorities

Residential

Q **KW Hydro** wants to better understand customer priorities. Among the following **KW Hydro** priorities, please tell me which one is most important to you.

[asked all respondents, n=511, percentages are calculated based on the full sample]



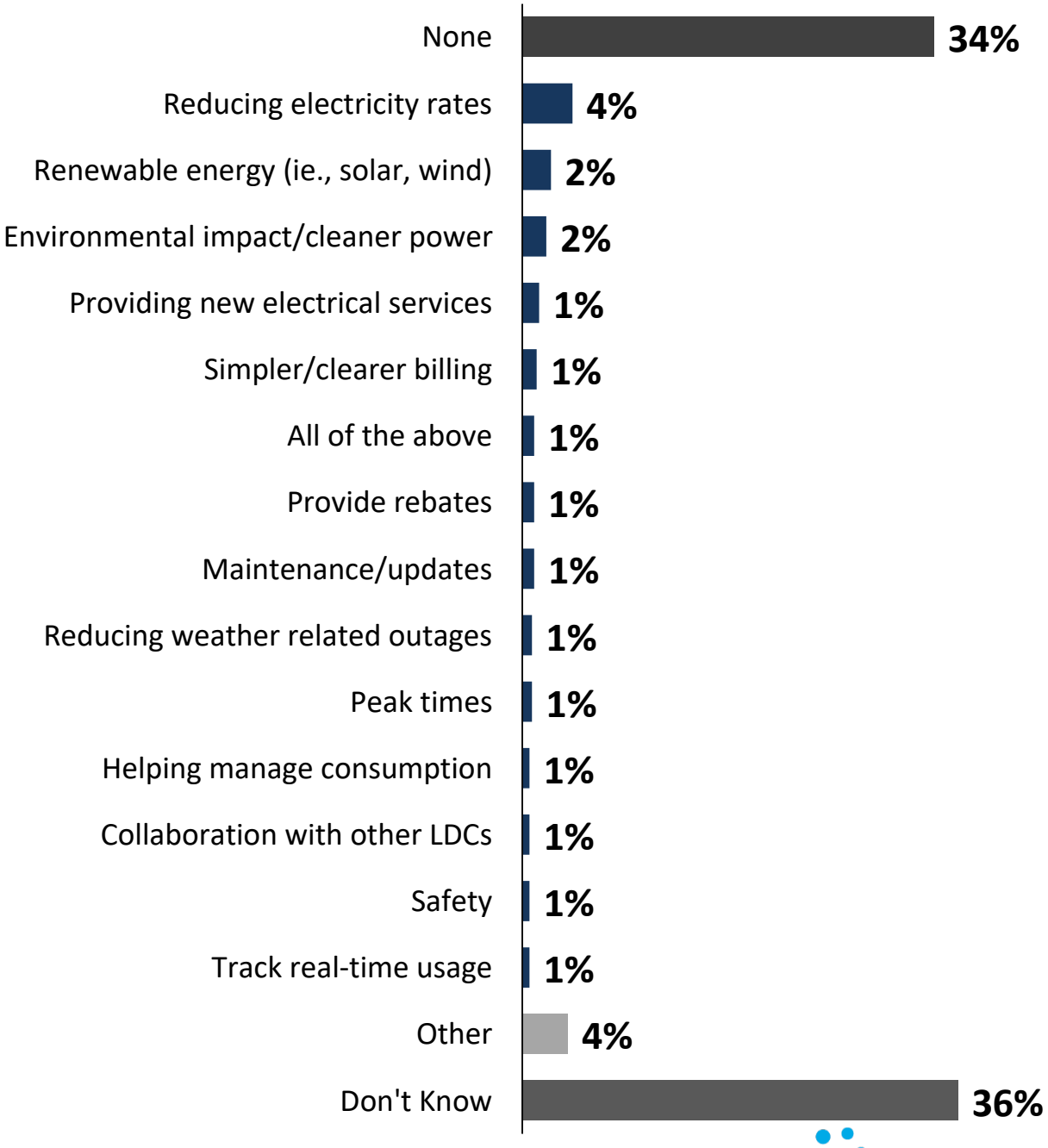
Note: 'Don't Know' and 'Refused' not shown.

Additional Customer Priorities

Residential

Q Are there any other important priorities that **KW Hydro** should be focusing on that weren't included in the previous list I read to you?

[asked all respondents, n=511]



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System Reliability Priorities

Residential

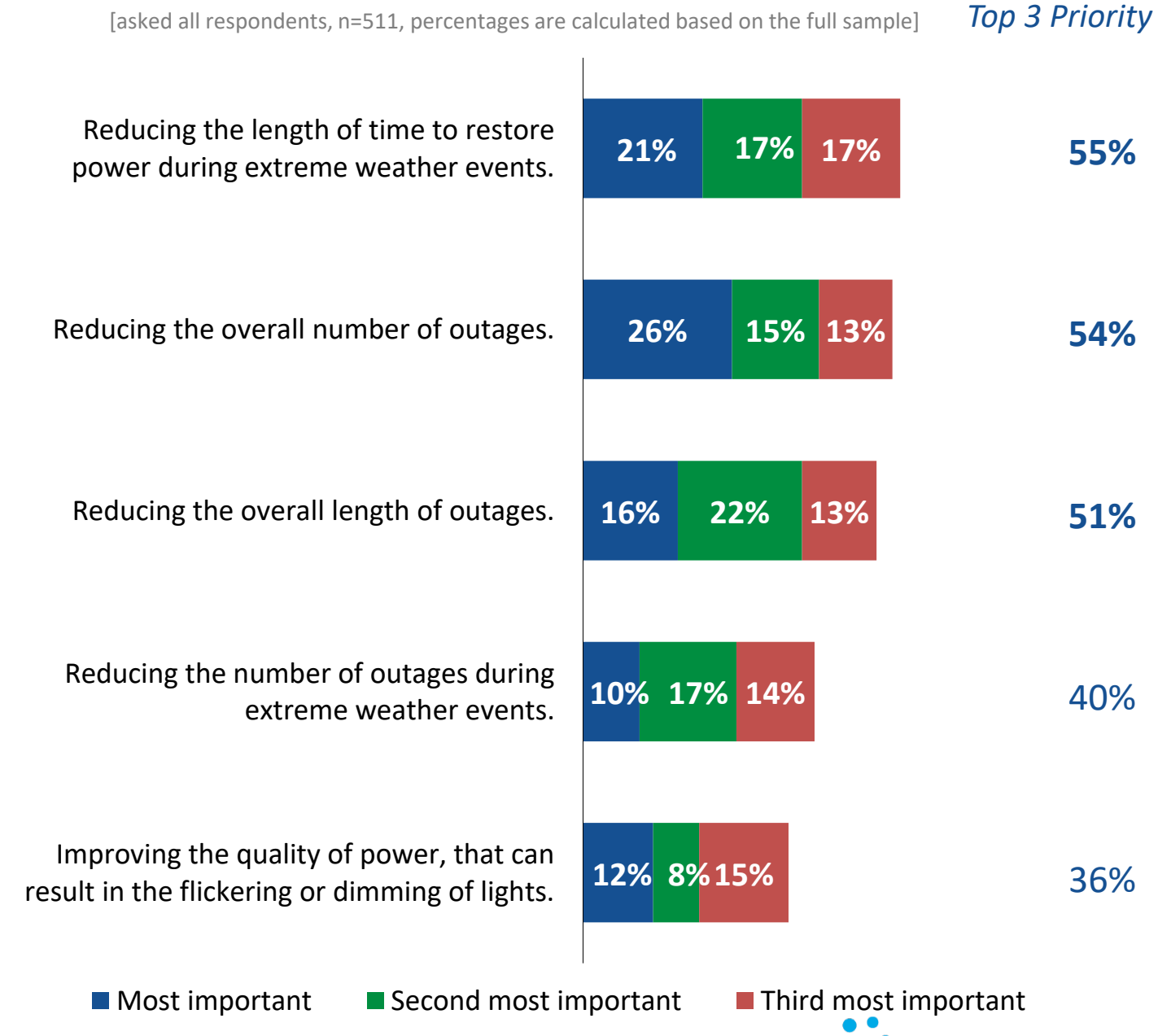
Q

We would like to understand your experience with reliability.

There are different outcomes when customers talk about power reliability.

Among the following reliability outcomes, please tell me which one is most important to you.

[asked all respondents, n=511, percentages are calculated based on the full sample]



Note: 'Don't Know' and 'Refused' not shown.

Planning Principles & Pacing Investments Preamble

Residential

Based on customer feedback, legal and regulatory obligations and internal business planning, **KW Hydro** has developed a plan that invests in projects that aim to improve reliability and customer service, a new basic customer information system and accommodates new customers.

It is estimated that if **KW Hydro** continues with its current plan, the distribution portion of the bill will increase by **about one dollar** in 2020. For the period 2021 to 2024, the annual bill increase is limited by the Ontario Energy Board to less than the rate of inflation – or approximately **1.35 percent**.

Over the course of the proposed 5-year plan, the typical residential customer would see the distribution portion of their electricity bill increase by **two dollars and 36 cents**.

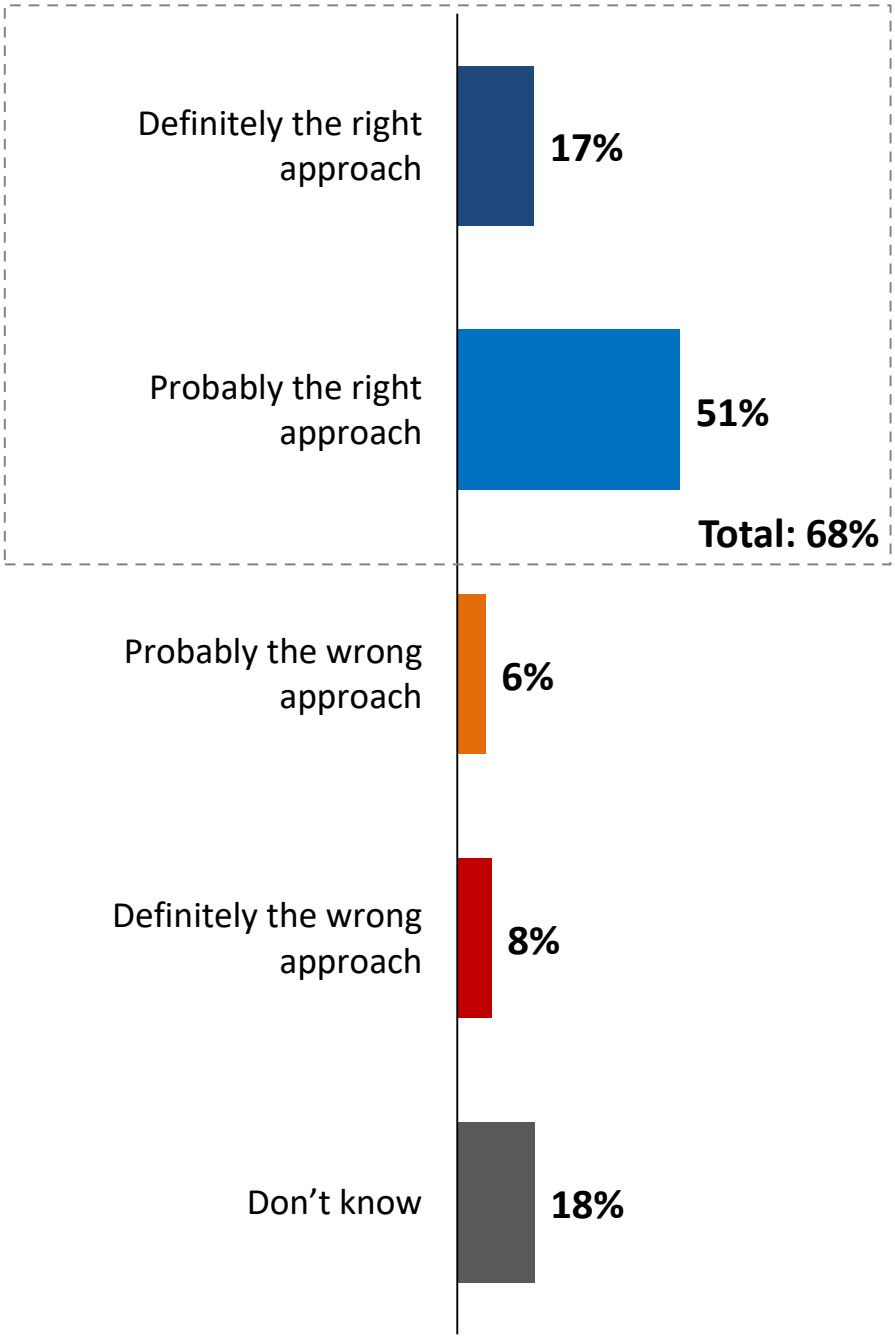
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Approach to Planning for the Next Five Years

Residential

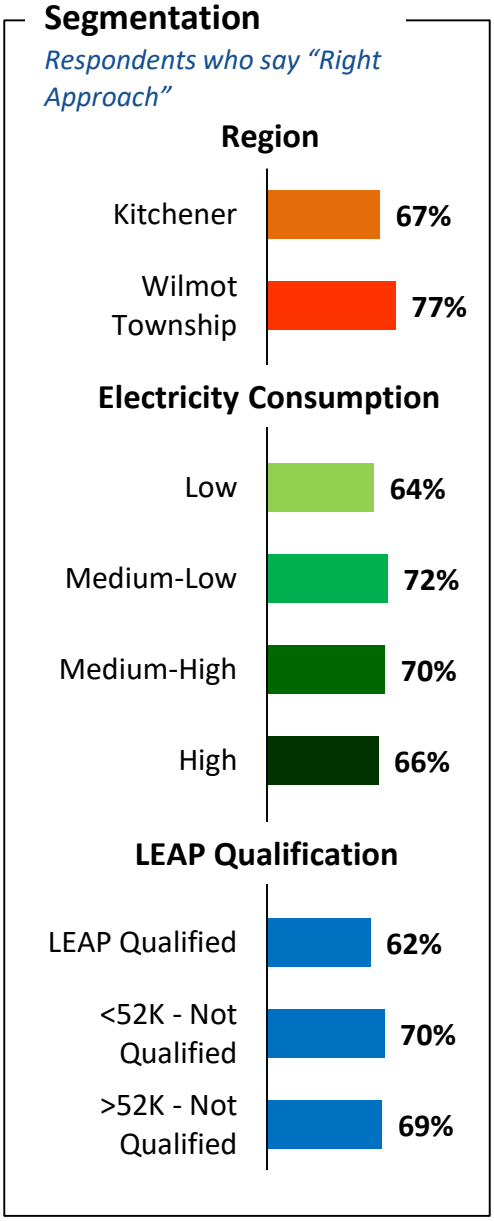
Q Do you feel that KW Hydro's approach to planning for the next five years is definitely the right approach, probably the right approach, probably the wrong approach, definitely the wrong approach or would you say you don't know?

[asked all respondents, n=511]



Segmentation

Respondents who say "Right Approach"



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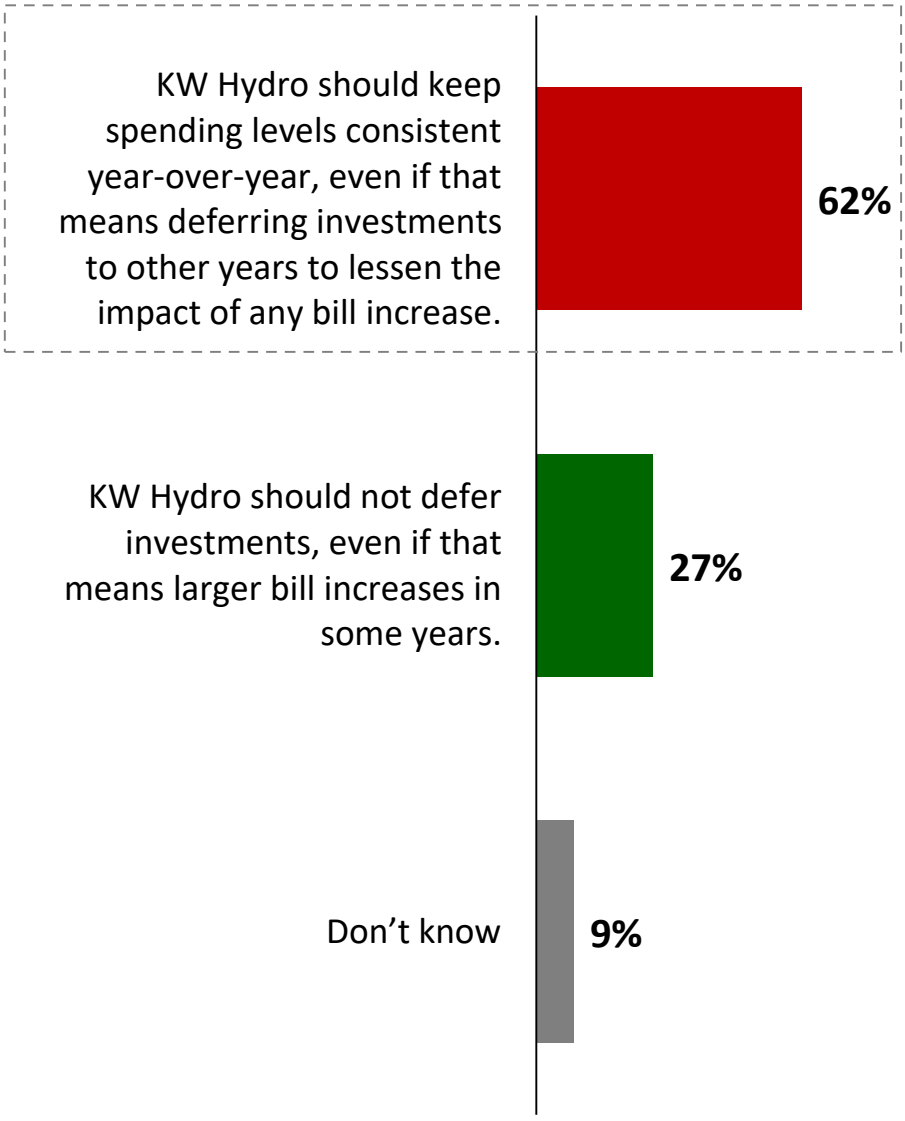
Pacing Investments

Residential

The overall amount **KW Hydro** invests in capital projects remains generally the same year over year, but what does change is where these investments are made. **KW Hydro** carefully paces spending on capital projects to remain as consistent as possible so the impact to customer rates is minimal. What does change is where the investments are made.

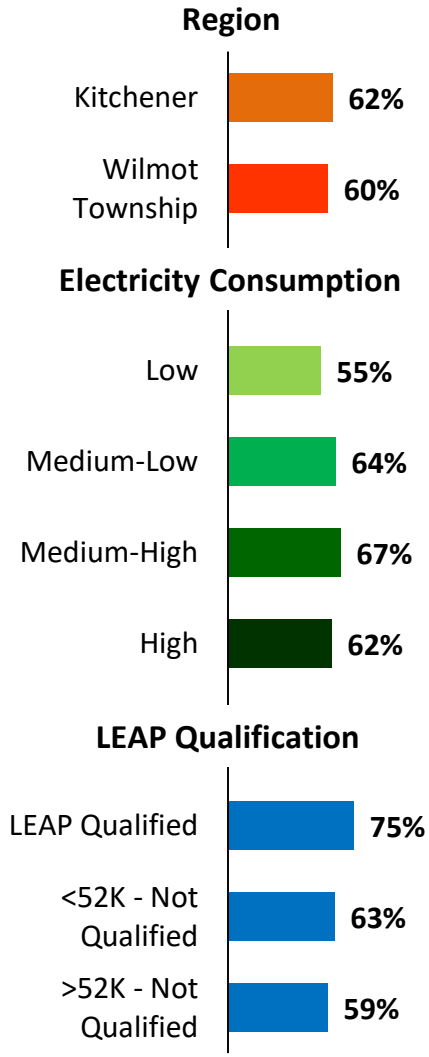
Which of the following statements best represents your point of view regarding **KW Hydro's** approach to pacing investments?

[asked all respondents, n=511]



Segmentation

Respondents who say "Keep spending levels consistent"



Note: 'Refused' (2%) not shown.

Preamble to Capital Plan Priorities and System Renewal

Residential

KW Hydro has identified four areas where it could accelerate investments. These accelerated projects could increase the **typical customer's bill by 83 cents** per month by 2024. These projects are in addition to the two dollar and 36 cent increase that is currently being proposed.

KW Hydro wants to get your feedback on these four particular projects before deciding whether or not to accelerate its investment plan in certain specific areas.

First, a recent asset health condition assessment shows that 15% of the poles in **KW Hydro's** distribution system are in poor or very poor condition. Customers served by these lines are more likely to experience power outages, and when they do, those outages are more likely to last longer and be more expensive to fix.

KW Hydro is proposing to replace these poles over the course of the next five years, however, there is an opportunity to replace these poles more quickly, improving reliability for customers served by this type of equipment.

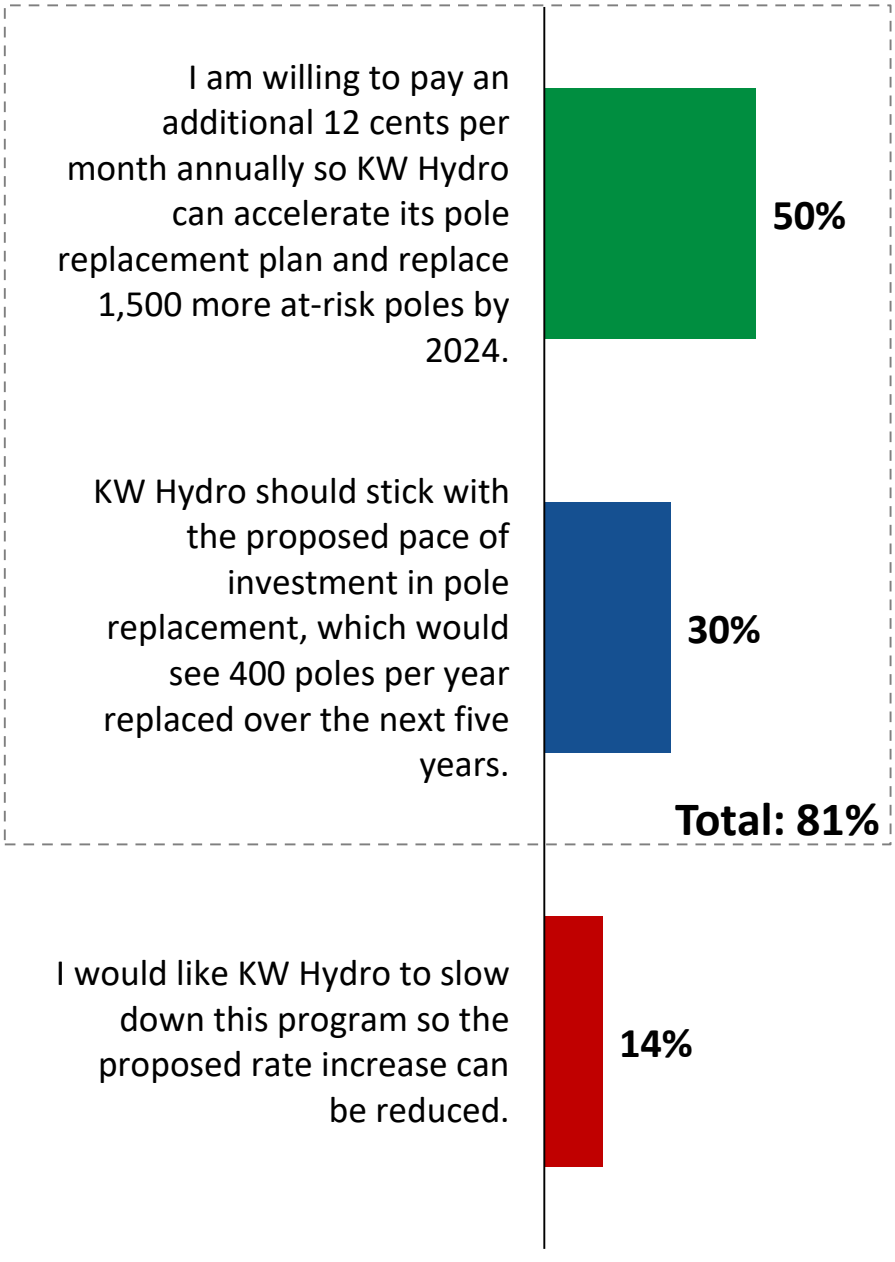
INNOVATIVE RESEARCH GROUP

Pole Replacement

Residential

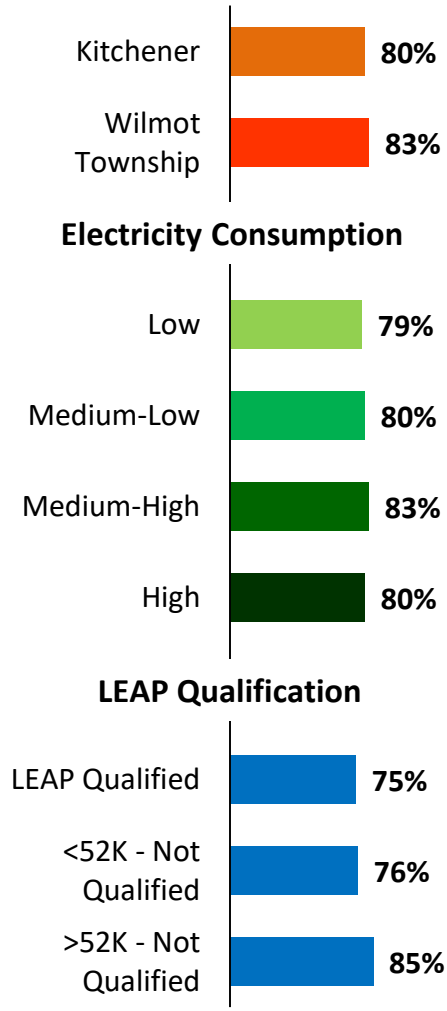
Q Which of the following is closest to your point of view regarding KW Hydro's pole replacement program?

[asked all respondents, n=511]



Segmentation

Respondents who say "Accelerate plan or stick with proposed"



Note: 'Don't Know' (4%) and 'Refused' (1%) not shown.

Preamble to Power Transformer Replacement Program

Residential

The second of four projects is related to **KW Hydro's** power transformer replacement program.

After analysis, it was determined that two power transformers are nearing end of life. These transformers are more than 40 years old and require a long time to replace. While initially they served **KW Hydro** customers well, they now pose reliability concerns.

These transformers feed entire neighbourhoods. Should either of these transformers fail, it could cause prolonged outages and result in more costly reactive costs. That said, they have been in service for more than 40 years, and could continue to operate even longer.

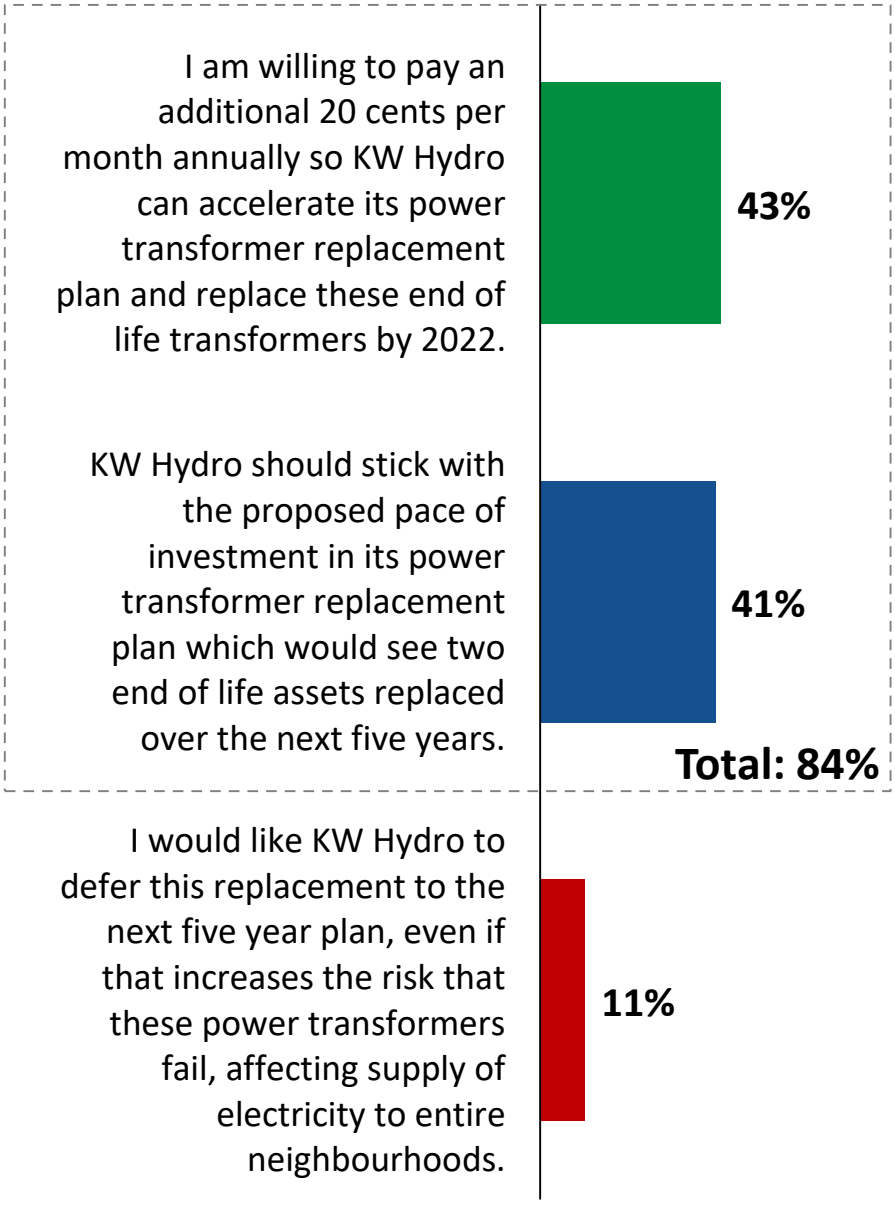
INNOVATIVE RESEARCH GROUP

Power Transformer Replacement

Residential

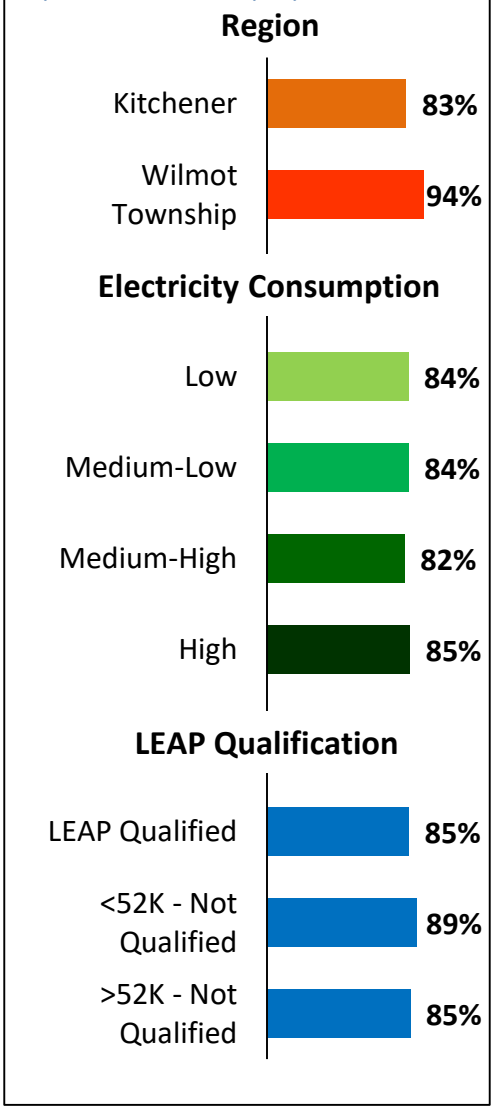
Q Which of the following is closest to your point of view regarding KW Hydro's power transformer replacement program?

[asked all respondents, n=511]



Segmentation

Respondents who say "Accelerate plan or stick with proposed"



Note: 'Don't Know' (4%) and 'Refused' (2%) not shown.

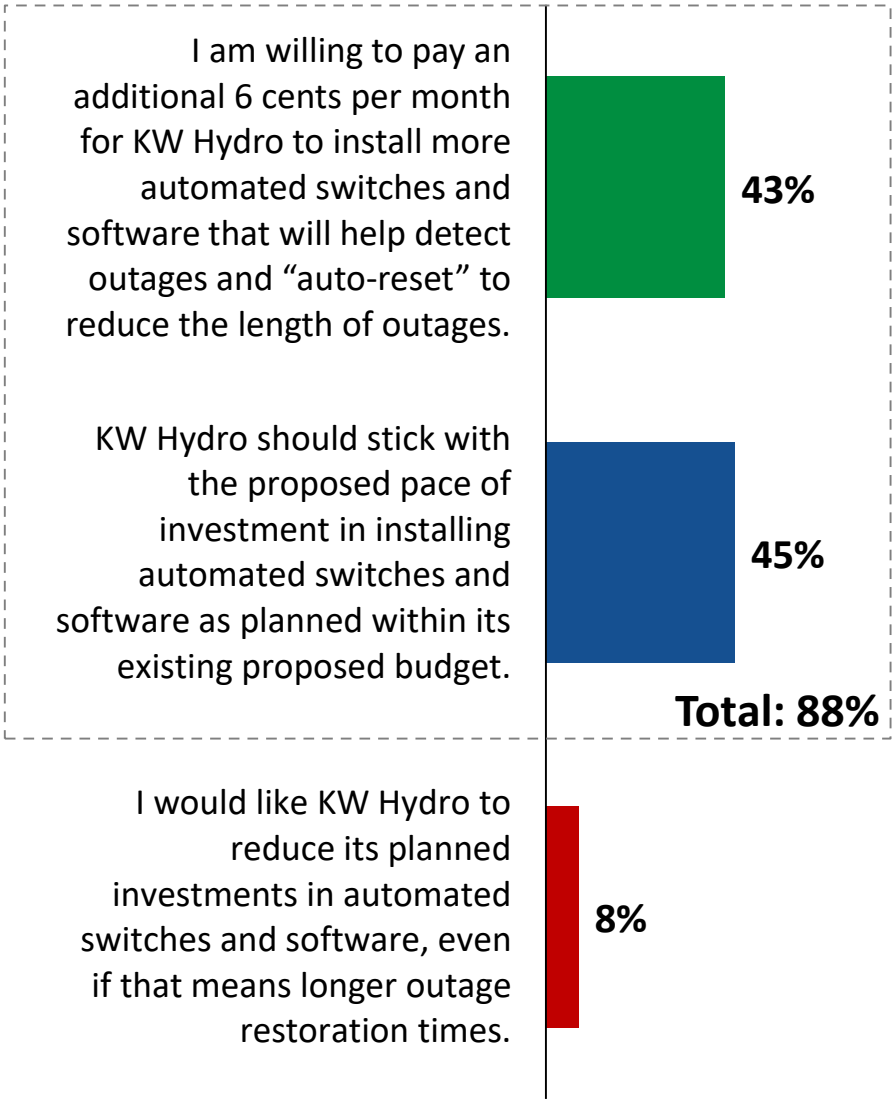
Spending on Automated Switches

Residential

Q Investments in technology -- such as automated switches -- helps KW Hydro quickly identify the location of outages, minimizes the number of people impacted by outages, and restores electricity to customers more quickly than was previously possible.

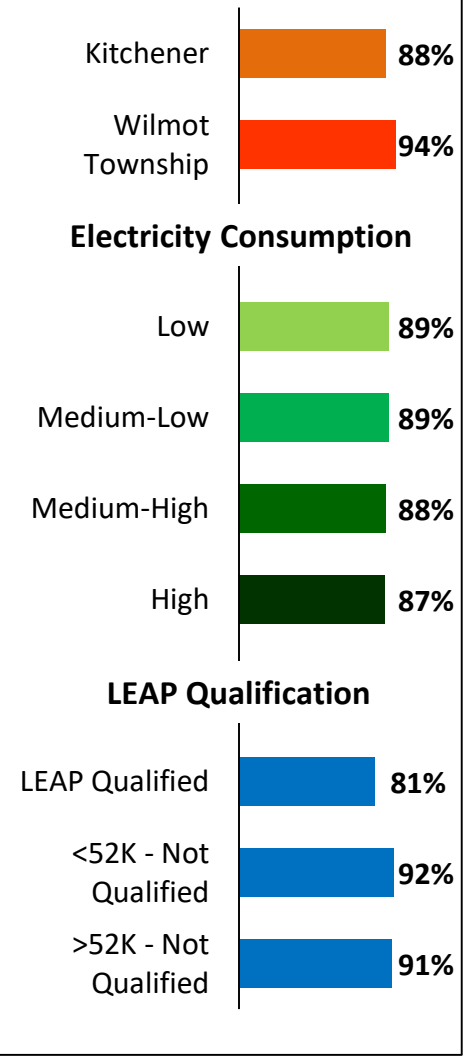
Regarding spending on automated switches, which of the following best represents your point of view?

[asked all respondents, n=511]



Segmentation

Respondents who say "Install more or stick with proposed"



Note: 'Don't Know' (3%) and 'Refused' (1%) not shown.

Customer Information System (CIS) Preamble



The final project is related to **KW Hydro's** 30-year-old customer information system or C-I-S, which requires replacement.

After an extensive procurement process, KW Hydro has identified two potential options: a basic system or an enhanced system with more features.

The first is a basic CIS, which provides features needed to ensure customers continue to receive a bill on time. This basic CIS will cost the typical customer 78 cents on the distribution portion of their electricity bill starting in 2020. This is included in the proposed two dollar and 36 cent increase.

The second is an enhanced CIS, which would allow **KW Hydro** to send email or text alerts, provide insights into electricity consumption, a self-service customer portal and automated and streamlined processes to improve the utility's back office efficiency. The enhanced CIS would cost customers an additional **46 cents** per month.

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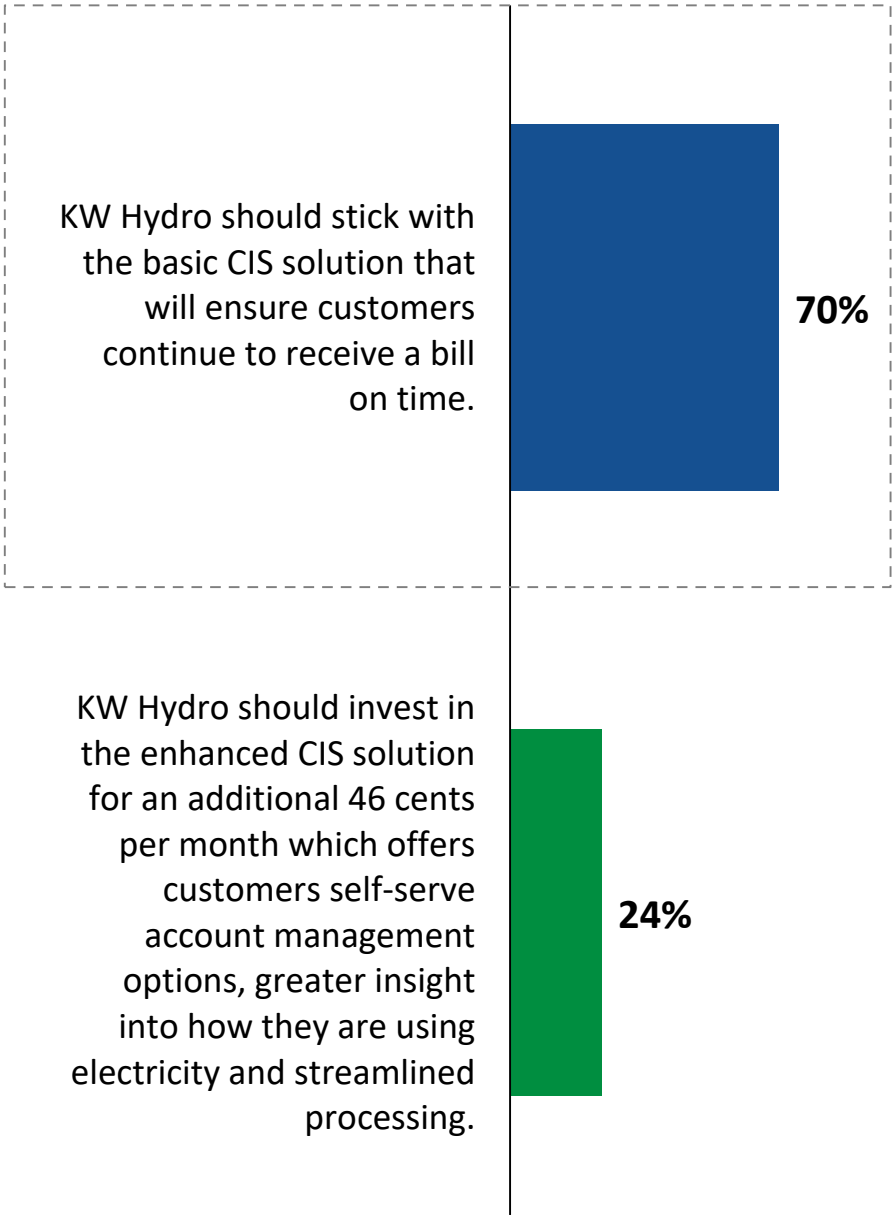
General Plant

Customer Information System

Residential

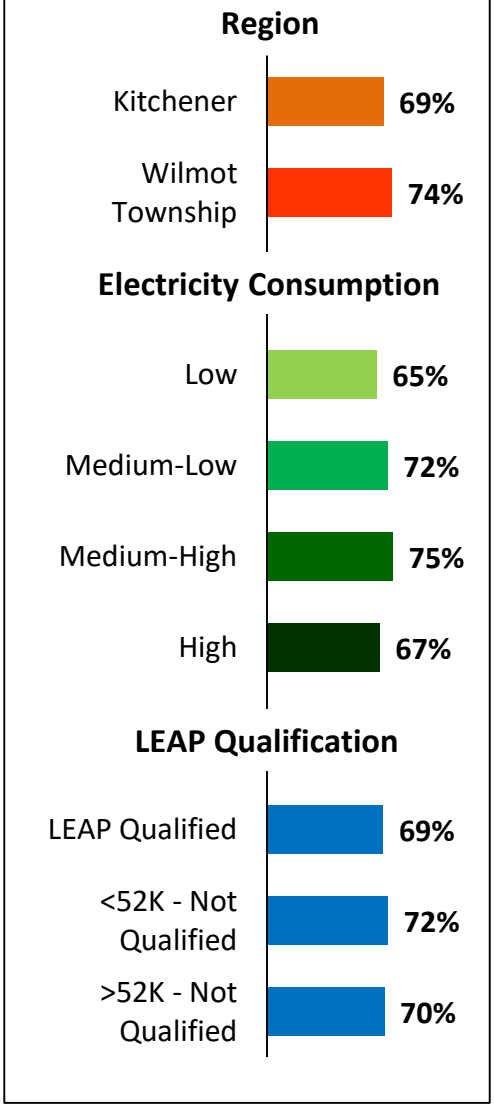
Q Which of the following statements best represents your point of view?

[asked all respondents, n=511]



Segmentation

Respondents who say "Stick with basic CIS solution"



Note: 'Don't Know' (5%) and 'Refused' (2%) not shown.

Assessment of Proposed Plan Preamble



Remember, the typical **KW Hydro** residential customer's electricity bill is about $101 per month, of which 23% or **22 dollars and 75** cents goes to KW Hydro.

Over the course of the proposed 5-year plan, the typical residential customer would see the KW Hydro portion of their electricity bill increase by **2 dollars and 36 cents** per month.

Throughout its planning process, **KW Hydro** has identified four potential investments that could be made beyond what is currently being proposed. Those four investments have been discussed throughout this survey.

These incremental investments would offer benefits to customers ranging from improved reliability to enhanced customer service offerings.

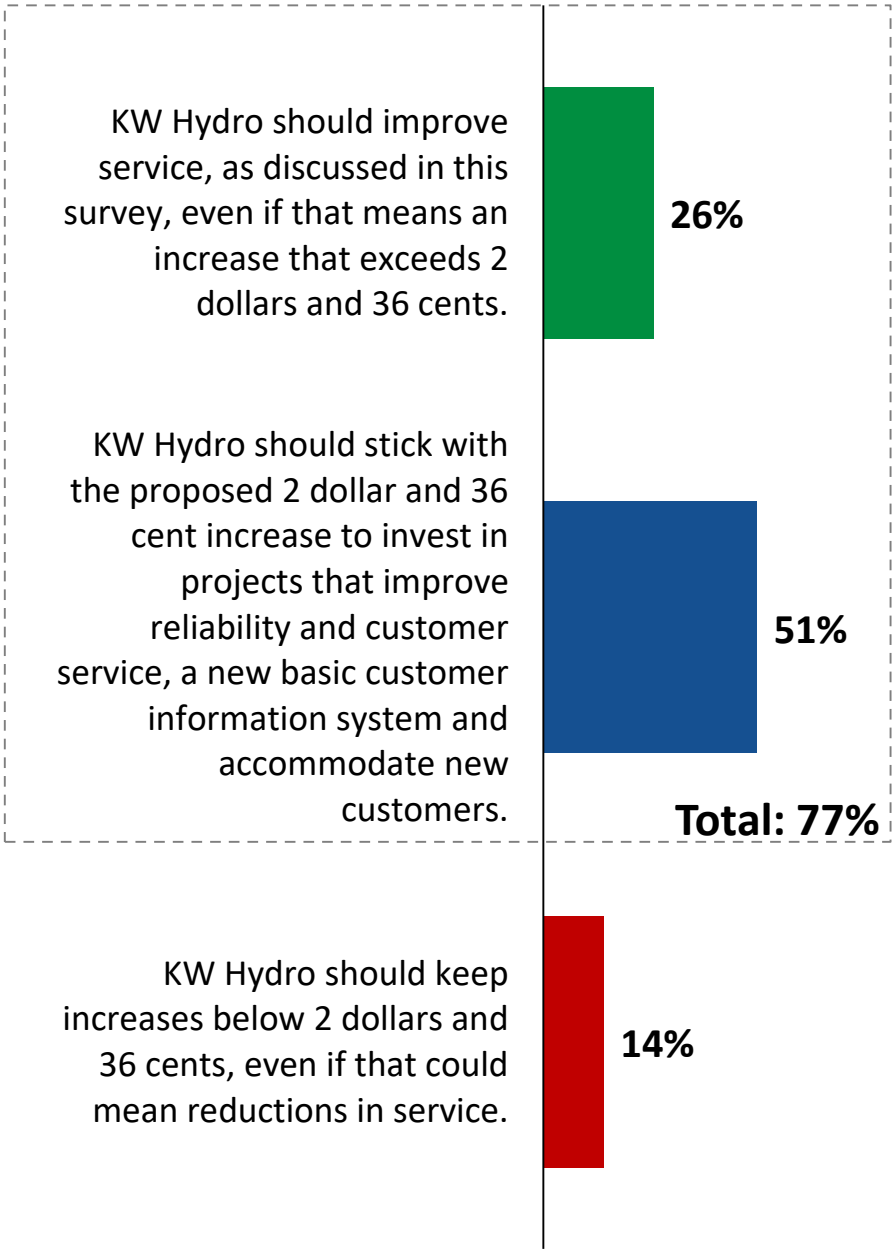
INNOVATIVE RESEARCH GROUP

Assessment of Proposed Plan

Residential

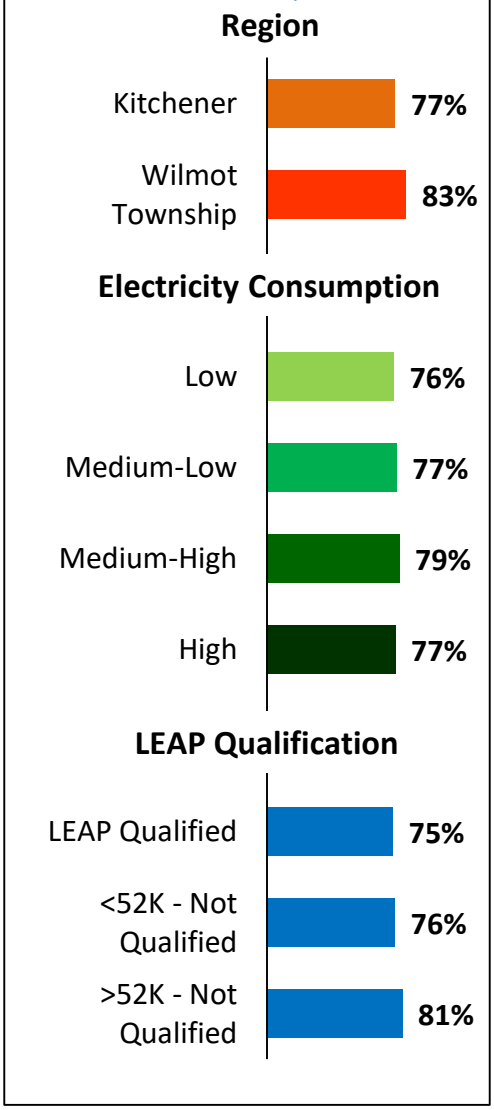
Q Considering what you know about KW Hydro's proposed plan, which of the following best represents your point of view?

[asked all respondents, n=511]



Segmentation

Respondents who say "Improve services or stick with plan"



Note: 'Don't Know' (5%) and 'Refused' (3%) not shown.

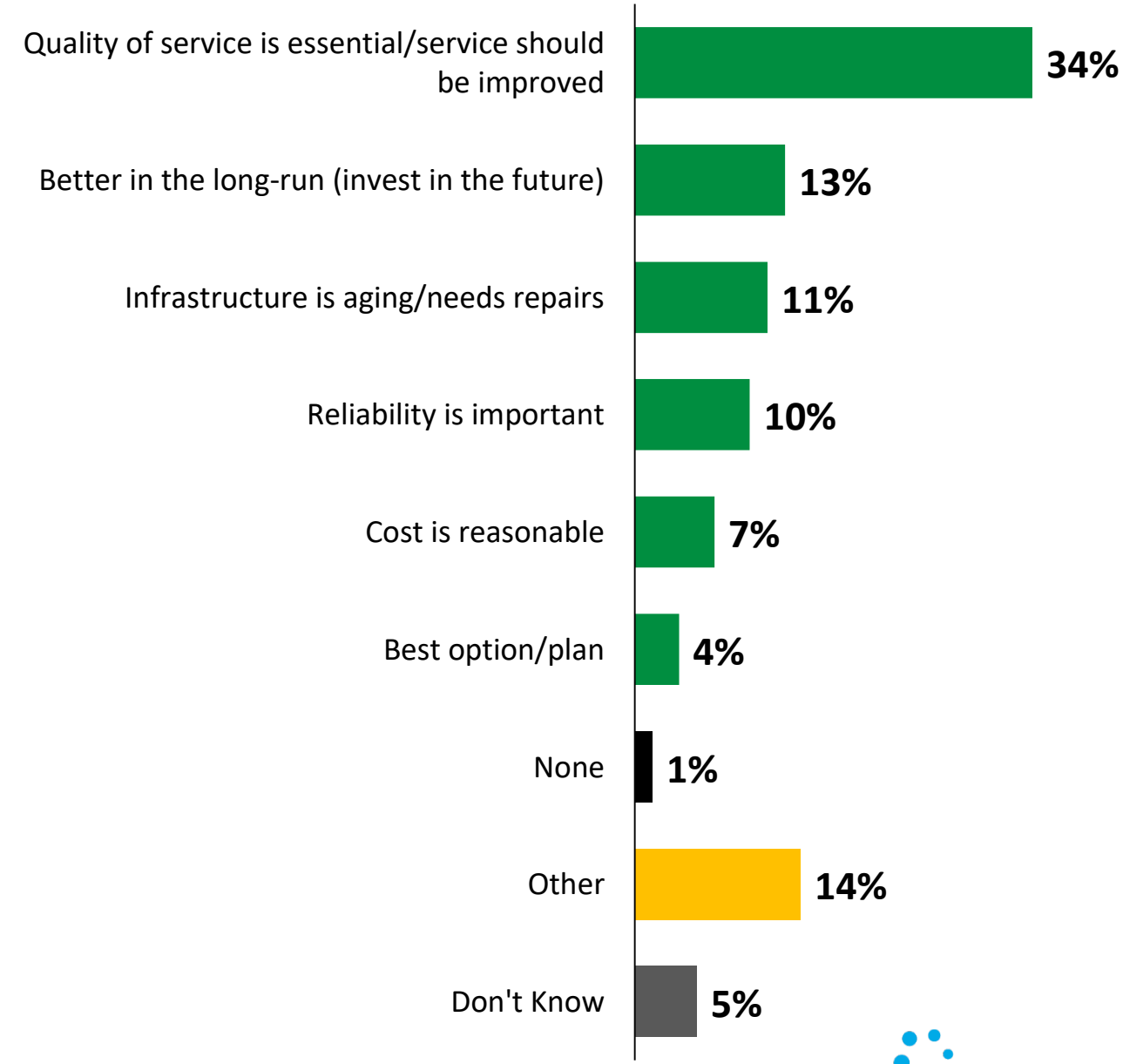
Opinion of KW Hydro's Proposed Plan

Residential

Q And why do you say that?

[asked all respondents, n=134]

Amongst those who answered: KW Hydro should improve service, as discussed in this survey, even if that means an increase that exceeds 2 dollars and 36 cents. (n=134)



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Note: 'Refused' (2%) not shown.

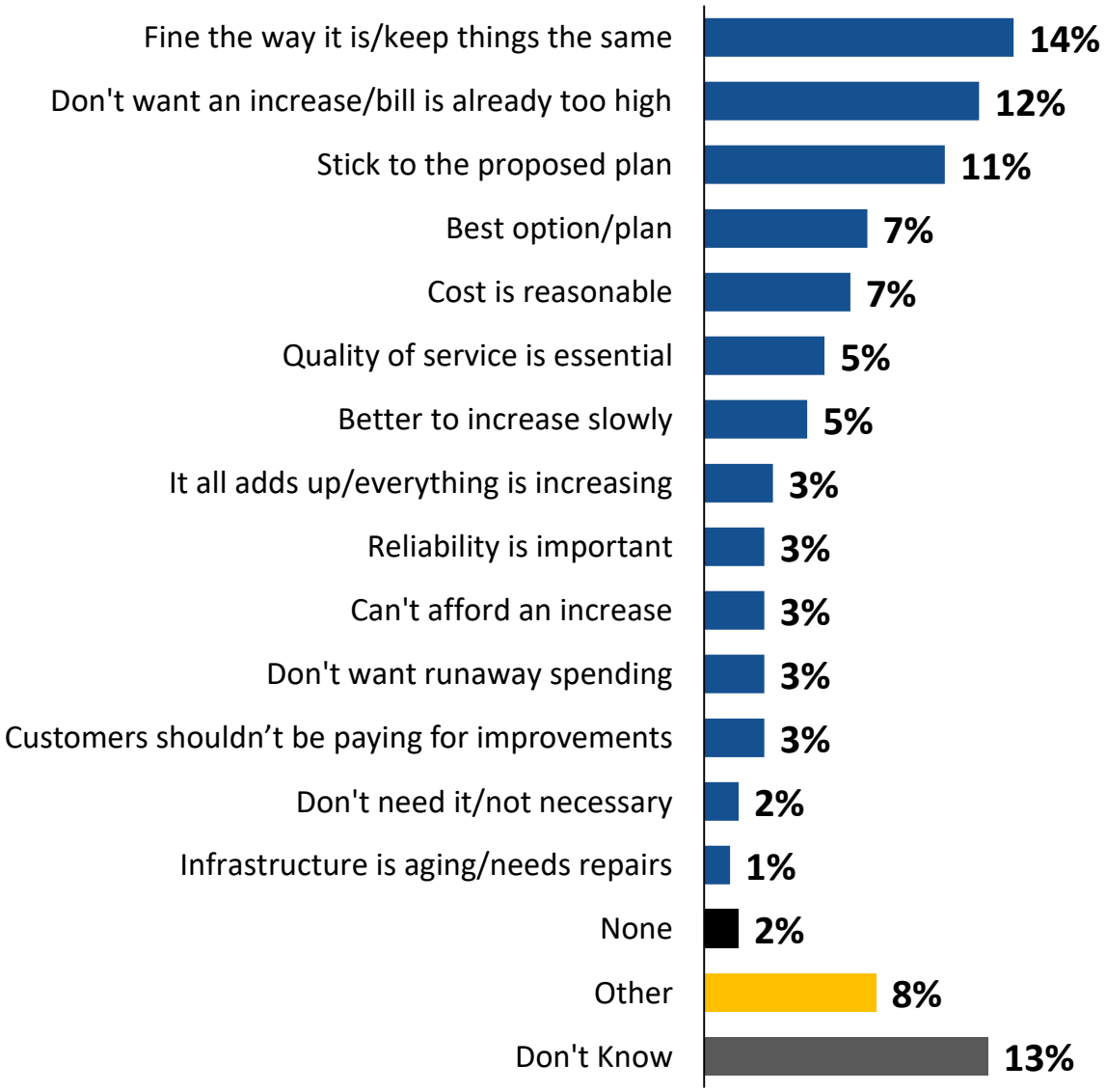
Opinion of KW Hydro's Proposed Plan

Residential

Q And why do you say that?

[asked all respondents, n=260]

Amongst those who answered: KW Hydro should stick with the proposed 2 dollar and 36 cent increase to invest in projects that improve reliability and customer service, a new basic customer information system and accommodate new customers. (n=260)



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Note: 'Refused' (<1%) not shown.

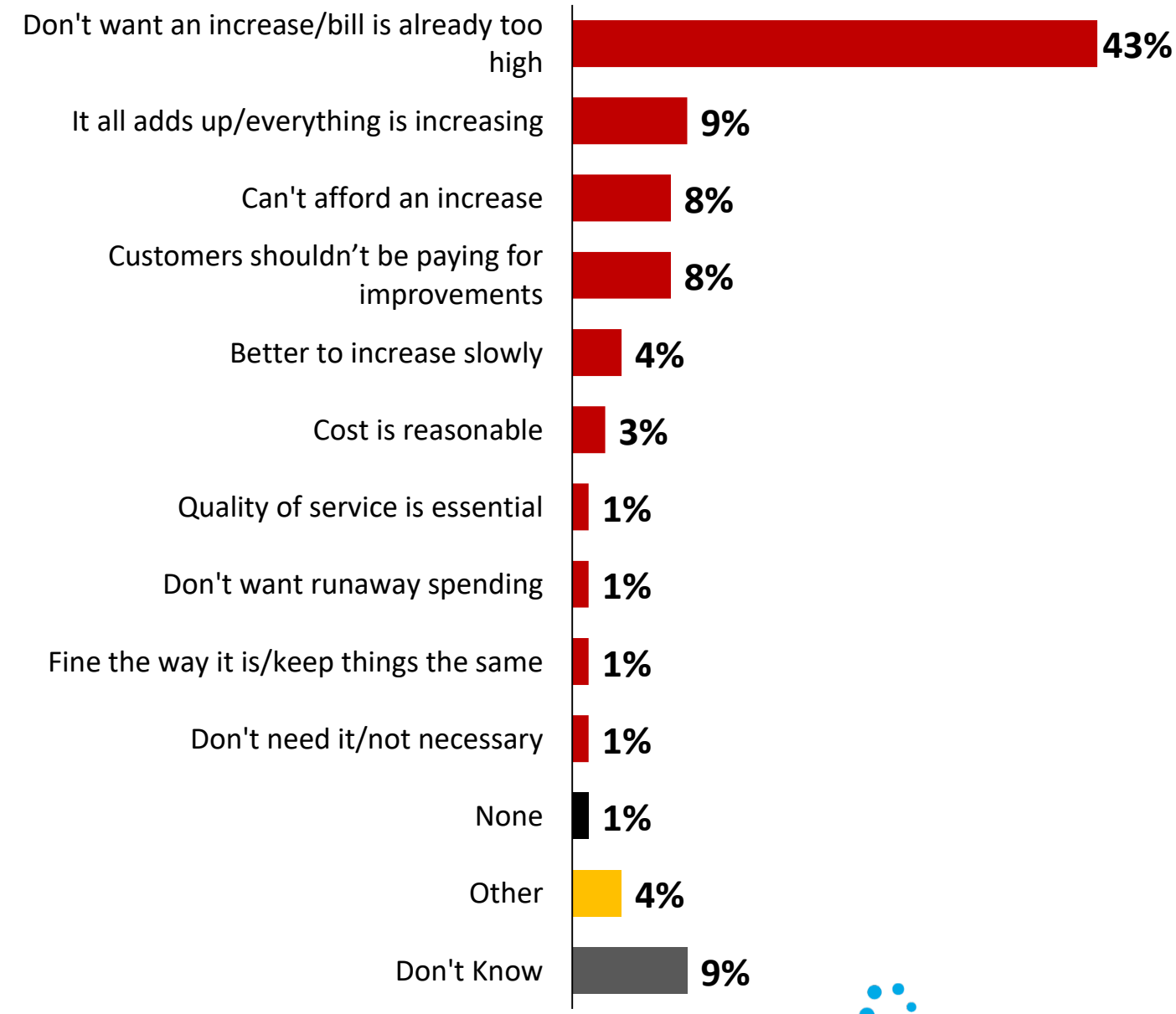
Opinion of KW Hydro's Proposed Plan

Residential

Q And why do you say that?

[asked all respondents, n=74]

Amongst those who answered: KW Hydro should keep increases below 2 dollars and 36 cents, even if that could mean reductions in service. (n=74)



Note: 'Refused' (4%) not shown.

Segmentation and Demographics

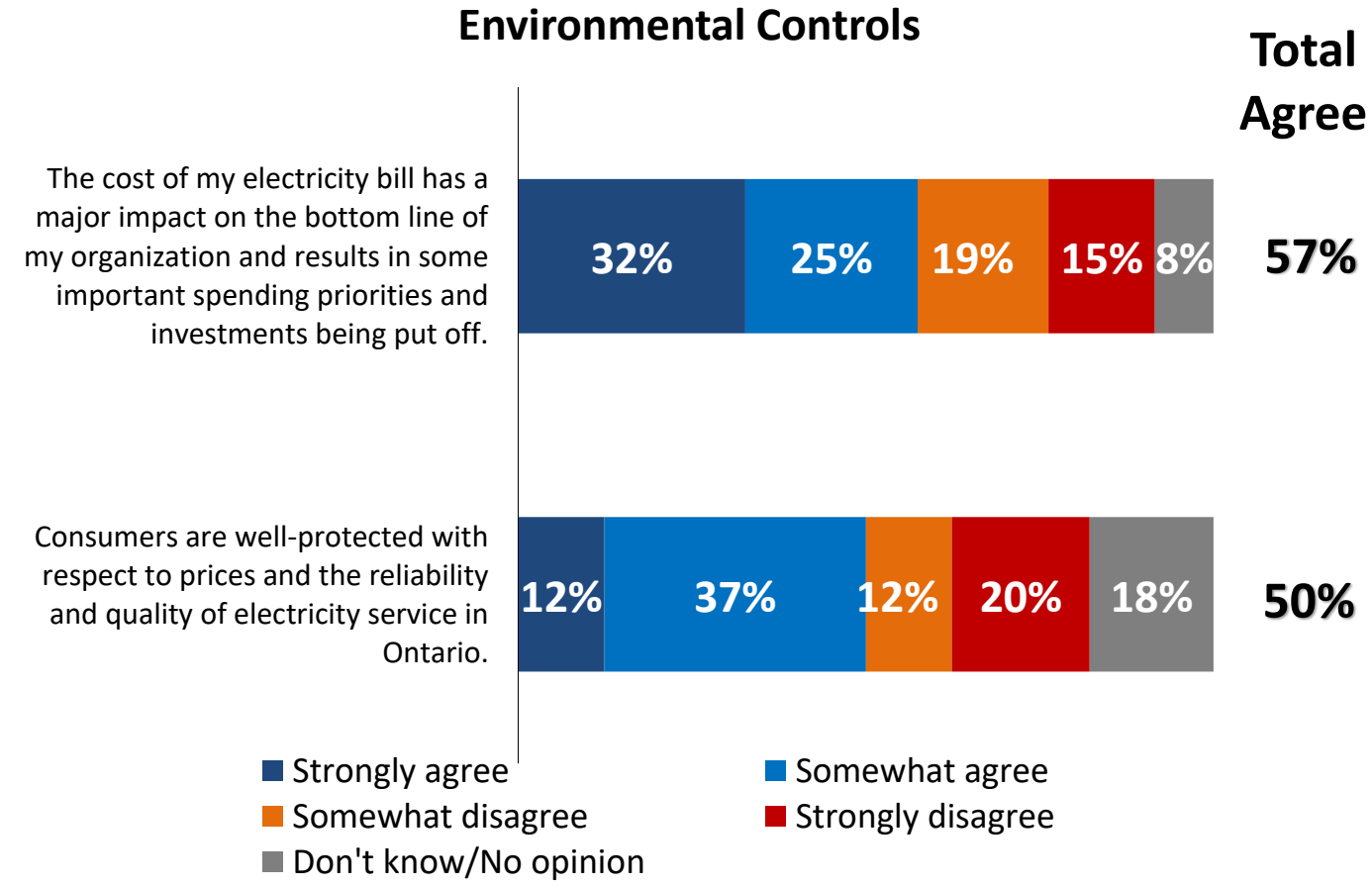


Small Business

Segmentation & Demographics

Small Business

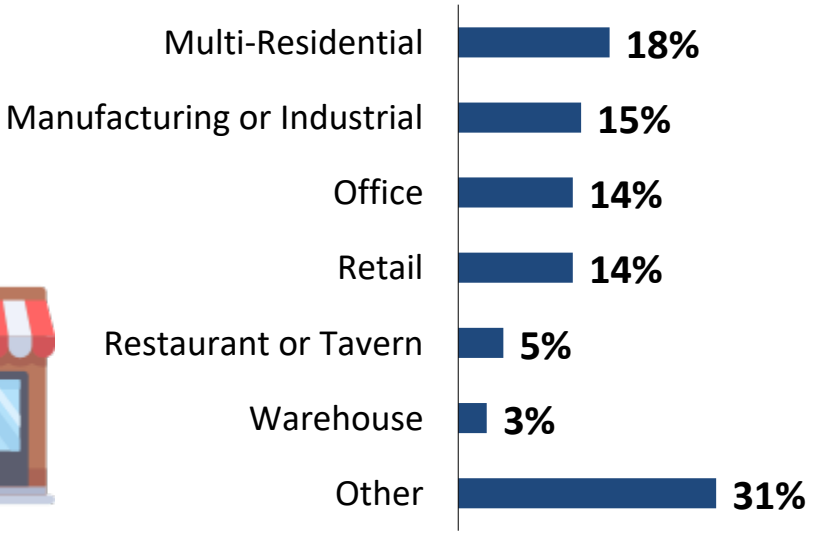
Environmental Controls



Note: 'Refused' not shown.

Business Type





Familiarity Preamble



“As you may know, **KW Hydro** operates and maintains the local electricity distribution system, delivers electricity throughout the community, reads meters, calculates and collects customer electricity bills, answers customer calls, responds during outages, clears trees from power lines and delivers electricity conservation programs.”

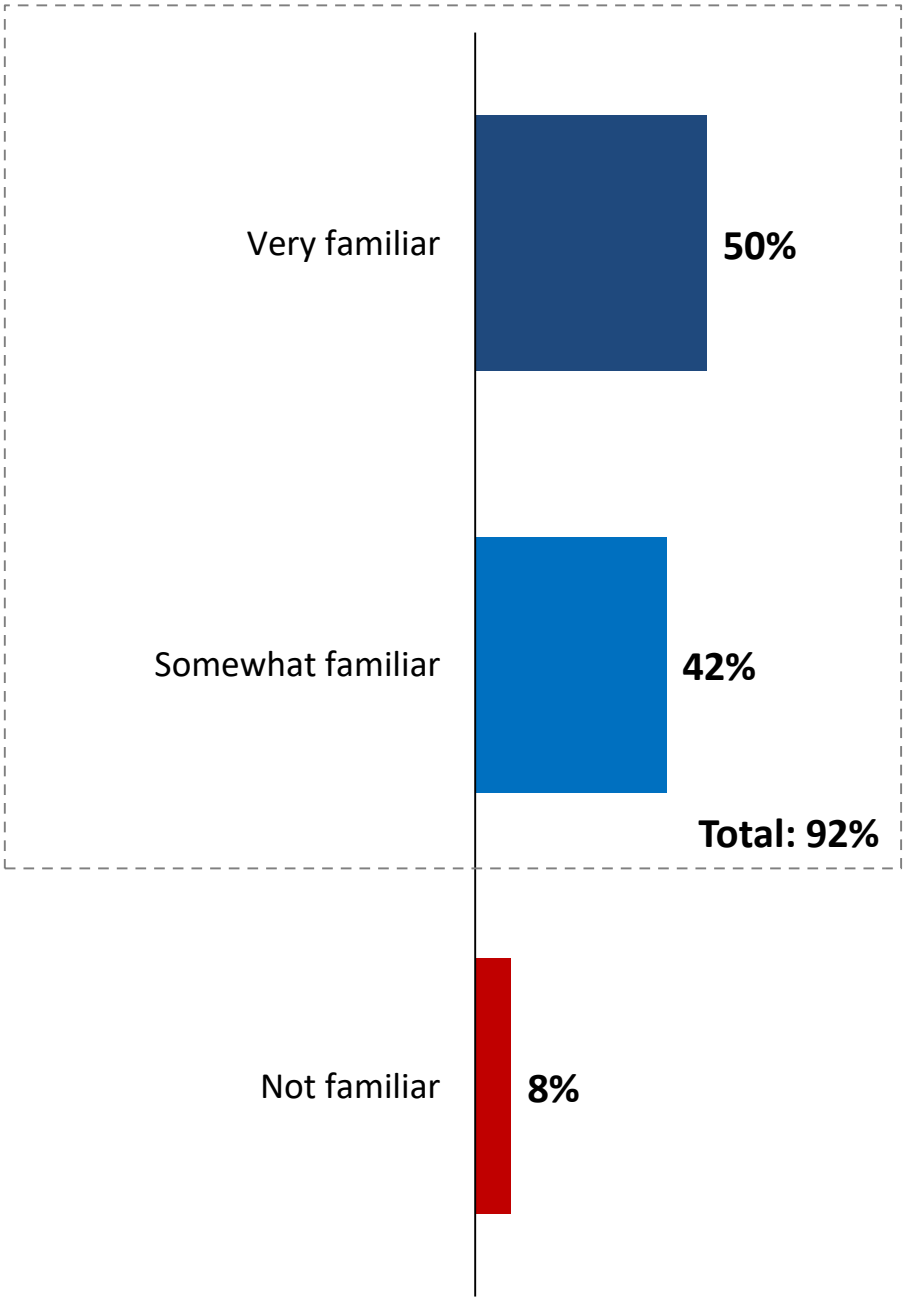
INNOVATIVE RESEARCH GROUP

Familiarity with Kitchener-Wilmot Hydro

Small Business

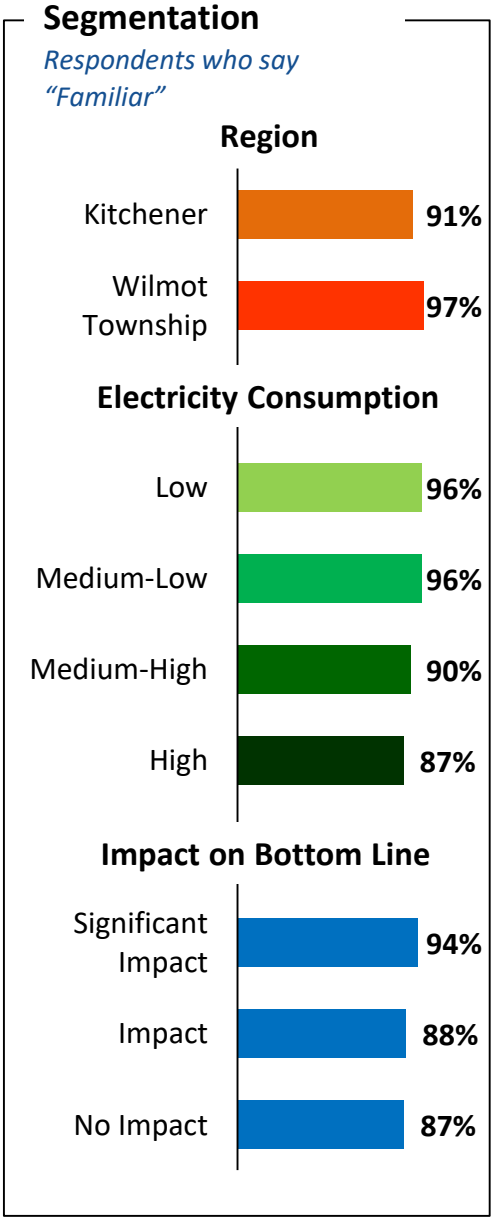
Q In general, how familiar are you with KW Hydro as your local distribution company?

[asked all respondents, n=204]



Segmentation

Respondents who say "Familiar"



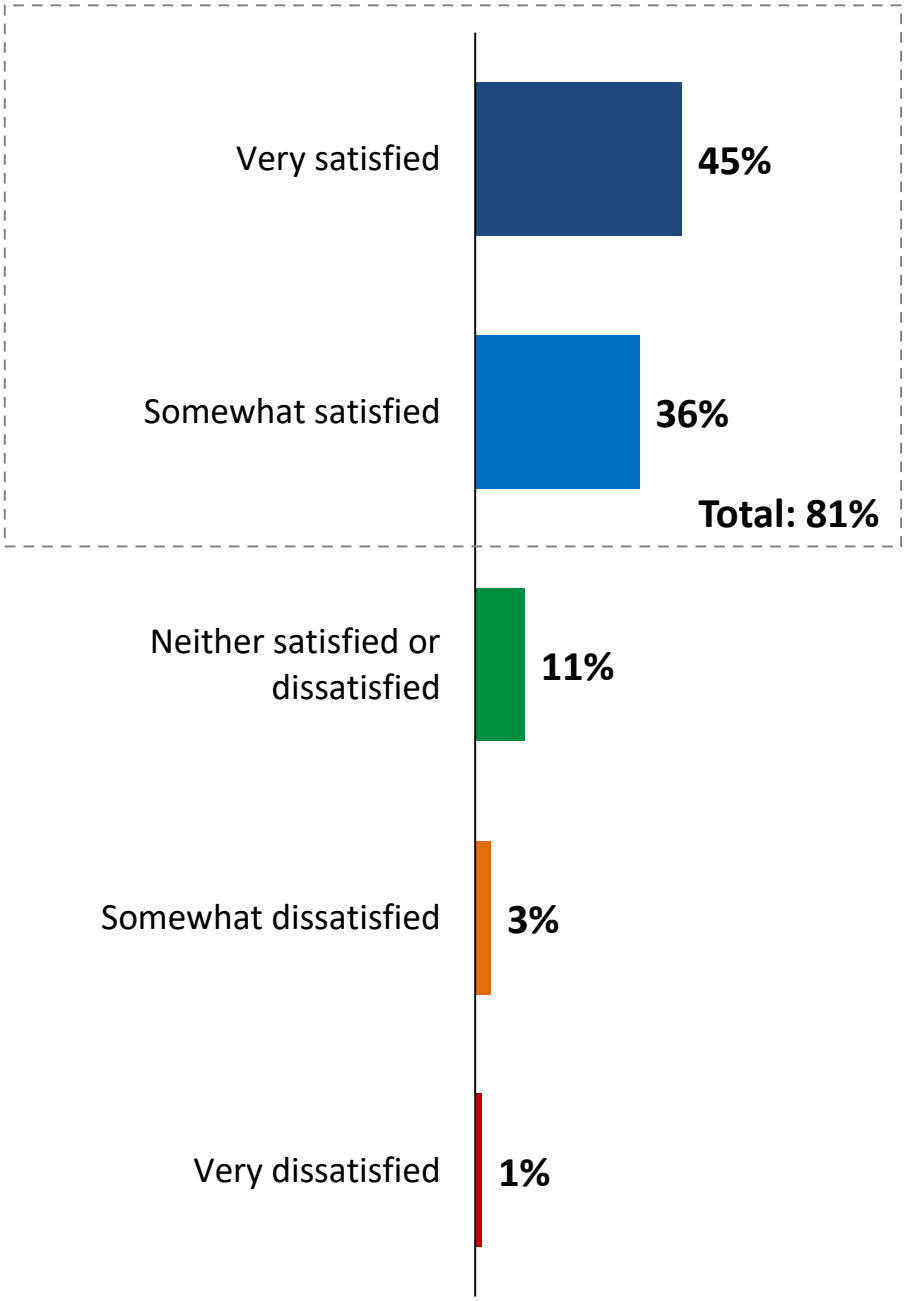
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Satisfaction with Services

Small Business

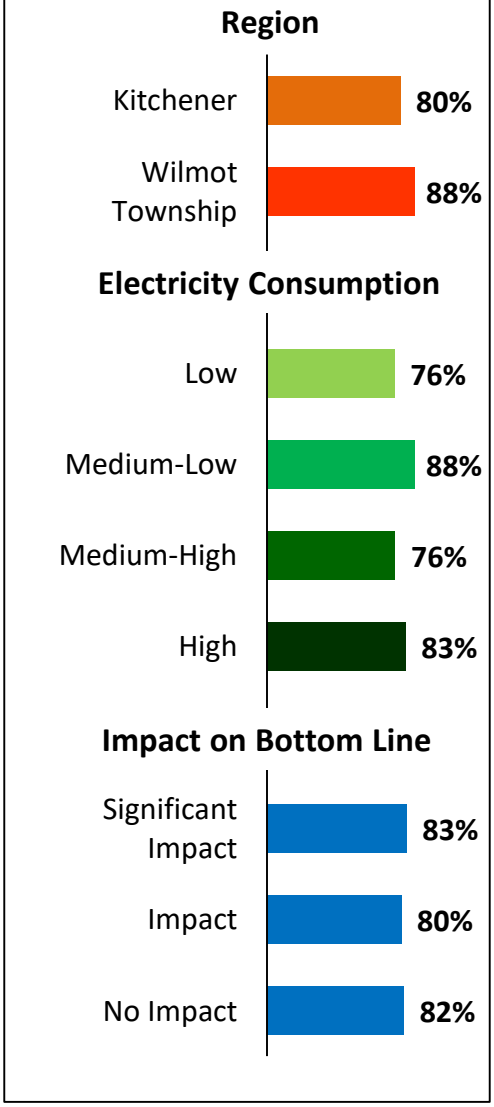
Q Generally, how satisfied or dissatisfied are you with the services your organization receives from **KW Hydro**?

[asked all respondents, n=204]



Segmentation

Respondents who say "Satisfied"



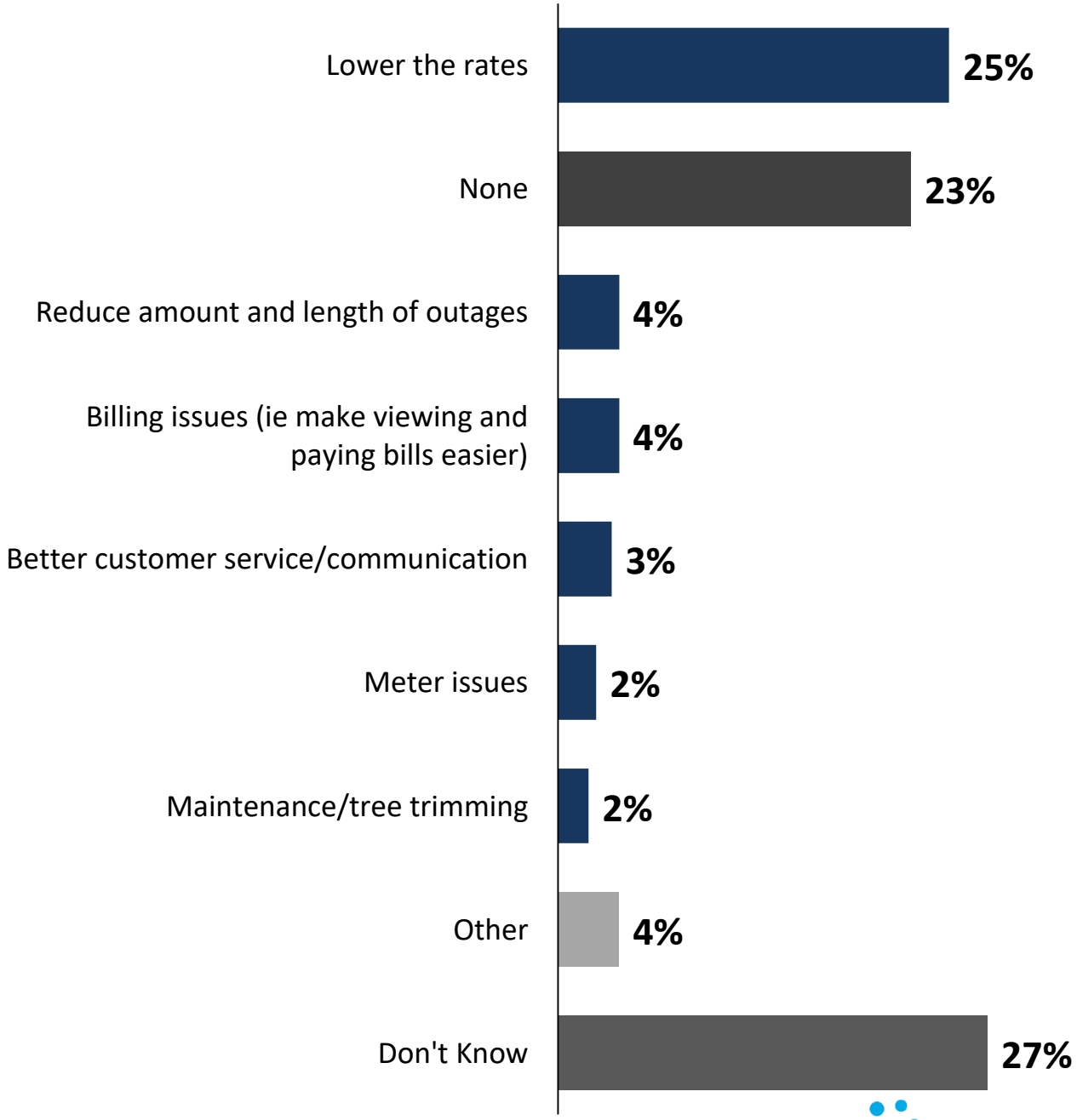
Note: 'Don't Know' (3%) not shown.

Suggestions for Improved Services

Small Business

Q Is there anything in particular KW Hydro can do to improve its services to your organization?

[OPEN; asked all respondents, n=204]



Note: 'Refused' (5%) not shown.

Bill Knowledge

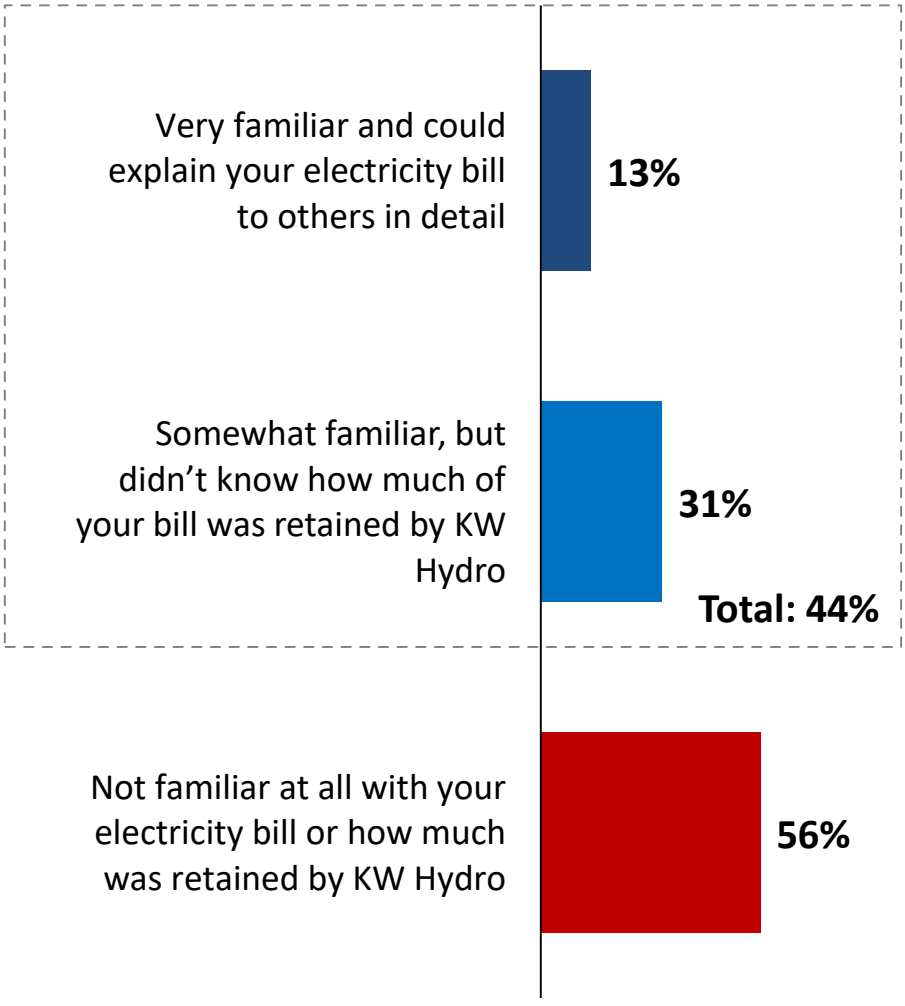
Small Business

Q While **KW Hydro** is responsible for billing customers for the entire electricity bill, about 21% of the electricity bill pays for KW Hydro's distribution system. This is about **53 dollars and 59 cents** on an average **$258** monthly small business electricity bill.

The rest of the bill goes to power generation companies, transmission companies, regulatory agencies, and government taxes.

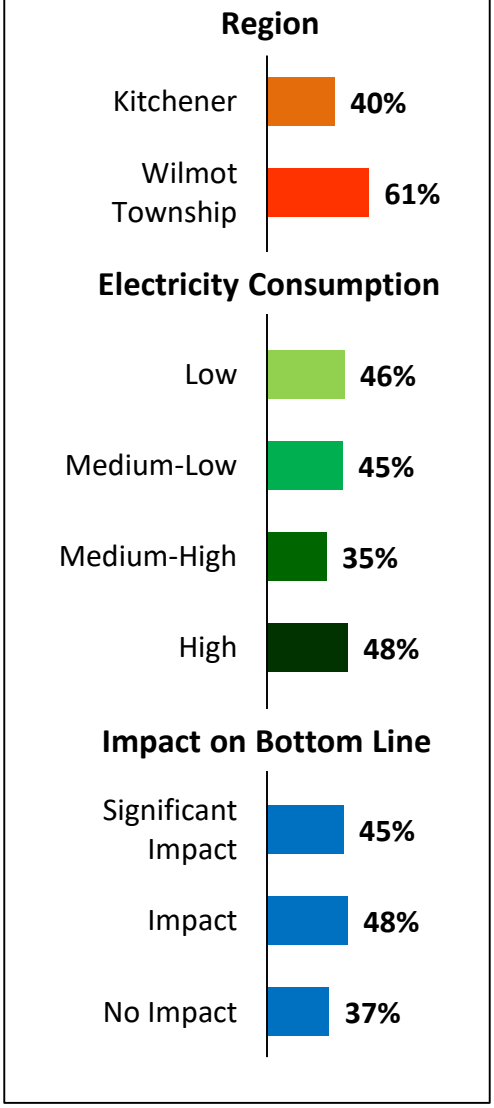
Before this survey, how familiar were you with the percentage of your organization's electricity bill that is retained by **KW Hydro**?

[asked all respondents, n=204]



Segmentation

Respondents who say "Familiar"



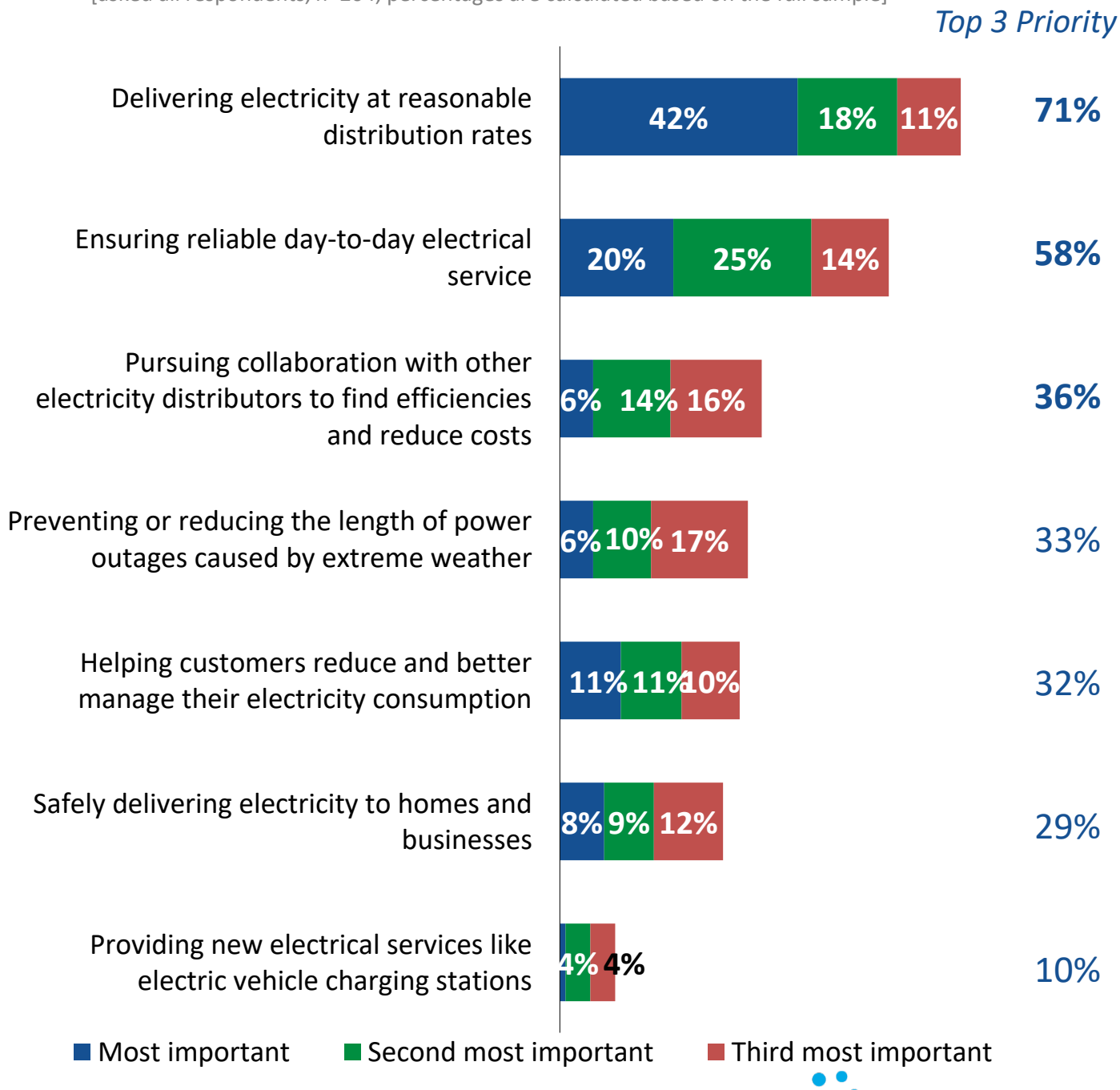
Note: 'Don't know' (<1%) not shown.

Customer Priorities

Small Business

Q **KW Hydro** wants to better understand customer priorities. Among the following **KW Hydro** priorities, please tell me which one is most important to you.

[asked all respondents, n=204, percentages are calculated based on the full sample]



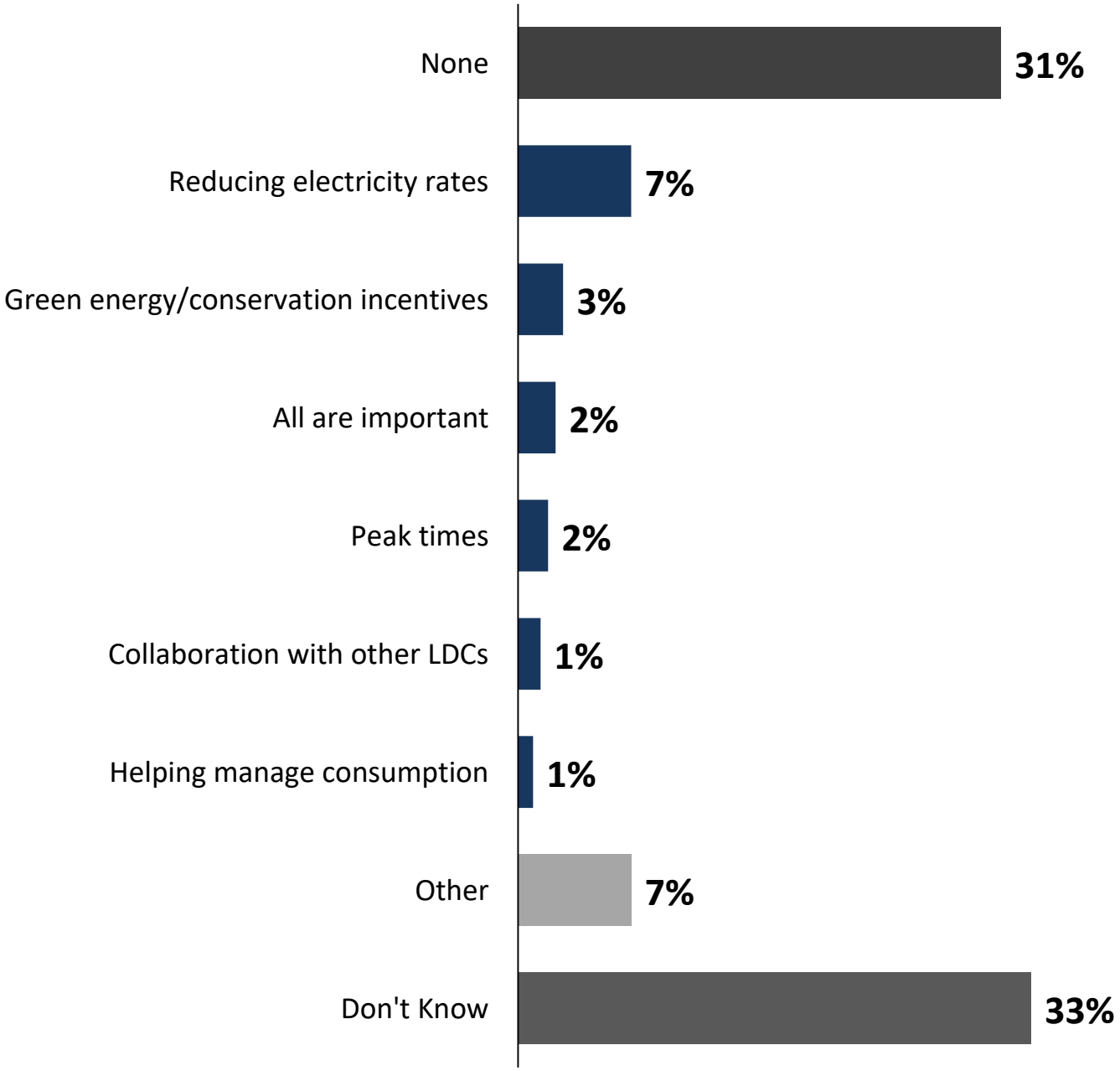
Note: 'Don't Know' and 'Refused' not shown.

Additional Customer Priorities

Small Business

Q Are there any other important priorities that **KW Hydro** should be focusing on that weren't included in the previous list I read to you?

[asked all respondents, n=204]



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Note: 'Refused' (11%) not shown.

System Reliability Priorities

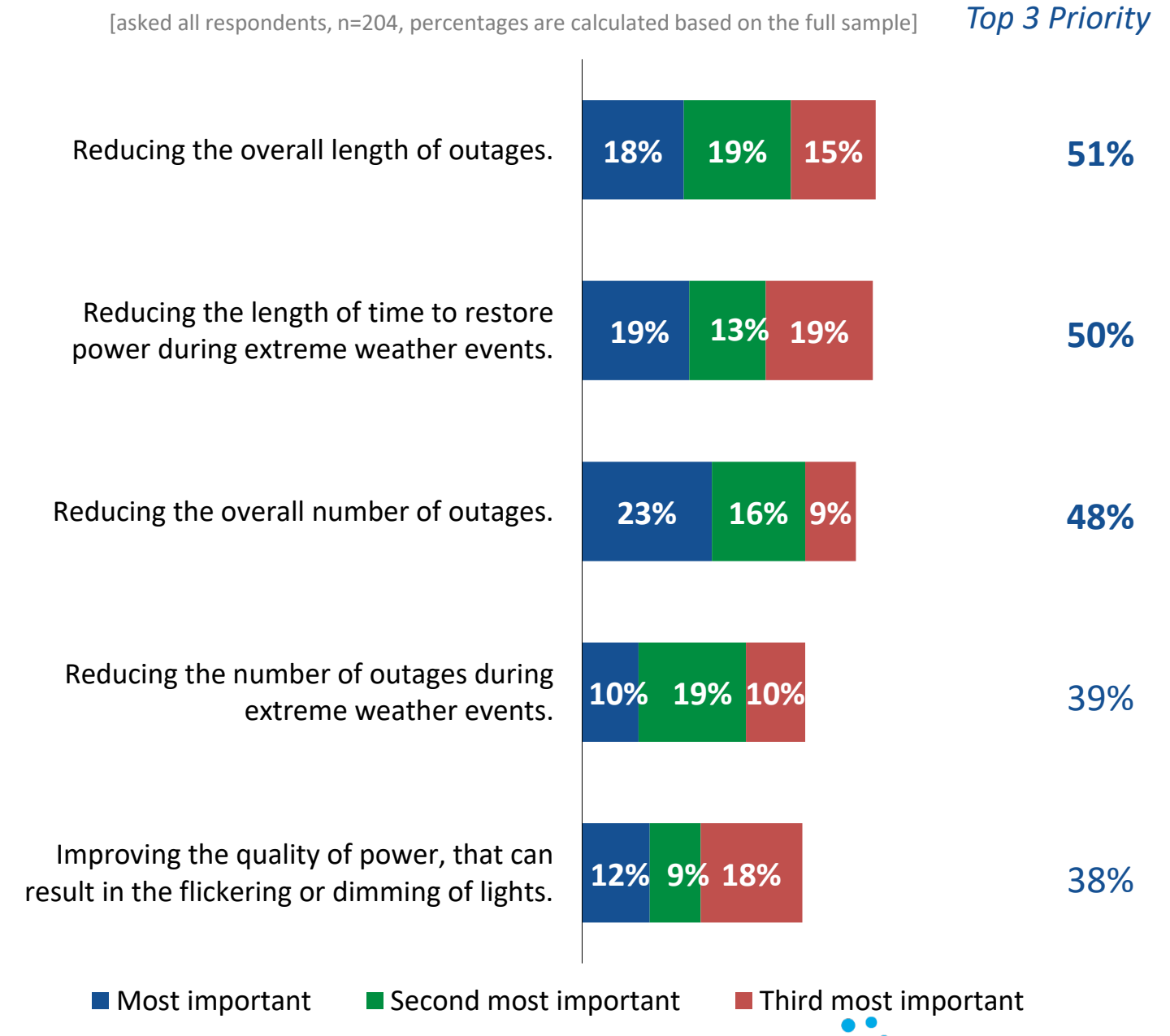
Small Business

Q We would like to understand your experience with reliability.

There are different outcomes when customers talk about power reliability.

Among the following reliability outcomes, please tell me which one is most important to you.

[asked all respondents, n=204, percentages are calculated based on the full sample]



Note: 'Don't Know' and 'Refused' not shown.

Planning Principles & Pacing Investments Preamble



Based on customer feedback, legal and regulatory obligations and internal business planning, **KW Hydro** has developed a plan that invests in projects that aim to improve reliability and customer service, a new basic customer information system and accommodates new customers.

It is estimated that if **KW Hydro** continues with its current plan, the distribution portion of the bill will increase by about **7 dollars and 60 cents** in 2020. For the period 2021 to 2024, the annual bill increase is limited by the Ontario Energy Board to less than the rate of inflation – or approximately **1.35 percent**.

Over the course of the proposed 5-year plan, the typical small business customer would see the distribution portion of their electricity bill increase by **11 dollars and one cent** per month.

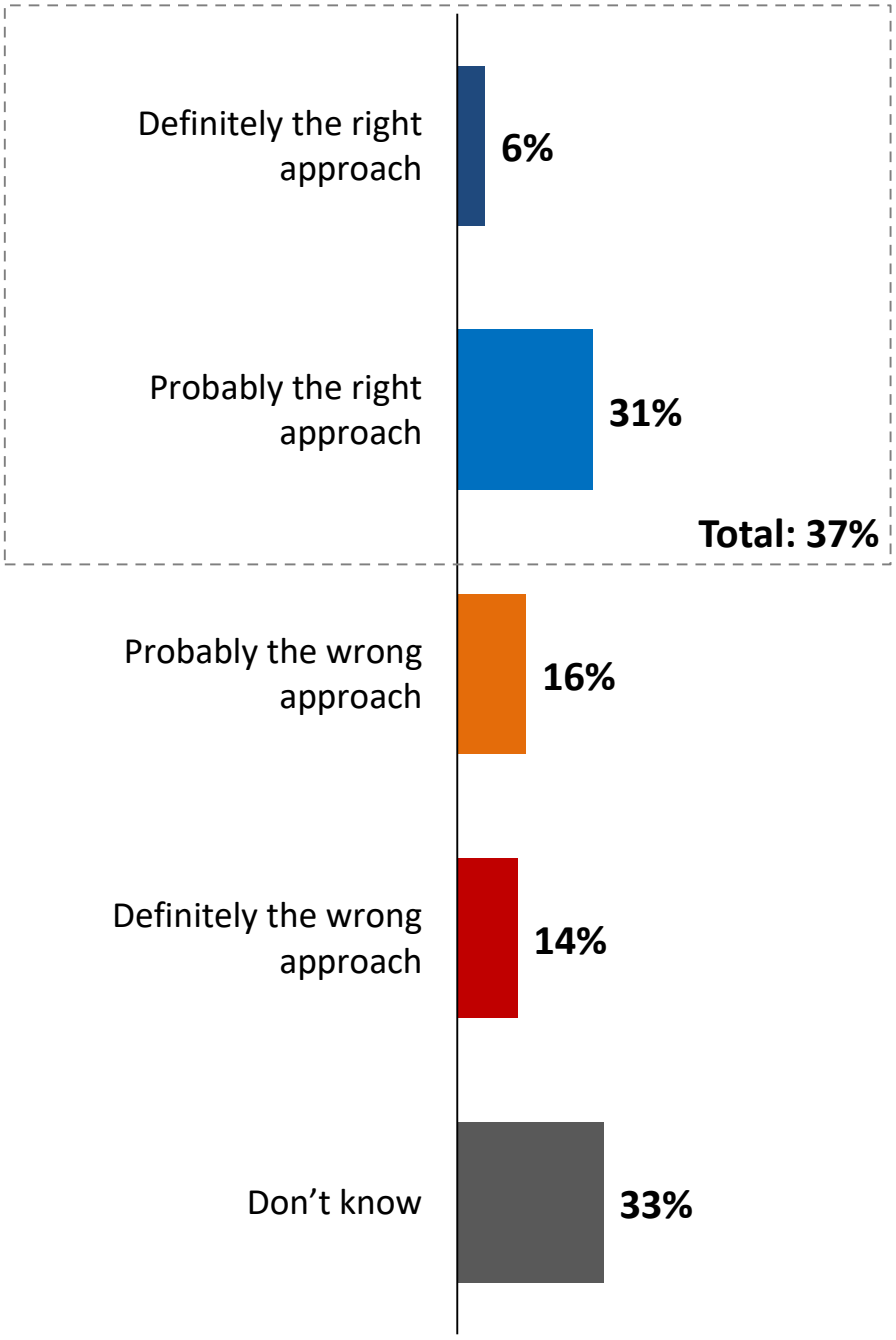
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Approach to Planning for the Next Five Years

Small Business

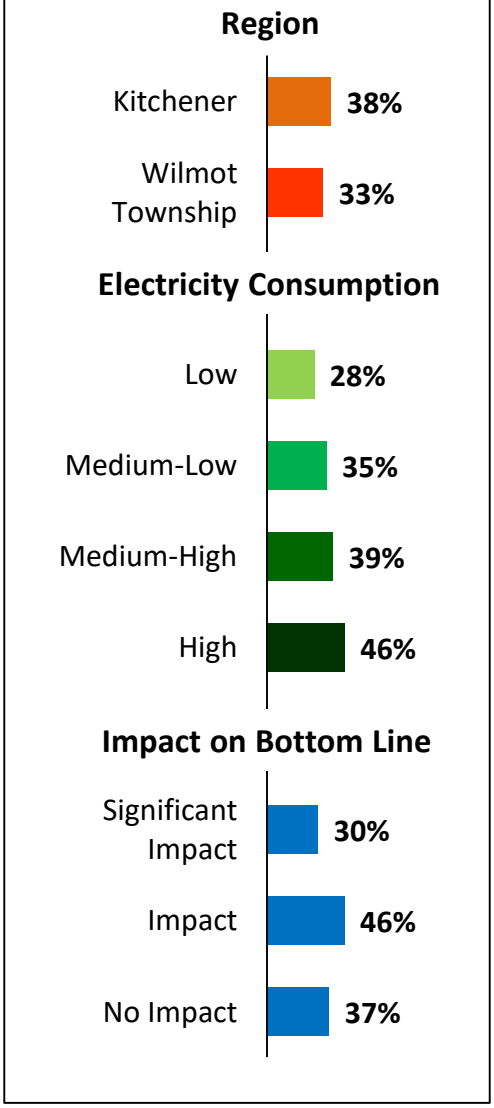
Q Do you feel that **KW Hydro's** approach to planning for the next five years is definitely the right approach, probably the right approach, probably the wrong approach, definitely the wrong approach or would you say you don't know?

[asked all respondents, n=204]



Segmentation

Respondents who say "Right Approach"



INNOVATIVE RESEARCH GROUP

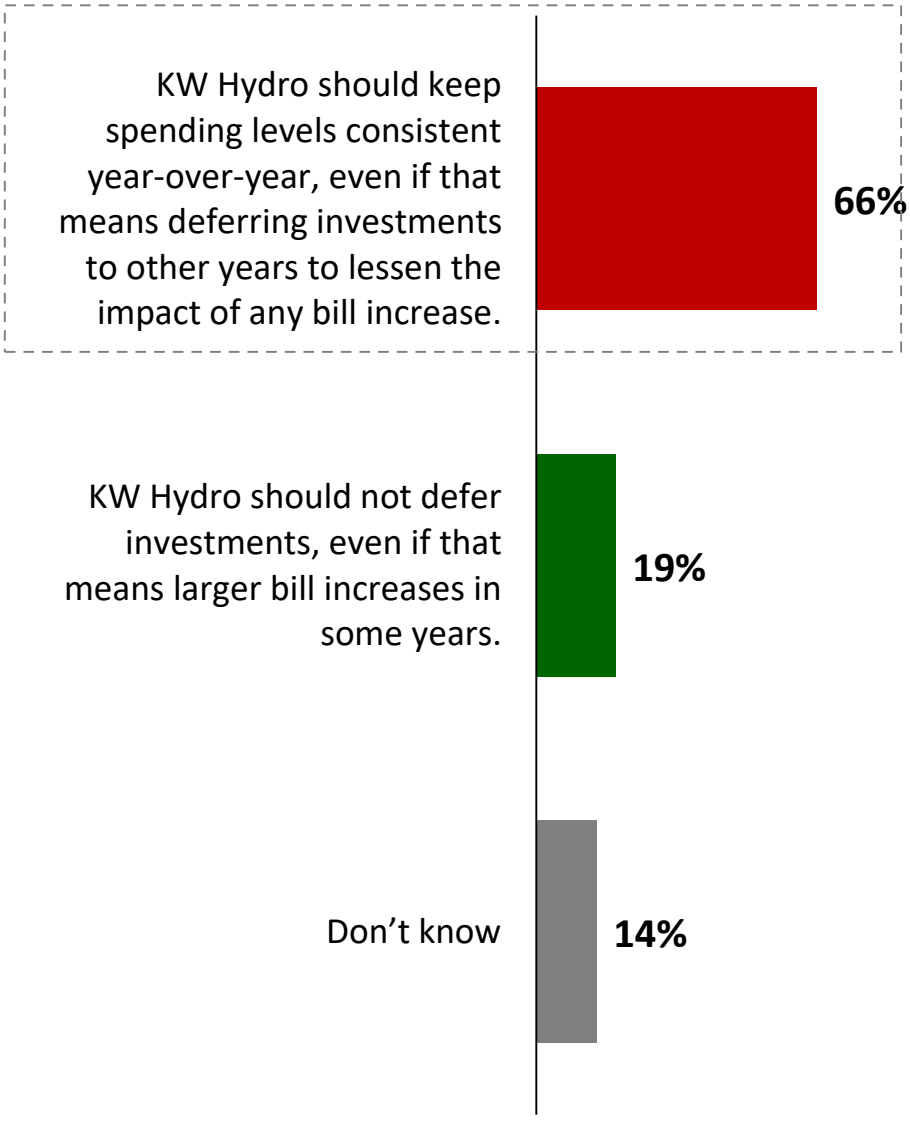
Pacing Investments

Small Business

Q The overall amount **KW Hydro** invests in capital projects remains generally the same year over year, but what does change is where these investments are made. **KW Hydro** carefully paces spending on capital projects to remain as consistent as possible so the impact to customer rates is minimal. What does change is where the investments are made.

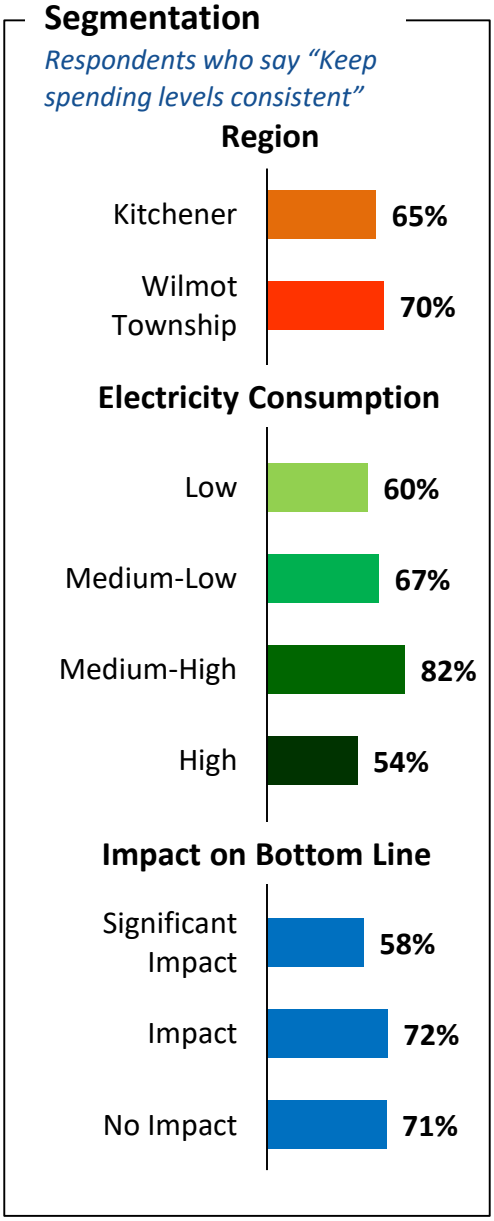
Which of the following statements best represents your point of view regarding **KW Hydro's** approach to pacing investments?

[asked all respondents, n=204]



Segmentation

Respondents who say "Keep spending levels consistent"



Note: 'Refused' (1%) not shown.

Preamble to Capital Plan Priorities and System Renewal



KW Hydro has identified four areas where it could accelerate investments. These accelerated projects could increase the **typical customer's bill by 4 dollars and 63 cents** per month by 2024. These projects are in addition to the **11 dollar and 1 cent** increase that is currently being proposed.

KW Hydro wants to get your feedback on these four particular projects before deciding whether or not to accelerate its investment plan in certain specific areas.

First, a recent asset health condition assessment shows that 15% of the poles in **KW Hydro's** distribution system are in poor or very poor condition. Customers served by these lines are more likely to experience power outages, and when they do, those outages are more likely to last longer and be more expensive to fix.

KW Hydro is proposing to replace these poles over the course of the next five years, however, there is an opportunity to replace these poles more quickly, improving reliability for customers served by this type of equipment.

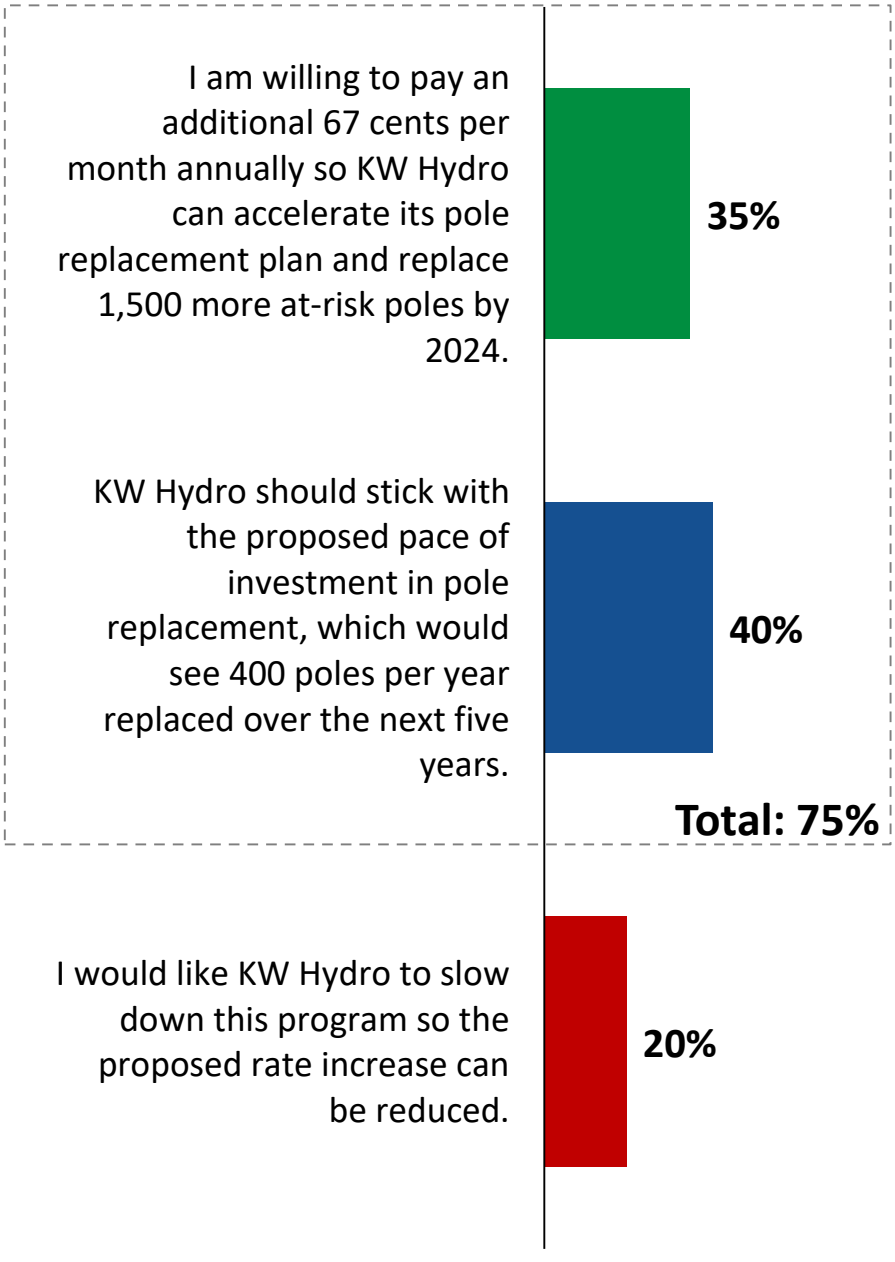
INNOVATIVE RESEARCH GROUP

Pole Replacement

Small Business

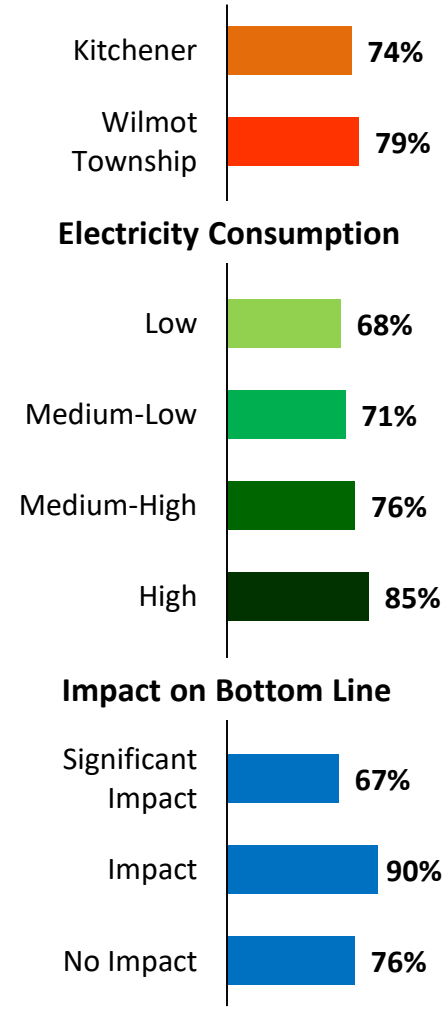
Q Which of the following is closest to your point of view regarding KW Hydro's pole replacement program?

[asked all respondents, n=204]



Segmentation

Respondents who say "Accelerate plan or stick with proposed"



INNOVATIVE RESEARCH GROUP

Note: 'Don't Know' (3%) and 'Refused' (2%) not shown.

Preamble to Power Transformer Replacement Program



The second of four projects is related to **KW Hydro's** power transformer replacement program.

After analysis, it was determined that two power transformers are nearing end of life. These transformers are more than 40 years old and require a long time to replace. While initially they served **KW Hydro** customers well, they now pose reliability concerns.

These transformers feed entire neighbourhoods. Should either of these transformers fail, it could cause prolonged outages and result in more costly reactive costs. That said, they have been in service for more than 40 years, and could continue to operate even longer.

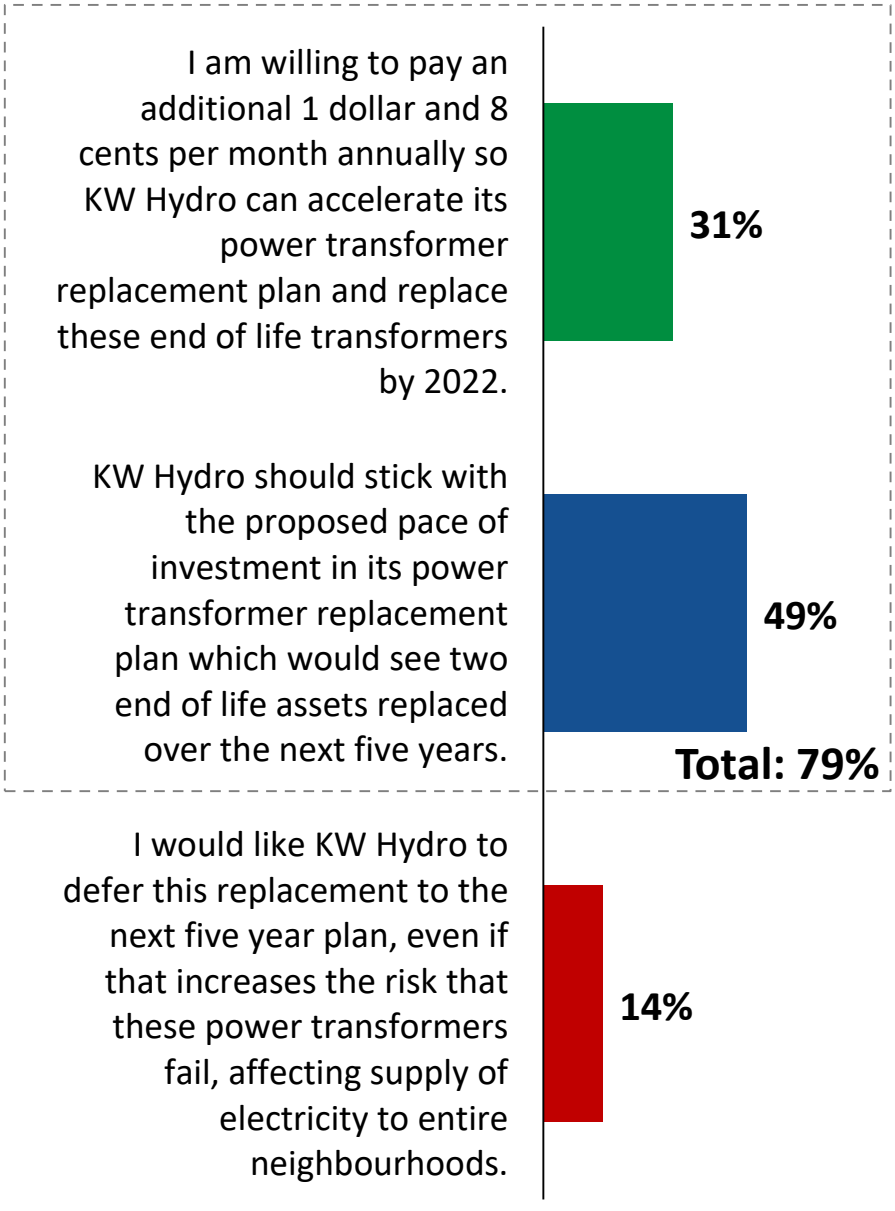
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Power Transformer Replacement

Small Business

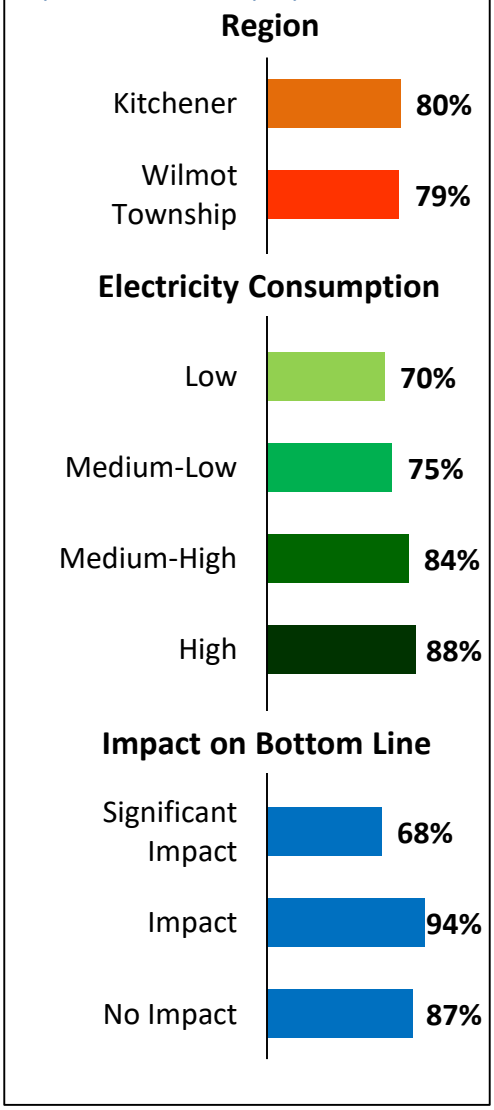
Q Which of the following is closest to your point of view regarding KW Hydro's power transformer replacement program?

[asked all respondents, n=204]



Segmentation

Respondents who say "Accelerate plan or stick with proposed"



Note: 'Don't Know' (4%) and 'Refused' (2%) not shown.

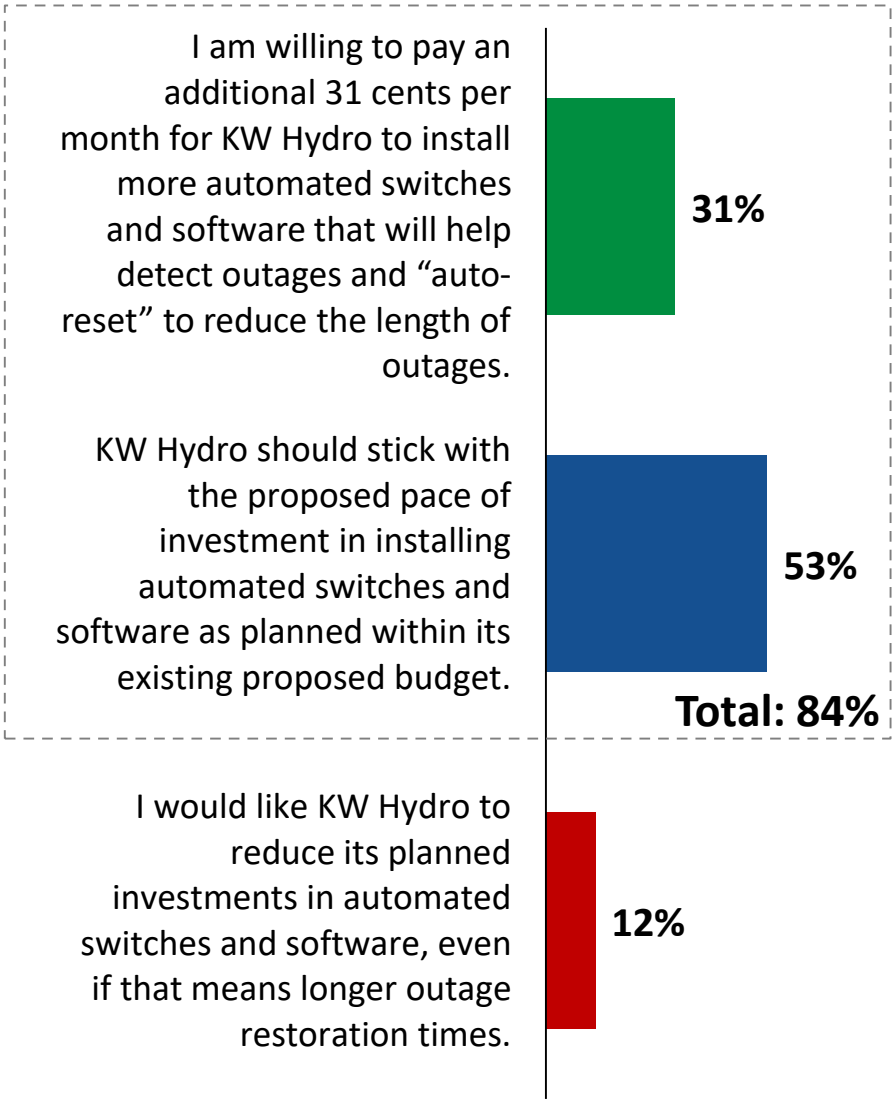
Spending on Automated Switches

Small Business

Q Investments in technology -- such as automated switches -- helps KW Hydro quickly identify the location of outages, minimizes the number of people impacted by outages, and restores electricity to customers more quickly than was previously possible.

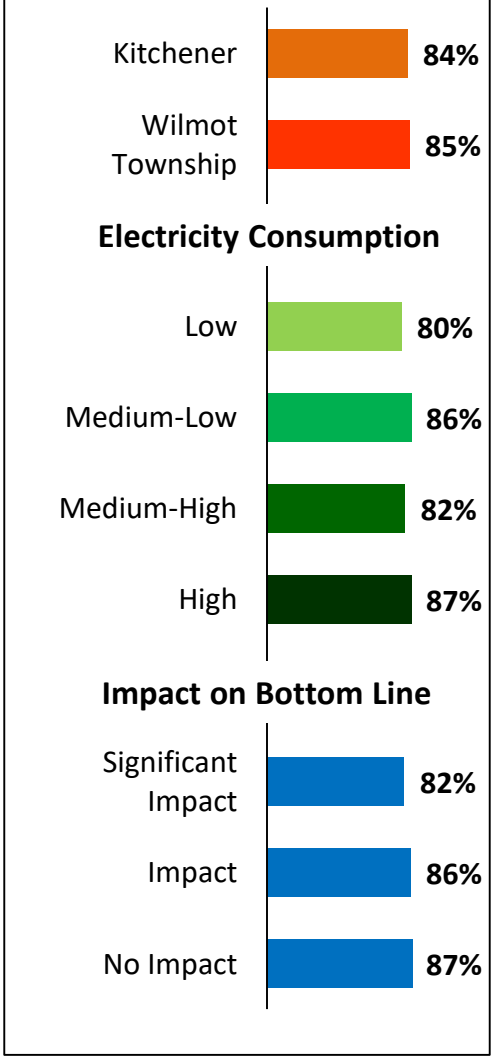
Regarding spending on automated switches, which of the following best represents your point of view?

[asked all respondents, n=204]



Segmentation

Respondents who say "Install more or stick with proposed"



Note: 'Don't Know' (3%) and 'Refused' (1%) not shown.

Customer Information System (CIS) Preamble



Small Business

The final project is related to **KW Hydro's** 30-year-old customer information system or C-I-S, which requires replacement.

After an extensive procurement process, KW Hydro has identified two potential options: a basic system or an enhanced system with more features.

The first is a basic CIS, which provides features needed to ensure customers continue to receive a bill on time. This basic CIS will cost the typical customer **4 dollars and 29 cents** on the distribution portion of their electricity bill starting in 2020. This is included in the proposed **11 dollar and 1 cent** increase.

The second is an enhanced CIS, which would allow KW Hydro to send email or text alerts, provide insights into electricity consumption, a self-service customer portal and automated and streamlined processes to improve the utility's back office efficiency. The enhanced CIS would cost customers an additional **2 dollars and 57 cents** per month.

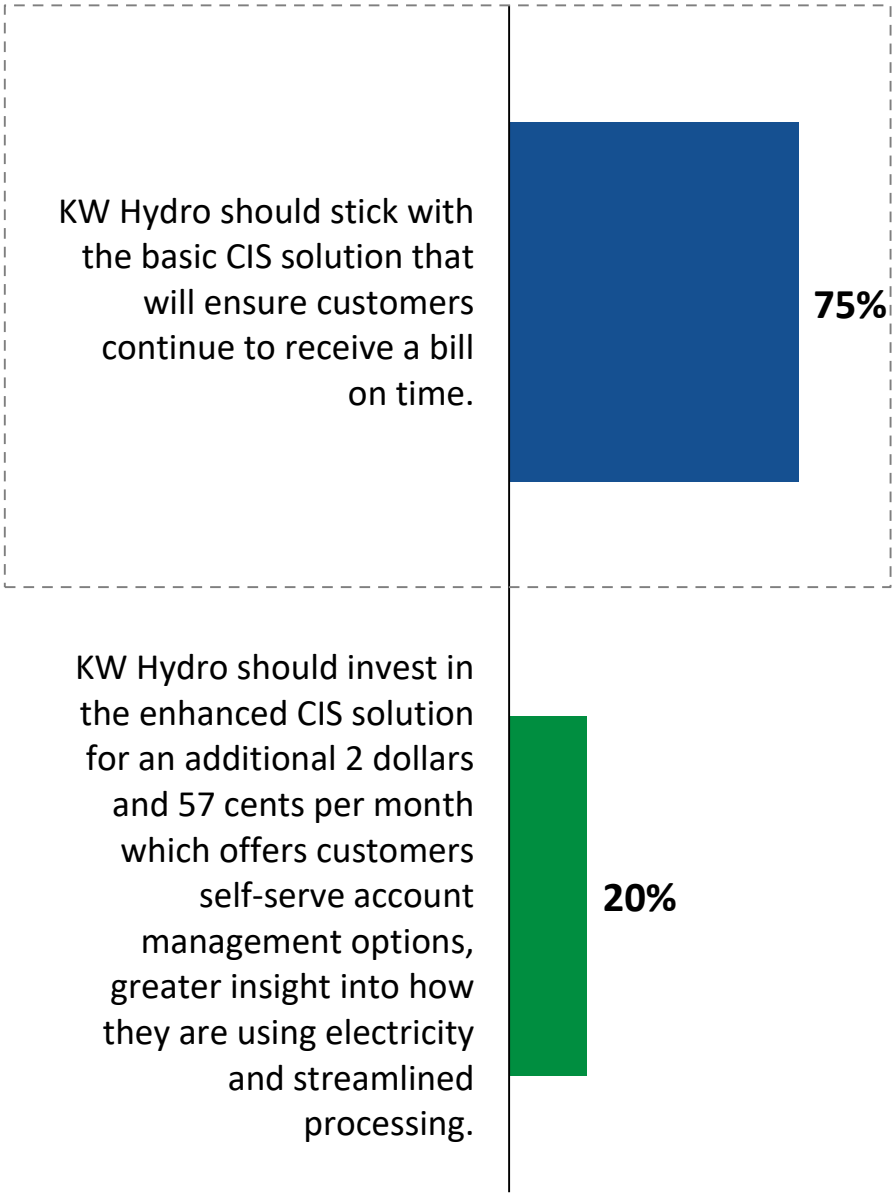
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Customer Information System

Small Business

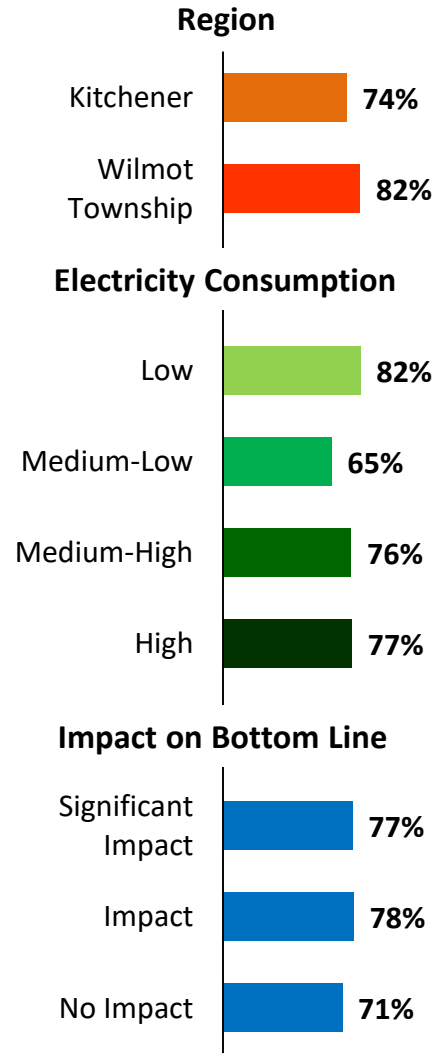
Q Which of the following statements best represents your point of view?

[asked all respondents, n=204]



Segmentation

Respondents who say "Stick with basic CIS solution"



Note: 'Don't Know' (4%) and 'Refused' (<1%) not shown.

Assessment of Proposed Plan Preamble



Remember, the typical **KW Hydro** small business customer's electricity bill is about **$258** per month, of which 21% or **53 dollars and 59 cents** goes to KW Hydro.

Over the course of the proposed 5-year plan, the typical small business customer would see the KW Hydro portion of their electricity bill increase by **11 dollars and 1 cent** per month.

Throughout its planning process, KW Hydro has identified four potential investments that could be made beyond what is currently being proposed. Those four investments have been discussed throughout this survey.

These incremental investments would offer benefits to customers ranging from improved reliability to enhanced customer service offerings.

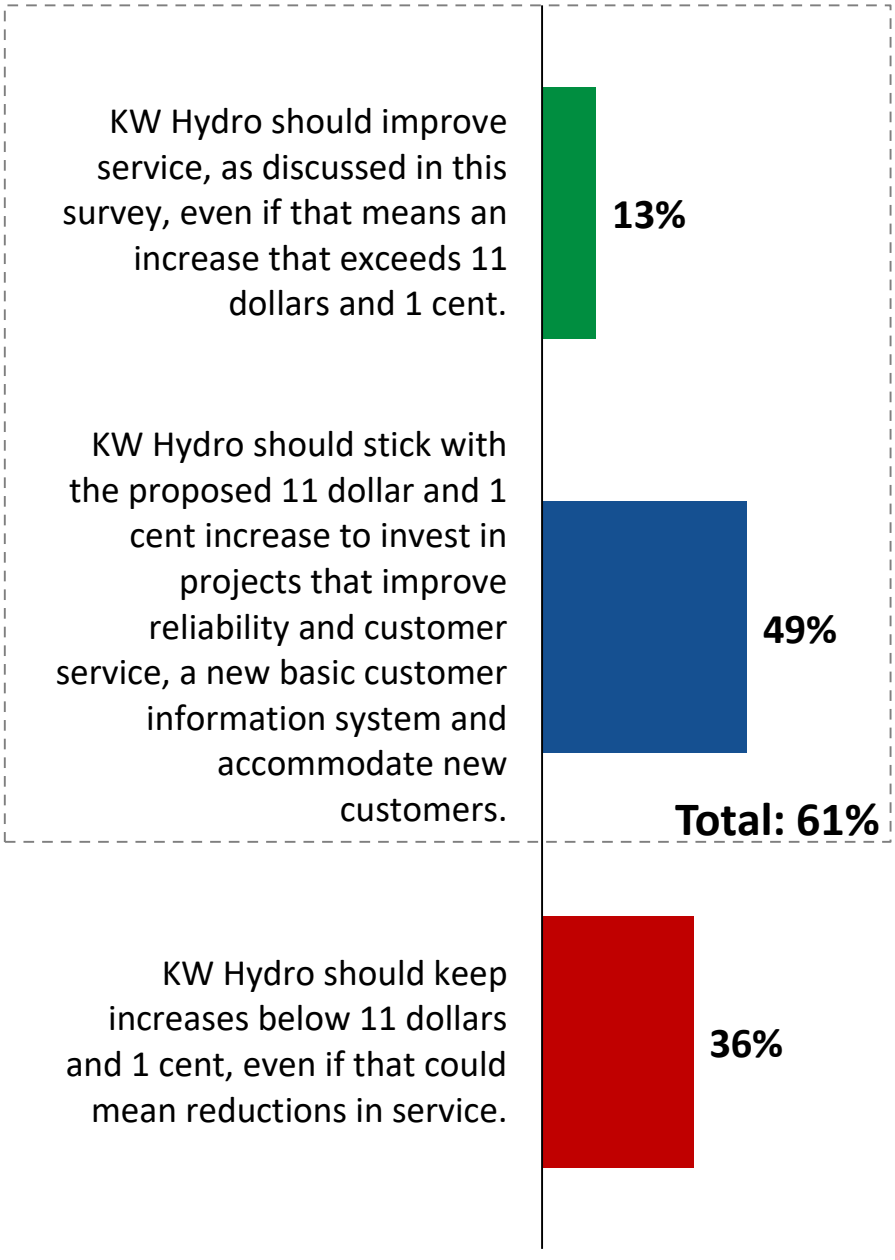
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Assessment of Proposed Plan

Small Business

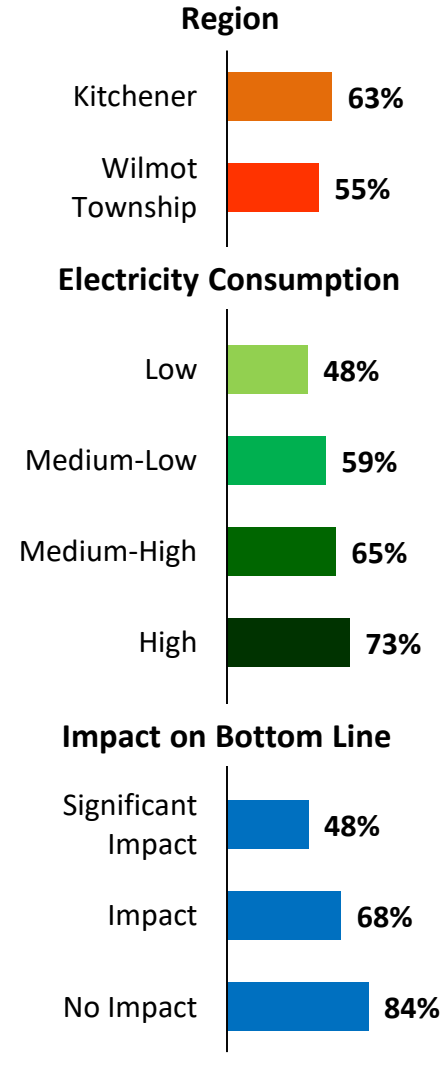
Q Considering what you know about KW Hydro's proposed plan, which of the following best represents your point of view?

[asked all respondents, n=204]



Segmentation

Respondents who say "Improve services or stick with plan"



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Note: 'Don't Know' (1%) and 'Refused' (1%) not shown.

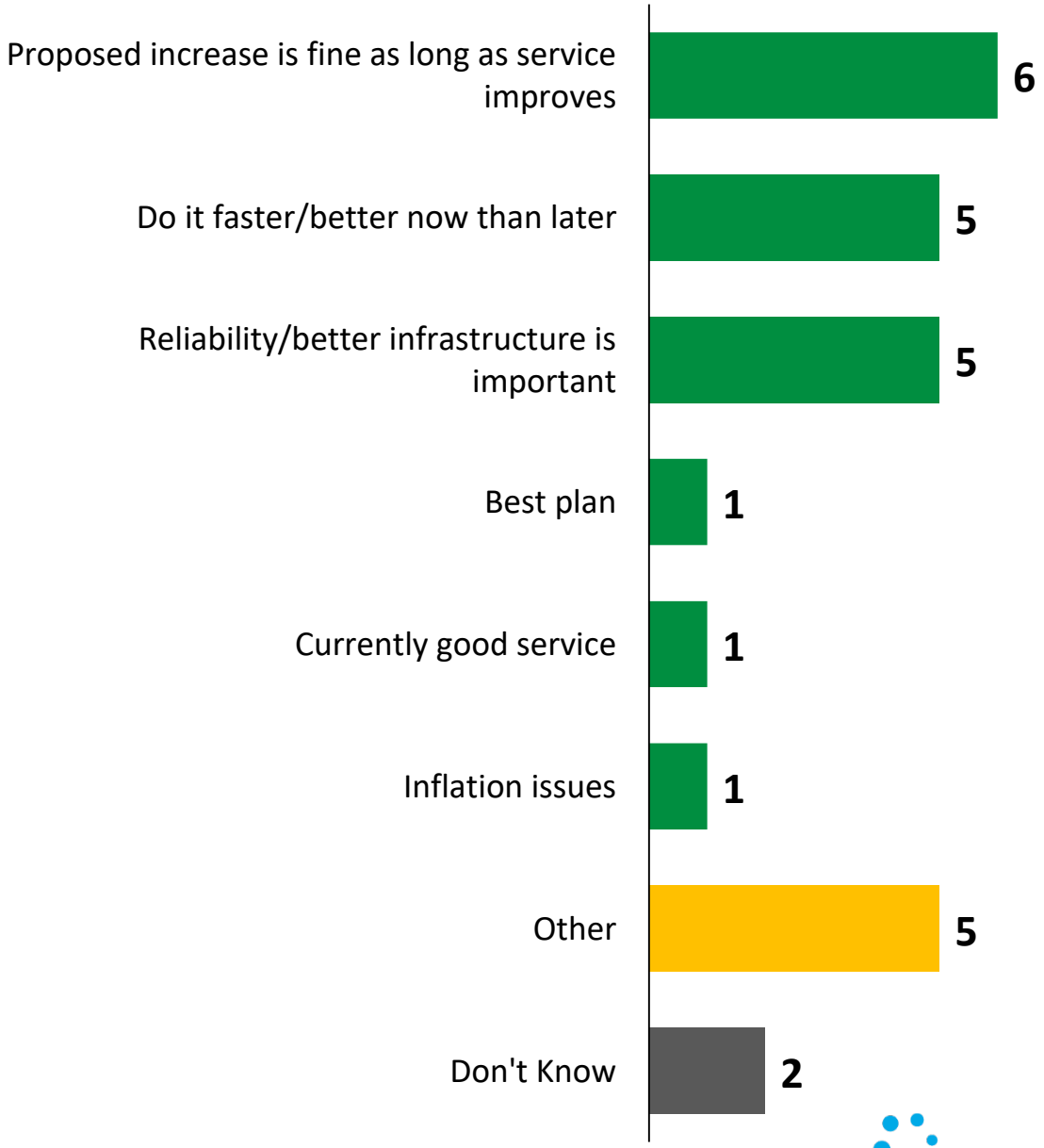
Opinion of KW Hydro's Proposed Plan

Small Business

Q And why do you say that?

[asked all respondents, n=26, **NOTE**: n-sizes shown below due to small sample size]

Amongst those who answered: KW Hydro should improve service, as discussed in this survey, even if that means an increase that exceeds 11 dollars and 1 cent. (n=26)



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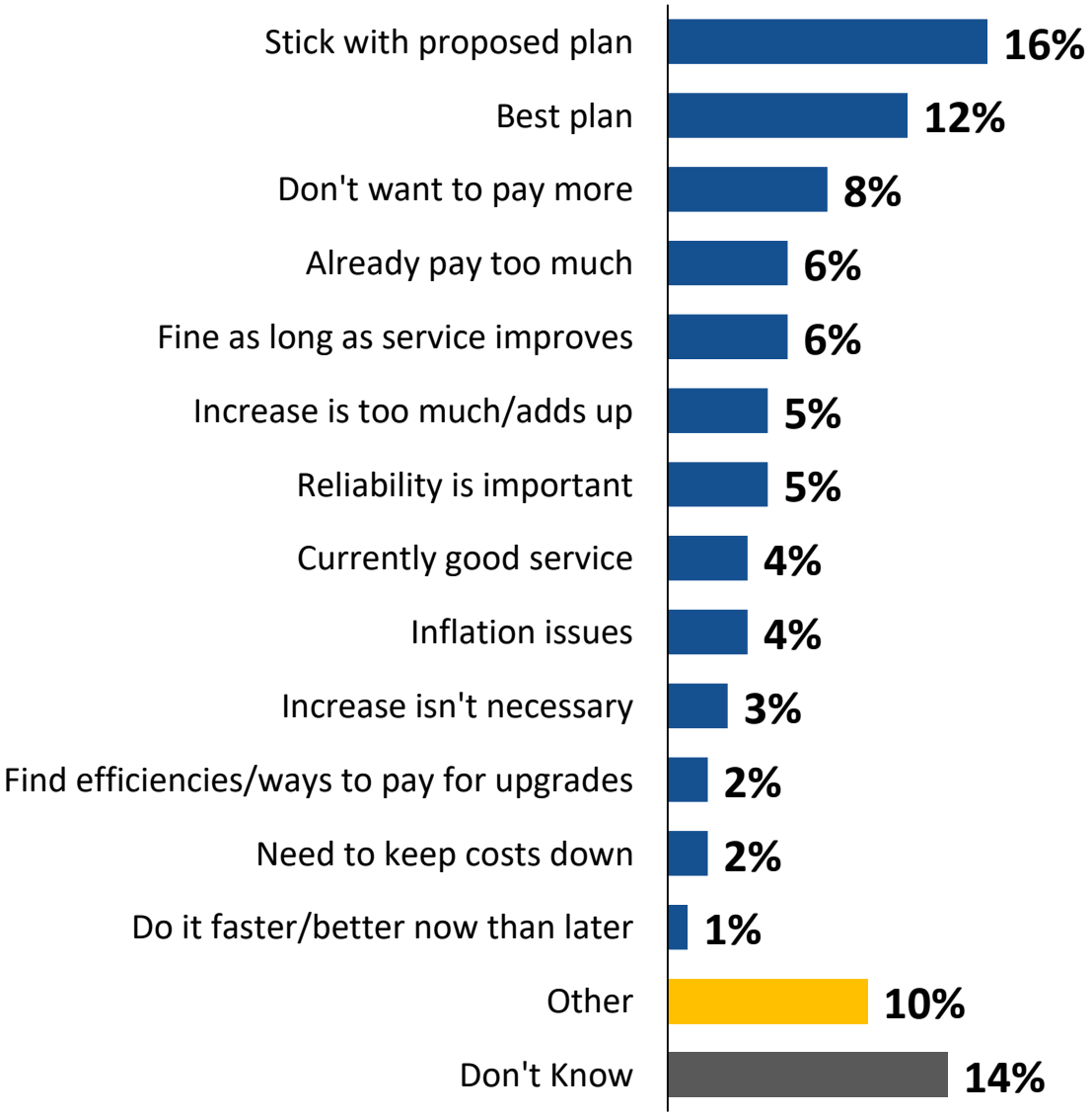
Opinion of KW Hydro's Proposed Plan

Small Business

Q And why do you say that?

[asked all respondents, n=99]

Amongst those who answered: KW Hydro should stick with the proposed 11 dollar and 1 cent increase to invest in projects that improve reliability and customer service, a new basic customer information system and accommodate new customers. (n=99)



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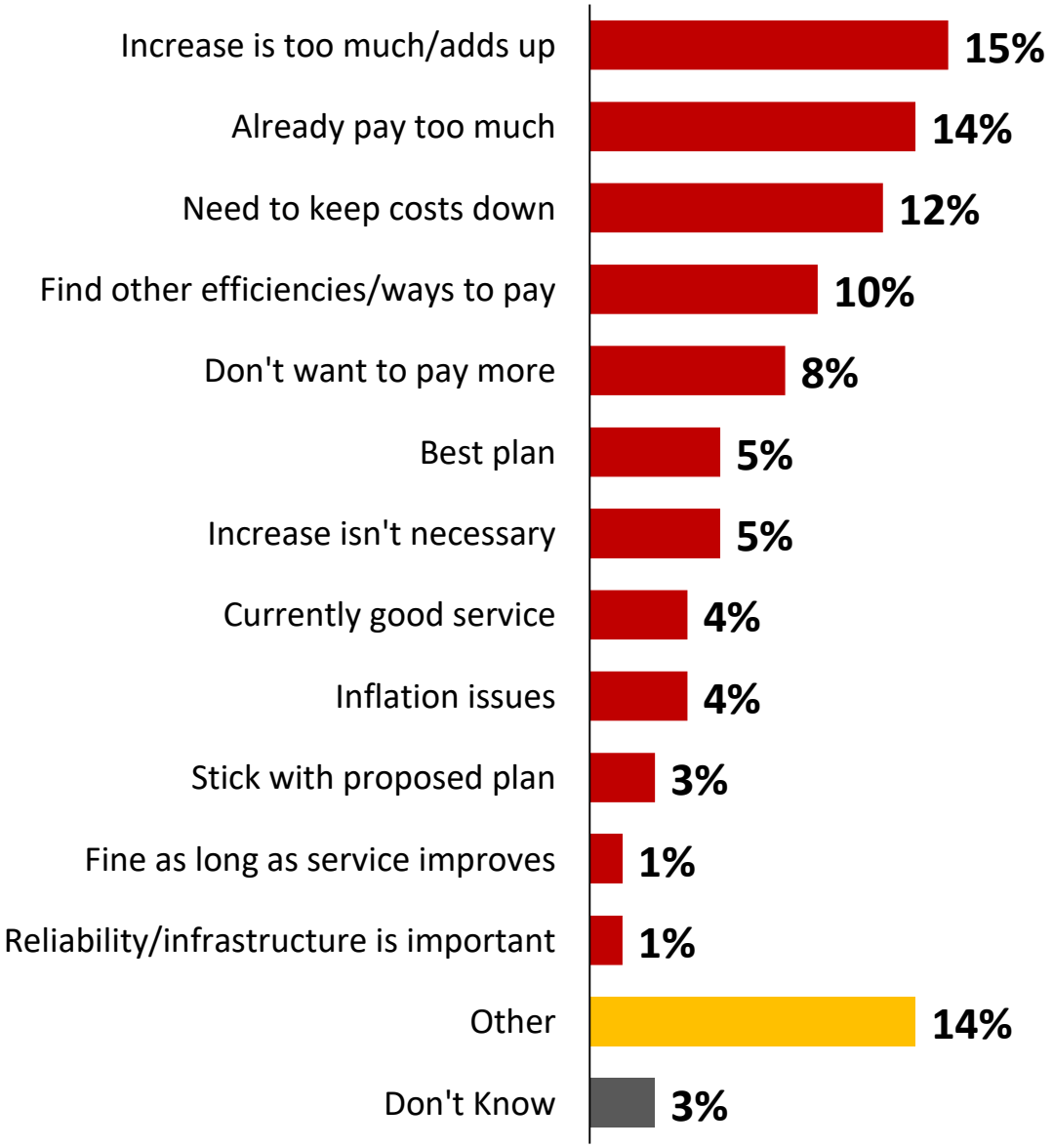
Opinion of KW Hydro's Proposed Plan

Small Business

Q And why do you say that?

[asked all respondents, n=73]

Amongst those who answered: KW Hydro should keep increases below 11 dollars and 1 cent, even if that could mean reductions in service. (n=73)



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Appendix E:
2015 Regional Infrastructure Plan (RIP) Report - Kitchener-Waterloo-Cambridge-Guelph

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Kitchener-Waterloo-Cambridge-Guelph

REGIONAL INFRASTRUCTURE PLAN

December 15, 2015

hydro one

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Prepared and supported by:

Company
Hydro One Networks Inc. (Lead Transmitter)
Cambridge and North Dumfries Hydro Inc.
Centre Wellington Hydro
Guelph Hydro Electric System Inc.
Halton Hills Hydro
Hydro One Distribution
Independent Electricity System Operator
Kitchener Wilmot Hydro Inc.
Milton Hydro
Waterloo North Hydro Inc.
Wellington North Power Inc.

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DISCLAIMER

This Regional Infrastructure Plan ("RIP") report was prepared for the purpose of developing an electricity infrastructure plan to address needs identified in previous planning phases and also any additional needs identified based on new and/or updated information provided by the RIP Working Group.

The preferred solution(s) that have been identified in this report may be reevaluated based on the findings of further analysis. The load forecast and results reported in this RIP report are based on the information provided and assumptions made by the participants of the RIP Working Group.

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

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EXECUTIVE SUMMARY

THIS REGIONAL INFRASTRUCTURE PLAN ("RIP") WAS PREPARED BY HYDRO ONE AND THE WORKING GROUP IN ACCORDANCE WITH THE ONTARIO TRANSMISSION SYSTEM CODE REQUIREMENTS. IT IDENTIFIES INVESTMENTS IN TRANSMISSION FACILITIES, DISTRIBUTION FACILITIES, OR BOTH, THAT SHOULD BE DEVELOPED AND IMPLEMENTED TO MEET THE ELECTRICITY INFRASTRUCTURE NEEDS WITHIN THE KITCHENER-WATERLOO-CAMBRIDGE-GUELPH ("KWCG") REGION.

The participants of the RIP Working Group included members from the following organizations:

- Cambridge and North Dumfries Hydro Inc.
- Centre Wellington Hydro
- Guelph Hydro Electric System Inc.
- Halton Hills Hydro One
- Hydro One Distribution
- Hydro One Transmission
- Independent Electricity System Operator
- Kitchener Wilmot Hydro Inc.
- Milton Hydro
- Waterloo North Hydro Inc.
- Wellington North Power Inc.

This RIP provides a consolidated summary of needs and recommended plans for the KWCG Region for the near-term (up to 5 years) and mid-term (5 to 10 years). No long term needs (10 to 20 years) have been identified at this time.

This RIP is the final phase of the regional planning process and it follows the completion of the KWCG Integrated Regional Resource Plan ("IRRP") by the IESO in April 2015.

The major infrastructure investments planned for the KWCG Region over the near and mid-term, identified in the various phases of the regional planning process, are given in the table below.

No.	Project	In-Service Date	Cost
1	Guelph Area Transmission Reinforcement	May 2016	$95 M
2	Arlen MTS: Install Series reactors	May 2016	$0.95 M
3	M20D/M21D – Install 230 kV In-line Switches	May 2017	$6 M
4	Waterloo North Hydro: MTS #4	2024	TBD

In accordance with the Regional Planning process, the Regional Plan should be reviewed and/or updated at least every five years. The Region will continue to be monitored and should there be a need that emerges due to a change in load forecast or any other reason, the next regional planning cycle may be started earlier to address the need.

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1. INTRODUCTION

THIS REPORT PRESENTS THE REGIONAL INFRASTRUCTURE PLAN ("RIP") TO ADDRESS THE ELECTRICITY NEEDS OF THE KWCG REGION.

The report was prepared by Hydro One Networks Inc. ("Hydro One") and documents the results of the joint study carried out by Hydro One, Kitchener-Wilmot Hydro Inc. ("Kitchener-Wilmot Hydro"), Waterloo North Hydro Inc. ("WNH"), Cambridge & North Dumfries Hydro Inc. ("CND"), Guelph Hydro Electric Systems Inc. ("Guelph Hydro"), Hydro One Distribution and the Independent Electricity System Operator ("IESO") in accordance with the Regional Planning process established by the Ontario Energy Board ("OEB") in 2013.

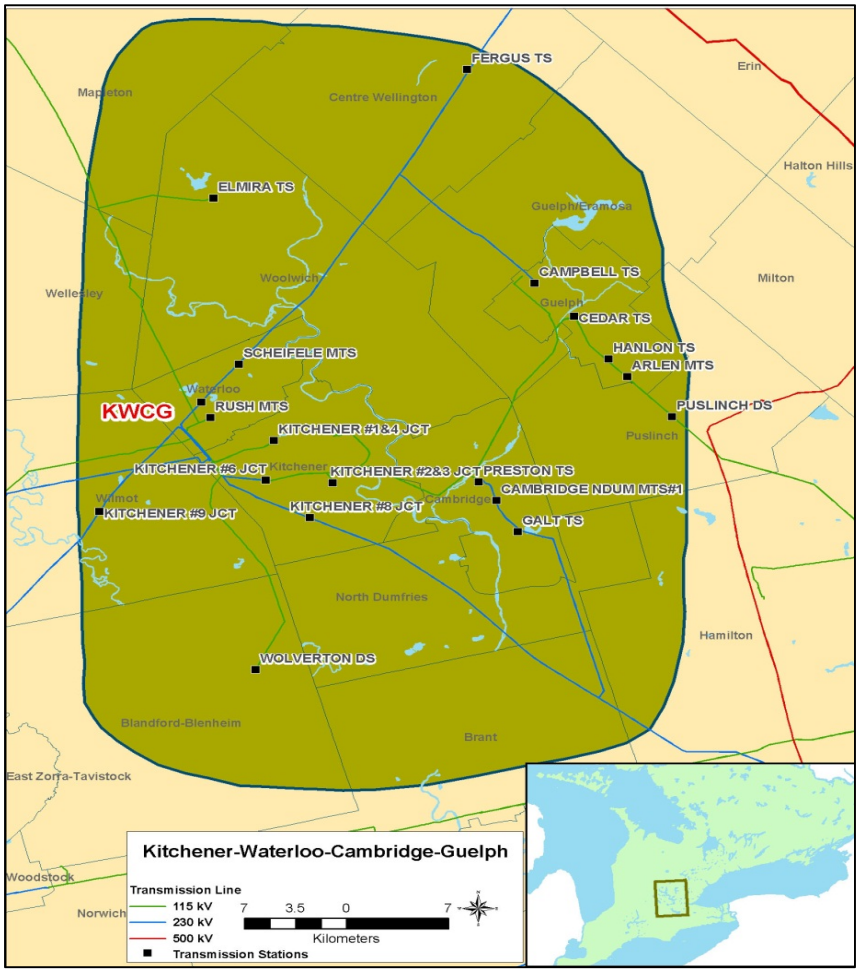


Figure 1-1 KWCG Region

The KWCG Region covers the cities of Kitchener, Waterloo, Cambridge and Guelph, portions of Oxford and Wellington counties and the townships of North Dumfries, Puslinch, Woolwich, Wellesley and Wilmot. Electrical supply to the Region is provided from eleven 230 kV and thirteen 115 kV step-down transformer stations. The summer 2015 coincident regional load was about 1240 MW. The boundaries of the Region are shown in Figure 1-1 above.

1.1 Scope and Objectives

This RIP report examines the needs in the KWCG Region. Its objectives are:

- To identify new supply needs that may have emerged since previous planning phases (e.g. Needs Assessment, Scoping Assessment, Local Plan, and/or Integrated Regional Resource Plan)
- To assess and develop a wires plan to address these needs
- To provide the status of wires planning currently underway or completed for specific needs
- To identify investments in transmission and distribution facilities or both that should be developed and implemented on a coordinated basis to meet the electricity infrastructure needs within the region.

The RIP reviews factors such as load forecast, transmission and distribution system capabilities along with any updates with respect to local plans, conservation and demand management ("CDM"), renewable and non-renewable generation development, and other electricity system and local drivers that may impact the need and alternatives under consideration.

The scope of this RIP is as follows:

- A consolidated report of all the needs and relevant plans to address near and mid-term needs (2015-2025) identified in previous planning phases (Needs Assessment, Scoping Assessment, Local Plan or Integrated Regional Resource Plan)
- Identification of any new needs over the 2015-2025 period and a wires plan to address these needs based on new and/or updated RIP phase information
- Develop a plan to address any longer term needs identified by the Working Group

The IRRP or RIP Working Group did not identify any long term needs at this time. If required, further assessment will be undertaken in the next planning cycle because adequate time is available to plan for required facilities.

1.2 Structure

The rest of the report is organized as the follows:

- Section 2 provides an overview of the regional planning process
- Section 3 describes the region
- Section 4 describes the transmission work completed over the last ten years
- Section 5 describes the load forecast and study assumptions used in this assessment
- Section 6 describes the results of the adequacy assessment of the transmission facilities and identifies the needs
- Section 7 summarizes the Regional Plan to address the needs
- Section 8 provides the conclusions and next steps

2. REGIONAL PLANNING PROCESS

2.1 Overview

Planning for the electricity system in Ontario is done at essentially three levels: bulk system planning, regional system planning, and distribution system planning. These levels differ in the facilities that are considered and the scope of impact on the electricity system. Planning at the bulk system level typically looks at issues that impact the system on a provincial level, while planning at the regional and distribution levels looks at issues on a more regional or localized level.

Regional planning looks at supply and reliability issues at a regional or local area level. Therefore, it largely considers the 115 kV and 230 kV portions of the power system that supply various parts of the province.

2.2 Regional Planning Process

A structured regional planning process was established by the Ontario Energy Board in 2013, through amendments to the Transmission System Code ("TSC") and the Distribution System Code ("DSC"). The process consists of four phases: the Needs Assessment[1] ("NA"), the Scoping Assessment ('SA"), the Integrated Regional Resource Plan ("IRRP"), and the Regional Infrastructure Plan ("RIP").

The regional planning process begins with the NA phase which is led by the transmitter to determine if there are regional needs. The NA phase identifies the needs and the Working Group determines whether further regional coordination is necessary to address them. If no further regional coordination is required, further planning is undertaken by the transmitter and the impacted local distribution company ("LDC") or customer and develops a Local Plan ("LP") to address them. These needs are local in nature and can be best addressed by a straight forward wires solution.

In situations where identified needs require coordination at the regional or sub-regional levels, the IESO initiates the SA phase. During this phase, the IESO, in collaboration with the transmitter and impacted LDCs, reviews the information collected as part of the NA phase, along with additional information on potential non-wires alternatives, and makes a decision on the most appropriate regional planning approach. The approach is either a RIP, which is led by the transmitter, or an IRRP, which is led by the IESO. If more than one sub-region was identified in the NA phase, it is possible that a different approach could be taken for different sub-regions.

The IRRP phase will generally assess infrastructure (wires) versus resource (CDM and Distributed Generation ("DG")) options at a higher or more macro level but sufficient to permit a comparison of options. If the IRRP process identifies that infrastructure options may be most appropriate to meet a need, the RIP phase will conduct detailed planning to identify and assess the specific wires alternatives and recommend the preferred wires solution. Similarly, resource options which the IRRP identifies as best

[1] Also referred to a Needs Screening

suited to meet a need are then further planned in greater detail by the IESO. The IRRP phase also includes IESO led stakeholder engagement with municipalities and establishes a Local Advisory Committee in the region or sub-region.

The RIP phase is the final stage of the regional planning process and involves: confirmation of previously identified needs; identification of any new needs that may have emerged since the start of the planning cycle; and development of a wires plan to address the needs where a wires solution would be the best overall approach. This phase is led and coordinated by the transmitter and the deliverable of this stage is a comprehensive report of a wires plan for the region. Once completed, this report can be referenced in rate filing submissions or as part of LDC rate applications with a planning status letter provided by the transmitter. Reflecting the timeliness provisions of the RIP, plan level stakeholder engagement is not undertaken at this stage. However, stakeholder engagement at a project specific level will be conducted as part of the project approval requirement.

To efficiently manage the regional planning process, Hydro One has been undertaking wires planning activities in collaboration with the IESO and LDCs for the region as part of and/or in parallel with:

- Planning activities that were already underway in the region prior to the new regional planning process taking effect
- The NA, SA, and LP phases of regional planning
- Participating in and conducting wires planning as part of the IRRP for the region or sub-region

Figure 2-1 illustrates the various steps of the regional planning process (NA, SA, IRRP and RIP) and their respective phase trigger, lead, and outcome.

Note that as the KWCG Region was identified as a “transitional” region at the onset of the OEB defined Regional Planning process in 2013, the Needs Assessment and Scoping Assessment phases were deemed complete and the region was placed into the IRRP phase of the process.

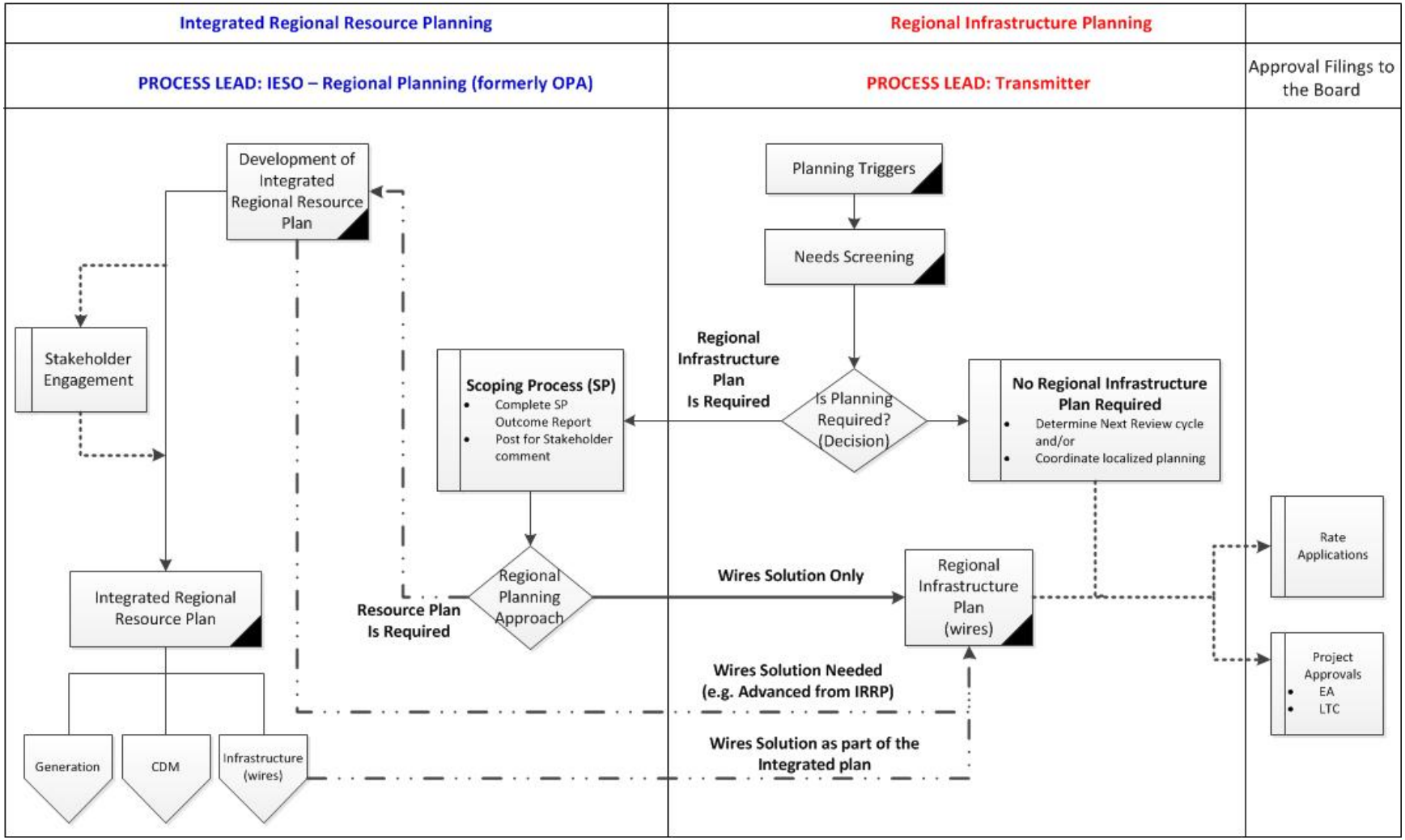


Figure 2-1 Regional Planning Process Flowchart

2.3 RIP Methodology

The RIP phase consists of four steps (see Figure 2-2) as follows:

1) Data Gathering: The first step of the RIP phase is the review of planning assessment data collected in the previous stages of the regional planning process. Hydro One collects this information and reviews it with the Working Group to reconfirm or update the information as required. The data collected includes:
   - Net peak demand forecast at the transformer station level. This includes the effect of any distributed generation or conservation and demand management programs.
   - Existing area network and capabilities including any bulk system power flow assumptions.
   - Other data and assumptions as applicable such as asset conditions; load transfer capabilities, and previously committed transmission and distribution system plans.
2) Technical Assessment: The second step is a technical assessment to review the adequacy of the regional system including any previously identified needs. Additional near and mid-term needs may be identified at this stage.
3) Alternative Development: The third step is the development of wires options to address the needs and to come up with a preferred alternative based on an assessment of technical considerations, feasibility, environmental impact and costs.
4) Implementation Plan: The fourth and last step is the development of the implementation plan for the preferred alternative.

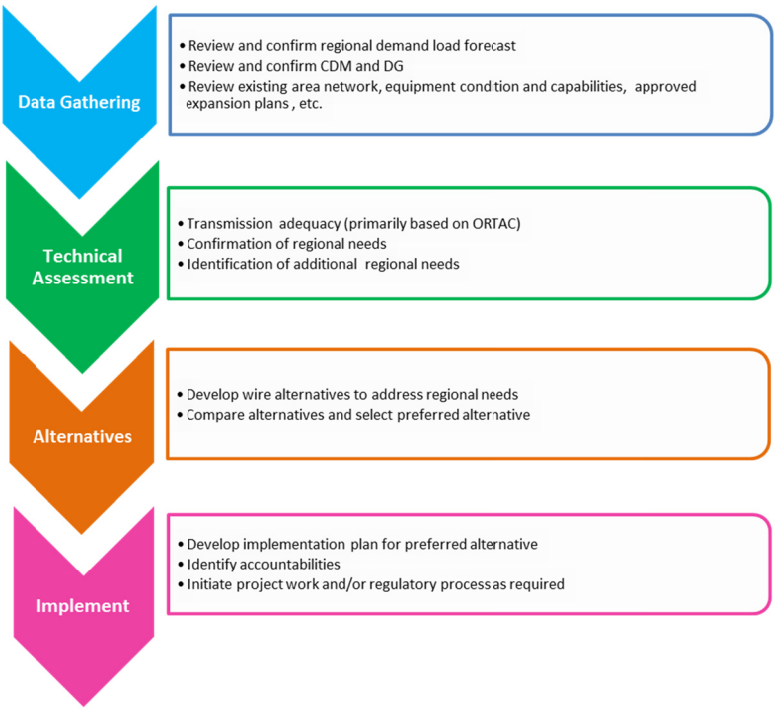


Figure 2-2 RIP Methodology

3. REGIONAL CHARACTERISTICS

THE KWCG REGION COMPRISES OF THE CITIES OF KITCHENER, WATERLOO, CAMBRIDGE AND GUELPH, PORTIONS OF OXFORD AND WELLINGTON COUNTIES AND THE TOWNSHIPS OF NORTH DUMFRIES, PUSLINCH, WOOLWICH, WELLESLEY AND WILMOT AS SHOWN IN FIGURE 3-1.

The main sources of electricity into the KWCG Region are from four Hydro One stations: Middleport TS, Detweiler TS, Orangeville TS and Burlington TS. At these stations electricity is transformed from 500 kV and 230 kV to 230 kV and 115 kV, respectively. Electricity is then delivered to the end users of LDCs and directly-connected industrial customers by 24 step-down transformer stations. Figure 3-2 illustrates these stations as well as the four major regional sub-systems: Waterloo-Guelph 230 kV sub-system, Cambridge-Kitchener 230 kV sub-system, Kitchener-Guelph 115 kV sub-system and South-Central Guelph 115 kV sub-system. Appendix A lists all step-down transformer stations in the KWCG Region, Appendix B lists all transmission circuits in the KWCG Region and Appendix C lists LDCs in the KWCG Region.

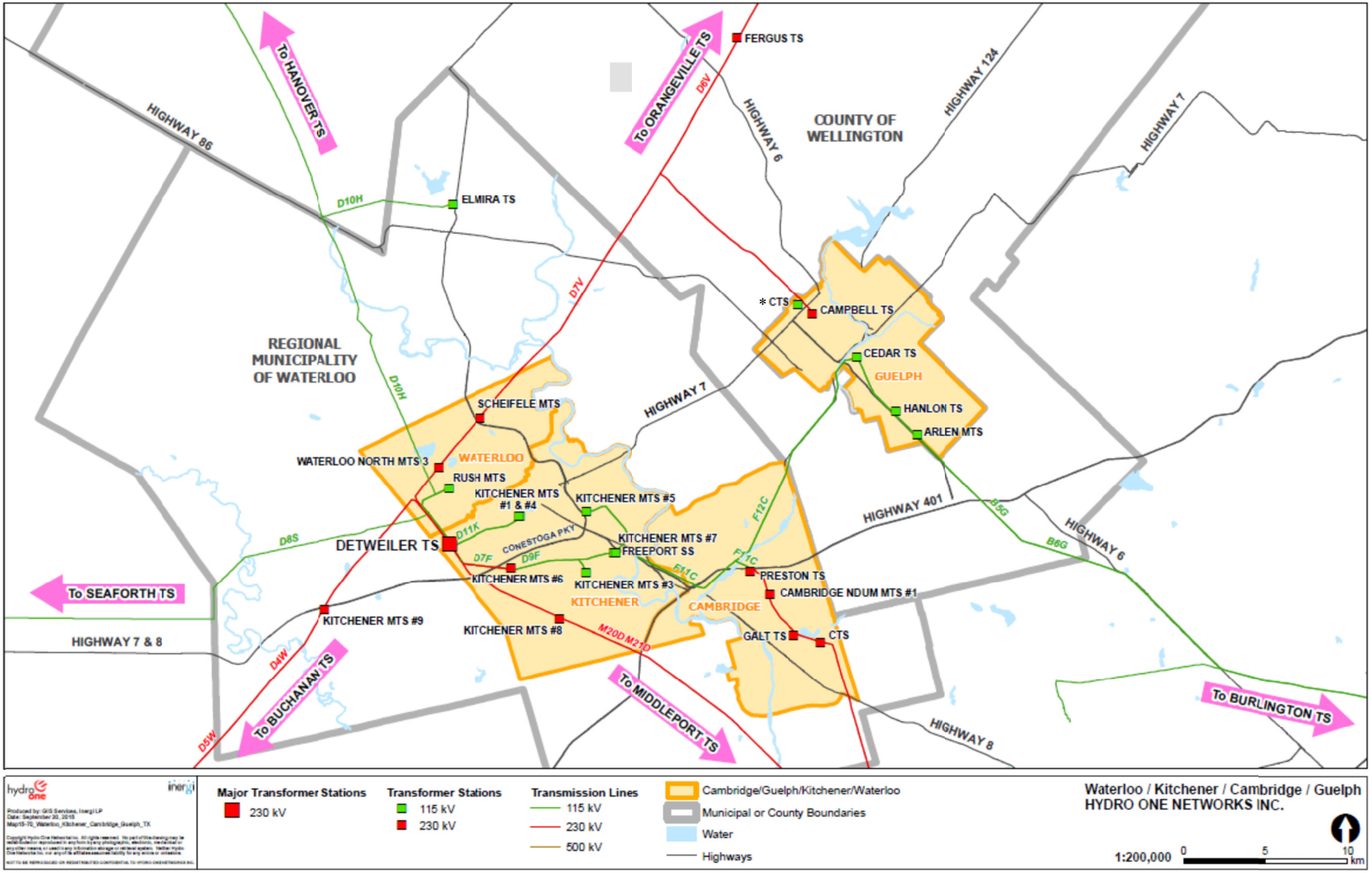


Figure 3-1 Geographical Area of the KWCG Region with Electrical Layout

*CTS relocated to the distribution system as part of the GATR project

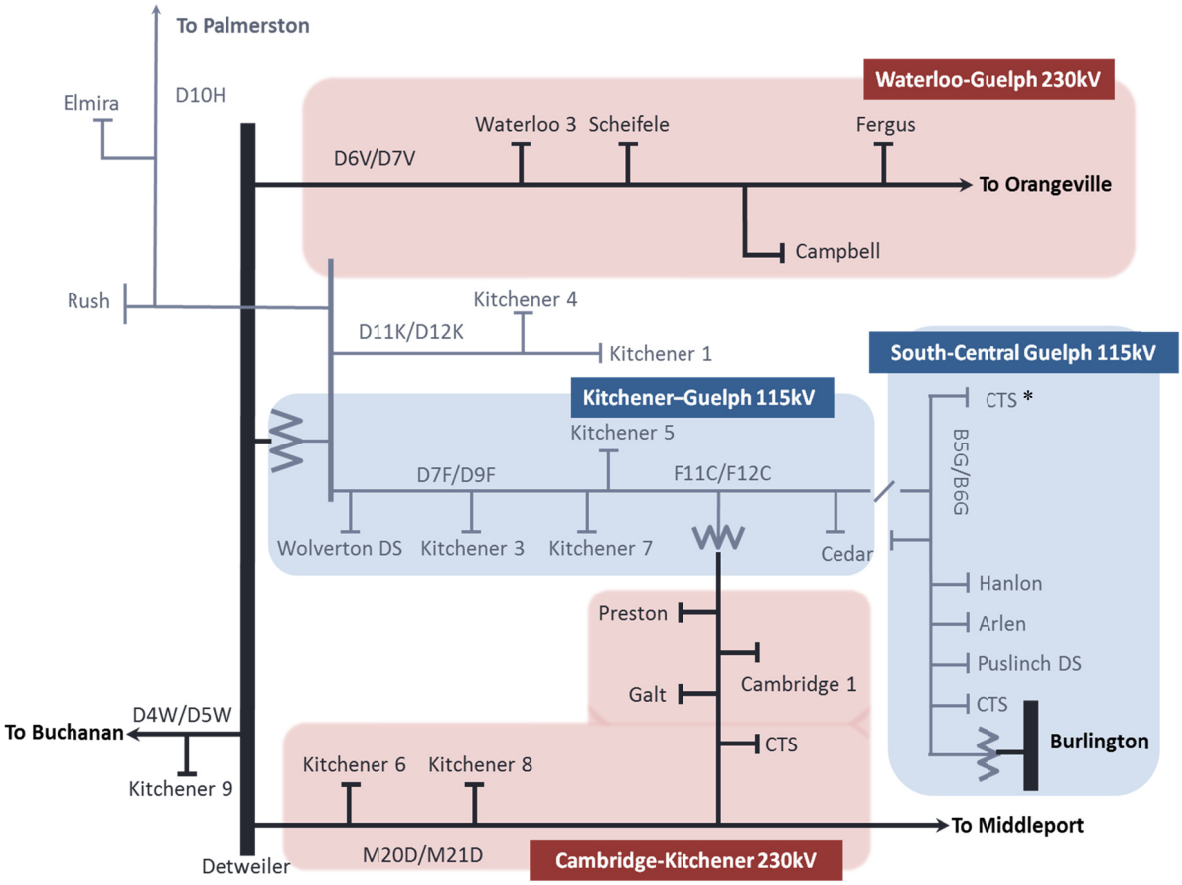


Figure 3-2 KWCG Single Line Diagram

*CTS relocated to the distribution system as part of the GATR project

4. TRANSMISSION FACILITIES COMPLETED OVER LAST TEN YEARS OR CURRENTLY UNDERWAY

OVER THE LAST 10 YEARS A NUMBER OF TRANSMISSION PROJECTS HAVE BEEN COMPLETED BY HYDRO ONE, OR ARE UNDERWAY, AIMED AT IMPROVING THE SUPPLY TO THE KWCG REGION.

These projects were identified as a result of joint planning studies undertaken by Hydro One, IESO and the LDCs; or initiated to meet the needs of the LDCs; and/or to meet Provincial Government policies. A brief listing of the completed projects is given below.

For transmission voltage level transformation capacity needs:

- 250 MVA 230/115 kV autotransformer T4 at Burlington TS replaced in 2006
- 250 MVA 230/115 kV autotransformer T6 at Burlington TS replaced in 2009

For distribution voltage level transformation capacity needs:

- Kitchener MTS#9 connected to replace the Detweiler TS DESN in 2010
- Arlen MTS connected in 2011

For reactive and voltage support needs:

- a 13.8 kV shunt capacitor bank installed at Cedar TS in 2006
- a 230 kV shunt capacitor bank installed at Detweiler TS in 2007
- a 230 kV shunt capacitor bank installed at Orangeville TS in 2008
- a 230 kV shunt capacitor bank installed at Burlington TS in 2010
- a 115 kV shunt capacitor bank installed at Detweiler TS in 2012

For transmission circuit capacity needs:

- M20D/M21D circuit sections capacity increased by sag limit mitigation in 2014

For transmission load security needs:

- Freeport SS installed to sectionalize circuits D7G/D9G (Detweiler TS by Cedar TS) in 2008

For transmission load restoration needs:

- 250 MVA 230/115 kV autotransformer T2 installed at Preston TS in 2007

The following projects are underway:

- Guelph Area Transmission Reinforcement (GATR) project that entails the extension the 230kV circuits D6V/D7V to Cedar TS; the installation of two new 250MVA, 230/115kV

autotransformers at Cedar TS; and the installation of two 230 kV in-line switches onto circuits D6V/D7V at Guelph North Junction. This project reinforces the Kitchener-Guelph and South-Central Guelph 115kV sub-systems as well as improves restoration capability to the Waterloo-Guelph 230 kV sub-system. This project is identified in the IESO KWCG IRRP, reference [1].

- The installation of a 13.8 kV series reactor to mitigate short circuit levels at Arlen MTS. This project was identified in the RIP phase.

- The installation two new 230kV in-line switches onto circuits M20D/M21D near Galt Junction to improve restoration capability in the Cambridge-Kitchener 230 kV sub-system. This project is identified in Hydro One's KWCG Adequacy of Transmission Facilities & Transmission Plan 2016-2025 report, reference [2]/Appendix F as well as reference [1].

5. FORECAST AND OTHER STUDY ASSUMPTIONS

5.1 Load Forecast

The load in the KWCG Region is forecast to increase at an average rate of approximately 1.7% annually between 2015 and 2025. The growth rate varies across the Region with most of the growth concentrated in the cities of Waterloo and Guelph, each at an average rate of 2.5% over the next ten years.

Figure 5-1 shows the KWCG Region's planning load forecast (summer net, regional-coincident extreme weather peak). The regional-coincident (at the same time) forecast represents the total peak load of the 24 step-down transformer stations in the KWCG Region. By 2025 the forecasted coincident regional peak load is approximately 1765 MW.

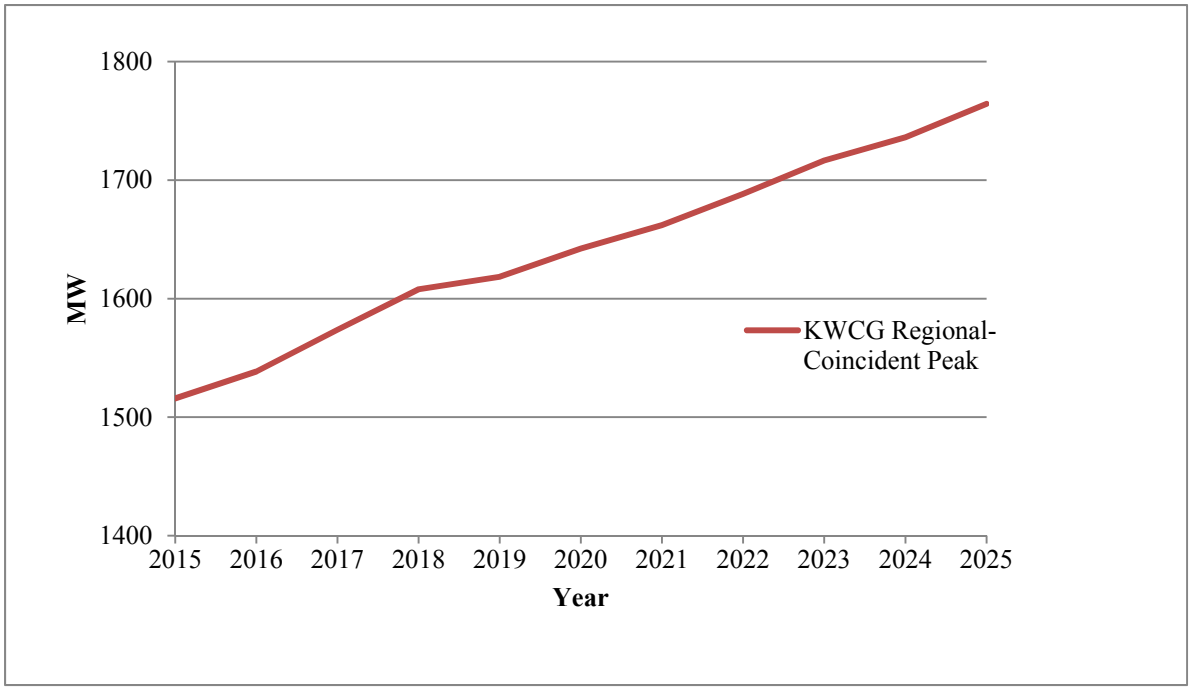


Figure 5-1 KWCG Region's Planning Forecast

The KWCG 2015 RIP planning load forecast is provided in Appendix D and is based upon the KWCG IRRP planning load forecast prepared by the IESO and was reaffirmed by the Working Group upon initiation of the RIP phase. In the IRRP phase, the LDC's provided the IESO with a 10 year gross, normal weather, regional-coincident, peak load forecast in MW. The IESO adjusted the forecast by subtracting the effective CDM capacity, applying an extreme weather factor and then subtracting the effective DG capacity. Further details regarding the CDM and connected DG are provided in reference [1]. The RIP forecast is identical to the IRRP forecast except as otherwise noted in Appendix D.

5.2 Other Study Assumptions

The following other assumptions are made in this report.

1) The Study period for the RIP assessment is 2015-2025.
2) All planned facilities for which work has been initiated and are listed in Section 4 are assumed to be in-service.
3) Summer is the critical period with respect to line and transformer loadings. The assessment is based therefore based on summer peak loads.
4) Station capacity adequacy is assessed by comparing the non-coincident peak load with the station's normal planning supply capacity, assuming a 90% lagging power factor for stations having no low-voltage capacitor banks and 95% lagging power factor for stations having low-voltage capacitor banks.
5) Normal planning supply capacity for Hydro One transformer stations in this Region is determined by the summer 10-Day Limited Time Rating (LTR), while some LDCs use different methodologies for determining transformer station LTR.
6) Adequacy assessment is done as per the Ontario Resource and Transmission Adequacy Criteria ("ORTAC").

6. ADEQUACY OF FACILITIES AND REGIONAL NEEDS OVER THE 2015-2025 PERIOD

THIS SECTION REVIEWS THE ADEQUACY OF THE EXISTING TRANSMISSION SYSTEM AND DELIVERY STATION FACILITIES SUPPLYING THE KWCG REGION AND LISTS THE FACILITIES REQUIRING REINFORCEMENT OVER THE NEAR AND MID-TERM.

Within the current regional planning cycle two regional assessments have been conducted for the KWCG Region. The findings of these studies are input to the RIP. The studies are:

1) IESO's KWCG Integrated Regional Resource Plan – dated April 28, 2015[1]
2) Hydro One's Adequacy of Transmission Facilities and Transmission Plan 2016-2025 – dated April 1, 2015 with revision 1 – dated October 30, 2015[2] (please see Appendix F)

The IRRP identified a number of regional needs to meet the forecast load demand over the near to mid-term. Due to the immediate nature of the needs the Guelph Area Transmission Reinforcement (GATR) project was initiated to provide adequate load supply capability to the KWCG area while the IRRP study was still underway. A detailed description and status of the GATR project and other work initiated or planned to meet these needs is given in Section 7.

This RIP reviewed the loading on transmission lines and stations in the KWCG Region assuming the GATR project is in-service. Sections 6.1-6.4 present the results of this review and Table 6-1 lists the Region's needs identified in both the IRRP and RIP phases.

Table 6-1 Near and Medium Term Regional Needs

Type	Section	Needs	Timing
Needs Identified in the IRRP [1] and the Adequacy Report [2]			
Transmission Circuit Capacity	7.1.1	South-Central Guelph 115 kV sub-system- Capacity of 115kV circuits B5G/B6G	Immediate
	7.1.2	Kitchener–Guelph 115 kV sub-system – Capacity of 115kV circuits D7F/D9F and F11C/F12C	Immediate
Load Restoration	7.1.3	Waterloo-Guelph 230 kV sub-system	Immediate
	7.2.1	Cambridge-Kitchener 230 kV sub-system	Immediate
Step-down Transformation Capacity	7.3.1	Waterloo North Hydro Inc.	2018
Additional Needs identified in RIP Phase			
Station Short Circuit Capability	7.4.1	Arlen MTS: Short Circuit capability	2016

6.1 230 kV Transmission Facilities

All 230 kV transmission circuits in the KWCG Region are classified as part of the Bulk Electricity System ("BES"). They connect the Region to the rest of the Ontario's transmission system and are also part of the transmission path from generation in Southwestern Ontario to the load centers in the Hamilton, Niagara and GTA areas. These circuits also serve local area stations within the Region and the power flow on them depends on the bulk system transfer as well as local area loads. These circuits are as follows (refer to Figure 3-2):

1) Detweiler TS to Orangeville TS 230 kV transmission circuits D6V/D7V – supplies Fergus TS, Campbell TS, Waterloo North MTS#3 and Scheifele MTS
2) Detweiler TS to Middleport TS 230 kV transmission circuits M20D/M21D – supplies Kitchener MTS #6, Kitchener MTS # 8, Cambridge MTS #1, Galt TS, Preston TS and Customer #1 CTS
3) Detweiler TS to Buchanan TS 230 kV transmission circuits D4W/D5W – supplies Kitchener MTS#9.

The RIP review shows that based on current forecast station loadings and bulk transfers, all 230 kV circuits are expected to be adequate over the study period. Refer to section 3.4.2 of Appendix F for the detailed analysis.

6.2 500/230 kV and 230/115 kV Transformation Facilities

Bulk power supply to the KWCG Region is provided by Hydro One's 500 kV to 230 kV and 230 kV to 115 kV autotransformers. The number and location of these autotransformers are as follows:

1) Two 500/230 kV autotransformers at Middleport TS
2) Four 230/115 kV autotransformers at Burlington TS
3) Three 230/115 kV autotransformers at Detweiler TS
4) Two 230/115 kV autotransformers at Cedar TS
5) One 230/115 kV autotransformer at Preston TS

The RIP review shows that based on current forecast station loadings and bulk transfers, the auto-transformation supply capacity is adequate over the study period. Refer to section 3.4.1 of Appendix F for the detailed analysis.

6.3 Supply Capacity of the 115 kV Network

The KWCG Region contains five pairs of double circuit 115 kV lines. This 115 kV network serves local area load. These circuits are as follows (see Figure 3-2):

1) Detweiler TS to Freeport SS 115 kV transmission circuits D7F/D9F – supplies Wolverton DS, Kitchener MTS #3, Kitchener MTS#7
2) Freeport SS to Cedar TS 115 kV transmission circuits F11C/F12C – supplies Kitchener MTS#5 and Cedar T1/T2 transformers
3) Burlington TS to Cedar TS 115 kV transmission circuits B5G/B6G – supplies Puslinch DS, Arlen MTS, Hanlon TS, Customer #2 CTS and Cedar T7/T8 transformers
4) Detweiler TS 115 kV radial transmission circuit D11K/D12K – supplies Kitchener MTS#1 and Kitchener MTS#4
5) Detweiler TS to Seaforth TS/Hanover TS 115 kV transmission circuit D8S/D10H with Normally Open (N/O) points – supplies Rush MTS and Elmira TS

The RIP review shows that based on current forecast station loadings and bulk transfers, the supply capacity of the 115 kV network is adequate over the study period. Refer to section 3.4.3 of Appendix F for the detailed analysis.

6.4 Step-down Transformer Stations

There are 24 step-down transformer stations within the KWCG Region. Twenty-two supply electricity to LDCs and two are transmission-connected industrial customer stations. These stations are listed within the load forecast in Appendix D. Of those 24 stations, 15 of them are owned and operated by the LDCs.

As part of the IRRP, step-down transformation station capacity was reviewed and resulted in the IRRP forecast which was reaffirmed by the Working Group for use in the RIP phase. According to the load forecast, Waterloo North Hydro anticipates requiring additional step-down transformation capacity in 2018.

6.5 Other Items Identified During Regional Planning

6.5.1 Customer Impact Assessment for the GATR project

Based on the Customer Impact Assessment [3] for the GATR project, Guelph Hydro identified the need to mitigate short circuit levels at Arlen MTS in order to ensure the short circuit levels remain within the TSC limits and equipment ratings. The project need date is May 2016 so as to correlate with the completion of the GATR project.

6.5.2 System Impact Assessment for the GATR Project

A System Impact Assessment (“SIA”) [4] was performed for Hydro One’s application to the IESO for the Guelph Area Transmission Reinforcement (GATR) project.

Several findings emanated from the SIA report due to conservative assumptions made for the Bulk Power System. The Working Group has reviewed these findings and recommends that the assumptions be

looked at in greater detail within a Bulk Power System study. If the Bulk Power System study results in regional needs then an early trigger of the next Regional Planning cycle may occur.

6.5.3 Load Restoration to the Cambridge area

The IRRP recommended Hydro One to continue to explore options with Cambridge and North Dumfries Hydro ("CND") to further improve the load restoration capability to the Cambridge area. During the RIP phase Hydro One presented to CND a detailed explanation of its capability to restore power to transformer stations that service the Cambridge area. Based on this discussion, CND and Hydro One have agreed that, at this time, no additional infrastructure is required and the restoration capability afforded by the GATR project and the 230 kV in-line switches at Galt Junction is acceptable for the study period.

6.6 Long-Term Regional Needs

The IRRP examined high-growth and low-growth scenarios to identify long-term needs. Under the high-growth scenario, there is sufficient transmission capacity afforded by the GATR project to meet demand in the long-term; however the need for additional step-down transformation capacity may arise. LDC's to closely monitor their load to determine the timing of potential step-down transformation needs. Under the low-growth scenario, no needs were identified in the long-term.

Consistent with the IRRP, the Working Group did not identify any additional long-term needs during the RIP phase. If new long-term needs were to arise, there is sufficient time to assess them in the next planning cycle which can also be started earlier to make timely investment decisions..

7. REGIONAL PLANS

THIS SECTION DISCUSSES THE ELECTRICAL SUPPLY NEEDS FOR THE KWCG REGION AND SUMMARIZES THE REGIONAL PLANS FOR ADDRESSING THE NEEDS. THESE NEEDS ARE LISTED IN TABLE 6-1 AND INCLUDE NEEDS PREVIOUSLY IDENTIFIED IN THE IRRP AS WELL AS THE NEEDS IDENTIFIED DURING THE RIP PHASE.

7.1 Transmission Circuit Capacity and Load Restoration

7.1.1 South-Central Guelph 115 kV Sub-system

The South-Central Guelph area is supplied by the 115 kV double circuit line B5G/B6G. As per section 6.2.1 of the IRRP, historical peak demand on the B5G/B6G line has already exceeded the 100 MW line Load Meeting Capability ("LMC").

7.1.2 Kitchener-Guelph 115 kV Sub-system

The Kitchener-Guelph area is supplied by two 115 kV double-circuit lines D7F/D9F and F11C/F12C supported by 230/115 kV autotransformers at Detweiler TS and Preston TS. As per section 6.2.1 of the IRRP, the planning forecast peak demand in the Kitchener-Guelph 115 kV sub-system will exceeded the 260 MW line LMC by summer 2014.

7.1.3 Waterloo-Guelph 230 kV Sub-system

As per section 6.2.2 of the IRRP, the transmission infrastructure supplying load in the Waterloo-Guelph 230 kV sub-system does not meet reliability requirements to quickly restore supply in the event of a major outage involving the loss of both transmission circuits, D6V and D7V.

7.1.4 Recommended Plan and Current Status

To address the transmission circuit capacity needs for the South-Central Guelph 115 kV sub-system and the Kitchener-Guelph 115 kV sub-system, the IRRP Working Group recommended reinforcement of the 115 kV transmission system by introducing a new 230 kV – 115 kV injection point. The new injection point is to be located at Cedar TS using two new 230 kV/115 kV autotransformers in conjunction with a 5 km extension of the existing 230 kV double-circuit transmission line, D6V/D7V from Campbell TS to Cedar TS. This reinforcement is covered under the GATR project.

To address the load restoration need of the Waterloo-Guelph 230 kV sub-system, the IRRP Working Group's preferred alternative is to install two new 230 kV in-line switches near Guelph North Junction. The switches will enable Hydro One to quickly isolate a problem and allow the resupply of load to occur expeditiously. This work is also covered under the GATR project.

Current Status of the GATR Project

Hydro One initiated construction on the GATR project in fall 2013 following the OEB approval in September 2013. The project has three components:

- Campbell TS x Cedar TS: Extend the 230 kV D6V/D7V tap from Campbell TS to Cedar TS. This requires replacing approximately a 5 km section of the existing 115 kV double circuit transmission section between CGE Junction and Campbell TS with a new 230 kV double circuit transmission line,
- Cedar TS: Install two new 230/115 kV autotransformers and associated 115 kV switching facilities at Cedar TS. Connect 115 kV switching facilities to the existing B5G/B6G line and the F11C/F12C at Cedar TS.
- Guelph North Junction: Install two in-line 230 kV switches at Guelph North Jct.

This investment will provide for sufficient 230/115 kV autotransformation capacity beyond the study period. The current in-service date of the project is May 2016.

The cost of this project is approximately $95 million. The project is a transmission pool investment as the autotransformers provide supply to all customers in the Region.

7.2 Load Restoration

7.2.1 Cambridge-Kitchener 230 kV Sub-system

As per section 6.2.2 of the IRRP and the section 3.4.8 of the Adequacy of Transmission Facilities report, transmission infrastructure supplying load in the Cambridge-Kitchener 230 kV sub-system does not meet reliability requirements to quickly restore supply in the event of a major outage involving the loss of both transmission circuits, M20D and M21D.

7.2.2 Recommended Plan and Current Status

To address the load restoration need of the Cambridge-Kitchener 230 kV sub-system, the IRRP Working Group's preferred alternative is to install two new 230 kV in-line switches on the M20D/M21D line near Galt Junction. The switches will enable Hydro One to quickly isolate a problem and allow the resupply of load to occur expeditiously. This work is covered under the M20D/M21D Install 230 kV In-line Switches project.

Current Status of the 230 kV In-Line Switches near Galt Junction

Hydro One has established a project to install the two 230 kV in-line switches onto the M20D/M21D double circuit line. One set of switches to be installed onto each circuit. One set of switches to be installed north of the Junction while the other to be installed south of Galt Junction. The switches will enable

Hydro One to quickly isolate a problem on either side of the junction and initiate the restoration of load to the Cambridge-Kitchener 230 kV sub-system.

The project is currently in the detailed design and estimation phase which also includes real estate negotiations. The cost of this project is approximately $6 million and it will be a transmission pool investment. The planned in-service date is May 2017.

7.3 Step-down Transformation Capacity

7.3.1 Waterloo North Hydro

The RIP/IRRP planning load forecast indicates that additional step-down transformation capacity is required by 2018, specifically Waterloo North Hydro's MTS #4.

7.3.2 Recommended Plan and Current Status

To address step-down transformation capacity needs of Waterloo North Hydro, Waterloo North Hydro will, wherever possible, manage load growth by maximizing the utilization of existing stations by increasing distribution load transfer capability between those stations and will continue to explore opportunities for CDM and DG. In addition Waterloo North Hydro will also explore, with other LDCs, opportunities to coordinate possible joint use and development of step-down transformer stations in the Region over the long term. With this in mind, additional step-down transformation capacity is not anticipated prior to 2024. This need will be reviewed in the next cycle of regional planning.

7.4 Station Short Circuit Capability

7.4.1 Arlen MTS

Arlen MTS is a 115/13.8 kV step-down transformer station owned by Guelph Hydro. As a result of the new 230/115 kV injection point afforded by the GATR project, the short circuit levels at Arlen MTS's 13.8 kV bus will exceed the TSC limit and equipment capability.

7.4.2 Recommended Plan and Current Status

To address the station short circuit capability need at Arlen MTS, Guelph Hydro will install series reactors to bring station short circuit levels within TSC limits and within equipment ratings.

Current Status of Short Circuit Mitigation

Guelph Hydro has initiated a project to install series reactors to bring station short circuit levels within TSC limits and equipment ratings. The cost of this project is $0.95 million and the expected completion date is May 2016 so as to correlate with the completion of the GATR project.

8. CONCLUSIONS

THIS REGIONAL INFRASTRUCTURE PLAN REPORT CONCLUDES THE REGIONAL PLANNING PROCESS FOR THE KWCG REGION. THIS REPORT MEETS THE INTENT OF THE PROCESS DESCRIBED IN SECTION 2 WHICH IS ENDORSED BY THE OEB AND MANDATED IN THE TSC AND DSC.

Six near and mid-term needs were identified for the KWCG Region. They are:

I. Transmission capacity in the South-Central Guelph 115 kV sub-system
II. Transmission capacity in the Kitchener-Guelph 115 kV sub-system
III. Load restoration capability in the Waterloo-Guelph 230 kV sub-system
IV. Load restoration capability in the Cambridge-Kitchener 230 kV sub-system
V. Step-down transformation capacity for Waterloo North Hydro
VI. Station Short Circuit Capacity at Arlen MTS

This RIP report addresses all six of these needs. Next Steps, Lead Responsibility, and Timeframes for implementing the wires solutions for the near and mid-term needs are summarized in the Table 8-1 below.

Table 8-1 Regional Plans – Next Steps, Lead Responsibility and Plan In-Service Dates

No.	Project	Next Steps	Lead Responsibility	I/S Date	Cost	Needs Mitigated
1	Guelph Area Transmission Reinforcement	Construction in the final stages	Hydro One	May 2016	$95M	I, II, III
2	Mitigate Short Circuit Levels at Arlen MTS	Construction underway	Guelph Hydro	May 2016	$0.95M	VI
3	M20D/M21D – Install 230 kV In-line Switches	Transmitter to carry out this work	Hydro One	May 2017	$6M	IV
4	Waterloo North Hydro: MTS #4	LDC to monitor growth	Waterloo North Hydro	2024	TBD	V

In accordance with the Regional Planning process, the Regional Plan should be reviewed and/or updated at least every five years. The region will continue to be monitored and should there be a need that emerges due to a change in load forecast or any other reason, the next regional planning cycle will be started earlier to address the need.

9. REFERENCES

[1] Independent Electricity System Operator, Kitchener-Waterloo-Cambridge-Guelph Region Integrated Region Resource Plan, 28 April 2015. http://www.ieso.ca/Documents/Regional-Planning/KWCG/2015-KWCG-IRRP-Report.pdf

[2] Hydro One Networks Inc., Kitchener-Waterloo-Cambridge-Guelph Area – Adequacy of Transmission Facilities and Transmission Plan 2016-2025, 1 April 2015, revised 30 October 2015.

[3] Hydro One Networks Inc., Customer Impact Assessment Guelph Area Transmission Refurbishment Project, 28 May 2013,

[4] Independent Electricity System Operator, System Impact Assessment, CAA ID: 2012-478, Project: Guelph Area Transmission Refurbishment, 17 May 2013. http://www.ieso.ca/Documents/caa/CAA_2012-478_GATR_Final_Report.pdf

Appendix A. Step-Down Transformer Stations in the KWCG Region

Station	Voltage (kV)	Supply Circuits
Waterloo-Guelph 230 kV sub-system		
Fergus TS	230 kV	D6V/D7V
Scheifele MTS	230 kV	D6V/D7V
Waterloo North MTS #3	230 kV	D6V/D7V
Campbell TS	230 kV	D6V/D7V
Cambridge-Kitchener 230 kV sub-system		
Kitchener MTS #6	230 kV	M20D/M21D
Kitchener MTS #8	230 kV	M20D/M21D
Cambridge MTS #1	230 kV	M20D/M21D
Preston TS	230 kV	M20D/M21D
Galt TS	230 kV	M20D/M21D
Customer #1 CTS	230 kV	M21D
Kitchener–Guelph 115 kV sub-system		
Wolverton DS	115 kV	D7F/D9F
Kitchener MTS #3	115 kV	D7F/D9F
Kitchener MTS #7	115 kV	D7F/D9F
Kitchener MTS #5	115 kV	F11C/F12C
Cedar TS (T1/T2)	115 kV	F11C/F12C
South-Central Guelph 115 kV sub-system		
Puslinch DS	115 kV	B5G/B6G
Arlen MTS	115 kV	B5G/B6G
Hanlon TS	115 kV	B5G/B6G
Cedar TS (T8/T7)	115 kV	B5G/B6G
Customer #2 CTS	115 kV	B5G
Other Stations in the KWCG Region		
Kitchener MTS #9	230 kV	D4W/D5W
Rush MTS	115 kV	D8S/D10H
Elmira TS	115 kV	D10H
Kitchener MTS #1	115 kV	D11K/D12K
Kitchener MTS #4	115 kV	D11K/D12K

Appendix B. Transmission Lines in the KWCG Region

Location	Circuit Designations	Voltage (kV)
Detweiler TS – Orangeville TS	D6V/D7V	230 kV
Detweiler TS - Middleport TS	M20D/M21D	230 kV
Detweiler TS - Buchanan TS	D4W/D5W	230 kV
Detweiler TS - Freeport SS	D7F/D9F	115 kV
Freeport SS - Cedar TS	F11C/F12C	115 kV
Burlington TS - Cedar TS	B5G/B6G	115 kV
Detweiler TS – Kitchener MTS #4	D11K/D12K	115 kV
Detweiler TS – Palmerston TS	D10H	115 kV
Detweiler TS – Seaforth TS	D8S	115 kV

Appendix C. Distributors in the KWCG Region

Distributor Name	Station Name	Connection Type
Cambridge and North Dumfries Hydro Inc.	Cambridge NDum MTS#1	Tx
	Galt TS	Tx
	Preston TS	Tx
	Wolverton DS	Dx
Centre Wellington Hydro Ltd.	Fergus TS	Dx
Guelph Hydro Electric System - Rockwood Division	Fergus TS	Dx
Guelph Hydro Electric Systems Inc.	Arlen MTS	Tx
	Campbell TS	Tx
	Cedar TS	Tx
	Hanlon TS	Tx
Halton Hills Hydro Inc.	Fergus TS	Dx
Hydro One Networks Inc.	Fergus TS	Tx
	Elmira TS	Tx
	Puslinch DS	Tx
	Wolverton DS	Tx
	Galt TS	Dx
Kitchener-Wilmot Hydro Inc.	Kitchener MTS#1	Tx
	Kitchener MTS#3	Tx
	Kitchener MTS#4	Tx
	Kitchener MTS#5	Tx
	Kitchener MTS#6	Tx
	Kitchener MTS#7	Tx
	Kitchener MTS#8	Tx
	Kitchener MTS#9	Tx
Milton Hydro Distribution Inc.	Fergus TS	Dx
Waterloo North Hydro Inc.	Elmira TS	Dx
		Tx
	Fergus TS	Dx
	Rush MTS	Tx
	Scheifele MTS	Tx
	Waterloo North MTS #3	Tx
	Preston TS	Dx
	Kitchener MTS#9	Dx
Wellington North Power Inc.	Fergus TS	Dx

Appendix D. KWCG Regional Load Forecast (2015-2025)

Table D-1 RIP Planning Demand Forecast (MW)

Station	LDC	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Cambridge MTS #1	Cambridge & North Dumfries Hydro	92.3	93.8	95.6	98.1	99.7	102.7	101.8	102.1	102.4	102.2	101.6
Galt TS	Cambridge & North Dumfries Hydro	108.1	109.5	112.3	113.7	116.1	119.0	122.8	127.9	134.8	141.9	148.8
Preston TS (1)	Cambridge & North Dumfries Hydro	108.0	100.3	102.0	104.4	105.9	108.7	109.6	111.8	111.9	111.5	111.8
Kitchener MTS #6	Kitchener-Wilmot Hydro	72.8	72.8	73.0	73.0	72.4	72.1	71.7	71.6	71.5	71.1	71.1
Kitchener MTS #8	Kitchener-Wilmot Hydro	44.2	37.6	40.3	43.1	45.3	38.6	41.1	43.5	46.0	48.2	50.6
Kitchener MTS #3	Kitchener-Wilmot Hydro	54.3	64.4	66.5	67.3	67.5	77.0	77.5	78.1	78.7	79.0	79.6
Kitchener MTS #7	Kitchener-Wilmot Hydro	44.9	45.1	45.9	46.0	45.6	45.6	45.6	45.7	39.9	39.8	39.9
Wolverton DS	Hydro One Distribution	21.2	21.4	21.6	21.6	21.6	21.6	21.6	21.7	21.8	21.7	21.9
Cedar TS T1/T2	Guelph Hydro	72.3	74.9	75.8	77.4	78.3	79.5	79.8	82.2	84.6	85.5	87.9
Cambridge MTS # 2 (2)	Cambridge & North Dumfries Hydro	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Kitchener MTS #5	Kitchener-Wilmot Hydro	73.9	73.8	74.6	74.5	73.8	73.5	73.2	73.1	78.8	78.3	78.2
Cedar TS T7/T8	Guelph Hydro	30.2	32.0	32.0	32.8	32.3	33.0	33.7	33.4	34.2	34.8	35.5
Hanlon TS	Guelph Hydro	29.8	30.7	31.6	32.5	33.0	33.7	34.4	35.1	34.9	35.5	35.3
Puslinch DS	Hydro One Distribution	35.6	36.2	36.8	37.3	37.5	37.9	38.3	38.7	39.2	39.5	39.9
Arlen MTS	Guelph Hydro	30.0	33.0	37.0	40.9	33.3	37.9	41.4	43.0	44.6	45.9	47.5
Campbell TS	Guelph Hydro	131.9	136.3	139.0	140.2	141.2	142.8	144.4	148.4	152.2	156.2	160.1
Scheifele MTS	Waterloo North Hydro	169.0	166.0	170.7	150.3	151.2	152.7	154.3	156.2	158.1	153.4	155.4
Waterloo North MTS #3	Waterloo North Hydro	61.9	70.8	72.7	75.3	79.3	64.6	58.0	75.3	76.8	76.9	78.4
MTS #4(2)	Waterloo North Hydro	0.0	0.0	0.0	30.6	35.2	50.9	60.3	61.9	64.4	65.6	68.1
Fergus TS	Hydro One Distribution	108.9	108.8	109.5	109.7	108.5	108.3	108.2	108.5	108.7	108.3	108.7
Kitchener MTS #1	Kitchener-Wilmot Hydro	29.1	29.6	31.1	31.6	31.8	32.1	32.4	32.9	33.3	33.5	33.9
Kitchener MTS #4	Kitchener-Wilmot Hydro	67.8	68.2	69.1	69.3	69.0	69.0	68.9	69.2	69.3	69.1	69.3
Kitchener MTS #9	Kitchener-Wilmot Hydro	33.7	33.9	34.3	34.6	34.5	34.7	34.9	35.0	35.3	35.4	35.5
Elmira TS (3)	Waterloo North Hydro/ Hydro One Distribution	38.0	32.6	33.5	33.3	34.8	35.4	36.0	36.8	38.4	39.0	40.6
Rush MTS	Waterloo North Hydro	54.9	63.8	65.7	67.4	67.4	67.8	69.1	53.0	53.6	60.7	61.3
Customer #1 CTS (4)	Customer Station	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5
Customer #2 CTS	Customer Station (Assumed Values)	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0

Table D1 -is based upon KWCG 2015 IRRP Planning Load Forecast except as noted.

(1) Cambridge and North Dumfries Hydro (“CND”) has confirmed 9.2 MW of cogeneration at a large customer to be accounted for in the Preston TS forecast starting year 2016. The generation plant is expected to run most of the time and would offset the customer's load. This cogeneration was not factored into the KWCG 2015 IRRP Planning Load Forecast.

(2) Both CND and Waterloo North Hydro (“WNH”) are monitoring the load closely to determine the timing of potential transformation needs. For planning purposes, WNH has moved back the in service date of MTS #4 from 2018 to 2024. WNH is closely monitoring the need for additional transformation capacity to determine if the load growth indicated at MTS #4 in the forecast can be managed through a combination of improving transformer station interties, CDM and DG in the Waterloo Region. Where possible, these LDCs are exploring opportunities to coordinate possible joint use and development of step-down transformer station facilities in the KWCG Region over the long term.

(3) Updated to include Hydro One Distribution load

(4) Based on information provided by the transmission-connected customer

Appendix E. List of Acronyms

Acronym	Description
A	Ampere
BES	Bulk Electric System
BPS	Bulk Power System
CDM	Conservation and Demand Management
CIA	Customer Impact Assessment
CGS	Customer Generating Station
CTS	Customer Transformer Station
DESN	Dual Element Spot Network
DG	Distributed Generation
DSC	Distribution System Code
GS	Generating Station
GTA	Greater Toronto Area
HV	High Voltage
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	Kilovolt
LDC	Local Distribution Company
LP	Local Plan
LTE	Long Term Emergency
LTR	Limited Time Rating
LV	Low Voltage
MTS	Municipal Transformer Station
MW	Megawatt
MVA	Mega Volt-Ampere
MVAR	Mega Volt-Ampere Reactive
NA	Needs Assessment
NERC	North American Electric Reliability Corporation
NGS	Nuclear Generating Station
NPCC	Northeast Power Coordinating Council Inc.
NUG	Non-Utility Generator
OEB	Ontario Energy Board
OPA	Ontario Power Authority
ORTAC	Ontario Resource and Transmission Assessment Criteria
PF	Power Factor
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Plan
ROW	Right-of-Way
SA	Scoping Assessment
SIA	System Impact Assessment
SPS	Special Protection Scheme
SS	Switching Station
TS	Transformer Station
TSC	Transmission System Code
UFLS	Under Frequency Load Shedding
ULTC	Under Load Tap Changer
UVLS	Under Voltage Load Rejection Scheme

Appendix F. KWCG Adequacy of Transmission Facilities and Transmission Plan 2016-2025

Revision 1

KITCHENER/WATERLOO/CAMBRIDGE/GUELPH AREA

ADEQUACY OF TRANSMISSION FACILITIES

AND

TRANSMISSION PLAN 2016 – 2025

October 30, 2015

Prepared by Hydro One Networks Inc. in Consultation with the KWCG Working Group

Foreword

This report is the result of a joint study by KWCG Working Group. It has been prepared by Hydro One Networks in consultation with the Working Group.

The working group members were:

Entity	Member
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The preferred plan has been selected based on technical and economic considerations. The issue of cost allocation between utilities was not addressed.

Prepared by: Qasim Raza – Transmission Planning Officer

Reviewed by: Alessia Dawes – Senior Transmission Planning Engineer

Approved by: Farooq Qureshy – Manager, Transmission System Development, Central & East

October 30, 2015

Revision History

Revision	Date	Author	Description of change
1	October 30, 2015	Qasim Raza	Refreshed based on 2015 IRRP/RIP load forecast (April/August2015)
0	April 1, 2015	Alessia Dawes	Original- based on May 2013 forecast

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EXECUTIVE SUMMARY

In 2010 an integrated regional planning study was initiated to assess the electricity supply and reliability over a twenty year period for the Kitchener-Waterloo-Cambridge-Guelph (KWCG) areas and continues to be conducted by a Working Group led by the Ontario Power Authority (OPA) and includes staff from the Independent Electricity System Operator (IESO), Hydro One Networks Inc., Kitchener-Wilmot Hydro, Waterloo North Hydro, Cambridge & North Dumfries Hydro, Guelph Hydro Electric Systems Inc. and Hydro One Distribution.

The early results of the integrated regional planning study identified the need to reinforce supply capacity for the South-Central Guelph and the City of Cambridge over the near and medium term. It also identified the need to minimize the impact of double circuit interruptions in the area[1]. As a result, the Working Group recommended two transmission projects in conjunction with conservation and distributed generation:

1. The Guelph Area Transmission Reinforcement (GATR) project – comprising a new 230/115kV autotransformer station at Guelph Cedar TS, upgrading the circuit section between Campbell TS and CGE Junction to 230 kV and in-line switching on the Orangeville TS x Detweiler TS 230kV circuits D6V/D7V – to reinforce supply to South Central Guelph,
2. The Preston TS Autotransformer Project – comprising the installation of a second 230/115kV autotransformer at Preston TS - to reinforce supply to the City of Cambridge.

Work on the GATR project was started in 2014 following approval from the Ontario Energy Board and the Ministry of Environment. The project's planned in-service date is June 2016.

For the Preston project, the OPA issued Hydro One a hand off letter to develop a "Wires" solution to improve the supply to the Cambridge area and to facilitate the connection of a future Cambridge and North Dumfries Hydro transformer station by 2018.

This report presents the results of Hydro One led "Wires" study of the adequacy of supply to the City of Cambridge and the wider KWCG area based on the planned in-service of the GATR project in summer 2016. The main conclusions of the report are as follows:

- The supply capability to the KWCG 115kV area has been significantly increased to meet all 2025 forecast loads by the addition of the GATR project. The need for the Preston autotransformer can be deferred to beyond 2025.
- There is inadequate load restoration capability for load connected to Middleport TS x Detweiler TS 230kV double circuit line M20D and M21D

This report recommends that the most cost effective plan to improve load restoration capability for load connected to circuits M20/21D is to install 230 kV in-line switches onto circuits M20/21D.

[1] OPA Submission to the OEB for the GATR Project – Document EB-2013-0053 dated March 8, 2013 entitled, "Kitchener-Waterloo-Cambridge-Guelph Area

1.0 INTRODUCTION

This transmission adequacy assessment focused on the electrical supply to the municipalities of Kitchener, Waterloo, Cambridge and Guelph and their surrounding areas of Ontario, collectively referred to as the KWCG area in this report. Its primary focus was to confirm the near and mid-term transmission needs for the area and to provide a 10-year transmission plan in order satisfy those Needs.

Geographically, the KWCG area consists of 4 municipalities – Kitchener, Waterloo, Cambridge, Guelph and portions of two counties - Perth and Wellington. Hydro One Networks Inc. is the sole high voltage transmitter in the KWCG area; however the low voltage distribution of electricity in the KWCG area is carried out by Cambridge and North Dumfries Hydro Inc., Guelph Hydro Electric System Inc., Hydro One Distribution, Kitchener-Wilmot Hydro Inc., and Waterloo North Hydro. A geographic map of the area is shown in Appendix A, Map 1 while an electrical map of the area is shown in Appendix A, Map 2.

The KWCG area is a major regional load centre in Ontario. The area has a well-established history in manufacturing and technology. The area peak load is approximately 1400 MW.

This report presents the results of the Hydro One led “Wires” study of the adequacy of supply to the City of Cambridge and the wider KWCG area based on the planned in-service of the GATR project in summer 2016.

2.0 EXISTING TRANSMISSION INFRASTRUCTURE

2.1 TRANSMISSION IN KWCG

Electrical Supply in this area is provided through 230 kV and 115 kV transmission lines and step down transformation facilities (transmission stations, TS) as show in Appendix A, Map 2.

The main sources of electricity into the KWCG Region are Middleport TS, Detweiler TS, Orangeville TS, Cedar TS and Burlington TS. At these stations electricity is transformed from 500 kV and 230 kV to 230 kV and 115 kV, respectively. The KWCG Region transmission system is connected as follows:

- Two 230 kV circuits (D6V/D7V) that run North-East from Detweiler TS to Orangeville TS that supply five load serving stations;
- Two 230 kV circuits (M20/21D) that run South-East from Detweiler TS to Middleport TS that supply five load serving stations and one transmission-connected customer;
- Two 230 kV circuits (D4W/D5W) that run South-West from Detweiler TS to Buchanan TS (in the "London area") that supply one load serving station;
- Four 115 kV circuits (D7F/D9F, F11C/F12C) that run East-West: D7/9F from Detweiler TS to Freeport SS that supply three load serving stations and F11/12C from Freeport SS to Cedar TS that supply one load serving station;
- Two 115 kV circuits (B5G/B6G) that run North-West from Burlington TS to Cedar TS that supply three load serving stations and one transmission-connect customer;
- Two 115 kV radial circuits (D11K/D12K) emanating East from Detweiler TS that supply two load serving stations; and,
- Two 115 kV circuit (D8S and D10H) emanating North from Detweiler TS that supply two load serving stations in the KWCG area.

Voltage support is provided in the area by:

- Four high voltage shunt capacitor banks and one SVC at Detweiler TS
- Four high voltage shunt capacitor banks at Middleport TS
- Three high voltage shunt capacitor banks at Burlington TS
- One high voltage shunt capacitor bank at Orangeville TS
- 43.2 MVar low voltage station shunt capacitor at Galt TS
- 21.6 MVar low voltage station shunt capacitors at Campbell TS
- 59.81 MVar low voltage station shunt capacitors at Cedar TS
- 9.92 MVar low voltage station shunt capacitors at Elmira TS
- Low voltage feeder shunt capacitors were lumped at: C&ND MTS#1, Waterloo North Hydro MTS #3, Scheifele MTS

All stations in the KWCG Region were considered in the analysis to determine the adequacy of the existing transmission system. Transformation capacity at individual load serving stations was previously analyzed by the OPA as part of the Integrated Regional Resource Plan (IRRP). The result of that analysis was a load forecast that included proposed new stations, as shown in Appendix C. Therefore, transformation capacity at individual load serving stations was not considered in this study.

2.2 TRANSMISSION-CONNECTED GENERATION

There are no existing large-scale transmission-connected generation plants in the KWCG area; however two contracted renewable transmission-connected wind farms were included in the study area and are listed in Appendix B.

3.0 ADEQUACY OF EXISTING TRANSMISSION INFRASTRUCTURE IN KWCG AREA

3.1 STUDY ASSUMPTIONS

Assumptions were made in order to assess the effects of contingencies to verify the adequacy of the transmission system. The assumptions used in the study were:

1. A 10 year load forecast: years 2016 to 2025; shown in Appendix C
2. Forecasted loads were provided by the LDC's in MW. The MVAR portion of the load was set to 40% of the MW load which is a reasonable assumption to achieve a power factor of 0.9 at the defined meter point of load serving transformer stations (TS, CTS, MTS)
3. A summer assessment was performed as the KWCG area is summer load peaking while the equipment is at its lowest rating during summer ambient conditions. This was deemed to be the most conservative approach;
4. Equipment continuous and Limited Time Ratings (LTR) were based on an ambient temperature of 35°C for summer and a wind speed of 4 km/hour;
5. The Guelph Area Transmission Reinforcement (GATR) project would be in-service in June 2016;
6. Circuits M20D and M21D are assigned their updated long-term emergency rating (LTE) based on a maximum temperature of 127°C;
7. Simulation of year 2025 load forecast was performed as it was the maximum loading of the area for the duration of the study period; year 2016 was simulated as necessary;
8. Waterloo North Hydro's Snider MTS #4 (MTS #4) will connect to 230 kV circuit D6/7V between Scheifele MTS and Guelph North Jct., projected in-service date 2024 (refer to Note 2 in Appendix C, Table C1)
9. The flows on Ontario's major internal transmission interfaces were assumed as follows:
    - FETT ~ 4500 MW
    - FS ~1250 MW
    - FABCW ~ 5800MW
    - NBLIP ~ 1650 MW (the slightly high NBLIP was offset by the lower FABCW)
    - QFW ~ 1550 MW

3.2 STUDY CRITERIA

The adequacy of the transmission system is assessed as per the IESO Ontario Resource and Transmission Assessment Criteria, Issue 5.0.

3.3 LOAD FORECAST

The load forecast used in this assessment is the KWCG 2015 RIP forecast as shown in Appendix C. This summer forecast is an extreme weather, area coincident, net, peak load forecast.

The KWCG 2015 RIP forecast is based upon the KWCG 2015 IRRP forecast. The LDC's provided the IESO with a 20 year gross, normal weather, area coincident, peak load forecast in MW. The IESO adjusted the forecast by subtracting the effective conservation and demand management (CDM) capacity, applying an extreme weather factor and then subtracting the effective Distribution Generation (DG) capacity.

3.4 SUPPLY CAPACITY NEEDS

Single element contingencies were considered in assessing the adequacy and reliability of the local transmission system that serves the KWCG area. Figure 1 summarizes the local KWCG area Needs for the 10-year period under study. Appendices D, F and G detail the technical study and results.

At stations, within the KWCG area, classified as NPCC Bulk Power System (BPS) additional contingencies were considered to establish their impact to the local KWCG area. Appendix E details the technical study and results.

3.4.1 AUTO-TRANSFORMATION SUPPLY CAPACITY

There is no major generation station in the KWCG area. Hence, the majority of supply to the load is provided by Hydro One's 500 kV to 230 kV and 230 kV to 115 kV auto-transformers. The number and location of these auto-transformers are as follows:

- Two 500/230 kV autotransformers at Middleport TS
- Four 230/115 kV autotransformers at Burlington TS[2]
- Three 230/115 kV autotransformers at Detweiler TS
- Two 230/115 kV autotransformers at Cedar TS
- One 230/115 kV autotransformer at Preston TS

Single autotransformer contingencies were performed to assess the adequacy of the transmission system to supply bulk power into the KWCG area via the autotransformers for year 2025 loading.

The results indicate that there are no thermal overloads and no voltage violations for the loss of a single autotransformer.

[2] The loading of the autotransformers at Burlington TS is mainly driven by the load connected in the Burlington to Nanticoke area. Only a small percentage of the autotransformer load is due to local Guelph load and as such, analysis of the Burlington TS autotransformers was undertaken in the 'Burlington to Nanticoke' Regional Infrastructure Plan.

3.4.2 SUPPLY CAPACITY OF THE 230 KV NETWORK

The KWCG area contains three pairs of double circuit 230 kV lines: M20D/M21D, D6V/D7V and D4W/D5W.

Single circuit contingencies were performed to assess the adequacy of the local 230 kV transmission system for year 2025 loading[3].

As indicated in Appendix D there are no thermal overloads and no voltage violations for the loss of a single 230 kV circuit.

3.4.3 SUPPLY CAPACITY OF THE 115 KV NETWORK

The KWCG area contains five pairs of double circuit 115 kV lines: D7F/D9F, F11C/F12C, B5G/B6G, D11K/D12K and D8S/D10H.

Single circuit contingencies were performed to assess the adequacy of the local 115 kV transmission system for year 2025 loading.

As indicated in Appendix D there are no thermal overloads and no voltage violations for the loss of a single 115 kV circuit. Appendix H details supply capacity on circuit D8S and D10H as request by the LDC.

3.4.4 VOLTAGE PERFORMANCE

Single circuit contingencies as well as single element HV shunt capacitor bank contingencies were performed to determine the overall voltage performance of the KWCG area for year 2025 loading.

As indicated in Appendix D there are no thermal overloads and no voltage violations for these contingencies. Appendix H details voltage performance at Elmira TS and Rush MTS as request by the LDC.

3.4.5 LOAD SECURITY ANALYSIS

The most stringent load security criterion that applies to the KWCG area states that with any two elements out of service:

- Voltage must be within applicable emergency ratings and equipment loading must be within applicable short-term emergency ratings;
- Load transfers to meet the applicable long-term emergency ratings must be able to be made in the time afforded by short-time ratings;
- Planned load curtailment or load rejection in excess of 150 MW is not permissible (except for local generation outages) and;

[3] Note, if another element such as an autotransformer, circuit or capacitor bank shared the same “switching position” and/or zone of protection with the circuit under contingency, both were removed from service.

- Not more than 600 MW of load may be interrupted by configuration and by planned load curtailment or load rejection excluding voluntary demand management with any two transmission elements out of service.

There are three pairs of 230 kV double circuit lines and five pairs of 115 kV double circuit lines in the KWCG area. While one circuit of a double circuit line is out of service, the loss of the companion circuit in the pair would result in the loss of all load stations connected to the pair by configuration. Tables F1 and F2 in Appendix F illustrate the load lost due to configuration in both years 2016 and 2025.

There are five stations in the KWCG area that have autotransformers. Overlapping autotransformer contingencies were taken and Table F3 in Appendix F illustrates any load transfer requirements due to two overlapping autotransformer outages.

As seen in Appendix F, the load forecasted on all circuit pairs is less than 600 MW within the 10-year study period and the loss of two autotransformers within this local area does not result in equipment loading beyond their applicable emergency ratings; therefore there is no concern with Load Security in the KWCG area for the study period.

3.4.6 LOAD RESTORATION CAPABILITY ANALYSIS

The load restoration criteria requires that the transmission system be planned such that following local area design criteria contingencies, the affected loads can be restored within the restoration times indicated below[4]:

- All load lost must be restored within 8 hours;
- Load lost in excess of 250 MW must be restored within 30 min; and
- Load lost between the amount of 150 MW and 250 MW must be restored within 4 hours.

Each pair of double circuit 230 kV and 115 kV lines were assessed to verify their load restoration capability. This assessment is detailed in Appendix G.

The results indicated the existing transmission system can adequately restore load to each circuit pair with the exception of M20/21D. Therefore, improvement to the restoration capability of load connected to circuits M20D and M21D is required.

3.4.7 IMPACT OF CONTINGENCIES ON THE BPS TO THE KWCG AREA

Northeast Power Coordinating Council (NPCC) Bulk Power System stations in the KWCG area are:

- Middleport TS 500 kV bus
- Middleport TS 230 kV bus
- Detweiler TS 230 kV bus

[4] As per ORTAC: “These approximate restoration times are intended for locations that are near staffed centres. In more remote locations, restoration times should be commensurate with travel times and accessibility.”

All elements connected to BPS buses are considered BPS facilities. Elements refer to circuit breakers, transmission lines, generators, transformers and reactive devices (e.g. SVC or capacitor bank).

Appendix E: Technical Results-Bulk Power System Considerations provides a list of BPS contingencies and the results. A *limited* number of BPS contingencies were performed in order to establish the impact of contingencies on the BPS to the local KWCG area.

Three NPCC Directory 1 contingency events were utilized in this study:

1. Simultaneous loss of two adjacent transmission circuits on a multiple circuit tower
2. Loss of any element with delayed fault clearing (a.k.a. Breaker Failure)
3. Loss of a critical element, followed by system adjustment, then loss of a critical element.

These BPS contingency events were applied to BPS buses only. The results can be summarized as follows:

- As per Table E3 and E5 when two of the three auto-transformers at Detweiler TS are not available the remaining auto-transformer may become overloaded. Since the loading of the remaining auto-transformer is within its 15-minute Short-Term Emergency Rating (STE) operational control actions can be taken to reduce the loading to within acceptable limits. Control actions could entail isolation of the faulted element e.g. circuit breaker, bus or transformer, and placing back in-service a healthy auto-transformer (at Detweiler TS and/or Preston TS). Another control action could entail opening of 115kV breakers at Freeport SS to redirect flows through the Cedar TS autotransformers.

3.4.8 SUMMARY OF NEEDS

Figure 1 illustrates the Needs timeline for the KWCG region.



Figure 1: Transmission Needs in the KWCG Area

4.0 OPTIONS TO ADDRESS THE NEED

Options were considered to address the insufficient load restoration capability for loads connected to circuits M20D and M21D. These options are shown in Table 1. Although there are several metrics that can be utilized to measure and compare options, the simple metric “initial capital cost/MW of load restored” was selected because it compares the unit costs of remedial measures. This was deemed sufficient in order to select the preferred option

Table 1: Options to Improve M20/21D Load Restoration

Option	**Options to Improve Restoration**	**Fault on the Main Line – Restorable Load** (Note 1)	**Fault on the Tap – Restorable Load** (Note 1)	**Initial Capital Cost** (Note 3)	**Initial Capital Cost/ MW Load Restored**
--	Existing (Benchmark)	100 MW (Preston TS only)	100 MW (Preston TS only)	0	$0/MW
1	230 kV in-line switches on M20/21D at **Preston Junction**	100 MW (C&ND load only-Note 2)	100 MW (C&ND load only-Note 2)	$6M	$60k/MW
2	230 kV in-line switches on M20/21D at **Galt Junction** (main line)	368 MW - 484 MW	234 MW (100 MW via existing Preston Auto)	$6M	$12k/MW to $26k/MW
3	One 230 kV cap bank at Preston TS plus 230 kV in-line switches on MxD at **Preston Junction**	140 MW (Note 4) (C&ND load only-Note 2)	140 MW (Note 4) (C&ND load only-Note 2)	$11M	$79k/MW
4	2nd autotransformer at Preston TS plus 230 kV in-line switches on MxD at **Preston Junction**	200 MW (Note 4) (C&ND load only-Note 2)	200 MW (Note 4) (C&ND load only-Note 2)	$21M	$105k/MW
5	2nd autotransformer at Preston TS plus 230 kV in-line switches on MxD at **Preston Junction** plus two 230 kV cap banks at Preston TS	280 MW (Note 4) (C&ND load only-Note 2)	280 MW (Note 4) (C&ND load only-Note 2)	$31M	$111k/MW

NOTE 1 Restorable load values are approximate values only as the actual amount of restorable load will depend on the prevailing system conditions and Operating/Control Centre protocols and priorities

NOTE 2 "C&ND load only" means that only those customers connected to Galt TS, C&ND MTS#1 and Preston TS will benefit. Cambridge and North Dumfries Hydro customers are the sole customers of these three stations.

NOTE 3 All prices are based on historical data: taxes extra, overhead extra, no escalation considered, no assumptions are made to feasibility or constructability, no assumptions made as to space requirements, real estate and environmental cost extra

NOTE 4 Restoration of 230 kV load (Cambridge and North Dumfries load) via the Preston TS auto-transformer may require operational measures on the 115 kV system to secure the transmission system to handle a subsequent contingency e.g. open the low voltage bus-tie breakers/switches at 115kV connected stations

5.0 DISCUSSION OF PREFERRED OPTIONS

5.1 PREFERRED OPTION TO IMPROVE RESTORATION TO M20/21D LOAD

Currently, loads connected to circuits M20/21D do not meet the restoration criteria.

Of the five options, option #2: 230 kV in-line switches on M20/21D at/near Galt Junction is the preferred option to satisfy the Need as it will provide the capability to restore the most load supplied from M20/21D.

Not only does Option #2 allow for more load to be restored, it provides for better operational flexibility; and is the most economical solution. As option 2 substantially meets the need by significantly improving the existing restoration capability, it is therefore the preferred option.

6.0 DEVELOPMENT PLAN

The transmission infrastructure development plan for the KWCG area is as followings:

1) Immediate Action: Install 230 kV In-Line Switches

Install 230 kV Load Interrupter type in-line switches on circuits M20D and M21D on the main line near Galt Junction. Note that load interrupter type switches cannot be used to interrupt fault current.

7.0 CONCLUSIONS

The following conclusions can be reached from the analysis performed by this study.

Local Area Performance

1. Improvement to the load restoration capability of transmission-connected customers on circuits M20D and M21D is required. The preferred option can be implemented by summer 2017.

BPS Performance

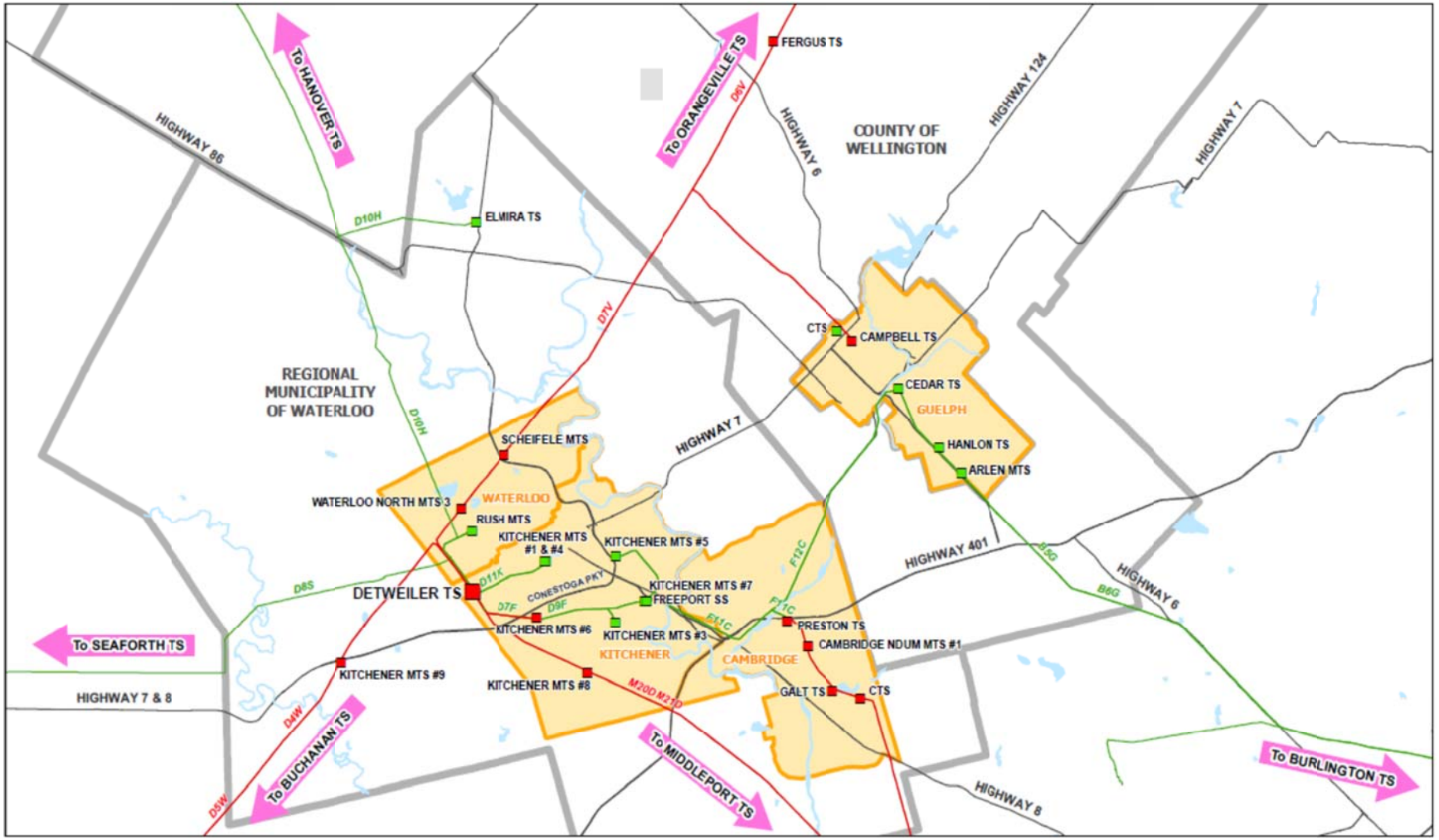
2. Autotransformer T2 at Detweiler TS is expected to be at 104.4% of LTE loading for year 2016 for the following contingency:
    i. Detweiler T4 outage plus Detweiler T3 with M20D (includes Preston T2 via Preston SPS). Since the post-contingency flow is below the auto-transformer STE, operational control actions can be taken to reduce loading to within the LTE rating.

8.0 RECOMMENDATIONS

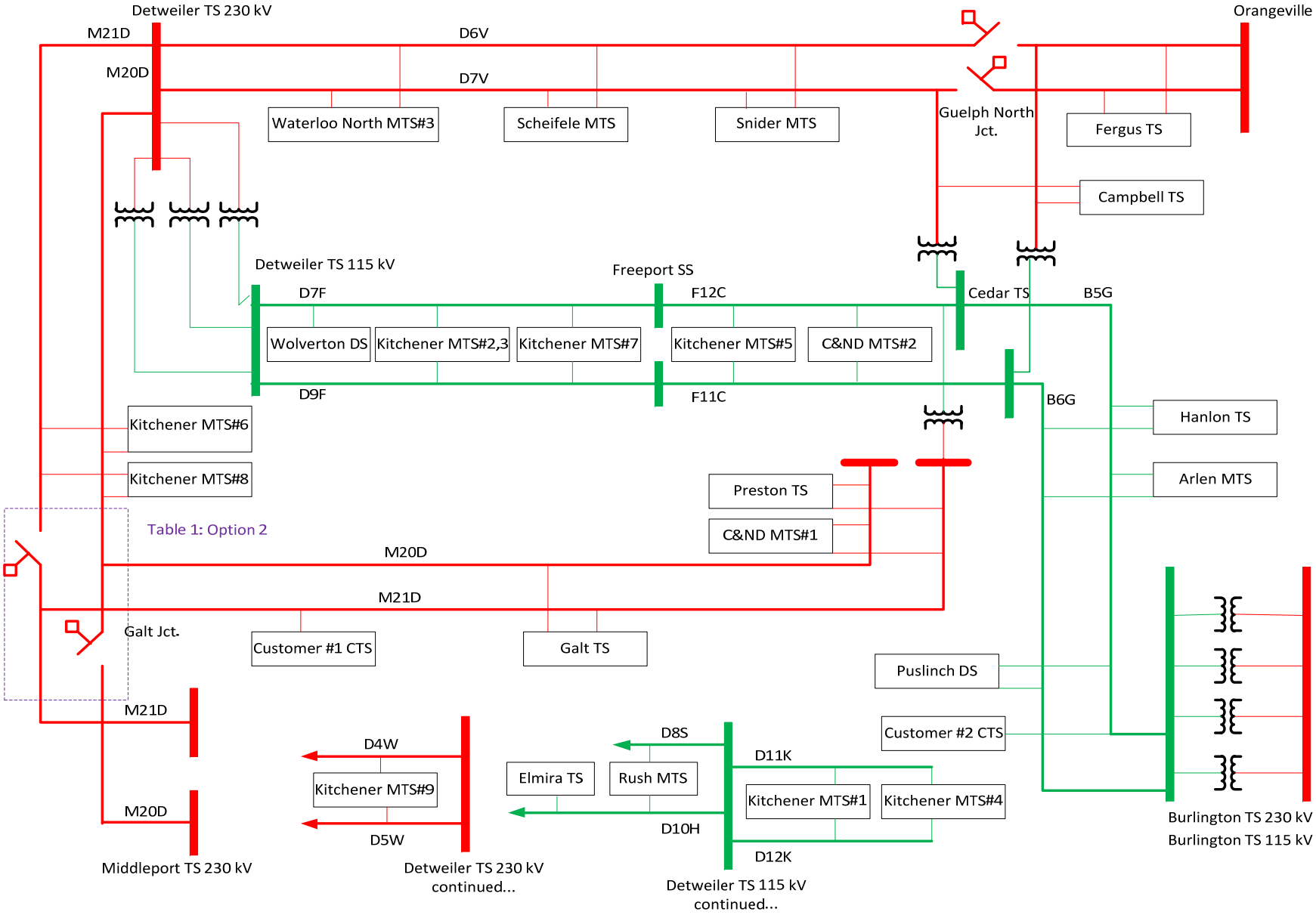
The following recommendations are to address the transmission infrastructure deficiencies within the study period for the KWCG area. These recommendations are:

1. Hydro One Networks to install a set of 230 kV in-line switches onto the main line of circuits M20D and M21D near Galt Junction as soon as possible.
2. Hydro One Networks, the LDCs and the IESO to review the KWCG local area in 2019 with updated KWCG load forecasts to decide on appropriate actions to meet longer-term needs as they emerge.

APPENDIX A: KWCG MAPS



Map 1: Geographical Area of KWCG with Electrical Layout



Map 2: KWCG Electrical Single-Line

APPENDIX B: TRANSMISSION-CONNECTED GENERATION IN THE KWCG AREA

Name	Installed Capacity	Peak Capacity Contribution[5]	Location	Existing or Contracted
Dufferin Wind Farm	97	13.6	Orangeville TS	Existing
Conestoga Wind Farm	67	10.8	D10H	Contracted (future i/s date unknown)

[5] Percentage of installed capacity is 14 % for wind generation

APPENDIX C: KWCG CUSTOMER & LDC LOAD FORECASTS

Table C1: KWCG 2015 RIP Load Forecast*

TS	LDC	Load Forecast	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Cambridge MTS #1	Cambridge & North Dumfries Hydro	Planning Demand	92.3	93.8	95.6	98.1	99.7	102.7	101.8	102.1	102.4	102.2	101.6
Galt TS	Cambridge & North Dumfries Hydro	Planning Demand	108.1	109.5	112.3	113.7	116.1	119.0	122.8	127.9	134.8	141.9	148.8
Preston TS-Note 1	Cambridge & North Dumfries Hydro	Planning Demand	108.0	100.3	102.0	104.4	105.9	108.7	109.6	111.8	111.9	111.5	111.8
Cambridge MTS # 2-Note	Cambridge & North Dumfries Hydro	Planning Demand	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Kitchener MTS #6	Kitchener-Wilmot Hydro	Planning Demand	72.8	72.8	73.0	73.0	72.4	72.1	71.7	71.6	71.5	71.1	71.1
Kitchener MTS #8	Kitchener-Wilmot Hydro	Planning Demand	44.2	37.6	40.3	43.1	45.3	38.6	41.1	43.5	46.0	48.2	50.6
Kitchener MTS #3	Kitchener-Wilmot Hydro	Planning Demand	54.3	64.4	66.5	67.3	67.5	77.0	77.5	78.1	78.7	79.0	79.6
Kitchener MTS #7	Kitchener-Wilmot Hydro	Planning Demand	44.9	45.1	45.9	46.0	45.6	45.6	45.6	45.7	39.9	39.8	39.9
Kitchener MTS #5	Kitchener-Wilmot Hydro	Planning Demand	73.9	73.8	74.6	74.5	73.8	73.5	73.2	73.1	78.8	78.3	78.2
Detweiler TS	Kitchener-Wilmot Hydro	Planning Demand	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Kitchener MTS #4	Kitchener-Wilmot Hydro	Planning Demand	67.8	68.2	69.1	69.3	69.0	69.0	68.9	69.2	69.3	69.1	69.3
Kitchener MTS #9	Kitchener-Wilmot Hydro	Planning Demand	33.7	33.9	34.3	34.6	34.5	34.7	34.9	35.0	35.3	35.4	35.5
Kitchener MTS #1	Kitchener-Wilmot Hydro	Planning Demand	29.1	29.6	31.1	31.6	31.8	32.1	32.4	32.9	33.3	33.5	33.9
Wolverton DS	Hydro One Distribution	Planning Demand	21.2	21.4	21.6	21.6	21.6	21.6	21.6	21.7	21.8	21.7	21.9
Fergus TS	Hydro One Distribution	Planning Demand	108.9	108.8	109.5	109.7	108.5	108.3	108.2	108.5	108.7	108.3	108.7
Puslinch DS	Hydro One Distribution	Planning Demand	35.6	36.2	36.8	37.3	37.5	37.9	38.3	38.7	39.2	39.5	39.9
Cedar TS T1/T2	Guelph Hydro	Planning Demand	72.3	74.9	75.8	77.4	78.3	79.5	79.8	82.2	84.6	85.5	87.9
Cedar TS T7/T8	Guelph Hydro	Planning Demand	30.2	32.0	32.0	32.8	32.3	33.0	33.7	33.4	34.2	34.8	35.5
Hanlon TS	Guelph Hydro	Planning Demand	29.8	30.7	31.6	32.5	33.0	33.7	34.4	35.1	34.9	35.5	35.3
Arlen MTS	Guelph Hydro	Planning Demand	30.0	33.0	37.0	40.9	33.3	37.9	41.4	43.0	44.6	45.9	47.5
Campbell TS	Guelph Hydro	Planning Demand	131.9	136.3	139.0	140.2	141.2	142.8	144.4	148.4	152.2	156.2	160.1
Scheifele MTS	Waterloo North Hydro	Planning Demand	169.0	166.0	170.7	150.3	151.2	152.7	154.3	156.2	158.1	153.4	155.4
Waterloo MTS #3	Waterloo North Hydro	Planning Demand	61.9	70.8	72.7	75.3	79.3	64.6	58.0	75.3	76.8	76.9	78.4
Snider MTS-Note 2	Waterloo North Hydro	Planning Demand	0.0	0.0	0.0	30.6	35.2	50.9	60.3	61.9	64.4	65.6	68.1
Bradley MTS-Note 2	Waterloo North Hydro	Planning Demand	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Elmira TS	Waterloo North Hydro	Planning Demand	30.4	25.1	26.0	25.8	27.4	28.1	28.8	29.6	31.3	31.9	33.6
Rush MTS	Waterloo North Hydro	Planning Demand	54.9	63.8	65.7	67.4	67.4	67.8	69.1	53.0	53.6	60.7	61.3
Customer #1 CTS-Note 3	Customer Tx Stations	Planning Demand	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5
Customer #2 CTS	Customer Tx Stations (Assumed values)	Planning Demand	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0

Planning demand (MW) = ((Gross-CDM) x Extreme Weather Factor) – DG

*Based upon KWCG 2015 IRRP Planning Load Forecast except where otherwise noted.

Note 1: The LDC has confirmed 9.2 MW of cogeneration at a large customer to be accounted for in the Preston TS forecast starting year 2016. The generation plant is expect to run most of the time and would offset the customer's load. This cogeneration was not factored into the KWCG 2015 IRRP Planning Load Forecast.

Note 2: The LDC has confirmed that additional transformation capacity (Snider/Bradley TS) would not be required until after 2024. The exact location and timing of these TS's have not been determined at this time. The load growth indicated at Snider and Bradley in the forecast can be managed by existing TS's/impact of CDM/DG in the Waterloo Region. LDCs are monitoring the load closely to determine the timing of potential transformation needs. Where possible, these LDCs are exploring opportunities to coordinate use and development of TS facilities in the KWCG Region over the long term. Cambridge #2 is assumed to be supplied off the KWCG 115kV system

Note 3: Slight modification from KWCG 2015 IRRP Planning forecast based on information provided by the transmission-connected customer

Note: Guelph CTS 1 forecast was removed as the LDC confirmed the load was already accounted for within their forecast

APPENDIX D: TECHNICAL RESULTS – LOCAL AREA ANALYSIS

Single element contingencies were considered in order to determine the presence of thermal overload and/or voltage violations.

Table D1: Single Element Contingencies (single zone of protection)

Loss of a Single Circuit (N-1)					
D11K	D12K	D8S	D10H	D7F	D9F
F11C	F12C	B5G	B6G	D4W	D5W
M20D*	M21D**	D6V***	D7V****		
Loss of a Single Autotransformer (N-1)					
Detw. T2	Detw. T3♦	Detw. T4♦♦	Cedar T3♦♦♦	Cedar T4♦♦♦♦	Preston T2**
Middleport T3♦♦♦♦♦		Middleport T6♦♦♦♦♦♦			
Loss of a Single HV Reactive Element (N-1)					
Detweiler 230 kV cap. bank	Middleport 230 kV cap. bank(K1D1)	Orangeville 230 kV cap. bank	Burlington 230 kV cap. bank		
Detweiler 230 kV SVC	Middleport 230 kV cap. bank(K2D2)	Detweiler 115 kV cap bank	Burlington 115 kV cap bank		

*M20D (includes Detweiler T3 and Preston T2 via Preston Special Protection Scheme)

**M21D (includes Preston T2)

***D6V (includes Detweiler T4 and Cedar T3)

****D7V (includes Cedar T4)

♦Detweiler T3 (includes circuit M20D and Preston T2 via Preston SPS)

♦♦Detweiler T4 (includes circuit D6V and Cedar T3)

♦♦♦Cedar T3 (includes circuit D6V and Detweiler T4)

♦♦♦♦Cedar T4 (includes circuit D7V)

♦♦♦♦♦Middleport T3 (includes circuit N580M and V586M due to Line End Open)

♦♦♦♦♦♦Middleport T6 (includes circuit N581M and M585M due to Line End Open)

Results: Thermal Overload and Voltage Violations

Table D3: Thermal Analysis (>100% LTE), year 2025

Element	Contingency	%LTE
All circuits and auto-transfers are within ratings		

Table D4: Voltage Analysis, year 2025

Element	Contingency	%Voltage Decline	Voltage kV
All voltages are within criteria			

APPENDIX E: TECHNICAL RESULTS – BULK POWER SYSTEM CONSIDERATIONS

Applicable contingencies were considered on BPS elements to establish their impact on the local area.

Table E1: N-2 Contingencies

Loss of a Double Circuit Line (N-2) emanating from a BPS station		
B22D and B23D	D4W and D5W	M20D and M21D
D6V and D7V	--	--
Breaker Failure (B/F) Contingencies at BPS station (N-2)		
Detweiler TS 230 kV bus	B/F of AL6	Loss of: D6V, Cedar T3, Detw T4, M21D, Preston T2
	B/F of AL7	Loss of: D7V, Cedar T4, M21D, Preston T2
	B/F of L7L20	Loss of: D7V, Cedar T4, M20D, Detw T3, Preston T2
	B/F of HT1A	Loss of: M21D, Preston T2, SVC1
	B/F of ACS21	Loss of : M21D, Preston T2, SC21
	B/F of HL20	Loss of: M20D, Detw T3, D5W, SC22
	B/F of T2SC21	Loss of: Detw T2, SC21
	B/F of HT2	Loss of: Detw T2, SC21, D5W
	B/F of DL22	Loss of: B22D, D6V, Cedar T3, Detw T4
Middleport TS 500 kV bus	Covered under Loss of Middleport T3 and T6 autotransformers for the local area analysis (Appendix D)	
Middleport TS 230 kV bus	There are no B/F conditions that would be critical to the supply to the KWCG area.	

Table E2: N-1-1 Contingencies

Loss of a Critical Element, System Adjustment, Loss of a Critical Element (N-1-1)
Loss of: Detw T4 plus Detw T3 (plus M20D by configuration which also includes the loss of Preston T2 via Preston SPS)
Loss of: Preston T2 plus D7V (plus Cedar T4 by configuration)

Note that during the simulations no System Adjustment was afforded; this is considered a conservative approach.

Results: Thermal Overloads and Voltage Violations

As per Table E3 and E5: Detweiler TS 230/115 kV autotransformer T2 will become overloads when Detweiler TS autotransformer T4 is out-of-service followed by the loss of Detweiler TS autotransformer T3 in conjunction with circuit M20D by configuration. Preston TS autotransformer T2 is also removed from service via the Preston SPS.

Table E3: Thermal Analysis (>95% LTE), year 2016

Element	Contingency	%LTE
Detweiler TS T2 autotransformer	Detweiler T4 plus Detweiler T3 with M20D (includes Preston T2 via Preston SPS)	104.4 (74.2% STE*) %

*STE rating of Detweiler T2 auto-transformer is 396 MVA.

Table E4: Voltage Analysis, year 2016

Element	Contingency	%Voltage Decline	Voltage kV
All voltages are within criteria			

Table E5: Thermal Analysis (>95% LTE), year 2025

Element	Contingency	%LTE
Detweiler TS T2 autotransformer	Detweiler T4 plus Detweiler T3 with M20D (includes Preston T2 via Preston SPS)	114.2 (81.4%STE*)

*STE rating of Detweiler T2 auto-transformer is 396 MVA.

Table E6 Voltage Analysis, year 2025

Element	Contingency	%Voltage Decline	Voltage kV
All voltages are within criteria			

APPENDIX F: LOAD SECURITY ANALYSIS

Load connected to each circuit pair that is lost by configuration following an [N-2] double circuit contingency is:

Table F1: Load Lost Due to Configuration, year 2016

Circuit Pair	MW
M20/21D	420
D6/7V	482
D4/5W	34
D7/9F	131
F11/12C	74
B5/6G	105
D11/12K	98
D8S/D10H	89

Table F2: Load Lost Due to Configuration, year 2025

Circuit Pair	MW
M20/21D	489
D6/7V	571
D4/5W	36
D7/9F	141
F11/12C	78
B5/6G	128
D11/12K	103
D8S/D10H	95[6]

Table F1 illustrates that none of the double circuit contingencies result in more than 482 MW of load lost in year 2016.

Table F2 illustrates that none of the double circuit contingencies result in more than 571 MW of load lost in year 2025.

[6] D8S and D10H emanate out of Detweiler TS as a double circuit line however after ~ 5 km they each become a single circuit 115 kV line. Based on their N/O open points, the loss of the double circuit line within the 5 km span out of Detweiler TS, will results in approximately 95 MW of load lost.

Table F3: Two Elements Out of Service

Loss of a Double Circuit Line				
D7F and D9F		F11C and F12C		B5G and B6G
D4W and D5W		M20D and M21D		D11K and D12K
D6V and D6V				
Loss of Two Autotransformers[7]				
Station	**Detweiler Auto**	**Preston Auto**	**Cedar Auto**	**Burlington Auto**
Detweiler Auto	N/A	Detweiler T3 + Preston T2	Cedar T3 + Detweiler T4	Burlington T6 + Detweiler T3
Preston Auto	Detweiler T3 + Preston T2	N/A	Cedar T4 + Preston T2	Burlington T6 + Preston T2
Cedar Auto	Cedar T3 + Detweiler T4	Cedar T4 + Preston T2	Cedar T3 + Cedar T4	Burlington T6 + Cedar T3
Burlington Auto	Burlington T6 + Detweiler T3	Burlington T6 + Preston T2	Burlington T6 + Cedar T3	N/A

Results: Thermal Overload and Voltage Violations

Table F5: Thermal Analysis (>100% STE), year 2025

Element	**Contingency**	**%STE**
All circuits and auto-transfers are within ratings		
Element	**Contingency**	**%LTE**
All circuits and auto-transfers are within ratings		

Table F6: Voltage Analysis (> emergency ratings), year 2025

Element	**Contingency**	**%Voltage Decline**	**Voltage kV**
All voltages are within criteria			

[7] For stations that have three or more autotransformers connected in parallel typical operating practice after the loss of one autotransformer is to make load transfers to other interconnected autotransformer station(s) such that the remaining load at the affected station would be at or below the station's reduced Limited Time Rating (LTR). It is assumed the in this case that sufficient time between single autotransformer contingencies is available for such load transfers to be carried out by operator response.

APPENDIX G: LOAD RESTORATION ANALYSIS

Restoration of Load Connected to M20/21D

By year 2025 the total forecasted load connected to circuits M20/21D is 489 MW. Loss of this double circuit line would result in the loss of all 489 MW. In order to restore load to these stations at least one circuit would have to be placed back in service**,** noting that to restore Customer #1 CTS circuit M21D must specifically be placed back in service due to the customer's single-circuit transmission-connection

Based on criteria:

Load Required to be Restored	Duration
239MW	30 min.
100 MW	Within 4 hrs.
150 MW	Within 8 hrs.

Existing infrastructure allows for only the restoration of 100 MW of load in approximately 30 min. This can be accomplished by opening the M20/211D line disconnect switches at Preston TS and back-feed Preston TS T2 230-115 kV autotransformer to supply load at Preston TS only.

Therefore, the existing restoration capability to loads connected to M20/21D does not meet criteria for the duration of the study period.

Restoration of Load Connected to D6/7V

By year 2025 the total forecasted load connected to D6/7V is 571 MW. Loss of this double circuit line would result in the loss of all 571 MW. As part of the Guelph Area Transmission Reinforcement project, two 230 kV in-line switches will be installed in year 2016 on the main line between Detweiler TS and Orangeville TS at Guelph North Junction. To restore load to these stations, the operator will utilize these switches to isolate the problem and return to service the remaining healthy circuit sections. These switches allow for more flexibility to restore load to the affected stations in a timely fashion.

Based on criteria:

Load Required to be Restored	Duration
321MW	30 min.
100 MW	Within 4 hrs.
150 MW	Within 8 hrs.

Depending on:

1. the severity of the double circuit contingency;
2. the prevailing system conditions and

3. the relative distance from the nearest field maintenance centre[8]

the load restoration criterion is substantially met. Therefore, no additional transmission restoration capability is warranted at this time.

Restoration of Load Connected to D4/5W

By year 2025 the total forecasted load connected to D4/5W is 36 MW. Loss of this double circuit line would result in the loss of all 36 MW. To restore load to this station at least one circuit would have to be placed back in service.

Based on criteria:

Load Required to be Restored	Duration
36 MW	Within 8 hrs.

Depending on:

1. the severity of the double circuit contingency;
2. the prevailing system conditions and
3. the relative distance from the nearest field maintenance centre

the load restoration criteria can be met. Therefore, no additional transmission restoration capability is warranted at this time.

Restoration of Load Connected to D7/9F

By year 2025 the total forecasted load connected to D7/9F is 141 MW. Loss of this double circuit line would result in the loss of all 141 MW. To restore load to these stations at least one circuit would have to be placed back in service.

Based on criteria:

Load Required to be Restored	Duration
141 MW	Within 8 hrs.

Depending on:

1. the severity of the double circuit contingency;
2. the prevailing system conditions and
3. the relative distance from the nearest field maintenance centre

the load restoration criteria can be met. Therefore, no additional transmission restoration capability is warranted at this time.

[8] The KWCG area is considered an urban area and as such, access to transmission facilities, repair materials and personnel in order to make a repair within 8 hours is realistic. A Hydro One field maintenance centre is located in Guelph.

Restoration of Load Connected to F11/12C

By year 2025 the total forecasted load connected to F11/12C is 78 MW. Loss of this double circuit line would result in the loss of all 78 MW. To restore load to these stations at least one circuit would have to be placed back in service.

Based on criteria:

Load Required to be Restored	Duration
78 MW	Within 8 hrs.

Depending on:

1. the severity of the double circuit contingency;
2. the prevailing system conditions and
3. the relative distance from the nearest field maintenance centre

the load restoration criteria can be met. Therefore, no additional transmission restoration capability is warranted at this time.

Restoration of Load Connected to B5/6G

By year 2025 the total forecasted load connected to B5/6G is 128 MW. Loss of this double circuit line would result in the loss of all 128 MW. To restore load to Enbridge Westover CTS's circuit B5G must be placed back in service due to the CTS's single-circuit transmission connection. To restore load at the other stations at least one circuit would to be placed back in service.

Based on criteria:

Load Required to be Restored	Duration
128 MW	Within 8 hrs.

Depending on:

1. the severity of the double circuit contingency;
2. the prevailing system conditions and
3. the relative distance from the nearest field maintenance centre

the load restoration criteria can be met. Therefore, no additional transmission restoration capability is warranted at this time.

Restoration of Load Connected to D11/12K

The total forecasted load serviced by radial circuits D11/12K will not exceed 103 MW by 2025. Loss of this double circuit line would result in the loss of all 103 MW. To restore load to these stations at least one circuit would have to be placed back in service.

Based on criteria:

Load Required to be Restored	Duration
103 MW	Within 8 hrs.

Depending on:

1. the severity of the double circuit contingency;
2. the prevailing system conditions and
3. the relative distance from the nearest field maintenance centre

the load restoration criteria can be met. Therefore, no additional transmission restoration capability is warranted at this time.

Restoration of Load Connected to D8S/D10H

The total forecasted load serviced by these radially operated 115 kV circuits will not exceed approximately 95 MW by year 2025. Loss of this double circuit line would result in loss of all 95MW. To restore Rush MTS either circuit can be placed back into service or the station could possibly be fed via circuit L7S out of Seaforth TS; however to restore Elmira TS circuit D10H must be placed back in service due to Elmira TS's single-circuit transmission-connection.

Based on criteria:

Load Required to be Restored	Duration
95 MW	Within 8 hrs.

Depending on:

1. the severity of the double circuit contingency;
2. the prevailing system conditions and
3. the relative distance from the nearest field maintenance centre

the load restoration criteria can be met. Therefore, no additional transmission restoration capability is warranted at this time.

APPENDIX H: SUPPLY TO ELMIRA TS AND RUSH MTS

Study Results:

Table H1: Station Capacity: Summer Ratings and Summer Load Forecast

Station	Transformer Capacity (10-day LTR)	Year 2025 Load Forecast
Rush MTS	69 MVA*	61.3 MW / 69.9 MVA (0.88 pf** at defined meter point, 115 kV side)
Elmira TS	58.5 MVA	33.6 MW / 37.1 MVA*** (0.91 pf at defined meter point, 115 kV side)

*The limiting component is a low voltage cable; when required the limiting component will be modified and the rating to be 75 MVA

** Power factor at the defined meter point improves to 0.92 when 5.4 MVar of installed feeder capacitor banks assumed lumped at the LV bus and results in 66.8 MVA loading

*** A 9.2 MVar @ 27.6 kV shunt capacitor bank is installed at Elmira TS not in-service; when in-service power factor improves and loading through the transformers decrease.

Table H2: Transmission Capacity of circuits D8S and D10H

Year	Contingency	D10H – Detweiler TS x Waterloo Jct. *590 A Continuous* *640 A Long-Term Emergency (LTE)* *660 A Short-Term Emergency (15-min.)*	D8S – Detweiler TS x Leong Jct. *590 A Continuous* *640 A Long-Term Emergency (LTE)* *660 A Short-Term Emergency (15-min.)*
2016	Pre	287 A	285 A
	Loss of D8S	454 A	--
	Loss of D10H	--	459 A
2025	Pre	319 A /	302 A
	Loss of D8S	511	--
	Loss of D10H	--	500 A

-assume all St. Mary's TS load is supplied by D8S (as this is more conservative for the study), assume Conestogo Wind Farm not-service (as it would displace load on D10H) and the normally-open point on D10H is between Elmira TS and Palmerston TS

Table H3: Voltage Profile at Rush MTS and Elmira TS

Year	Contingency	Rush MTS 115 kV D8S	Rush MTS 115 kV D10H	Rush MTS 13.8 kV	Elmira TS 115 kV	Elmira TS 27.6 kV
2016	Pre	122.2	122.2	14.4	120.8	27.2
	Loss of D8S	--	121.8	13.7	120.6	27.1
	Loss of D10H	121.5	--	13.7	--	--
2025	Pre	123.2	123.1	14.2	121.6	27.3
	Loss of D8S	--	122.6	13.6	121.1	27.2
	Loss of D10H	122.4	--	13.6	--	--

-assume all St. Mary's TS load is supplied by D8S (as this is more conservative for the study), assume Conestogo Wind Farm not-service (as it would displace load on D10H) and the normally-open point on D10H is between Elmira TS and Palmerston TS

Analysis:

D8S

Circuit D8S has a normally open point at St. Mary's TS separating the circuit from circuit L7S. D8S normally supplies half the load at Rush MTS and half the load at St. Mary's TS. The other half of the load at Rush MTS is normally supplied by circuit D10H and the other half of the load at St. Mary's TS is normally supplied by L7S. Referring to Table H2, for the loss of circuit D10H, circuit D8S has sufficient capacity to supply all load at Rush MTS and St. Mary's TS for year 2025 and beyond.

D10H

Circuit D10H runs between Detweiler TS and Hanover TS and has a normally open point between Elmira TS and Palmerston TS. Elmira TS is normally supplied from Detweiler TS while Palmerston TS is normally supplied from Hanover TS. Referring to Table H2, D10H has sufficient capacity to supply all load at Elmira TS for year 2025 and beyond. When circuit D8S is out of service, D10H has sufficient capacity to supply all load at Elmira TS and Rush MTS (while St. Mary's TS is supplied by circuit L7S).

Rush MTS

Since this station is a Municipal owned station, Waterloo North Hydro is to ensure there is sufficient transformation capacity to accommodate load growth. According to load forecasts and referring to Table H1, over the next 10-years load will fluctuate above and below the year 2025 forecast but will be remain within the station's Limited Time Rating (LTR). Waterloo North Hydro is to inform Hydro One if the connection requires

modification and/or if a new station connection is required in order to accommodate load growth. Waterloo North Hydro has already incorporated their future Snider MTS and Bradley MTS into the KWCG regional plan to cater for load growth.

Rush MTS is supplied by two 115 kV circuits, D8S and D10H. Referring to Tables H2 and H3, when one of these circuits is out of service, the voltage profile at Rush MTS is healthy and the other circuit has sufficient capacity to supply all load to Rush MTS.

Elmira TS

According to the forecast and referring to Table H1, transformers at Elmira TS have sufficient capacity for year 2025 loading and beyond.

Elmira TS is supplied by one 115 kV circuit, D10H. Referring to Tables H2 and H3, the voltage profile at Elmira TS is healthy and the circuit has sufficient capacity to supply load to Elmira TS for year 2025 loading and beyond.

When circuit D10H out of Detweiler TS is unavailable, Elmira TS may also be supplied by D10H out of Hanover TS (by closing the normally open point between Palmerston TS and Elmira TS). Assuming Palmerston TS is at its forecasted year 2025 normal weather peak load, approximately 25 MW of load at Elmira TS may be supplied out of Hanover TS. The limiting factor being the 115 kV voltage profile on D10H as Elmira TS is nearly 80 circuit km from Hanover TS.

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Appendix F:
2015 Integrated Regional Resource Plan (IRRP) Report - Kitchener-Waterloo-Cambridge-Guelph

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KITCHENER-WATERLOO-CAMBRIDGE-GUELPH REGION
INTEGRATED REGIONAL RESOURCE PLAN

April 28, 2015



ieso
Independent Electricity System Operator

Integrated Regional Resource Plan

Kitchener-Waterloo-Cambridge-Guelph

This Integrated Regional Resource Plan ("IRRP") was prepared by the IESO pursuant to the terms of its Ontario Energy Board licence, EI-2013-0066.

This IRRP was prepared on behalf of the KWCG Region Working Group, which included the following members:

- Independent Electricity System Operator
- Kitchener-Wilmot Hydro Inc.
- Waterloo North Hydro Inc.
- Cambridge & North Dumfries Hydro Inc.
- Guelph Hydro Electric Systems Inc.
- Hydro One Networks Inc. (Distribution) and
- Hydro One Networks Inc. (Transmission)

The KWCG Region Working Group assessed the adequacy of electricity supply to customers in the KWCG Region over a 20-year period; developed a flexible, comprehensive, integrated plan that considers opportunities for coordination in anticipation of potential demand growth scenarios and varying supply conditions in the KWCG Region; and developed an implementation plan for the recommended options, while maintaining flexibility in order to accommodate changes in key assumptions over time.

KWCG Region Working Group members agree with the IRRP's recommendations and support implementation of the plan through the recommended actions. KWCG Region Working Group members do not commit to any capital expenditures and must still obtain all necessary regulatory and other approvals to implement recommended actions.

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List of Abbreviations

Abbreviation	Description
BCP	Brant County Power
C&S	Codes and Standards
CDM	Conservation Demand Management
CEP	Community Energy Plan
CHP	Combined Heat and Power
CHPSOP	Combined Heat and Power Standard Offer Program
DG	Distributed Generation
DR	Demand Response
ECO	(Region of Waterloo's) Energy Conservation Office
EV	Electric Vehicle
EE	Energy Efficiency
FIT	Feed-in Tariff
GATR	Guelph Area Transmission Refurbishment
GS	Generating Station
GHG	Greenhouse Gases
GDP	Gross Domestic Product
IESO	Independent Electricity System Operator
IPSP	(2007) Integrated Power System Plan
IRRP	Integrated Regional Resource Plan
KWCG Region or Region	Kitchener, Waterloo, Cambridge and Guelph
kV	Kilovolt
LAC	Local Advisory Committee
LRT	Light Rail Transit
LMC	Load Meeting Capability
LDC	Local Distribution Company
LED	Light Emitting Diode
LTEP	(2013) Long-Term Energy Plan
MW	Megawatt
MEP/CEP	Municipal or Community Energy Plan
MTS	Municipal Transformer Station
NERC	North American Electric Reliability Corporation
NPCC	Northeast Power Coordinating Council
OEB or Board	Ontario Energy Board
OPA	Ontario Power Authority
ORTAC	Ontario Resource and Transmission Assessment Criteria
PPWG	Planning Process Working Group

Abbreviation	Description
PV	Photovoltaic
RIP	Regional Infrastructure Plan
SCADA	Supervisory Control and Data Acquisition
SS	Switching Station
TWh	Terawatt Hour(s)
TOR	Terms of Reference
TOU	Time-of-Use
TS	Transformer Station
Working Group	Technical Working Group of the KWCG Region

1. Introduction

This report outlines the Integrated Regional Resource Plan ("IRRP") for the Kitchener, Waterloo, Cambridge and Guelph ("KWCG") Region (together "KWCG Region" or "Region") over the next 20 years. This report was prepared by the IESO on behalf of a technical Working Group composed of Kitchener-Wilmot Hydro, Waterloo North Hydro, Guelph Hydro Electric Systems Inc., Hydro One Distribution, Cambridge and North Dumfries Hydro, and Hydro One Transmission (the "Working Group").

The KWCG Region is located in southwestern Ontario and includes the Region of Waterloo, the City of Guelph, Wellington County and a portion of Oxford County. The population of the region is forecast to significantly grow during the 20-year period (2011-2031) – by roughly 40% – according to the province's "Places to Grow" initiative.[1] This growth will be accompanied by population intensification, the development of regional transit infrastructure, redevelopment of the downtown areas, and the development of commercial and industrial parks. A reliable supply of electricity is essential to supporting community growth. There is therefore a strong need for integrated regional electricity planning to ensure that the electricity system can support the pace of development over the long term.

In Ontario, planning to meet the electrical supply and reliability needs of a large area or region is done through regional electricity planning, a process that was formalized by the Ontario Energy Board ("OEB" or "Board") in 2013. In accordance with the OEB regional planning process, transmitters, distributers and the IESO are required to carry out regional planning activities for the 21 electricity planning regions at least once every five years.

The KWCG Region is one of the 21 electricity planning regions in Ontario as identified through the regional planning process. This IRRP fulfills the requirements for the Region as required by the IESO's OEB licence.

This IRRP for KWCG identifies electricity supply and reliability needs in the near term (0-5 years), medium term (5-10 years) and long term (10-20 years), and sets out specific priorities and investments to meet near- and medium-term needs, respecting the lead time for development. This IRRP also identifies actions to develop long-term options and to facilitate discussions about how the communities may plan their future electricity supply. Since

[1] http://www.placestogrow.ca/

economic, demographic, and technological conditions will inevitably change, IRRPs will be reviewed on a five-year cycle so that plans can be updated to reflect the changing electricity outlook. The KWCG IRRP will be revisited in 2020 or sooner, if significant changes occur relative to the current forecast.

This report is organized as follows:

- A summary of the recommended plan for the Region is provided in Section 2;
- The process and methodology used to develop the plan are discussed in Section 3;
- The context for electricity planning in the Region and the study scope are discussed in Section 4;
- Demand forecast scenarios, and conservation and DG assumptions, are described in Section 5;
- The near- and medium-term plan is presented in Section 6;
- The long-term plan is presented in Section 7;
- A summary of community, aboriginal and stakeholder engagement to date and moving forward in developing this IRRP is provided in Section 8;
- A conclusion is provided in Section 9.

2. The Integrated Regional Resource Plan

The KWCG IRRP addresses the Region's electricity needs over the next 20 years, based on application of the IESO's Ontario Resource and Transmission Assessment Criteria ("ORTAC"). This IRRP identifies the needs that are forecast to arise in the near- and medium-term (0-10 years) and in the long-term (10-20 years). These two planning horizons are distinguished in the IRRP to reflect the level of commitment required to address needs over these time periods. The plans for both timeframes are coordinated to ensure consistency. The IRRP was developed based on consideration of planning criteria, including reliability, cost and feasibility; and, in the near term, it seeks to maximize the use of the existing electricity system, where it is economic to do so.

For the near- and medium-term, the IRRP identifies specific actions and investments for immediate implementation. This ensures that necessary resources are in service in time to address the KWCG Region's more urgent needs.

For the long term, the IRRP identifies potential approaches to meet needs that may arise in 10-20 years. It is not necessary to recommend specific projects at this time (nor would it be prudent given forecast uncertainty and the potential for technological change). Instead, the long-term plan focuses on developing and maintaining the viability of long-term options, engaging with the communities, and gathering information to lay the groundwork for making decisions on future options. These actions are intended to be completed before the next IRRP cycle in 2020 so that their results can inform a decision, should one be needed at that time.

The needs and recommended actions are summarized below.

2.1 Near- and Medium-Term Plan (2014-2023)

Today, the electricity system supplying the KWCG Region is approaching its maximum capacity and has limited ability to minimize potential supply interruptions to customers. The plan to meet the needs of electricity customers in the KWCG Region over the near and medium term was developed based on consideration of planning criteria, including reliability, cost, feasibility, and maximizing the use of the existing electricity system, where it is economic to do so. The near- and medium-term plan was also developed to be consistent with the long-term development of the Region's electricity system.

Recommendations

1. Implement conservation and distributed generation (LDCs/IESO)

The implementation of provincial energy conservation targets established in the 2013 Long-Term Energy Plan ("LTEP") is a key component of the near- and medium-term plan for the KWCG Region. As part of the near- and medium-term plan, peak demand savings from provincial energy conservation targets are estimated to account for 40% of the forecast peak demand growth in the KWCG Region between 2014-2023.

To ensure that these savings materialize, it is recommended that the LDCs' conservation efforts be focused not only on achieving their energy savings targets, but also maximizing peak demand reductions. Monitoring conservation achievements, and measuring peak demand savings, will be important elements of the near- and medium-term plan, and will also lay the foundation for the long-term plan by reviewing performance of specific conservation measures in the KWCG Region, and assessing potential in the KWCG Region for further conservation efforts.

Provincial programs that encourage the development of DG, such as the Feed-in Tariff ("FIT"), and Combined Heat and Power Standard Offer ("CHPSOP") programs, and local interests and opportunities for distributed generation ("DG") development can also contribute to reducing peak demand in the KWCG Region. The LDCs and the IESO will continue their activities to support these initiatives and monitor their impacts.

2. Implement the Guelph Area Transmission Refurbishment (GATR) project (Hydro One)

In 2012, the Working Group recommended proceeding with the implementation of the Guelph Area Transmission Refurbishment ("GATR") project to address imminent supply needs in South-Central Guelph and the Kitchener area and to minimize the impact of potential supply interruptions to customers in Waterloo, Guelph and surrounding areas. This project includes the installation of two 115 kV/230 kV auto-transformers, switching facilities, and the upgrade of an existing transmission line in Guelph. The GATR project was approved by the OEB on September 26, 2013 and is expected to be in service by spring 2016. The project will substantially contribute to meeting near- and medium-term needs in the KWCG Region.

3. Install two circuit switchers at Galt Junction and explore opportunities to further improve restoration capability in the Cambridge area (Hydro One)

To substantially improve load restoration in the Cambridge and Kitchener area following a major transmission outage, the Working Group recommends proceeding with the installation of two 230 kilovolt ("kV") circuit switchers at Galt Junction, near Highway 5. Hydro One has begun early development work on these switching facilities, which are expected to be in-service by spring 2017. Hydro One will continue to examine other potential measures to further improve the restoration capability in the Cambridge area. Please refer to Appendix C for further information regarding load restoration improvements for the Cambridge-Kitchener 230 kV sub-system.

2.2 Long-Term Plan (2024-2033)

There are no major regional supply and reliability needs identified in the KWCG Region beyond 2023, therefore early development work for major infrastructure projects in the KWCG Region is not required at this time. Localized needs, such as transformer station ("TS") capacity needs in the KWCG Region, may arise over the long term under certain growth scenarios, but these potential needs do not require any immediate action. There may be opportunity for communities and local utilities to manage their future electricity demand through the development of community-based solutions. Communities and local utilities in the KWCG Region have become increasingly involved in the development of DG and conservation initiatives. The results of early community-based pilot projects, energy conservation initiatives, and achievable potential studies of the IESO will provide useful information to consider the potential for conservation to address identified needs in the KWCG Region in the next iteration of the plan and the ongoing regional planning process.[2]

Recommendations

1. Undertake community engagement (IESO/LDCs)

In between the 5-year regional planning cycle, the IESO and LDCs will continue to engage with First Nations communities and other stakeholders through community planning, environmental and sustainability initiatives, and broader community outreach such as, informational public open houses.

[2] The IESO's is currently developing an achievable potential study scheduled to be completed by June 1, 2016. This study will provide an updated forecast for conservation potential in Ontario.

2. Monitor demand growth, conservation and demand management (CDM) achievement and distributed generation (IESO)

On an annual basis, the IESO will coordinate a review of conservation and demand management ("CDM" or "conservation") achievement, provincial DG projects, and demand growth in the KWCG Region. This information will be used to track the expected timing of long-term needs to determine when a decision on the long-term plan is required. Information on CDM and DG performance will also provide useful input into the ongoing development of these options as potential long-term solutions.

3. Explore opportunities to coordinate use and development of transformation station facilities in the KWCG Region (LDCs)

Depending on the location, timing and magnitude of electricity demand growth, TS capacity needs may arise in the KWCG Region beyond 2023. LDCs will monitor the load closely to determine the timing of potential transformation needs. Where possible, these LDCs will coordinate use and development of transformation station facilities in the KWCG Region. The need, timing and location of transformer(s) will be confirmed in the next planning cycle.

3. Development of the IRRP

3.1 The Regional Planning Process

In Ontario, planning to meet the electricity needs of customers at a regional level is done through regional planning. Regional planning assesses the interrelated needs of a region - defined by common electricity supply infrastructure over the near, medium and long term, and develops a plan to ensure cost-effective, reliable, electricity supply. Regional plans consider the existing electricity infrastructure in an area, forecast growth and customer reliability, evaluate options for addressing needs, and recommend actions.

Regional planning has been conducted on an as needed basis in Ontario for many years. Most recently, the Ontario Power Authority ("OPA") carried out regional planning activities to address regional electricity supply needs. The OPA conducted joint regional planning studies with distributors, transmitters, the IESO and other stakeholders in regions where a need for coordinated regional planning had been identified.

In 2012, the Ontario Energy Board convened the Planning Process Working Group ("PPWG") to develop a more structured, transparent, and systematic regional planning process. This group was composed of industry stakeholders including electricity agencies, utilities, and stakeholders. In May 2013, the PPWG released its Working Group Report to the Board, setting out the new regional planning process. Twenty-one electricity planning regions in the province were identified in the Working Group Report and a phased schedule for completion was outlined. The Board endorsed the Working Group Report and formalized the process timelines through changes to the Transmission System Code and Distribution System Code in August 2013, as well as through changes to the OPA's licence in October 2013. The OPA licence changes required it to lead a number of aspects of regional planning, including the completion of comprehensive IRRPs. Following the merger of the IESO and the OPA on January 1, 2015, the regional planning responsibilities identified in the OPA's licence were transferred to the IESO.

The regional planning process begins with a Needs Screening process performed by the transmitter, which determines whether there are needs requiring regional coordination. If regional planning is required, the IESO then conducts a Scoping Assessment to determine whether a comprehensive IRRP is required, which considers conservation, generation, transmission, and distribution solutions, or whether a straightforward "wires" solution is the

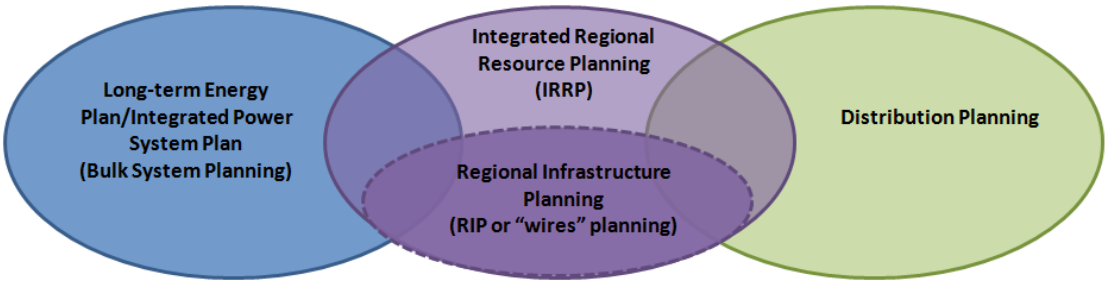
only option. If the latter applies, then a transmission and distribution focused Regional Infrastructure Plan ("RIP") is required. The Scoping Assessment process also identifies any sub-regions that require assessment. There may also be regions where infrastructure investments do not require regional coordination and can be planned directly by the distributor and transmitter, outside of the regional planning process. At the conclusion of the Scoping Assessment, the IESO produces a report that includes the results of the Needs Screening process – identifying whether an IRRP, RIP or no regional coordination is required - and a preliminary Terms of Reference. If an IRRP is the identified outcome, then the IESO is required to complete the IRRP within 18 months. If a RIP is required, the transmitter takes the lead and has six months to complete it. Both RIPs and IRRPs are to be updated at least every five years.

The final IRRPs and RIPs are to be posted on the IESO and relevant transmitter websites, and can be used as supporting evidence in a rate hearing or Leave to Construct application for specific infrastructure investments. These documents may also be used by municipalities for planning purposes and by other parties to better understand local electricity growth and infrastructure requirements.

Regional planning, as shown in Figure 3-1, is just one form of electricity planning that is undertaken in Ontario. There are three types of electricity planning in Ontario:

- Bulk system planning
- Regional system planning
- Distribution system planning

Figure 3-1: Levels of Electricity System Planning



Bulk System Planning

- 500 kV & 230 kV transmission
- Interconnections
- Inter-area network transfer capability
- System reliability (security and adequacy) to meet NERC, NPCC, ORTAC
- Congestion and system efficiency
- System supply and demand forecasts
- Incorporation of large generation
- Typically medium- and long-term focused

Regional Planning

- 230 kV & 115 kV transmission
- 115/230 kV autotransformers and associated switchyard facilities
- Customer connections
- Load supply stations
- Regional reliability (security and adequacy) to meet NERC, NPCC & ORTAC
- ORTAC local area reliability criteria
- Regional/local area generation & CDM resources
- Typically near- & medium-term focused

Distribution Network Planning

- Transformer stations to connect to the transmission system
- Distribution network planning (e.g. new & modified Dx facilities)
- Distribution system reliability (capacity & security)
- Distribution connected generation & CDM resources
- LDC demand forecasts
- Near- & medium-term focused

Planning at the bulk system level typically considers the 230 kV and 500 kV network. Bulk system planning considers the major transmission facilities and assesses the resources needed to adequately supply the province. Bulk system planning is carried out by the IESO in accordance with government policy. Distribution planning, which is carried out by local distribution companies, looks at specific investments on the low voltage, distribution system.

Regional planning can overlap with bulk system planning. For example, overlap can occur at interface points where regional resource options may also address a bulk system issue. Similarly, regional planning can overlap with the distribution planning of LDCs. An example of this is when a distribution solution addresses the needs of the broader local area or region. Therefore, to ensure efficiency and cost-effectiveness, it is important for regional planning to be coordinated with both bulk and distribution system planning.

By recognizing the linkages with bulk and distribution system planning, and coordinating multiple needs identified within a given region over the long term, the regional planning process provides an integrated assessment of needs. Regional planning aligns near- and long-term solutions and allows specific investments recommended in the plan to be understood as part of a larger context. Furthermore, regional planning optimizes ratepayer interests by avoiding piecemeal planning and asset duplication, and allows Ontario ratepayers' interests to be represented along with the interests of LDC ratepayers. Where IRRPs are undertaken, they

allow an evaluation of the multiple options available to meet needs, including conservation, generation, and "wires" solutions. Regional plans also provide greater transparency through engagement in the planning process, and by making plans available to the public.

3.2 The IESO's Approach to Regional Planning

IRRPs assess electricity system needs for a region over a 20-year period. The 20-year outlook anticipates long-term trends so that near-term actions are developed within the context of a longer-term view. This enables coordination and consistency with the long-term plan, rather than simply reacting to immediate needs.

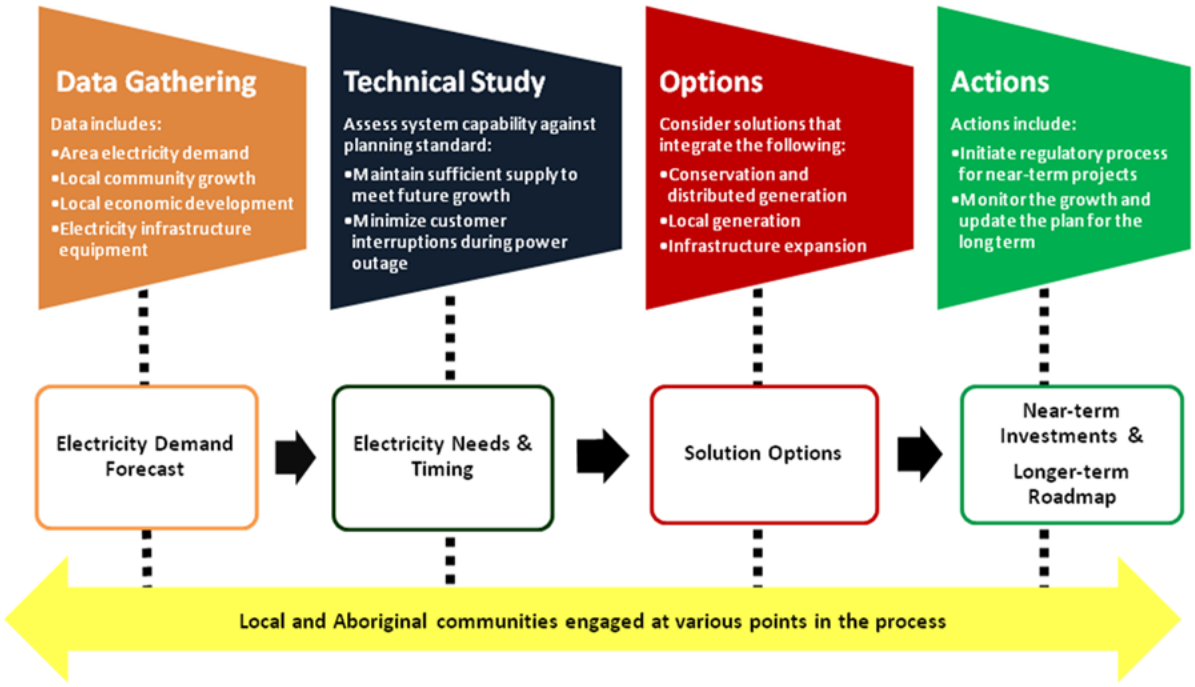
In developing an IRRP, a different approach is taken to developing the plan for the first 10 years of the plan—the near- and medium-term—than for the longer-term period of 10-20 years. The plan for the first 10 years is developed based on best available information on demand, conservation, and other local developments. Given the long lead time to develop electricity infrastructure, near-term electricity needs require prompt action to enable the specified solutions in a timely manner. By contrast, the long-term plan is characterized by greater forecast uncertainty and longer development lead time; as such solutions do not need to be committed to immediately. Given the potential for changing conditions and technological development, the IRRP for the long term is more directional, focusing on developing and maintaining the viability of options for the future, and continuing to monitor demand forecast scenarios.

In developing an IRRP, the IESO and regional working groups (see Figure 3-2 below) carry out a number of steps. These steps include electricity demand forecasts; technical studies to determine electricity needs and the timing of these needs; the development of potential options; and, a recommended plan including actions for the near and long-term. Throughout this process, engagement is carried out with communities, including local First Nations and Métis communities and stakeholders who may have an interest in the planning area. The steps of an IRRP are illustrated in Figure 3-2 below.

The IRRP report documents the inputs, findings and recommendations developed through the process described above, and provides recommended actions for the various entities responsible for plan implementation. Where "wires"" solutions are included in the plan recommendations, the completion of the IRRP report is the trigger for the transmitter to initiate an RIP process to develop those options. Other actions may involve development of

conservation, local generation, or other solutions, community engagement, or information gathering to support future iterations of the regional planning process in the region.

Figure 3-2: Steps in the IRRP Process



3.3 KWCG Working Group and IRRP Development

Prior to the formation of the OEB's Regional Planning Process in 2013, regional planning activities were undertaken by the IESO, the OPA, Hydro One and local LDCs in order to maintain a reliable supply of electricity to the KWCG Region. In the absence of a formalized process, regional planning activities in the area were triggered on an as needed basis, and solutions were examined, implemented, or deferred depending on the timing of electricity system requirements.

In 2003, as the result of a regional transmission study conducted by Hydro One and the local LDCs, a 115 kV/230 kV auto-transformer and associated remedial measures were installed at the Preston Transformer Station ("TS") to improve the Region's reliability. In 2007, in order to meet forecast electricity demand growth in the South-Central Guelph and Kitchener area, the Integrated Power System Plan ("IPSP")[3] recommended proceeding with the development of the GATR project. However, as a result of the global economic recession in 2008/2009, electricity

[3] Integrated Power System Plan 2007 - EB-2007-0707 – Exhibit E Tab 5 Schedule 2

consumption declined across the KWCG Region and the development work for the GATR project was put on hold.

In 2010, the KWCG planning electricity supply study was initiated to re-assess electricity supply and reliability over the next 20 years. The OPA agreed that a coordinated, integrated approach was appropriate and formed the Working Group. The Working Group developed the Terms of Reference for the study[4] and gathered data, identified near and long-term needs in the Region, and assessed a range of integrated options. In 2012/2013, the Working Group recommended proceeding with the implementation of GATR and initiating early development work on the second 115 kV/230 kV auto-transformer at Preston TS to address imminent supply and reliability needs in the KWCG Region.[5] In March 2013, Hydro One submitted the Leave to Construct application for the GATR project and in September 2013, the application was approved by the OEB.[6]

In October 2013, the KWCG planning electricity supply study was transitioned to align with the OEB's new regional planning process. The Working Group revised the Terms of Reference to reflect the new process, and updated the study information, including demand forecasts and conservation and DG data.[7] With this updated information, the Working Group re-confirmed the reliability and supply needs in the KWCG Region, re-examined the need for the second 115 kV/230 kV auto-transformer at Preston in the near term, and continued to revise the near-term plan and to develop recommendations for the long-term plan. This IRRP reflects this revised and updated information.

[4] Original Terms of Reference:
http://www.ieso.ca/Documents/Regional-Planning/KWCG/KWCG-Terms-of-References.pdf
[5] OPA Letter to Hydro One - March 8, 2012:
http://www.ieso.ca/Documents/Regional-Planning/KWCG/Exhibit%20B-1-4,%20Attachments%201%20and%202.pdf
OPA Letter to Hydro One - May 29, 2013:
http://www.ieso.ca/Documents/Regional-Planning/KWCG/OPA-Letter-Hydro-One-KWCG.pdf
[6] (EB-2013-0056) Ontario Energy Board Decision and Order dated September 26, 2013
[7] Revised July 2014 Terms of Reference (Addendum):
http://www.ieso.ca/Documents/Regional-Planning/KWCG/Addendum-TOR-KWCG.pdf

4. Background and Scope of the KWCG IRRP

The KWCG IRRP assesses the regional electricity supply and reliability needs for the KWCG Region, and identifies integrated solutions for the 20-year period from 2014 to 2033. Specifically, this IRRP includes the following components:

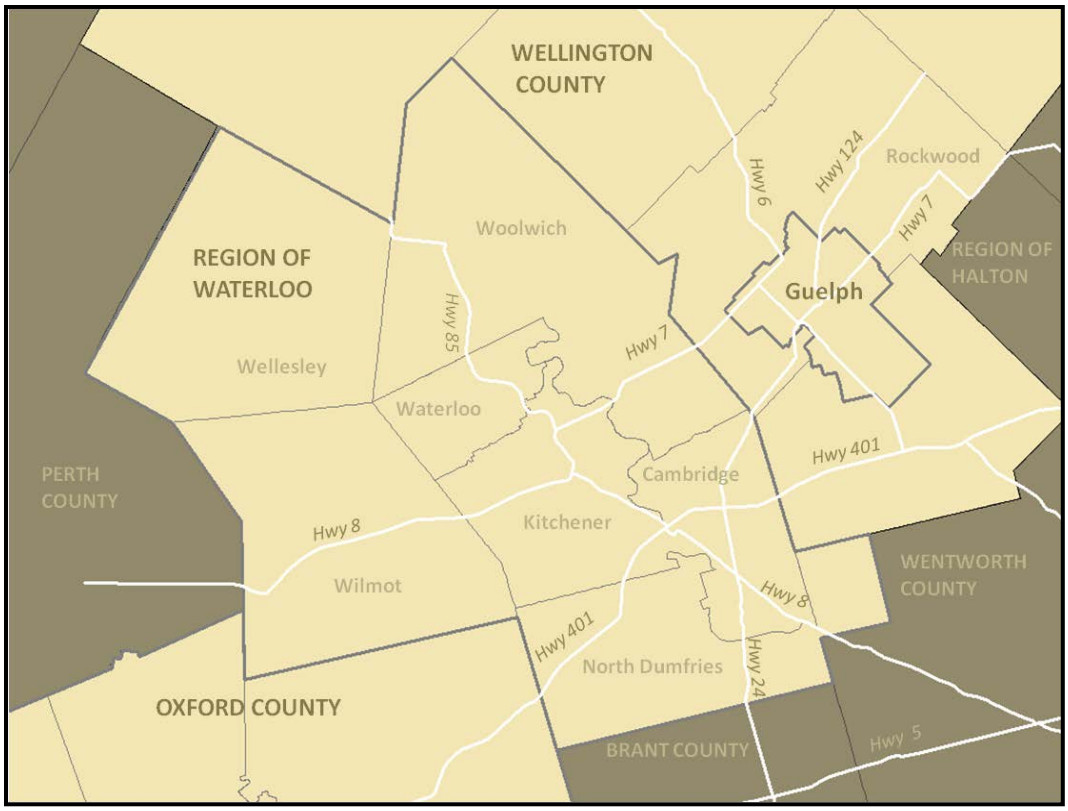
- Examination of electricity demand requirements in the near- and medium-term (2014-2023) and under alternate long-term demand growth scenarios (2024-2033);
- Reliability and adequacy assessment of the electricity system in the KWCG Region;
- Development and evaluation of integrated alternatives including a mix of CDM, generation, transmission and distribution facilities, and other electricity system initiatives to address near- and medium-term electricity supply needs in this region (2014-2023);
- Assessment of alternate demand scenarios and development of potential approaches for the local community to address future long-term electricity supply needs (2024-2033); and
- Development of an implementation plan to address near- and medium-term electricity requirements and to ensure that options remain available to address long-term needs.

To set the context for this IRRP, the scope of this IRRP and a description of the Region are set out in Section 4.1. Section 4.2 details the existing transmission system in the KWCG Region.

4.1 Scope of the KWCG IRRP

The KWCG Region is located in southwestern Ontario and includes the Region of Waterloo, the City of Guelph, Wellington County and the Township of Blandford-Blenheim (Oxford County), as shown in Figure 4-1.

Figure 4-1: Kitchener, Waterloo, Cambridge and Guelph Area



The KWCG Region has an estimated population of 735,000.[8] Based on growth plans, as detailed in the provincial Places to Grow Initiative,[9] the population is forecast to increase by approximately 40% over a 20-year period (2011-2031). This is equivalent to adding 14,500 new residents and 6,500 new jobs each year. This growth will be accompanied by population intensification, the development of regional transit infrastructure, redevelopment of the downtown areas, and the development of commercial and industrial parks.

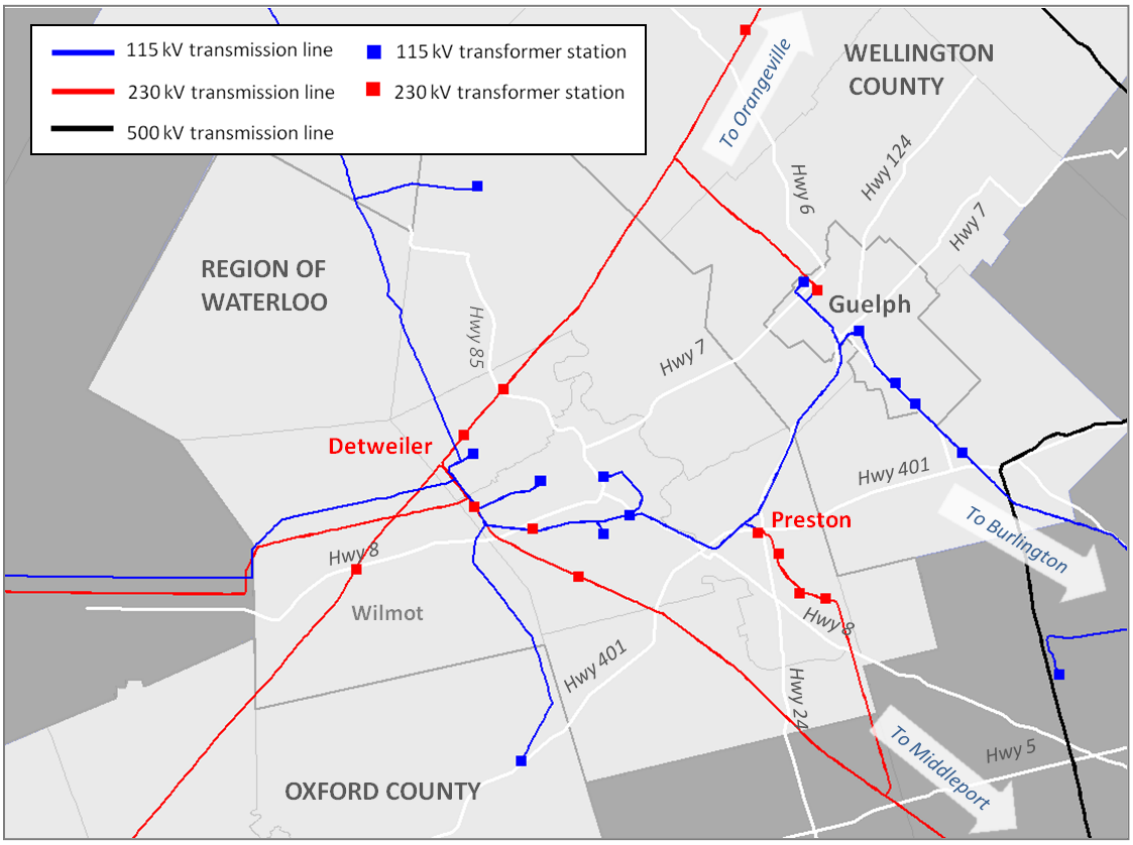
Given the mix of rural and urban development, the nature of growth and local developments may vary across the Region of Waterloo, City of Guelph, Wellington County and the Township of Blandford-Blenheim. The economic activities in the Region of Waterloo and the City of Guelph include a mix of educational institutions, manufacturing, and high-tech industries. For Wellington County and the Township of Blandford-Blenheim, the agriculture and manufacturing sectors play a key role in its economic development.

[8] 2011 Census Data
[9] http://www.placestogrow.ca/

4.2 Existing Electricity System in the KWCG Region

The KWCG Region relies primarily on the regional transmission and distribution infrastructure to deliver electricity into the local area, as there is no large, centralized generation resource in the region. The transmission system within the KWCG Region consists of an integrated 230 kV and 115 kV network. As shown in Figure 4-2, the main sources of electricity into the KWCG Region are Middleport Transformer Station, Detweiler TS, Orangeville TS, and Burlington TS.

Figure 4-2: KWCG Electricity System

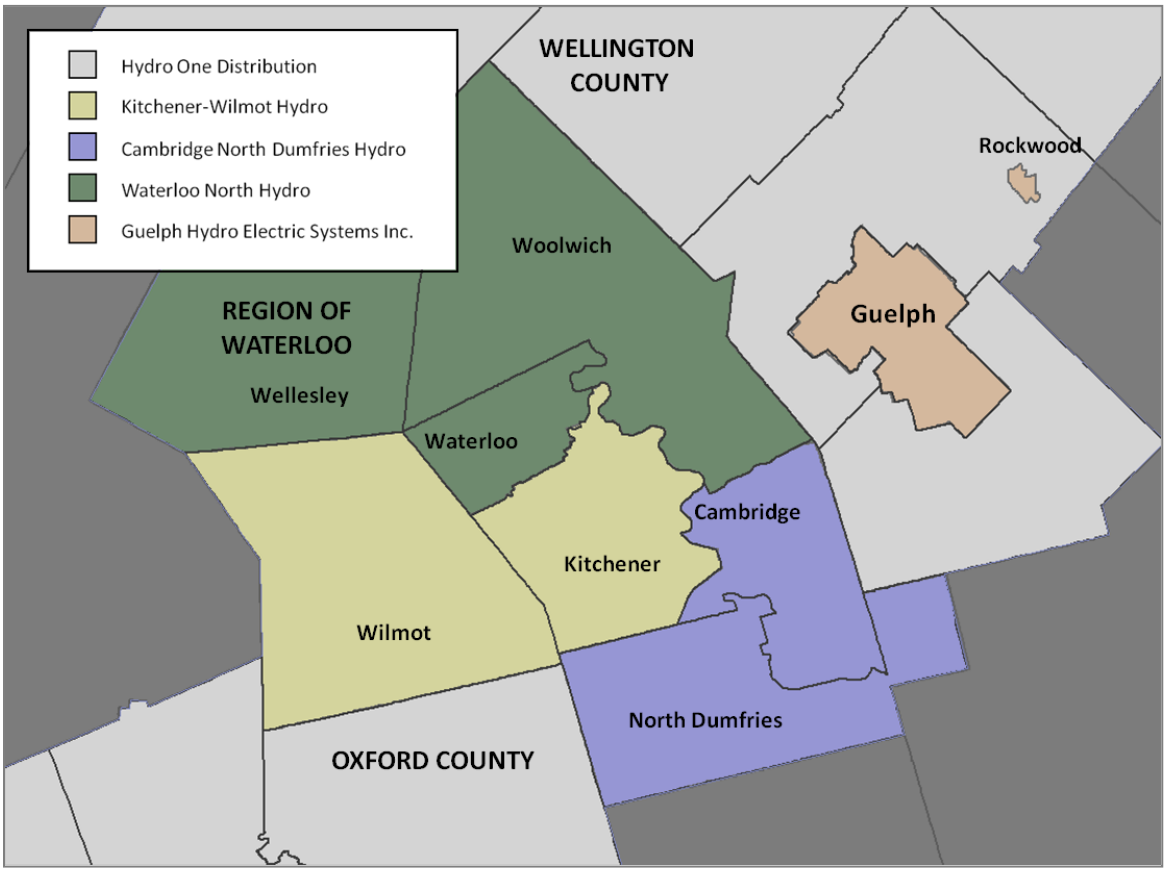


Along these local 230 kV and 115 kV networks, there are three transmission-connected customers and 25 step-down transformers that enable electricity to be delivered from the high-voltage transmission system (115 kV or 230 kV) to the low-voltage distribution systems that serve the communities.

The local distribution system in the KWCG Region is operated and managed by five LDCs: Guelph Hydro Electric Systems Inc. ("Guelph Hydro"), Waterloo North Hydro Inc. ("Waterloo North Hydro"), Kitchener-Wilmot Hydro Inc. ("Kitchener-Wilmot Hydro") Hydro One

Networks Inc. ("Hydro One Distribution"), and Cambridge North Dumfries Hydro Inc. ("Cambridge North Dumfries Hydro"), as shown in Figure 4-3 below.

Figure 4-3: LDC Service Area



5. Demand Forecast

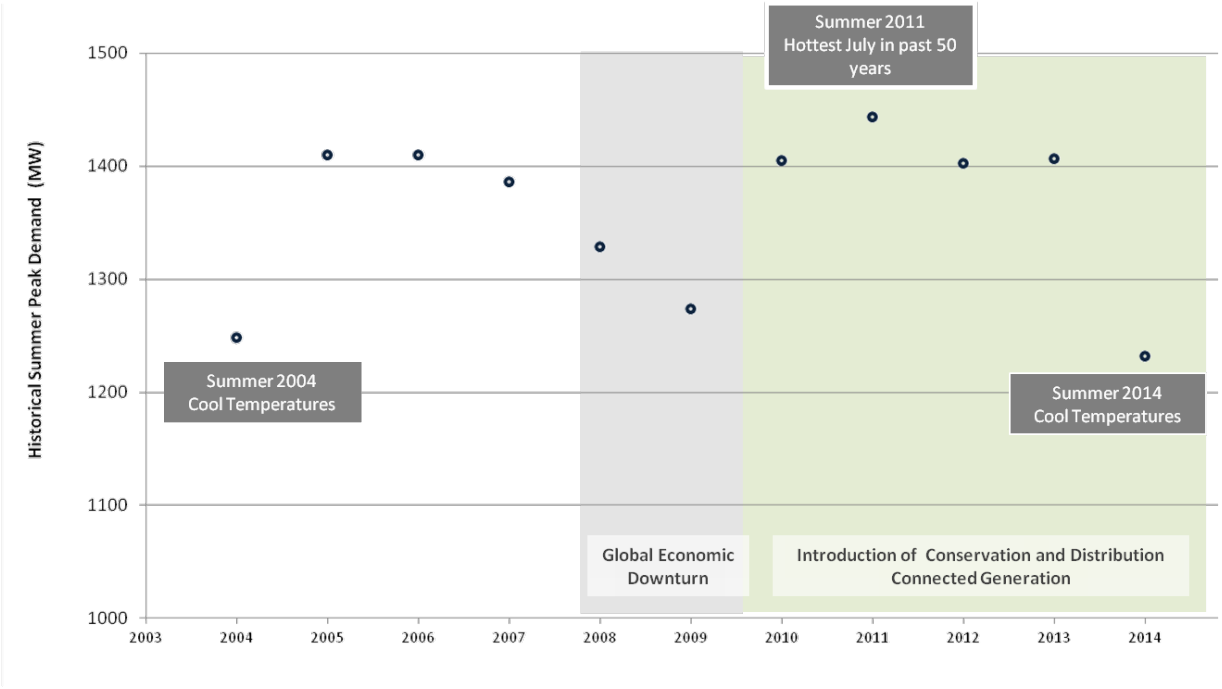
This section describes the specific details of the development of the regional demand forecast: Section 5.1 describes electricity demand trends in the region from 2004 to 2014; Section 5.2 describes the demand forecast methodology used in this study; Section 5.3 provides the near- and medium-term planning forecast; and Section 5.4 explains the long-term planning demand forecast.

5.1 Historical Electricity Demand

The KWCG Region electricity demand is a mix of residential, commercial and industrial loads, encompassing diverse economic activities ranging from educational institutions to automobile manufacturing. While the industrial and commercial sector is the largest consumer of electricity, high-energy-consuming end uses such as air conditioning also play a significant role in contributing to peak electricity demand. During the summer months, peak demand can also be influenced by extreme weather conditions, with peaks in demand typically occurring after several days of high temperatures.

As shown in Figure 5-1, the 2004-2014 historical summer peak demand has fluctuated between 1,250 MW to 1,450 MW, due to a combination of extreme summer temperatures and factors affecting commercial and industrial energy demand, such as the impact of the economic downturn, improvements in energy efficiency ("EE"), and the development of on-site generation. Specifically, the combination of the global recession and low summer temperatures resulted in a decrease in peak demand consumption during 2008 and 2009.

Figure 5-1: Historical Summer Peak Demand in the KWCG Region



In recent years, provincial policies and incentives encouraging conservation, demand response ("DR") and on-site generation have provided opportunities for businesses and residents to better manage their electricity use. These initiatives have resulted in an increase in on-site generation, district energy systems and EE improvements for industrial, commercial, and municipal customers. This in turn has resulted in a reduced reliance on the provincial electricity grid. Local utilities in the KWCG Region have also observed more modest growth in electricity consumption in their service areas due to increased DG and conservation.

5.2 Demand Forecast Methodology

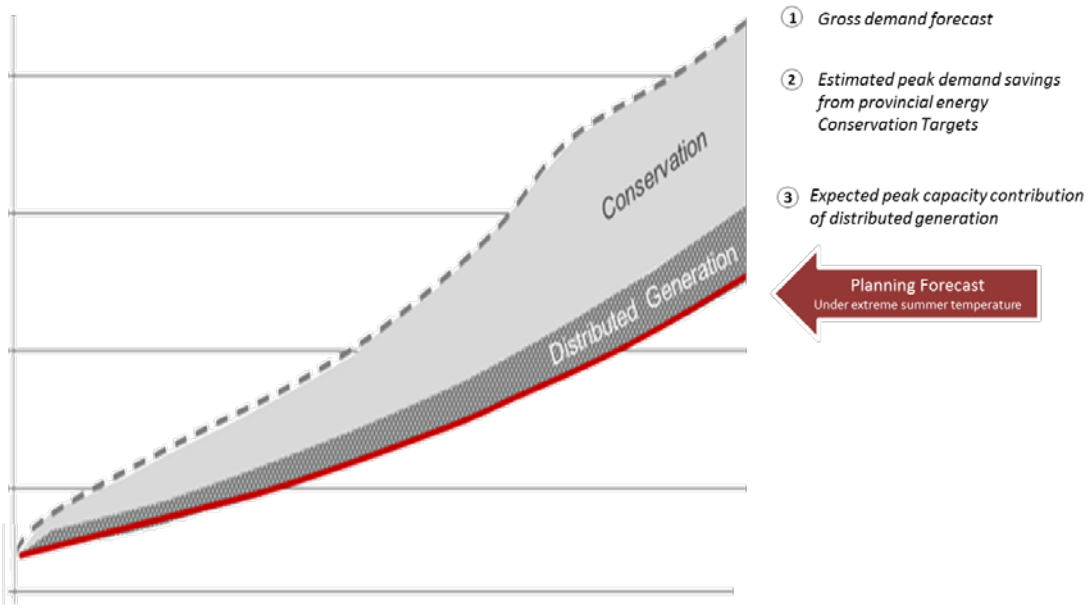
The regional electricity systems in southern Ontario are designed to meet regional coincident peak demand under extreme summer temperature conditions. Regional coincident peak demand is the 1-hour period each year when total regional demand for electricity is the highest.

For the purpose of the IRRP, a 20-year planning forecast is developed to assess supply and reliability needs at the regional level.

The 20-year planning forecast takes into consideration the gross demand forecast, estimated peak demand savings from provincial energy conservation targets, and expected peak capacity contribution of contracted DG, and adjusted to reflect extreme summer temperature conditions,

as shown in Figure 5-2. The methodology and assumptions used for the development of planning forecasts are described in detail in Appendix A.

Figure 5-2: Development of a 20-Year Planning Forecast



The 20-year planning forecast is divided into two timeframes. The first 10 years is developed under normal-year temperature conditions and is based on expected peak demand consumption growth projections from LDCs and from transmission-connected customers' in the LDC's service territory. These growth projections are modified to reflect the estimated peak demand savings from provincial energy conservation targets and contracted DG, and are also adjusted to reflect extreme temperature conditions. This modified forecast represents the near- and medium-term planning forecast, which is required to inform more immediate planning decisions.

For the 10-20-year timeframe, there is greater uncertainty with electricity demand growth, peak demand impact of conservation, DG, and emerging technologies. Longer-term demand scenarios, which consider policy drivers and emerging trends, are developed. These scenarios help communities anticipate potential future electricity demand requirements and electricity supply and reliability needs.

5.3 Near- and Medium-Term Planning Forecast

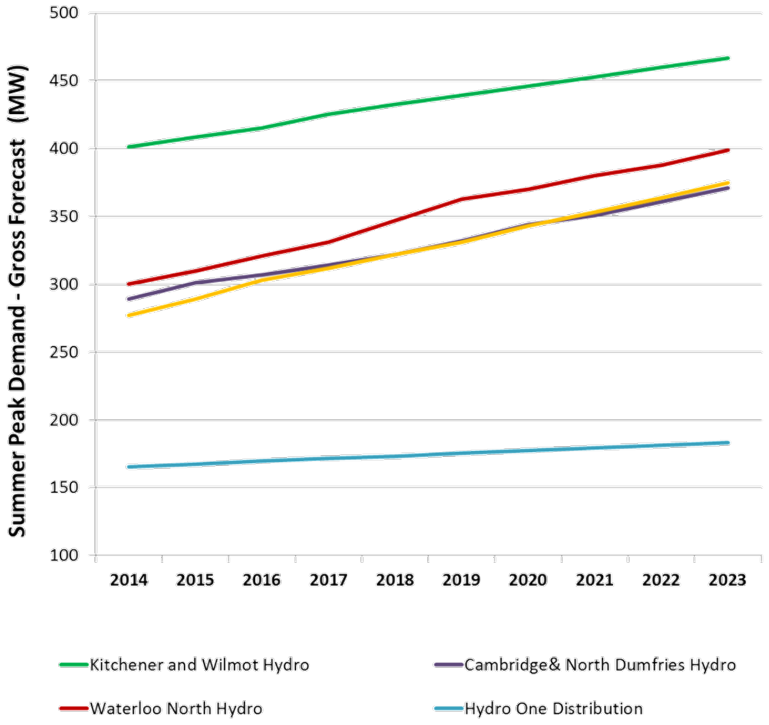
As described above, the near- and medium-term planning forecast (2014-2023) begins with the LDCs' gross demand forecast. Peak demand savings from provincial energy conservation targets and contracted DG are then deducted, and the forecast adjusted for extreme weather to produce the planning forecast. The details of this near- and medium-term forecast are described in the following sections.

5.3.1 Gross Demand Forecast

The gross demand forecast was initially developed in 2010 by the LDCs based on customer connection requests, local economic development and growth assumptions outlined in Ontario's *Places to Grow Act, 2005*, which are reflected in municipal and regional plans. LDCs periodically reviewed and updated the gross demand forecast for their service area to reflect the latest information and electricity demand trends.

Based on the most up-to-date information, LDCs indicate that the gross demand in the KWCG Region is expected to grow at an annual rate of 2.5% in the near and medium term. Consistent with the 2010 projection, Kitchener-Wilmot Hydro, Waterloo North Hydro, and Hydro One Distribution's service areas are forecast to grow at annual rates of 1.7%, 3.2%, and 1.1% respectively. Although Guelph Hydro has made a downward adjustment to the 2014 electricity peak demand level to align with current electricity consumption patterns, it expects electricity peak demand in its service area to grow at an annual rate of 3.4% over the next 10 years. In contrast, Cambridge and North Dumfries Hydro anticipate slower growth in the near term than initially forecast in 2010. A slower than expected economic recovery and a decline in energy usage from industrial customers are the primary reasons for the reduced peak demand growth in the near and medium term. Figure 5-3 shows the gross demand forecast for the LDCs in the KWCG Region.

Figure 5-3: Gross Demand Forecast by LDCs



LDCs	Gross Demand Forecast 2014-2023 Annual Growth Rate
Cambridge & North Dumfries Hydro	2.8%
Guelph Hydro	3.4%
Kitchener-Wilmot Hydro	1.7%
Waterloo North Hydro	3.2%
Hydro One Distribution	1.1%

In addition, three transmission-connected customers also contribute to the overall peak demand in the KWCG Region. For planning purposes, the IESO estimates the peak demand of these transmission-connected customers based on historical metering data and expected peak demand consumption. Prior to 2014, the peak demand of the three transmission-connected customers accounted for approximately 47 MW of the peak demand in the KWCG Region. In 2014, the total peak demand contributed by the transmission-customers was reduced to 12 MW to reflect a reduction in energy usage by a transmission-connected customer in the Cambridge area.

The specific forecasting methodology and assumptions for the gross demand forecast can be found in Appendix A.

5.3.2 Estimated Peak Demand Savings from Provincial Energy Conservation Targets

Conservation plays a key role in maximizing the useful life of existing infrastructure, and maintaining reliable supply. The 2013 LTEP committed to establishing a new 6-year

Conservation First Framework beginning in January 2015 to enable the achievement of all cost-effective conservation. In the near term, Ontario's LDCs have an aggregate energy reduction target of 7 TWh, as well as individual LDC specific targets. These targets are to be achieved between 2015 and the end of 2020 through LDC conservation programs enabled by the Conservation First Framework. Each LDC is required to prepare a CDM Plan describing how their target will be achieved and submit their CDM Plan by May 1, 2015.[10] The LDC CDM Plans will link closely with regional plans, providing more detail about how a portion of the conservation targets that have been incorporated into regional planning will be realized.

As part of the Conservation First policy, the provincial government has adopted a broad definition of conservation that includes various types of customer action and behind-the-meter generation. This means that conservation includes any efforts to reduce the amount of energy consumed from the provincial electricity grid. Conservation initiatives, including behind the meter generation projects and on-site generation,[11] are expected to reduce customers' reliance on the provincial electricity grid and contribute to peak demand savings in the KWCG Region over the next 10 years. For the purpose of this IRRP, the allocation of the provincial energy savings target for the KWCG Region is estimated to offset approximately 144 MW or 40% of the forecast peak demand growth in the KWCG Region between 2014-2023. It is assumed that existing DR already in the base year will continue but savings from potential future DR resources are not included in the forecast. Instead, future savings are considered as possible solution to identified future needs.

Using a planning forecast that is net of provincial energy conservation targets provides consistency with the province's Conservation First policy by reducing demand requirements before assessing any growth-related needs. The planning forecast assumes that the targets will be met, and will produce the expected local peak demand impacts. Therefore, an important aspect of plan implementation will be monitoring the actual peak demand impacts of conservation programs delivered by the local LDCs.

The estimated annual peak demand savings from the provincial energy conservation targets in the KWCG Region are summarized in Appendix A.

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[10] At the time of this report, the CDM plans have not been submitted by the LDCs. The CDM plans will be available on the IESO and LDCs' websites once they have been submitted and reviewed.

[11] The government has directed the former OPA to "consider CDM to be inclusive of activities aimed at reducing electricity consumption and reducing the draw from the electricity grid, such as geothermal heating and cooling, solar heating and small scale (i.e., < 10 MW) behind-the-meter customer generation."

5.3.3 Expected Peak Demand Contribution of Contracted Distributed Generation

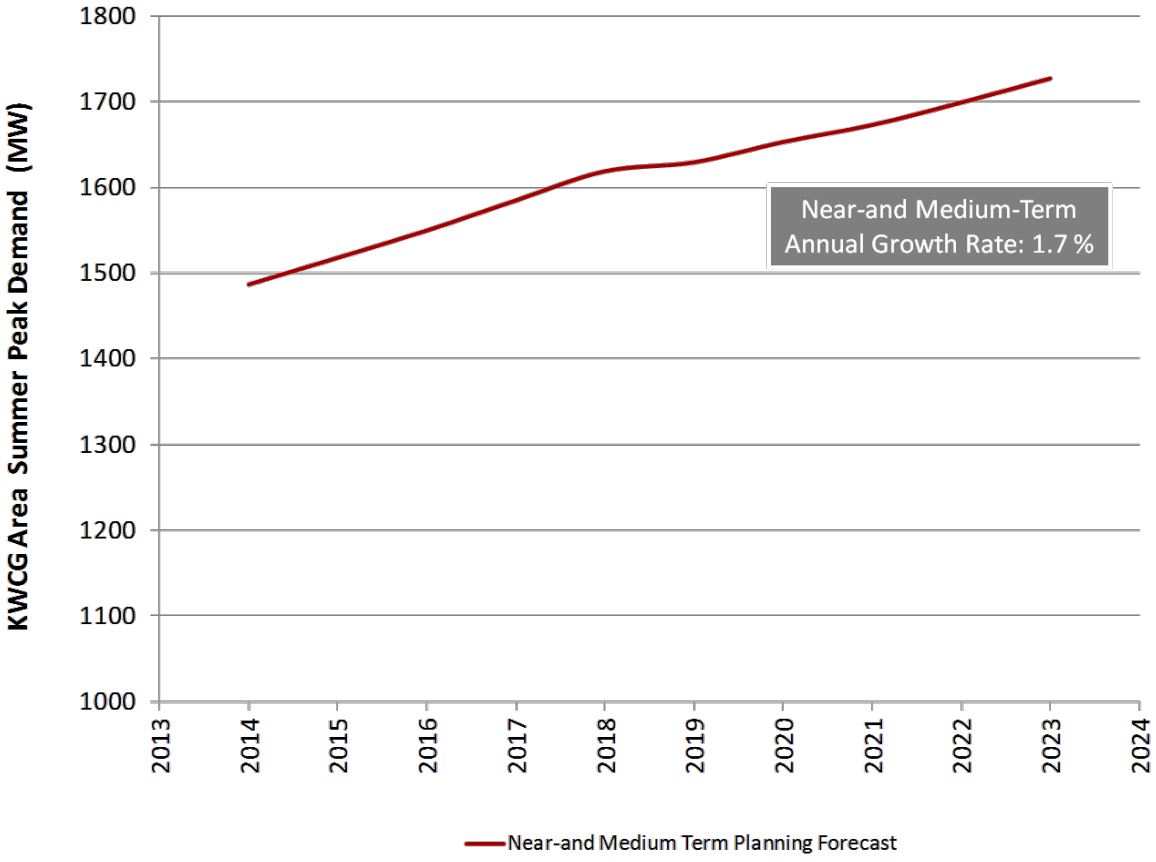
In recent years, a number of DG projects including, wind, solar, hydro and combined heat and power ("CHP") projects, have been developed in the KWCG Region as a result of provincial procurement programs such as FIT and CHPSOP. Since 2010, an additional 98 MW of DG was contracted in the KWCG Region. These contracted DG resources are expected to reduce the regional peak demand by 35 MW or about 10% of forecast demand growth in the Region during the 2014-2023 timeframe. Future DG uptake was, as noted, not included in the planning forecast and is instead considered as an option for meeting identified needs.

The expected annual peak demand contribution of contracted DG in the KWCG Region can be found in Appendix A.

5.3.4 Planning Forecast

Figure 5-4 shows the near- and medium-term planning forecast for the KWCG Region (2014-2023), which takes into consideration the gross demand forecast, estimated peak demand savings from provincial energy conservation targets, and contracted DG adjusted to reflect extreme summer temperature conditions.

Figure 5-4: KWCG Near-and Medium-Term Planning Forecast 2014-2023



According to the planning forecast, the summer peak electricity demand in the KWCG Region is expected to increase at a rate of approximately 1.7% each year, with an incremental peak demand growth of approximately 250 MW between 2014-2023. Over the next 10 years, a large portion of the demand growth will be concentrated in Guelph and Waterloo. The near- and medium-term growth is driven by several concentrated areas of local developments, such as the Region of Waterloo East-Side Lands, the Rapid Transit Initiatives in Waterloo, and the Hanlon Creek Business Park in Guelph.

5.4 Long-Term Planning Forecast

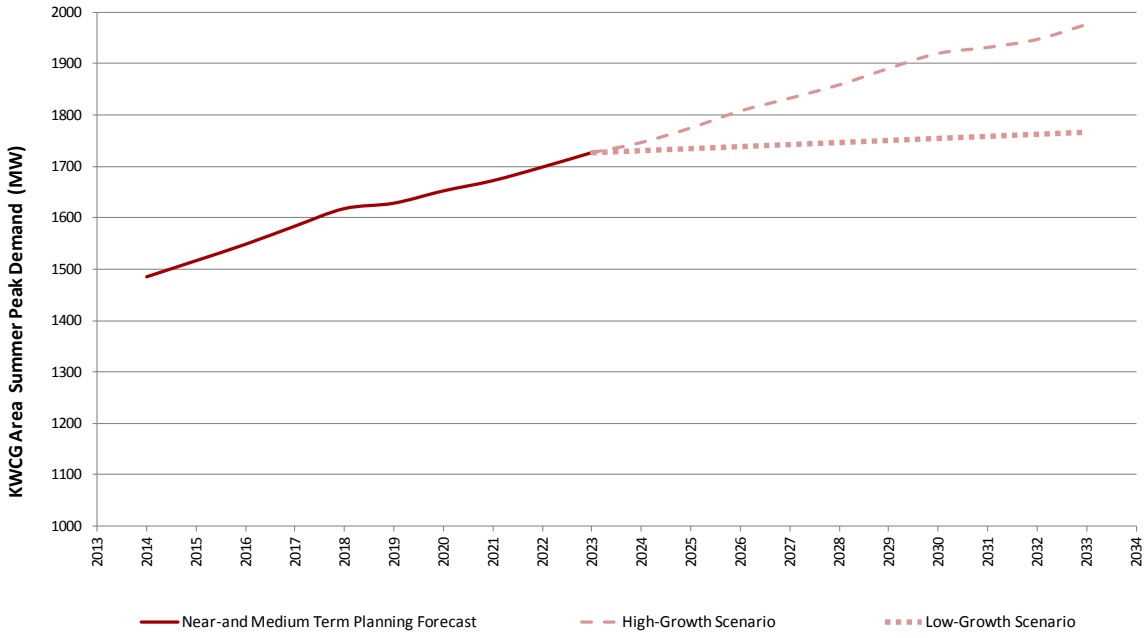
As described in Section 5.2 above, for the 10-20 year timeframe, due to greater uncertainty with electricity demand growth, two longer-term demand scenarios were developed.

Two alternate policy drivers were considered in the development of long-term demand scenarios for the KWCG Region:

- Ontario's *Places to Grow Act, 2005*; and
- Ontario's 2013 LTEP.

The two long-term demand scenarios are shown in Figure 5-5 below and are described in the following sections. Additional details related to the development of these longer-term scenarios are provided in Appendix A.

Figure 5-5: Long-Term Planning Forecast Scenarios 2024-2033



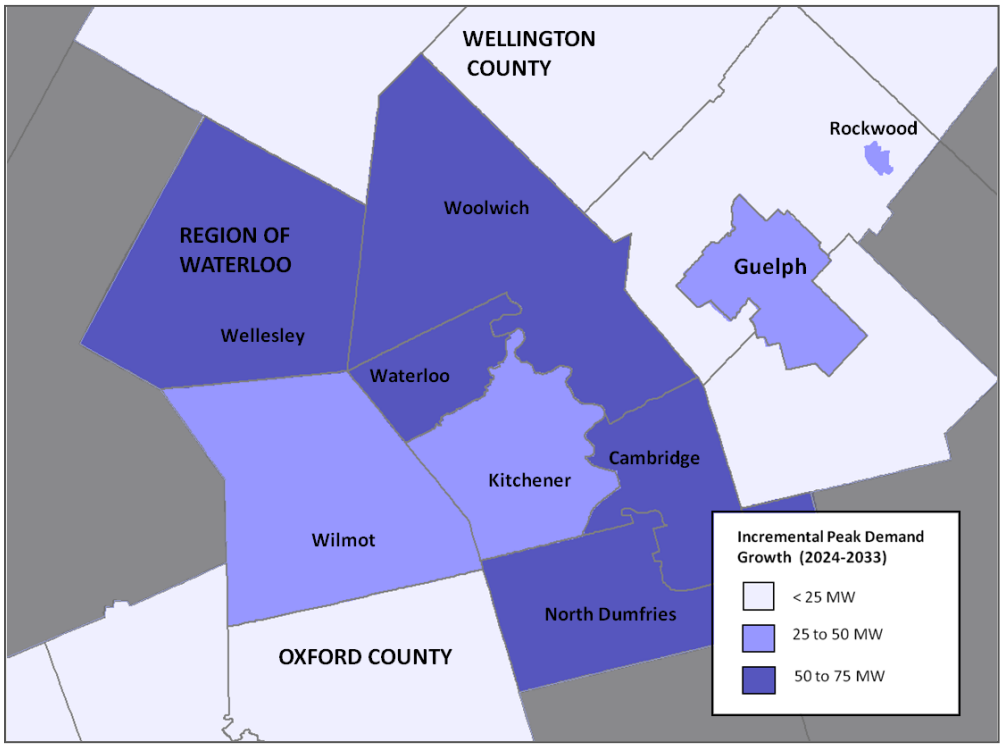
5.4.1 High-Growth Scenario

This scenario reflects the Region's forecast peak electricity demand requirements associated with growth assumptions as detailed in Ontario's Places to Grow plan. It represents a future with sustained electricity demand growth across the region driven by local developments and intensification initiatives outlined in the Places to Grow plan and as reflected in municipal official plans.

Under the high-growth scenario, the summer peak electricity demand requirement in the KWCG Region is forecast to increase at a rate of 1.4% each year over the long term, with an

incremental growth of 150 MW between 2024-2033. Figure 5-6 shows the forecast incremental peak demand growth for the municipalities in the KWCG Region over the longer term.

Figure 5-6: High-Growth Scenario – Incremental Peak Demand Growth 2024-2033 by Municipality



5.4.2 Low-Growth Scenario

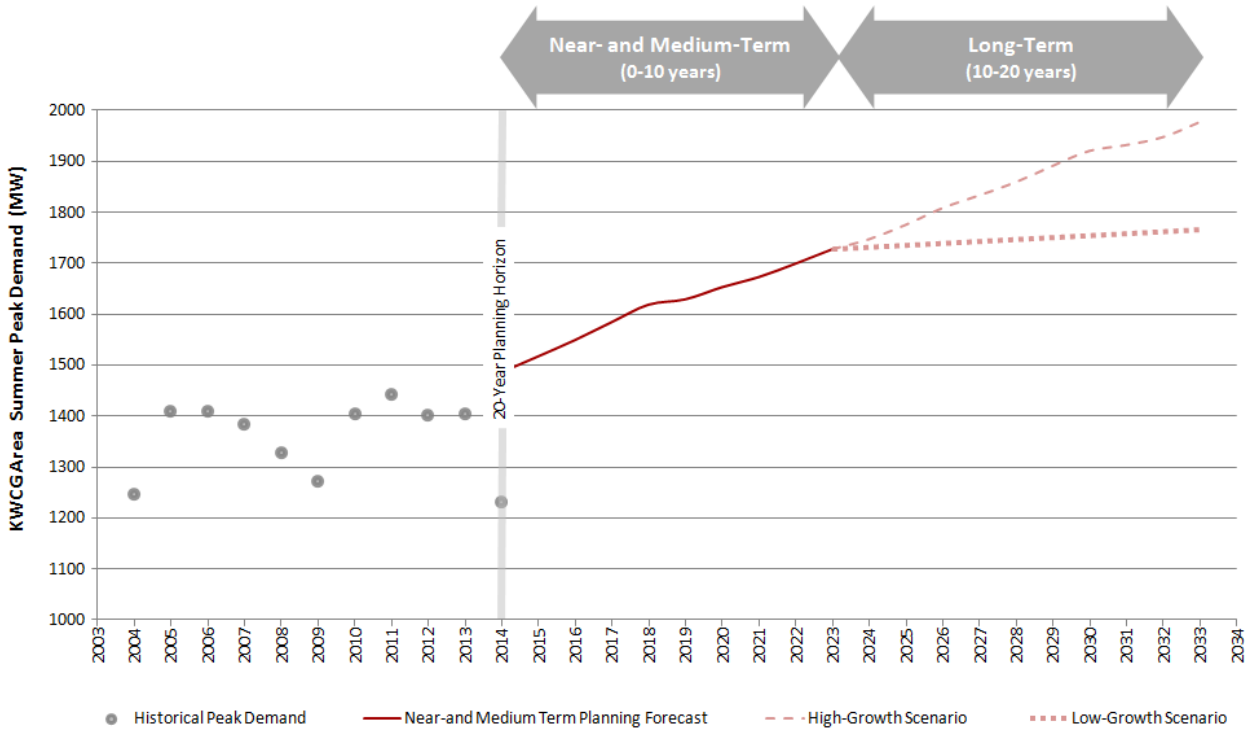
This scenario reflects the region's forecast peak electricity demand requirements associated with the more modest growth assumptions in the 2013 LTEP. The low-growth scenario represents a future with lower electricity demand growth due to higher electricity prices, increased electricity conservation and lower energy intensity within the broader economy. Despite an expected increase in population, energy consumption per household is assumed to decrease over time. Similarly, lower energy intensity is assumed for the commercial and industrial sectors.

Consistent with the 2013 LTEP forecast for southwest Ontario, the peak demand in the KWCG Region beyond 2023 is assumed to grow at a rate of 0.2%, far less than the high-growth scenario. This scenario assumes that electricity demand growth is managed through increased conservation and DG efforts, resulting in less incremental consumption on the provincial electricity grid in the long term.

5.5 Summary of Demand Forecast

The historical peak demand, near- and medium-term planning forecast, and long-term scenarios are shown in Figure 5-7. The annual historical demand data is influenced by variable weather and energy consumption patterns. The planning forecast was developed using assumptions based on extreme weather conditions and typical energy consumption patterns so that demand can be met under a range of conditions. Historical peak demand data was not adjusted to align with the extreme temperature and typical consumption pattern assumptions used in the planning forecast, and as such, may be lower than future projections.

Figure 5-7: Historical Peak Demand, Planning Forecast and Long-Term Scenarios



6. Near- and Medium-Term Plan

The regional planning process considers when system needs may arise by comparing the capability of the existing system with the forecast electricity demand. This section identifies the needs in the near and medium term, considers available options, and recommends actions in the near and medium term.

6.1 Needs Assessment Methodology

The IESO's Ontario Resource and Transmission Assessment Criteria ("ORTAC"),[12] the provincial standard for assessing the reliability of the transmission system, was applied to assess supply capacity and reliability needs. ORTAC includes criteria related to the assessment of the bulk transmission system, as well as the assessment of local or regional reliability requirements (see Appendix B for more details).

Through the application of these criteria, three broad categories of needs can be identified:

- **Transformer Station Capacity** describes the electricity system's ability to deliver power to the local distribution network through the regional transformer stations. This is limited by the 10-day Limited Time Rating ("LTR") of the step-down transformer stations in the local area. Transformer station capacity need is identified when the peak demand at step-down transformer stations in the local area exceeds the combined LTR ratings.
- **Supply Capacity** describes the electricity system's ability to provide continuous supply to a local area. This is limited by the load meeting capability ("LMC") of the transmission line or sub-system which is the maximum demand that can be supplied on a transmission line or sub-system under applicable transmission and generation outage scenarios as prescribed by ORTAC, and is determined through power system simulations analysis (See Appendix B for more details). Supply capacity needs are identified when peak demand on a transmission line or sub-system exceeds its LMC.
- **Load Security and Restoration** describes the electricity system's ability to minimize the impacts of potential supply interruptions to customers in the event of a major transmission outage, such as an outage on a double-circuit tower line resulting in the loss of both circuits. Load security describes the amount of load susceptible to supply interruptions in the event of a major transmission outage. Load restoration describes the

[12] http://www.ieso.ca/imoweb/pubs/marketadmin/imo_req_0041_transmissionassessmentcriteria.pdf

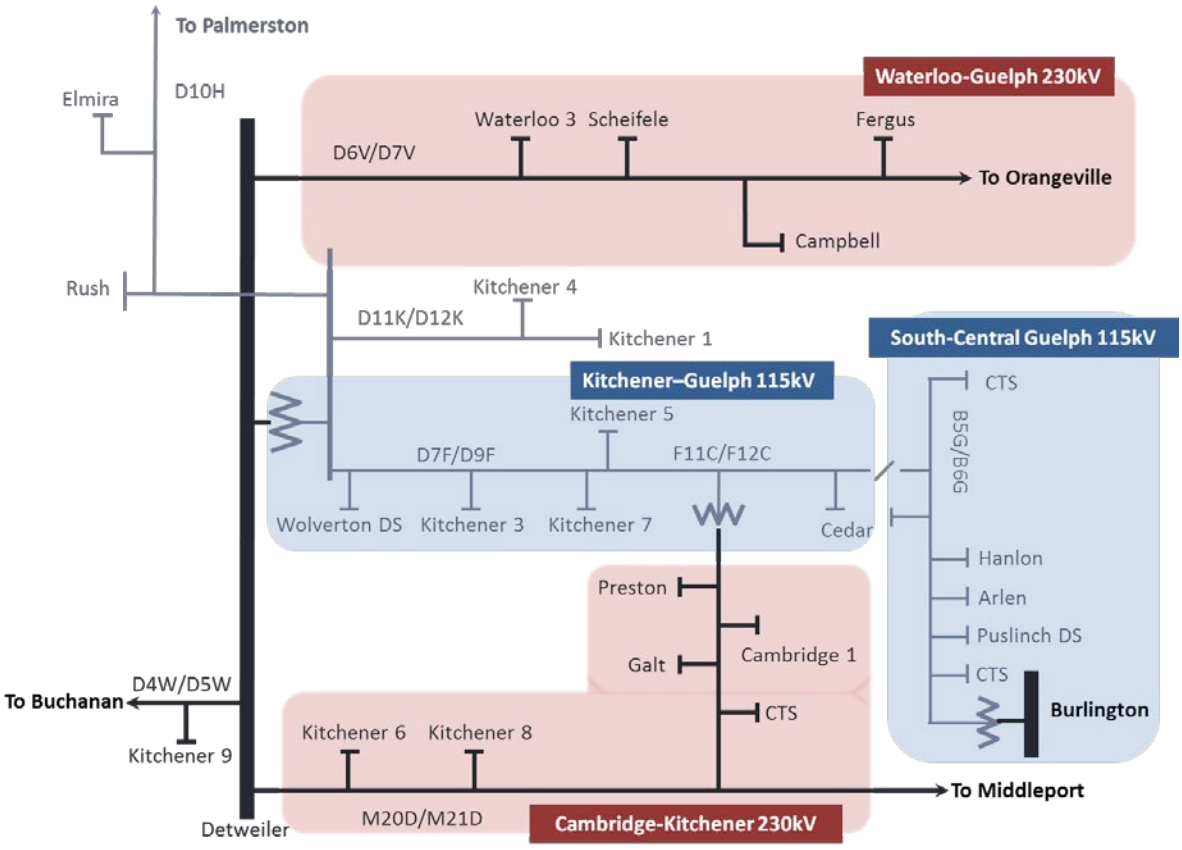
electricity system's ability to restore power to those affected by a major transmission outage within reasonable timeframes. The specific load security and restoration requirements prescribed by ORTAC are described in Appendix B.

In addition, the needs assessment may also identify needs related to transmission reliability performance, equipment end-of-life and planned sustainment activities. Reliability performance describes the frequency and probability of major outages on an electricity system, which can be affected by various factors such as exposure to elements, age and maintenance of equipment, and length and configuration of the transmission or distribution network. Equipment reaching the end of its life and planned sustainment activities may have an impact on the needs assessment and option development.

6.2 Summary of Near- and Medium-Term Needs

As noted earlier, the transmission system within the KWCG Region consists of an integrated 230 kV and 115 kV network. Figure 6-1, The KWCG transmission system can be further subdivided into four regional sub-systems.

Figure 6-1: Regional Sub-systems in the KWCG Region



Today, the 115 kV sub-systems supplying the KWCG Region are at or approaching maximum capacity, and the 230 kV sub-systems have limited ability to restore electricity supply to customers in the event of a major transmission outage. Table 6-1 provides a summary of the near- and medium-term needs in the KWCG Region.

Table 6-1: Near- and Medium-Term Needs in the KWCG Region

Needs	Regional Sub-systems	Need Date
Supply Capacity	South-Central Guelph 115 kV	Today
	Kitchener-Guelph 115 kV	
Load Restoration	Waterloo-Guelph 230 kV	
	Cambridge-Kitchener 230 kV	

6.2.1 Supply Capacity Needs on the South-Central Guelph and Kitchener-Guelph 115 kV Systems

South-Central Guelph 115 kV Sub-system

The South-Central Guelph 115 kV sub-system can provide up to 100 MW of continuous supply to the Kitchener and Guelph area under specific transmission and outage scenarios as defined by ORTAC (South-Central Guelph 115 kV System LMC = 100 MW). Based on the historical peak demand, the summer peak demand in the South-Central Guelph area has already exceeded the 100 MW LMC limit of the South-Central Guelph 115 kV sub-system over the last two years. The existing South-Central Guelph 115 kV sub-system therefore does not meet the ORTAC supply capacity criteria.

Kitchener-Guelph 115 kV sub-system

The Kitchener-Guelph 115 kV sub-system can provide up to 260 MW of continuous supply to the Kitchener and Guelph area under specific transmission and outage scenarios as defined by ORTAC (Kitchener-Guelph 115 kV sub-system LMC = 260 MW). Based on the planning forecast, the peak demand in the Kitchener and Guelph area exceeded the 260 MW LMC limit of Kitchener-Guelph 115 kV system in the summer of 2014. Given the forecast near- and medium-term summer peak demand growth, the existing Kitchener-Guelph 115 kV sub-system does not meet the ORTAC supply capacity criteria.

6.2.2 Load Restoration Needs on the Waterloo-Guelph, and Cambridge-Kitchener 230 kV Sub-system

Waterloo-Guelph 230 kV Sub-system

The Waterloo-Guelph 230 kV sub-system is a 77 km double-circuit 230 kV transmission line (D6V/D7V) between Detweiler TS and Orangeville TS. This system currently supplies about 465 MW of peak demand load in the Waterloo and Guelph area. Based on the planning forecast, the summer peak demand on this system is expected to increase to about 550 MW by 2023. As prescribed by ORTAC, no more than 250 MW of load can be without electricity supply within 30 minutes of a major outage involving the loss of two transmission elements.

In the event of a major outage involving the loss of both transmission circuits on the Waterloo-Guelph 230 kV system (D6/7V), all load supplied by this transmission line would be interrupted. The existing system cannot restore any load within 30 minutes, and can only

restore electricity supply in 3-4 hours using manual restoration procedures. As a result, the Waterloo-Guelph 230 kV system does not meet the ORTAC 30 minute restoration criteria.

A major outage of this type occurred on February 29, 2012, when a forced outage on one of the D6V/D7V circuits, coupled with scheduled maintenance on the companion circuit, resulted in the interruption of electricity supply for three hours to approximately 350 MW of load in Waterloo, Guelph and the surrounding area.

Cambridge-Kitchener 230 kV Sub-system

The Cambridge-Kitchener 230 kV sub-system consists of an 82 km double-circuit 230 kV transmission line (M20D/M21D) between Detweiler TS and Middleport TS. This system currently supplies about 420 MW of peak electricity demand in the Cambridge and Kitchener area. Based on the planning forecast, the summer peak demand on this system is expected to increase to about 480 MW by 2023. As prescribed by ORTAC, no more than 250 MW of load can be without electricity supply within 30 minutes of a major transmission outage.

Should a major outage involving the loss of both transmission circuits on the Cambridge-Kitchener 230 kV system (M20/21D) occur, all load supplied by M20D/M21D would be interrupted. The existing system has the ability to restore up to 65 MW of electricity supply in Cambridge within 30 minutes via the existing 115 kV/230 kV auto-transformer and the circuit switchers at Preston TS. This existing system does not meet the ORTAC criteria because more than 250 MW of load on the Cambridge-Kitchener 230 kV system would still be without service within 30 minutes of a major outage. In fact, a large portion of the customers on the Cambridge-Kitchener 230 kV sub-system would be without power for at least 3-4 hours.

Prior to the installation of the existing 115 kV/230 kV auto-transformer and disconnect switches at Preston TS, power could not be restored to any customers in the area in a timely manner. Such was the case in 2003, when supply to parts of the City of Cambridge, the Township of North Dumfries and the City of Kitchener, totaling over 250 MW, was interrupted for nearly four hours.

6.3 Options to Address the Near- and Medium-Term Needs

In developing the near- and medium-term plan, the Working Group considered a range of integrated alternatives for addressing the needs, including a mix of conservation, generation, transmission and distribution facilities, and other electricity system initiatives. Technical

feasibility, cost, and consistency with long-term needs and options were considered when evaluating alternatives. Solutions that maximized the use of existing infrastructure were given priority.

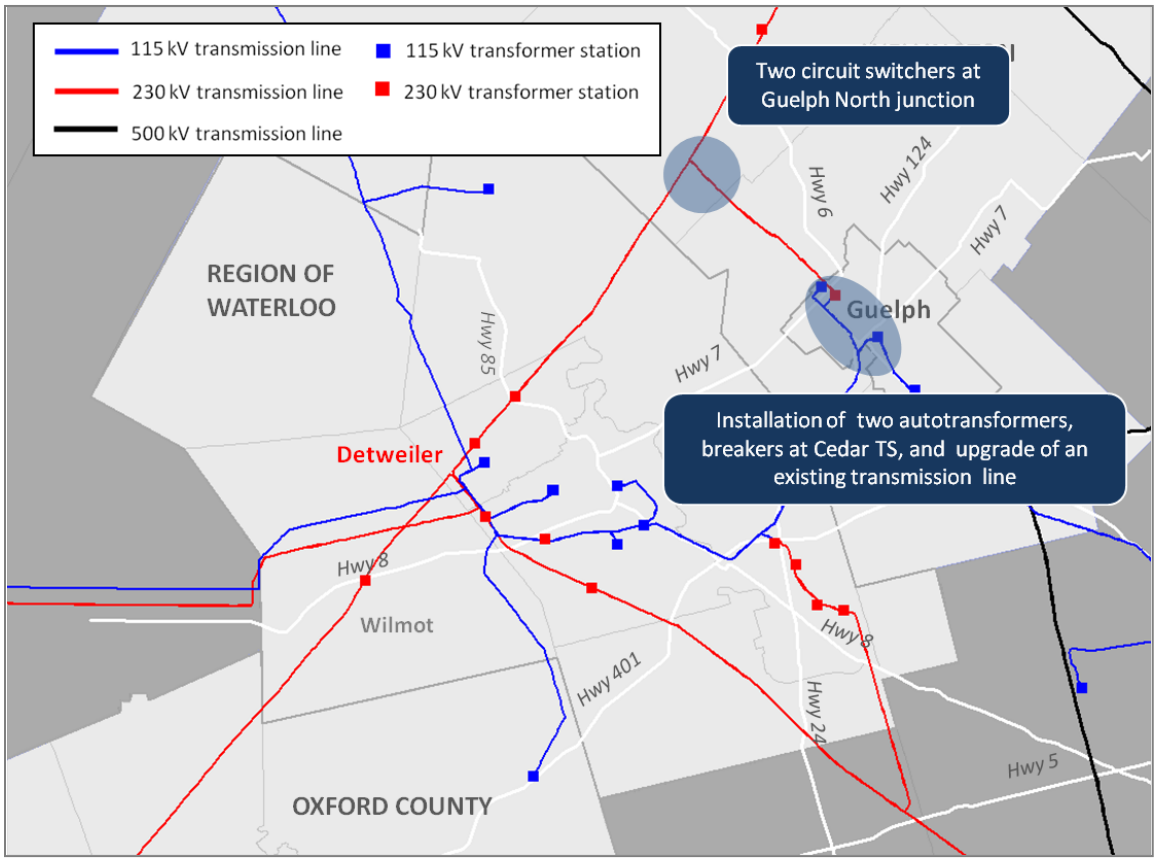
For needs arising in the near term, specific projects are recommended. Given the lead time required to develop electricity infrastructure and CDM programs, these projects must be commenced as soon as possible to ensure customer reliability. Typically, conservation solutions can be implemented within six months, or up to two years for larger projects, whereas transmission and distribution facilities can take 5-7 years. The lead time for generation development is typically 2-3 years, but it could be longer depending on the size and technology type. Recommended actions are therefore identified to initiate investments.

6.3.1 Guelph Area Transmission Refurbishment (GATR) Project

As discussed in Section 3.3, the Working Group recommended proceeding with the implementation of the GATR project, in combination with increased conservation and DG, to address imminent supply capacity and restoration needs in the KWCG Region. This project includes the installation of two 115 kV/230 kV auto-transformers, two 230 kV circuit switchers at Guelph North Junction, two 115 kV breakers at Cedar TS, and the upgrade of an existing transmission line in Guelph (as shown in Figure 6-2). The cost of the GATR project is approximately $95 million. The project was approved by the OEB and is expected to be in-service by spring 2016.[13]

[13] EB-2013-0056 Ontario Energy Board Decision and Order dated September 26, 2013

Figure 6-2: Guelph Area Transmission Refurbishment (GATR) Project



By interconnecting the Waterloo-Guelph 230 kV system with the South Central Guelph 115 kV system and the Kitchener-Guelph 115 kV system, the GATR project maximizes the use of the existing infrastructure and brings a strong source of supply capacity into both 115 kV systems. Following the installation of GATR, there will be sufficient supply capacity on both 115 kV systems to supply electricity demand growth in Guelph and Kitchener and to accommodate up to 100 MW of electricity demand growth in the Cambridge area over the longer term.

The GATR project also improves the ability to restore power to customers on the Waterloo-Guelph 230 kV system. By installing two 230 kV circuit switchers at Guelph North Junction,[14] the sections of the Waterloo-Guelph 230 kV system affected by a possible outage can be isolated

[14] The installation of two 230 kV circuit breakers at Guelph North Junction was originally identified in the GATR Section 92 filing as the preferred option to reduce the impact of supply interruptions to customers on the Waterloo-Guelph 230 kV sub-system. However, after reviewing detailed engineering studies and considering other options, the Working Group determined that it would be cost-effective to install circuit switchers at Guelph North Junction in the near-term and to defer the installation of breakers if and when they are required.

quickly. As a result, about 50% of the electricity supply to customers on the Waterloo-Guelph 230 kV system could be restored within 30 minutes.

The detailed discussion on rationale for GATR and alternatives considered can be found in the Hydro One Inc. Leave to Construct filing for GATR.[15]

6.3.2 Options to Improve Load Restoration on the Cambridge-Kitchener 230 kV Sub-system

As shown in Table 6-2, the GATR project provides sufficient supply capacity on the 115 kV regional sub-systems to meet the electricity demand growth in Guelph, Kitchener and Cambridge over the near and medium term, and improve the ability to restore supply to customers in Waterloo and Guelph. However, the restoration needs on the Cambridge-Kitchener 230 kV sub-system remain.

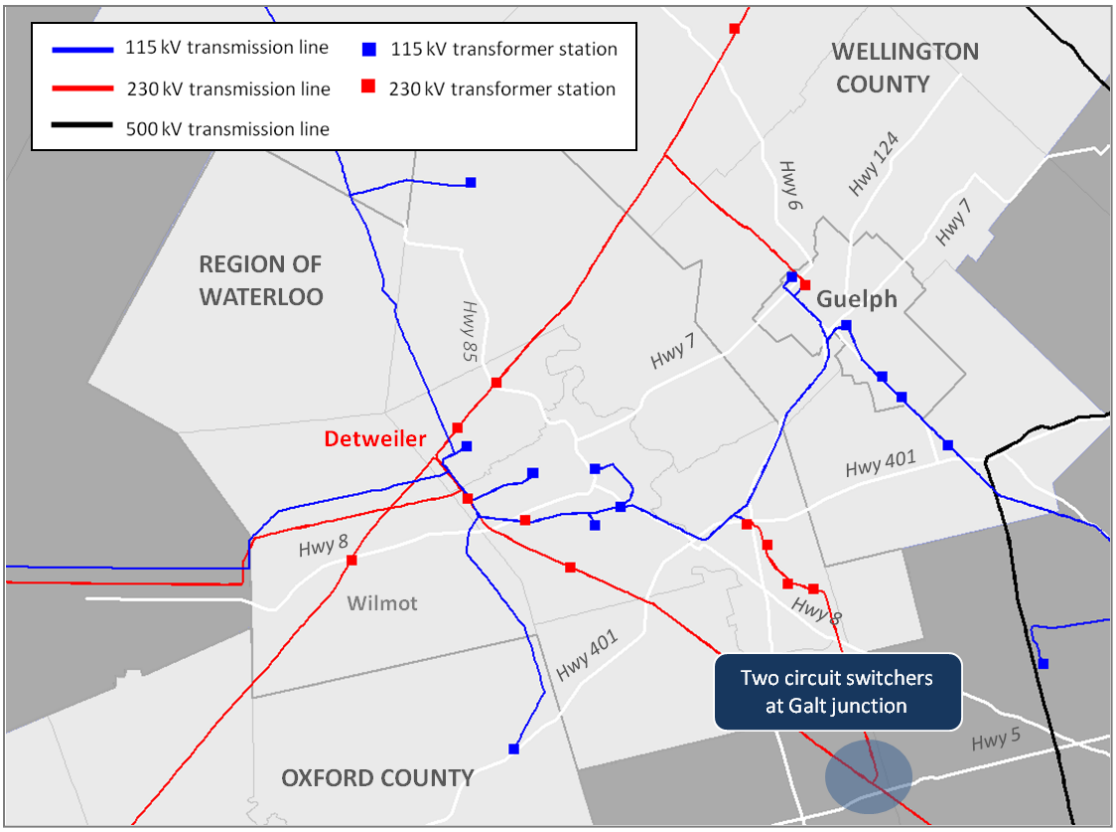
Table 6-2: Summary of Needs Addressed by the GATR Project

Needs	Regional Sub-systems	Needs addressed by the GATR project
Supply Capacity	South Central Guelph 115 kV	✓
	Kitchener-Guelph 115 kV	✓
Load Restoration	Waterloo-Guelph 230 kV	✓
	Cambridge-Kitchener 230 kV	

To substantially improve load restoration in Cambridge and Kitchener in the event of major transmission outages, the Working Group recommended proceeding with the installation of two 230 kV circuit switchers at Galt Junction, near Highway 5, as shown in Figure 6-3. The following section describes the alternatives considered and the rationale for the recommendation.

[15] EB-2013-0056
http://www.rds.ontarioenergyboard.ca/webdrawer/webdrawer.dll/webdrawer/search/rec&sm_udf10=eb-2013-0053&sortd1=rs_dateregistered&rows=200

Figure 6-3: Two Circuit Switchers at Galt Junction



6.3.2.1 Conservation Options

The allocation of the provincial energy savings target is estimated to account for about 40 MW or 40% of the forecast peak demand growth on the Cambridge-Kitchener 230 kV sub-system between 2014-2023. After taking into consideration the estimated peak demand savings from the provincial energy savings conservation targets in the development of the planning forecast, more than 400 MW will still be interrupted on the Cambridge-Kitchener 230 kV sub-system in the event of major transmission outage and power will need to be restored to these customers.

While conservation can be an effective means for communities to manage electricity demand growth and reduce their reliance on the provincial electricity grid, conservation cannot aid in the restoration of power to customers in the event of a major transmission outage. As such, conservation was not considered a feasible solution to address the restoration needs on the Cambridge-Kitchener 230 kV system.

6.3.2.2 Local Generation Options

The extent to which DG can restore electricity supply following a major transmission outage depends on a number of factors, such as the size of the facility, the facility's start-up time, the ramp rate, the availability of black-start capability, storage options, safety protocols and other operating procedures. Given the uncertainties and variability associated with DG, the Working Group agreed that it cannot rely on DG to address restoration needs on the Cambridge-Kitchener 230 kV sub-system.

A large, centralized, transmission-connected generation source (100-200 MW) could improve the restoration on the 230 kV system if properly sited and integrated (e.g., Preston TS and associated switching devices). However, given the high cost associated with large, centralized generation, this option is only cost-effective when it can contribute to both regional and provincial capacity and energy needs. It is not cost-effective to implement a large, centralized generation only for improving load restoration in a local area. This option was therefore ruled out by the Working Group.

6.3.2.3 Distribution Options

One method to restore electricity supply to customers following a major outage on the transmission system is to execute temporary load transfers through the distribution network to unaffected neighboring transformer stations. The amount of load that can be transferred temporarily through the distribution network, as well as the time required to transfer, are highly variable and can depend on various factors such as load level at neighboring stations, distance between stations, voltage of the neighboring distribution system, time of day and operating procedures in place on the distribution system. As such, the Working Group determined that it is difficult to rely on distribution load transfer to restore large amounts of load on the Cambridge-Kitchener 230 kV sub-system in the event of a major transmission outage.

6.3.2.4 Transmission Options

As discussed in Section 3.3, in 2013, the installation of a second 115 kV/230 kV auto-transformer at Preston TS and associated switching and reactive facilities was previously identified by the Working Group as a potential option to address the restoration needs on the Cambridge-Kitchener 230 kV sub-system. In response to the hand-off letter to undertake a detailed study

on the development of the second 115 kV/230 kV auto-transformer at Preston TS option,[16] Hydro One also identified and examined a number of alternatives to reduce the impact of supply interruptions to customers in Cambridge and Kitchener in the event of a major transmission outage on the 230 kV system. Based on Hydro One's analysis,[17] the installation of two 230 kV circuit switchers at Galt junction meets the ORTAC 30-minute restoration criteria on the Cambridge-Kitchener 230 kV sub-system, provides regional benefits, and strikes a reasonable balance between cost, reliability improvement, and feasibility. As such, the Working Group recommended proceeding with the installation of two 230 kV circuit switchers at Galt junction. Hydro One has begun early development work on these switching facilities, which are expected to be in service by spring 2017. Hydro One will continue to examine other potential measures to further improve the restoration capability in the Cambridge area. Please refer to Appendix C for further information regarding load restoration improvements for the Cambridge-Kitchener 230 kV sub-system.

6.4 Recommendations for the Near and Medium Term

Based on the evaluation of alternatives discussed above, the Working Group recommends the actions described below to meet the near-term electricity needs of the KWCG Region. Successful implementation of this plan will substantially address the regional electricity supply needs in the KWCG Region over the next 20 years.

To ensure that the near-term electricity needs of the KWCG Region are addressed, it is important that the near-term plan recommendations are implemented in a timely manner. The specific actions and deliverables associated with the near-term plan are outlined in Table 6-3, along with the proposed timing and the parties that will lead the implementation.

The KWCG Working Group will continue to meet at regular intervals during the implementation phase of this IRRP to monitor developments in the KWCG Region and to track progress toward these deliverables.

[16] OPA Letter to Hydro One - May 29, 2013 for the 2nd Preston Autotransformer: http://www.ieso.ca/Documents/Regional-Planning/KWCG/OPA-Letter-Hydro-One-KWCG.pdf

[17] Hydro One's Kitchener-Waterloo-Cambridge-Guelph area Adequacy of Transmission Facilities Report 2013/2014 report

Table 6-3: Implementation of the Near-Term Plan for the KWCG Region

Recommendations		Action(s)/Deliverable(s)	Lead Responsibility	Timeframe
1	Implement conservation and DG	Develop CDM plans	LDCs	May 2015
		LDC CDM programs implemented	LDCs	2015-2020
		Conduct Evaluation, Measurement and Verification (EM&V) of programs, including peak-demand impacts, and provide results to Working Group	IESO	annually
		Continue to support provincial DG programs	LDCs/ IESO	ongoing
2	Implement the GATR project	Design, develop and construct Seek project approval from the OEB (Leave to Construct application)	Hydro One	Submitted Leave to Construct application on March 8, 2013 Approved by the OEB on Sept 29 2013 In-service spring 2016
3	Install two 230 kV circuit switchers at Galt Junction and explore opportunities to further improve restoration capability in the Cambridge area	Design, develop and construct two 230 kV circuit switchers near Galt junction, near Highway 5 Examine cost and feasibility of potential measures to further improve restoration capability in the Cambridge area	Hydro One	In-service spring 2017

7. Long-Term Plan (2024-2033)

Given the uncertainty in forecasting demand beyond 2023, the purpose of the long-term plan is to consider alternate potential demand scenarios in order to facilitate discussions about how the KWCG Region may plan its future electricity supply, and to lay the groundwork for the next regional planning cycle. This section describes potential long-term needs, approaches to addressing these needs, and recommended actions.

7.1 Summary of Long-Term Needs

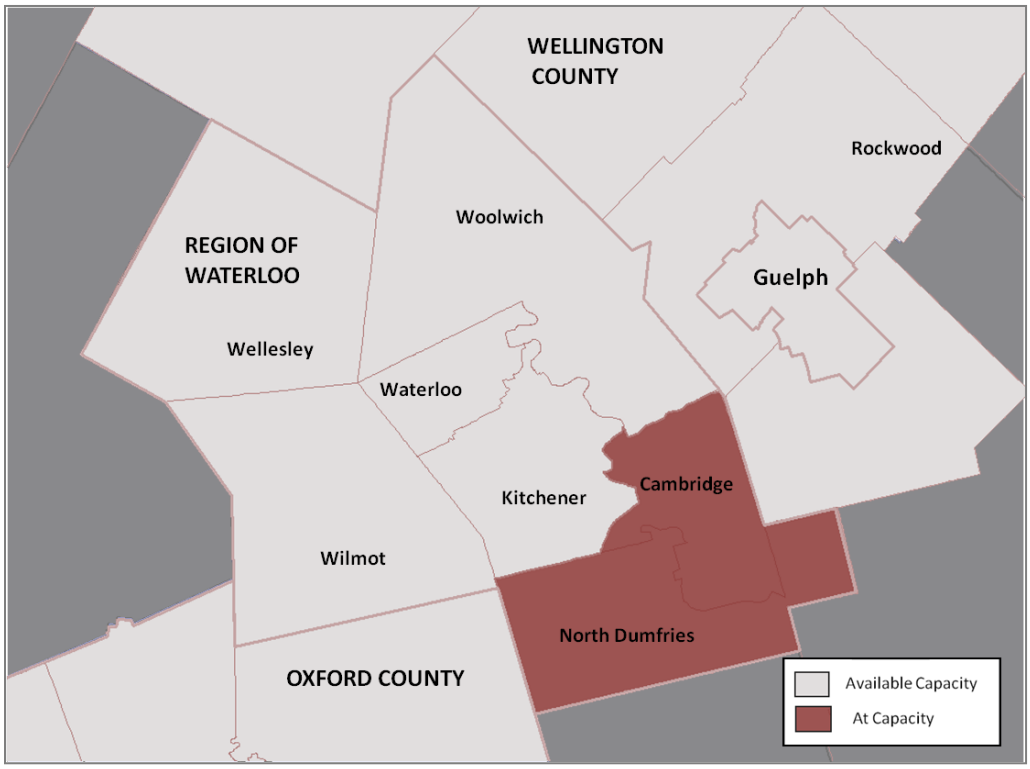
Using the needs assessment methodology outlined in Section 6.1, the KWCG Region was assessed under both of the long-term scenarios: the high-growth scenario and the low-growth scenario.

7.1.1 High-Growth Scenario – Long-Term Needs

Following the implementation of the near-term plan (Section 6.4), there will be sufficient supply capacity on the 115 kV and 230 kV systems over the long term to support the electricity demand growth projected under the high-growth scenario.

Although the 230 kV transmission system supplying customers in the Cambridge area is expected to approach its maximum capacity in the long term, as shown in Figure 7-1, future electricity demand growth in the Cambridge area can utilize the Kitchener-Guelph 115 kV sub-system as an alternative source of supply.

Figure 7-1: Remaining Transmission Supply Capacity 2024-2033



As discussed in Section 6.3.1, once the GATR project comes into service around 2016, there will be sufficient capacity on the Kitchener-Guelph 115 kV sub-system to supply up to 100 MW of peak demand growth in Cambridge over the longer-term. Therefore, no major regional supply and reliability needs are identified in the KWCG Region beyond 2023.

However, localized reliability and supply needs, such as TS capacity needs, may arise in the long term. LDCs are monitoring the load closely to determine the timing of potential transformation needs. Where possible, these LDCs are exploring opportunities to coordinate use and development of TS facilities in the KWCG Region over the long term.

7.1.2 Low-Growth Scenario – Long-Term Needs

Under the low-growth scenario, there is little incremental demand growth in the long term, and no additional needs are identified beyond 2023. Following the implementation of the near- and medium-term plan (see Section 6.4), the electricity system would have sufficient capacity to maintain reliability and manage the demand requirements under the low-growth scenario.

7.2 Approaches to Address Long-Term Needs

For localized needs developing over the long term, there is an opportunity to develop and explore a broader set of options, as specific projects do not need to be committed to immediately. Instead, the focus is on identifying possible approaches to meeting long-term needs, including alternatives that are not currently in widespread use but which show promise for the future. To facilitate these long-term options, preliminary actions should be taken to develop the identified alternatives, monitor growth, and engage with stakeholders and communities in the KWCG Region.

This approach is designed to maintain flexibility, avoid committing ratepayers to investments before they are needed, provide adequate time to gauge the success and future potential of conservation measures, test out emerging technologies, engage with communities and stakeholders, coordinate with any municipal or community energy planning ("MEP/CEP") activities, and to lay the foundation for informed decisions in the future. While it is not necessary to commit to specific projects given forecast uncertainty and technological change, the long-term plan identifies near-term actions to develop alternatives, engage with the communities, gather information and lay the groundwork for future options.

To facilitate discussions about how the KWCG Region may plan its future electricity supply and lay the groundwork for the next planning cycle, the Working Group examined three conceptual approaches to address potential long-term electricity needs in the KWCG Region: community self-sufficiency; delivering provincial resources ("wires" planning); and, large localized generation. In practice, certain elements of electricity plans will be common to all three approaches, and some overlap between them may be necessary. It is likely that all plans will contain some combination of conservation, local generation, transmission and distribution elements. The following section describes the attributes, benefits, risks and implementation requirements associated with each of the three long-term approaches.

7.2.1 Community Self-Sufficiency

The purpose of the community self-sufficiency approach is to reduce a community's reliance on the provincial electricity system by meeting their electricity needs with local, distributed resources and community-based solutions. This approach can include: aggressive DR and conservation programs, DG and advanced storage technologies, micro-grid and smart-grid technologies, and more efficient and integrated process systems combining heat and power and electric vehicles ("EV").

Community self-sufficiency can supplement and/or defer transmission or generation infrastructure development and improve energy security for communities by reducing their reliance on the provincial electricity system through conservation efforts and DG. This approach can be an effective means for addressing localized supply and reliability needs and managing a community's electricity demand growth over the long term.

This approach acknowledges community interest and the desire for grassroots involvement in local electricity planning and infrastructure siting. In recent years, a number of municipalities across the province began undertaking Municipal Energy Plans[18] to better understand their local energy needs, identify opportunities for EE and renewable energy, and to begin aligning their land use planning with energy infrastructure planning. With the self-sufficiency approach, commercial and industrial businesses, educational institutions, municipalities and community energy cooperatives have the ability to take greater ownership of their electricity needs and related infrastructure requirements.

Addressing the long-term needs of the KWCG Region through community self-sufficiency requires leadership from the community to identify local opportunities, to align community energy planning initiatives with the regional electricity planning process, and to develop appropriate local and provincial policy and incentives to guide the development of community-based energy solutions. This can be achieved through the development of municipal and community energy plans and increased coordination between the provincial, regional and municipal governments and local utilities.

As this approach relies on emerging technologies, recently, some communities and/or local utilities are taking action to examine the feasibility, scalability and cost-effectiveness of such technologies through the implementation of pilot projects. Going forward, regulatory guidance would be required to clarify cost recovery mechanisms for emerging technologies and to address the potential risk of stranding assets.

Communities and local utilities in the KWCG Region have become increasingly involved in the development of DG and conservation initiatives as a result of provincial procurement programs and conservation policy. The following sections provide an overview of the ongoing

[18] A Municipal Energy Plan is a comprehensive long-term plan to improve energy efficiency, reduce energy consumption and greenhouse gas (GHG) emissions.

community energy initiatives, policies and solutions being developed in the City of Guelph, Region of Waterloo, Wellington County and Oxford County.

City of Guelph

The City of Guelph places an emphasis on community-based energy management and solutions. According to the Guelph Community Energy Initiative, the City of Guelph has established ambitious goals to reduce energy use per capita, to encourage and facilitate community-based renewable energy systems and to reduce greenhouse gases ("GHG") over the next 20 years.

To facilitate the implementation of these goals under the Guelph Community Energy Initiative, the City of Guelph formed Envida Community Energy Inc. to develop and implement community-based electricity generation, thermal energy and energy management solutions. In recent years, Envida has successfully developed and implemented various district energy, combined heat and power, solar energy and bio-energy projects. Such projects include the Hanlon Creek Business Park District Energy System and Combined Heat and Power Project, the Eastview Landfill Gas Facility, and the Galt District Energy System in downtown Guelph. To facilitate the integration and optimization of these distributed resources, Guelph Hydro has been upgrading its smart grid.

In addition, Guelph Hydro and Envida have taken steps to better understand the potential and feasibility of community-based solutions and emerging technologies. Guelph Hydro conducted an Electric Vehicle Market Research Study in 2011 and was involved with an EV charging station pilot. As part of Guelph's District Energy Strategic Plan, Envida identified 10 potential areas for district energy development and set out a 20-year roadmap for district energy development in Guelph.

To facilitate EE improvements, the City of Guelph has established building codes and efficiency requirements on building renovations and implemented voluntary energy performance labeling in buildings.

Region of Waterloo

The Region of Waterloo released a Corporate Energy Plan for 2014-2024 to effectively manage the region's corporate energy use. Over the next 10 years, the region plans to pursue EE retrofits for buildings and renewable energy generation. The region's Energy Conservation Office ("ECO"), established in 2007, will play a leading role in implementing the goals as

detailed in the Corporate Energy Plan. To date, the ECO has implemented more than 130 conservation and DG projects across the region, including demand shifting, energy audits, building retrofits, and geothermal, biogas, landfill gas, solar heating and solar photovoltaic ("PV") installations. The ECO will provide information on new and emerging generation technologies to the region, by initiating new partnerships with cities and local organizations, attending relevant conferences, and reviewing research publications.

A Climate Action Plan was also developed for the region, as a collective direction for municipal and community leaders to investigate several strategies to reduce energy needs and increase local renewable energy generation. According to the plan, local building codes and standards are to be updated and improved in terms of energy efficiency, targeting building retrofits and new development. In order to help cover capital costs of building retrofits and renewable generation for homeowners, the region will consider using Local Improvement Charges as a funding mechanism. A district energy feasibility study will be conducted for the Region of Waterloo, to identify opportunities within the region for both homes and businesses. By installing public EV charging stations and raising awareness among the local residents, the region intends to have 1,000 EVs in the community. The application of geothermal energy, solar hot water systems and PV net metering solutions will be explored and developed through increased collaboration with LDCs.

The Community Environmental Fund in the Region of Waterloo has supported community-based environmental initiatives, such as supporting a solar thermal project and associated education workshops, and funding a green housing demonstration project combining passive and active solar design as well as integrated energy production.

To facilitate the integration and optimization of distributed resources, LDCs in the Region of Waterloo have invested in advanced smart grid technologies, such as automated switching, Supervisory Control and Data Acquisition ("SCADA"), and outage management systems.

Wellington and Oxford Counties

Both Wellington and Oxford Counties have recently published their Energy Management Plans that outline their goals and initiatives to monitor energy usage, reduce energy consumption and minimize carbon emission and environmental footprints in their communities. These initiatives include installing light emitting diode ("LED") streetlights, conducting energy audits in municipal-owned and high-energy consumption buildings and exploring opportunities for the development of DG in their communities. Today, Wellington County has 15 solar PV units

operating with revenues directed to the Green Energy Reserve, a fund for future green initiatives.

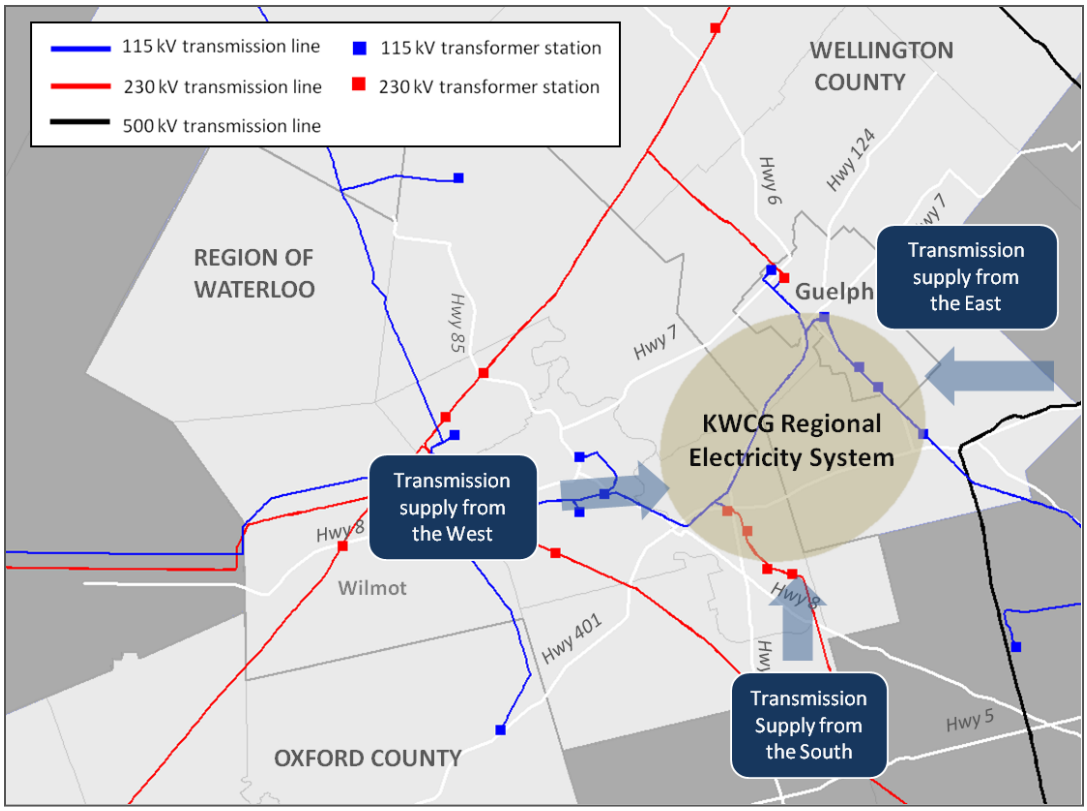
7.2.2 Delivering Provincial Resources ("Wires" Planning)

Delivering provincial resources, or "wires" planning, reflects the traditional regional electricity planning approach associated with the development of centralized electric power systems. This approach involves using transmission and distribution infrastructure to supply a region's electricity needs, taking power from the provincial electricity system. This model takes advantage of generation that is planned at the provincial level, with generation sources typically located remotely from the region. Utilities, both transmitters and distributors, play a lead role in the development of this approach.

Transmission and distribution enhancements, such as the installation of a TS, reactive support and switching facilities, can be an effective means for addressing localized supply and reliability needs in the KWCG Region in the long term.

Although it is not required at this time, a transmission line bringing supply from the west, south or east into the KWCG regional electricity system can be a potential option to address major regional supply needs (as shown in Figure 7-2), if such needs are identified in future planning cycles.

Figure 7-2: Potential Transmission Supply into the KWCG Region



Standard planning practices give preference to solutions that make use of existing corridors and brownfield sites, or that involve development of new joint-use corridors for linear infrastructure. Planning, coordination and engagement with local communities and key stakeholders are required to align land use planning and the siting of transmission and distribution infrastructure. Depending on the requirements and size of the transmission and distribution facilities, the lead time for transmission or distribution facilities is typically 5-7 years. These enhancements may be subject to regulatory approvals, such as a Class Environmental Assessment and a Leave to Construct application. The costs of "wires" solutions would depend not only on the specific infrastructure involved, but also on the cost of providing energy at the provincial system level. Cost responsibility for the transmission and distribution infrastructure would be determined as part of the regulatory application review process.

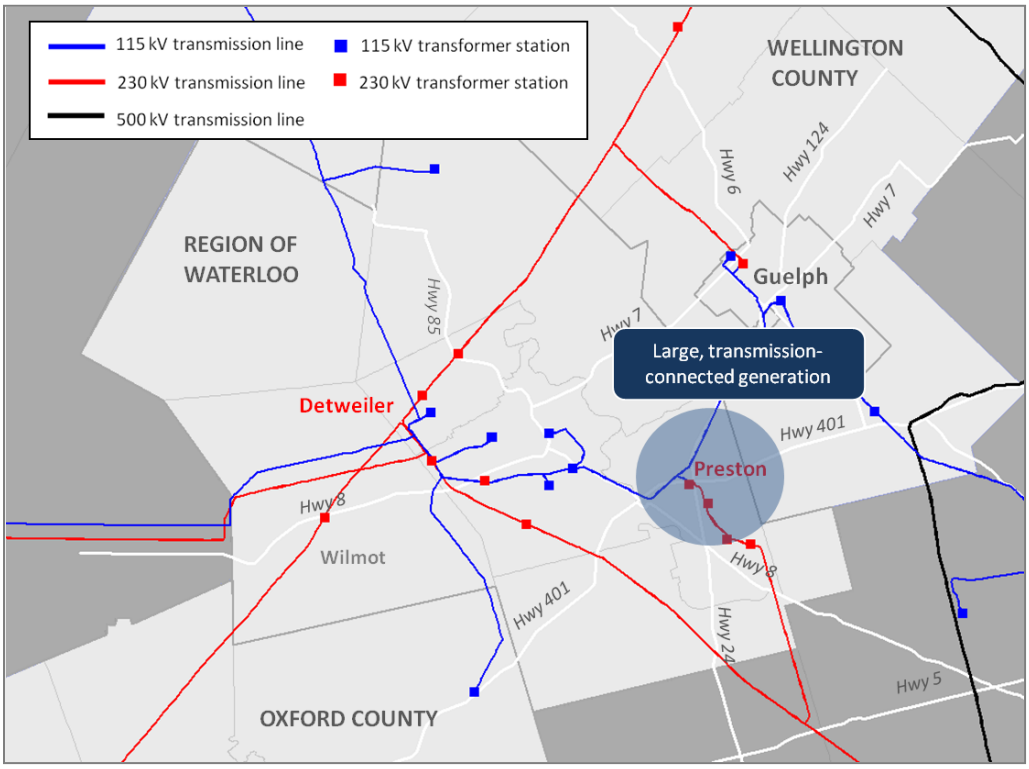
7.2.3 Large, Localized Generation Resources

Siting localized generation based on the size and location of the electricity requirements can be an effective means for addressing major regional supply and reliability needs over the long

term. While this approach is similar to community self-sufficiency in that it shares the goal of providing supply locally, the emphasis is on large, transmission-connected generation facilities rather than smaller, distributed resources.

In the context of the KWCG Region, a large, transmission-connected generation source can be sited near Cambridge (as shown in Figure 7-3) to address major regional supply needs, if such needs are identified in future planning cycles.

Figure 7-3: Large, Transmission-Connected Generation Option



There are a number of factors that need to be considered when siting localized generation, and any decisions about siting this generation would need to align with appropriate recommendations found in the August 2013 report entitled "Engaging Local Communities in Ontario's Electricity Planning Continuum"[19] that was prepared for the Minister of Energy by the OPA and the IESO.

[19] http://www.powerauthority.on.ca/stakeholder-engagement/stakeholder-consultation/ontario-regional-energy-planning-review

As the requirements in the KWCG Region are for additional capacity during times of peak demand, a large, transmission-connected generation solution would need to be capable of being dispatched when needed, and to operate at an appropriate capacity factor. In some cases, additional transmission reinforcements may be required to accompany the generation. In addition, siting may be a challenge if the generation is to be sited in densely populated and/or urban areas.

The cost of the centralized generation option depends on the size and technology of the units chosen, as well as the degree to which they can contribute to the local and provincial capacity or energy need. The lead time for generation development is typically 2-3 years, but it could be longer depending on the size and technology type.

7.3 Recommendations for the Long Term

While specific solutions do not need to be committed to today, it is appropriate to begin work now to gather information, monitor developments, engage the community and develop alternatives to support decision-making for the next iteration of the IRRP. The long-term plan sets out the near-term actions required to ensure that options remain available to address future needs, if and when they arise.

Localized reliability and supply needs may still arise in the long term under certain growth scenarios, but these potential needs do not require any immediate action. There may be opportunity for communities and local utilities to manage their future electricity demand through the development of community-based solutions. Communities and local utilities in the KWCG Region have become increasing involved in the development of DG and conservation initiatives. The results of early community-based pilot projects, energy conservation initiatives, and achievable potential studies will be an important input to the long-term plan for the KWCG Region and will be considered in the next iteration of the KWCG IRRP.

The recommended actions and deliverables for the long-term plan are outlined in Table 7-1, along with the proposed timing, and the parties assigned with lead responsibility for implementation. The KWCG Working Group will continue to meet regularly during the implementation phase of this IRRP to monitor developments in the KWCG Region and to track progress of these deliverables.

Table 7-1: Implementation of Near-Term Actions in Support of the Long-Term Plan for KWCG Region

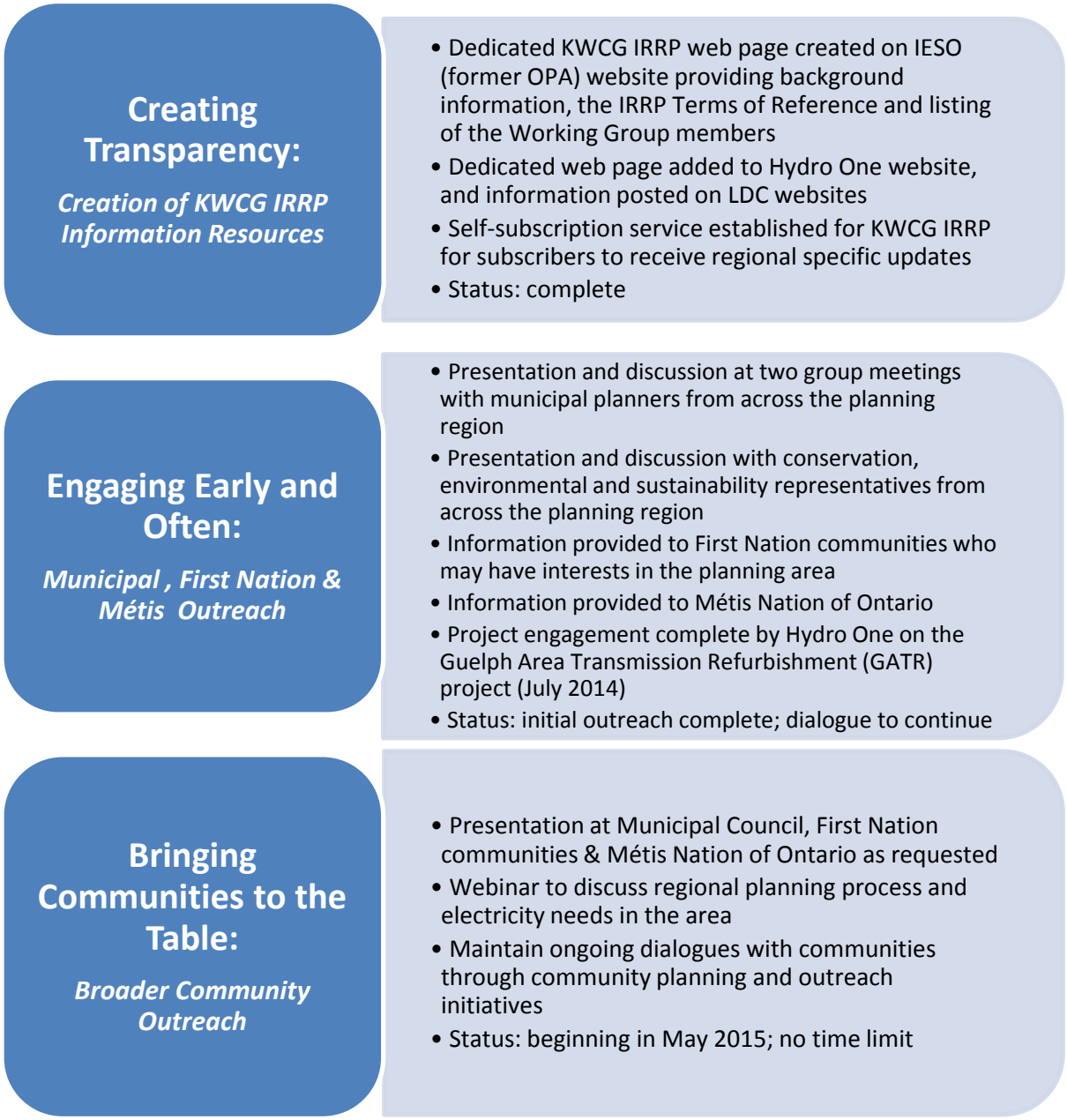
Recommendations		Action(s)/Deliverable(s)	Lead Responsibility	Timeframe
1	Maintain ongoing dialogues with communities about their future electricity supply	Engage with municipalities through community planning and outreach initiatives Engage with First Nations communities through community planning and outreach initiatives	IESO/LDC	2015-2020
2	Monitor load growth, CDM achievement, and DG uptake	Prepare annual update to the Working Group on demand, conservation and DG trends in the area, based on information provided by Working Group	IESO	Annually
3	Coordinate use and development of TS facilities	Monitor growth in respective service area Explore opportunity to coordinate use and development of TS facilities among the LDCs in the KWCG Region	LDCs	2015-2020

8. Community, Aboriginal and Stakeholder Engagement

Community engagement is an important aspect of the regional planning process. Providing opportunities for input in the regional planning process enables the views and preferences of the community to be considered in the development of the plan, and helps lay the foundation for successful implementation. This section outlines the engagement principles as well as the activities undertaken to date for the KWCG Region IRRP and those that will take place to discuss the long-term needs identified in the plan and obtain input in the development of options.

A phased community engagement approach has been developed for the KWCG IRRP based on the core principles of creating transparency, engaging early and often, and bringing communities to the table. These principles were established as a result of the IESO's outreach with Ontarians to determine how to improve the regional planning process, and they are now guiding the IRRP outreach with communities and will ensure this dialogue continues and expands as the plan moves forward.

Figure 8-1: Summary of the KWCG IRRP Community Engagement Process



Creating Transparency

To start the dialogue on the KWCG IRRP and build transparency in the planning process, a number of information resources were created for the plan. A dedicated web page was created on the IESO (former OPA) website to provide a map of the regional planning area, information on why the plan was being developed, the Terms of Reference for the IRRP and a listing of the organizations involved was posted on the websites of the Working Group members. A dedicated email subscription service was also established for the KWCG IRRP where communities and stakeholders could subscribe to receive email updates about the IRRP.

Engaging Early and Often

The first step in the engagement of the KWCG IRRP was meeting with representatives from the municipalities and the First Nations communities in the Region. For the municipal meetings, presentations were made to the KWCG Region municipal planners at two group meetings held in Kitchener and Guelph. The IESO held a separate meeting with representatives of the Six Nations Elected Council. During these meetings, key topics of discussion included Hydro One's Guelph Area Transmission Refurbishment Project (GATR), confirmation of the growth projections, discussion of the near- and long-term needs identified in the KWCG Region, a review of the identified near-term projects including those that have already begun due to timing requirements, and a discussion of the possible approaches to address long-term needs. The discussion also focused on ways to achieve greater community self-sufficiency in the long term, a topic which was also discussed at a separate meeting with conservation, environmental and sustainability representatives from across the planning Region. Invitations to meet to discuss the KWCG IRRP were also extended to the Mississaugas of the New Credit First Nation and to the Haudenosaunee Confederacy Chiefs Council, and the IESO remains committed to responding to any questions or concerns from these communities.

Over the last couple of years, Hydro One has undertaken engagement activities for the GATR project. Going forward, additional engagement activities may be undertaken for other near-term projects. Information on these project-level engagements will be provided on Hydro One's website and will also be listed on the IESO's KWCG IRRP main webpage.

Bringing Communities to the Table

This engagement will begin with a webinar hosted by the Working Group to discuss the plan and potential approaches of possible long-term options. Presentations on the KWCG IRRP will also be made to Municipal Councils on request. To maintain ongoing dialogues with

communities, the IESO and LDCs will continue to engage with First Nations, the Métis Nation of Ontario and municipalities through community planning, environmental and sustainability initiatives and broader community outreach such as, informational public open houses, in between the 5-year regional planning cycle.

Strengthening processes for early and sustained engagement with communities and the public were introduced following an engagement held in 2013 with 1,250 Ontarians on how to enhance regional electricity planning in 2013. This feedback resulted in the development of a series of recommendations that were presented to, and subsequently adopted by the Minister of Energy. Further information can be found in the report entitled "Engaging Local Communities in Ontario's Electricity Planning Continuum"[20] available on the IESO website.

Information on outreach activities for the KWCG Region IRRP can be found on the IESO website and updates will be sent to all subscribers who have requested updates on the KWCG IRRP.

[20] http://www.powerauthority.on.ca/stakeholder-engagement/stakeholder-consultation/ontario-regional-energy-planning-review

9. Conclusion

This report documents the IRRP that has been carried out for the KWCG Region and fulfills the OEB's regional planning requirement for the KWCG Region. The IRRP identifies electricity needs in the KWCG Region over the 20-year period from 2014 to 2033, and recommends a plan to address near-term needs and actions to facilitate discussions about how the KWCG Region may plan its future electricity supply over the longer-term.

Implementation of the near-term plan is already underway. Consistent with the Conservation First policy, LDCs are currently preparing CDM plans, which will be submitted to the IESO by May 2015. Concurrently, the GATR project has been approved and is expected to come into service in 2016. The early development work for the two circuit switchers on the Cambridge-Kitchener 230 kV sub-system is underway. The implementation of these near-term actions would substantially address electricity supply and reliability needs in the KWCG Region and there are no major regional needs identified beyond 2023. Early development work for major electricity infrastructure projects in the KWCG Region is not required at this time. Localized reliability and supply needs may still arise in the long term under certain growth scenarios, but these potential needs do not require any immediate action. There may be opportunity for communities and local utilities to manage their future electricity demand through the development of community-based solutions.

The KWCG Working Group will continue to meet regularly throughout the implementation of the plan to monitor progress and developments in the area, and will produce annual update reports that will be posted on the IESO website. To support development of the long-term plan, a number of actions have been identified to develop alternatives, engage with the community, and monitor growth in the area, and responsibility has been assigned to appropriate members of the Working Group for these actions. Information gathered and lessons learned from these activities will inform development of the next iteration of the IRRP for the KWCG Region. The plan will be revisited according to the OEB-mandated 5-year schedule.

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Appendix G:
Hydro One Planning Status Letter

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Hydro One Networks Inc.
483 Bay Street
13th Floor, North Tower
Toronto, ON M5G 2P5
www.HydroOne.com

Tel: (416) 345-5420
Fax: (416) 345-4141
Ajay.Garg@HydroOne.com

February 4th, 2019

Greig Cameron
Vice President, Engineering & IT
Kitchener-Wilmot Hydro Inc.
301 Victoria St S,
Kitchener, ON N2G 4L2,

Dear Mr. Cameron,

Subject: Regional Planning Status

As per your request, this Planning Status letter is provided to meet one of the requirements of your upcoming Cost of Service application to the Ontario Energy Board (OEB).

As you are aware, the province of Ontario is divided into 21 Regions for the purpose of Regional Planning (RP), and these regions have been split into three (3) groups for the purposes of prioritizing and managing the RP process. A map of Ontario showing the 21 Regions and the list of LDCs in each of the Region are attached as Appendix A and B respectively.

Kitchener Wilmot Hydro Inc. service territory is part of the Kitchener-Waterloo-Cambridge-Guelph (KWCG) Region in Group 1, where Hydro One Networks Inc. (Hydro One) is the lead transmitter.

This letter confirms that the first cycle of RP for KWCG Region was completed in December 2015. Since then, the second cycle for the Region is in progress and Needs Assessment report was completed and published in December 2018. An overview of the RP process is available on Hydro One's RP homepage, which also includes this region's current status and corresponding reports. The current RP status for KWCG Region is summarized below:

Kitchener – Waterloo – Cambridge - Guelph Region

The KWCG region includes the municipalities of Kitchener, Waterloo, Cambridge and Guelph, as well as portions of Perth and Wellington Counties and the Townships of Wellesley, Woolwich, Wilmot and North Dumfries.

The following transmission projects were completed by Hydro One to address near-term supply needs that were recommended in the first cycle RIP (attached as Appendix C):

- The Guelph Area Transmission Refurbishment Project (GATR), placed into service since Q4 2016.
- The switching facilities work at Galt Junction to improve supply reliability for the Cambridge-Kitchener 230 kV Sub-system, placed into service in Oct 2017.

As mentioned above, the second cycle is in progress and the Needs Assessment (Appendix D) report was completed and published in December 2018. The Needs Assessment has identified new needs in the region.
It is expected that there will be little or no cost implications for Kitchener Wilmot Hydro Inc. from the following transmission projects being undertaken by Hydro One:

- Project addressing the near term aging Infrastructure needs
    - Campbell TS – T1 (2018)
    - Detweiler TS -Auto T2 &T4 (2021-2022)
    - 115 kV B5C/ B6C Circuits (2019-2020)
    - 115 kV D7F/ D9F Circuits (2019-2020)
    - 230 kV D6V/ D7V Circuits (2019- 2020)

- Project to address the mid-term aging Infrastructure needs
    - Hanlon TS - T1 & T2 (2023-2024)
    - Cedar TS - T7 & T8 (2024-2025)
    - Preston TS - T3 & T4 (2025-2026)

Other two distribution projects addressing mid-term aging infrastructure needs for the LDCs, as outlined in the 2nd cycle Needs Assessment Report, are being planned and managed by the LDCs:

- Project to address the mid-term aging Infrastructure needs
    - Scheifele MTS - T1 & T2 (2024-2026) for Waterloo North Hydro
    - Kitchener MTS #5 - T9 & T10 (2023-2024) for Kitchener Wilmot Hydro Inc.

The above projects are expected to improve the overall reliability performance in the region. The future system capacity need for Waterloo North Hydro MTS #4 and the new future system capacity need for Energy+ MTS #2 will be studied during the next phases of second cycle regional planning.

In summary, little or no capital contribution is expected from Kitchener Wilmot Hydro Inc. for the projects developed by Hydro One in the KWCG Region.

Kitchener Wilmot Hydro Inc. is an active participating member of the KWCG Region Study Team. Further planning details will be communicated and discussed with Study Team Members as they become available. Hydro One is looking forward to continue working with Kitchener Wilmot Hydro Inc. in executing the regional planning process. Please feel free to contact me if you have any questions.

Sincerely,



Ajay Garg, Manager - Regional Planning Coordination
Hydro One Networks Inc.

Appendix A: Map of Ontario's Planning Regions

Northern Ontario



Southern Ontario



Greater Toronto Area (GTA)



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

Appendix B: List of LDCs for Each Region

[Hydro One as Upstream Transmitter]

Region	LDCs
1. Burlington to Nanticoke	• Energy+ Inc. • Brantford Power Inc. • Burlington Hydro Inc. • Haldimand County Hydro Inc.** • Alectra Utilities Corporation • Hydro One Networks Inc. • Norfolk Power Distribution Inc.** • Oakville Hydro Electricity Distribution Inc.
2. Greater Ottawa	• Hydro 2000 Inc. • Hydro Hawkesbury Inc. • Hydro One Networks Inc. • Hydro Ottawa Limited • Ottawa River Power Corporation • Renfrew Hydro Inc.
3. GTA North	• Alectra Utilities Corporation • Hydro One Networks Inc. • Newmarket-Tay Power Distribution Ltd. • Toronto Hydro Electric System Limited • Veridian Connections Inc.
4. GTA West	• Burlington Hydro Inc. • Alectra Utilities Corporation • Halton Hills Hydro Inc. • Hydro One Networks Inc. • Milton Hydro Distribution Inc. • Oakville Hydro Electricity Distribution Inc.
5. Kitchener- Waterloo-Cambridge-Guelph (“KWCG”)	• Energy+ Inc. • Centre Wellington Hydro Ltd. • Guelph Hydro Electric System - Rockwood Division • Guelph Hydro Electric Systems Inc. • Halton Hills Hydro Inc. • Hydro One Networks Inc. • Kitchener-Wilmot Hydro Inc. • Milton Hydro Distribution Inc. • Waterloo North Hydro Inc. • Wellington North Power Inc.

6. Metro Toronto	• Alectra Utilities Corporation • Hydro One Networks Inc. • Toronto Hydro Electric System Limited • Veridian Connections Inc.
7. Northwest Ontario	• Atikokan Hydro Inc. • Chapleau Public Utilities Corporation • Fort Frances Power Corporation • Hydro One Networks Inc. • Kenora Hydro Electric Corporation Ltd. • Sioux Lookout Hydro Inc. • Thunder Bay Hydro Electricity Distribution Inc.
8. Windsor-Essex	• E.L.K. Energy Inc. • Entegrus Power Lines Inc. [Chatham- Kent] • EnWin Utilities Ltd. • Essex Powerlines Corporation • Hydro One Networks Inc.
9. East Lake Superior	N/A → This region is not within Hydro One's territory
10. GTA East	• Hydro One Networks Inc. • Oshawa PUC Networks Inc. • Veridian Connections Inc. • Whitby Hydro Electric Corporation
11. London area	• Entegrus Power Lines Inc. [Middlesex] • Erie Thames Power Lines Corporation • Hydro One Networks Inc. • London Hydro Inc. • Norfolk Power Distribution Inc.** • St. Thomas Energy Inc. • Tillsonburg Hydro Inc. • Woodstock Hydro Services Inc.**
12. Peterborough to Kingston	• Eastern Ontario Power Inc. • Hydro One Networks Inc. • Kingston Hydro Corporation • Lakefront Utilities Inc. • Peterborough Distribution Inc. • Veridian Connections Inc.

13. South Georgian Bay/Muskoka	• Collingwood PowerStream Utility Services Corp. (COLLUS PowerStream Corp.) • Hydro One Networks Inc. • InnPower Corporation • Lakeland Power Distribution Ltd. • Midland Power Utility Corporation • Orangeville Hydro Limited • Orillia Power Distribution Corporation • Alectra Utilities Corporation • Veridian Connections Inc. • Veridian Connections Inc. • Wasaga Distribution Inc.
14. Sudbury/Algoma	• Espanola Regional Hydro Distribution Corp. • Greater Sudbury Hydro Inc. • Hydro One Networks Inc.
15. Chatham/Lambton/Sarnia	• Bluewater Power Distribution Corporation • Entegrus Power Lines lnc. [Chatham- Kent] • Hydro One Networks Inc.
16. Greater Bruce/Huron	• Entegrus Power Lines lnc. [Middlesex] • Erie Thames Power Lines Corporation • Festival Hydro Inc. • Hydro One Networks Inc. • Wellington North Power Inc. • West Coast Huron Energy Inc. • Westario Power Inc.
17. Niagara	• Canadian Niagara Power Inc. [Port Colborne] • Grimsby Power Inc. • Haldimand County Hydro Inc.** • Alectra Utilities Corporation • Hydro One Networks Inc. • Niagara Peninsula Energy Inc. • Niagara-On-The-Lake Hydro Inc. • Welland Hydro-Electric System Corp. • Niagara West Transformation Corporation* * Changes to the May 17, 2013 OEB Planning Process Working Group Report
18. North of Moosonee	N/A → This region is not within Hydro One's territory

19. North/East of Sudbury	• Greater Sudbury Hydro Inc. • Hearst Power Distribution Company Limited • Hydro One Networks Inc. • North Bay Hydro Distribution Ltd. • Northern Ontario Wires Inc.
20. Renfrew	• Hydro One Networks Inc. • Ottawa River Power Corporation • Renfrew Hydro Inc.
21. St. Lawrence	• Cooperative Hydro Embrun Inc. • Hydro One Networks Inc. • Rideau St. Lawrence Distribution Inc.

**This Local Distribution Company (LDC) has been acquired by Hydro One Networks Inc.

Appendix C: KWCG Regional Infrastructure Plan (1st Cycle)



Kitchener-Waterloo-Cambridge-Guelph

REGIONAL INFRASTRUCTURE PLAN

December 15, 2015

hydro one

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Prepared and supported by:

Company
Hydro One Networks Inc. (Lead Transmitter)
Cambridge and North Dumfries Hydro Inc.
Centre Wellington Hydro
Guelph Hydro Electric System Inc.
Halton Hills Hydro
Hydro One Distribution
Independent Electricity System Operator
Kitchener Wilmot Hydro Inc.
Milton Hydro
Waterloo North Hydro Inc.
Wellington North Power Inc.

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DISCLAIMER

This Regional Infrastructure Plan ("RIP") report was prepared for the purpose of developing an electricity infrastructure plan to address needs identified in previous planning phases and also any additional needs identified based on new and/or updated information provided by the RIP Working Group.

The preferred solution(s) that have been identified in this report may be reevaluated based on the findings of further analysis. The load forecast and results reported in this RIP report are based on the information provided and assumptions made by the participants of the RIP Working Group.

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

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EXECUTIVE SUMMARY

THIS REGIONAL INFRASTRUCTURE PLAN ("RIP") WAS PREPARED BY HYDRO ONE AND THE WORKING GROUP IN ACCORDANCE WITH THE ONTARIO TRANSMISSION SYSTEM CODE REQUIREMENTS. IT IDENTIFIES INVESTMENTS IN TRANSMISSION FACILITIES, DISTRIBUTION FACILITIES, OR BOTH, THAT SHOULD BE DEVELOPED AND IMPLEMENTED TO MEET THE ELECTRICITY INFRASTRUCTURE NEEDS WITHIN THE KITCHENER-WATERLOO-CAMBRIDGE-GUELPH ("KWCG") REGION.

The participants of the RIP Working Group included members from the following organizations:

- Cambridge and North Dumfries Hydro Inc.
- Centre Wellington Hydro
- Guelph Hydro Electric System Inc.
- Halton Hills Hydro One
- Hydro One Distribution
- Hydro One Transmission
- Independent Electricity System Operator
- Kitchener Wilmot Hydro Inc.
- Milton Hydro
- Waterloo North Hydro Inc.
- Wellington North Power Inc.

This RIP provides a consolidated summary of needs and recommended plans for the KWCG Region for the near-term (up to 5 years) and mid-term (5 to 10 years). No long term needs (10 to 20 years) have been identified at this time.

This RIP is the final phase of the regional planning process and it follows the completion of the KWCG Integrated Regional Resource Plan ("IRRP") by the IESO in April 2015.

The major infrastructure investments planned for the KWCG Region over the near and mid-term, identified in the various phases of the regional planning process, are given in the table below.

No.	Project	In-Service Date	Cost
1	Guelph Area Transmission Reinforcement	May 2016	$95 M
2	Arlen MTS: Install Series reactors	May 2016	$0.95 M
3	M20D/M21D – Install 230 kV In-line Switches	May 2017	$6 M
4	Waterloo North Hydro: MTS #4	2024	TBD

In accordance with the Regional Planning process, the Regional Plan should be reviewed and/or updated at least every five years. The Region will continue to be monitored and should there be a need that emerges due to a change in load forecast or any other reason, the next regional planning cycle may be started earlier to address the need.

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1. INTRODUCTION

THIS REPORT PRESENTS THE REGIONAL INFRASTRUCTURE PLAN ("RIP") TO ADDRESS THE ELECTRICITY NEEDS OF THE KWCG REGION.

The report was prepared by Hydro One Networks Inc. ("Hydro One") and documents the results of the joint study carried out by Hydro One, Kitchener-Wilmot Hydro Inc. ("Kitchener-Wilmot Hydro"), Waterloo North Hydro Inc. ("WNH"), Cambridge & North Dumfries Hydro Inc. ("CND"), Guelph Hydro Electric Systems Inc. ("Guelph Hydro"), Hydro One Distribution and the Independent Electricity System Operator ("IESO") in accordance with the Regional Planning process established by the Ontario Energy Board ("OEB") in 2013.

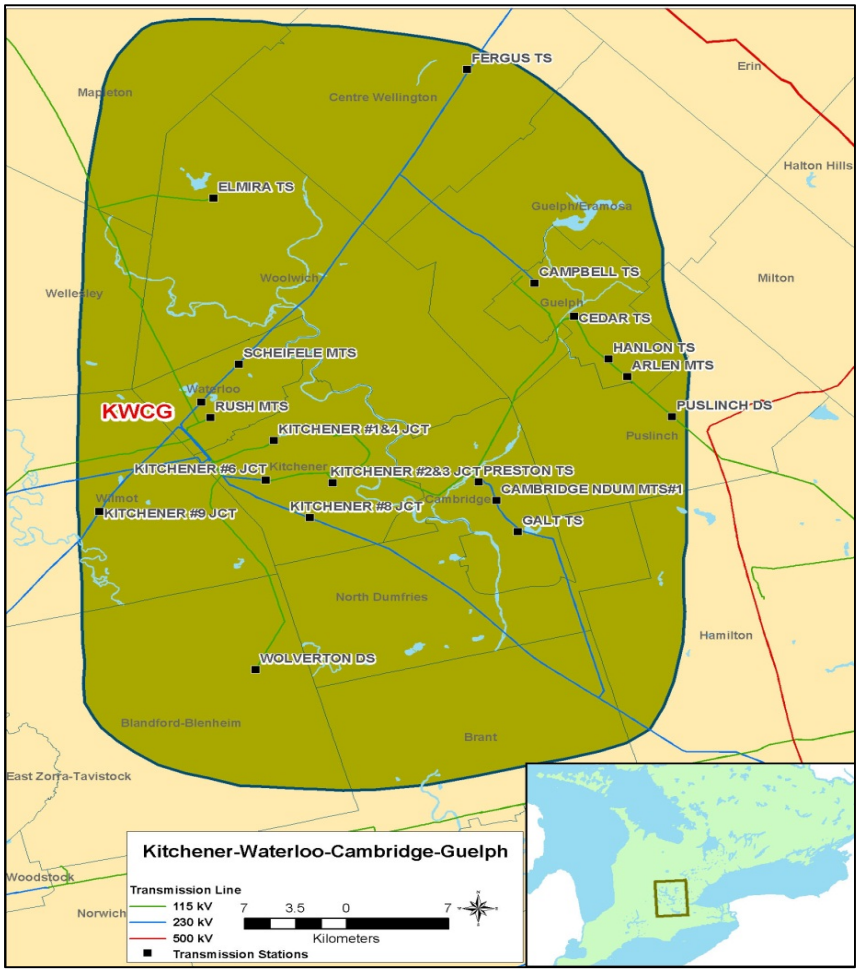


Figure 1-1 KWCG Region

The KWCG Region covers the cities of Kitchener, Waterloo, Cambridge and Guelph, portions of Oxford and Wellington counties and the townships of North Dumfries, Puslinch, Woolwich, Wellesley and Wilmot. Electrical supply to the Region is provided from eleven 230 kV and thirteen 115 kV step-down transformer stations. The summer 2015 coincident regional load was about 1240 MW. The boundaries of the Region are shown in Figure 1-1 above.

1.1 Scope and Objectives

This RIP report examines the needs in the KWCG Region. Its objectives are:

- To identify new supply needs that may have emerged since previous planning phases (e.g. Needs Assessment, Scoping Assessment, Local Plan, and/or Integrated Regional Resource Plan)
- To assess and develop a wires plan to address these needs
- To provide the status of wires planning currently underway or completed for specific needs
- To identify investments in transmission and distribution facilities or both that should be developed and implemented on a coordinated basis to meet the electricity infrastructure needs within the region.

The RIP reviews factors such as load forecast, transmission and distribution system capabilities along with any updates with respect to local plans, conservation and demand management ("CDM"), renewable and non-renewable generation development, and other electricity system and local drivers that may impact the need and alternatives under consideration.

The scope of this RIP is as follows:

- A consolidated report of all the needs and relevant plans to address near and mid-term needs (2015-2025) identified in previous planning phases (Needs Assessment, Scoping Assessment, Local Plan or Integrated Regional Resource Plan)
- Identification of any new needs over the 2015-2025 period and a wires plan to address these needs based on new and/or updated RIP phase information
- Develop a plan to address any longer term needs identified by the Working Group

The IRRP or RIP Working Group did not identify any long term needs at this time. If required, further assessment will be undertaken in the next planning cycle because adequate time is available to plan for required facilities.

1.2 Structure

The rest of the report is organized as the follows:

- Section 2 provides an overview of the regional planning process
- Section 3 describes the region
- Section 4 describes the transmission work completed over the last ten years
- Section 5 describes the load forecast and study assumptions used in this assessment
- Section 6 describes the results of the adequacy assessment of the transmission facilities and identifies the needs
- Section 7 summarizes the Regional Plan to address the needs
- Section 8 provides the conclusions and next steps

2. REGIONAL PLANNING PROCESS

2.1 Overview

Planning for the electricity system in Ontario is done at essentially three levels: bulk system planning, regional system planning, and distribution system planning. These levels differ in the facilities that are considered and the scope of impact on the electricity system. Planning at the bulk system level typically looks at issues that impact the system on a provincial level, while planning at the regional and distribution levels looks at issues on a more regional or localized level.

Regional planning looks at supply and reliability issues at a regional or local area level. Therefore, it largely considers the 115 kV and 230 kV portions of the power system that supply various parts of the province.

2.2 Regional Planning Process

A structured regional planning process was established by the Ontario Energy Board in 2013, through amendments to the Transmission System Code ("TSC") and the Distribution System Code ("DSC"). The process consists of four phases: the Needs Assessment[1] ("NA"), the Scoping Assessment ('SA"), the Integrated Regional Resource Plan ("IRRP"), and the Regional Infrastructure Plan ("RIP").

The regional planning process begins with the NA phase which is led by the transmitter to determine if there are regional needs. The NA phase identifies the needs and the Working Group determines whether further regional coordination is necessary to address them. If no further regional coordination is required, further planning is undertaken by the transmitter and the impacted local distribution company ("LDC") or customer and develops a Local Plan ("LP") to address them. These needs are local in nature and can be best addressed by a straight forward wires solution.

In situations where identified needs require coordination at the regional or sub-regional levels, the IESO initiates the SA phase. During this phase, the IESO, in collaboration with the transmitter and impacted LDCs, reviews the information collected as part of the NA phase, along with additional information on potential non-wires alternatives, and makes a decision on the most appropriate regional planning approach. The approach is either a RIP, which is led by the transmitter, or an IRRP, which is led by the IESO. If more than one sub-region was identified in the NA phase, it is possible that a different approach could be taken for different sub-regions.

The IRRP phase will generally assess infrastructure (wires) versus resource (CDM and Distributed Generation ("DG")) options at a higher or more macro level but sufficient to permit a comparison of options. If the IRRP process identifies that infrastructure options may be most appropriate to meet a need, the RIP phase will conduct detailed planning to identify and assess the specific wires alternatives and recommend the preferred wires solution. Similarly, resource options which the IRRP identifies as best

[1] Also referred to a Needs Screening

suited to meet a need are then further planned in greater detail by the IESO. The IRRP phase also includes IESO led stakeholder engagement with municipalities and establishes a Local Advisory Committee in the region or sub-region.

The RIP phase is the final stage of the regional planning process and involves: confirmation of previously identified needs; identification of any new needs that may have emerged since the start of the planning cycle; and development of a wires plan to address the needs where a wires solution would be the best overall approach. This phase is led and coordinated by the transmitter and the deliverable of this stage is a comprehensive report of a wires plan for the region. Once completed, this report can be referenced in rate filing submissions or as part of LDC rate applications with a planning status letter provided by the transmitter. Reflecting the timeliness provisions of the RIP, plan level stakeholder engagement is not undertaken at this stage. However, stakeholder engagement at a project specific level will be conducted as part of the project approval requirement.

To efficiently manage the regional planning process, Hydro One has been undertaking wires planning activities in collaboration with the IESO and LDCs for the region as part of and/or in parallel with:

- Planning activities that were already underway in the region prior to the new regional planning process taking effect
- The NA, SA, and LP phases of regional planning
- Participating in and conducting wires planning as part of the IRRP for the region or sub-region

Figure 2-1 illustrates the various steps of the regional planning process (NA, SA, IRRP and RIP) and their respective phase trigger, lead, and outcome.

Note that as the KWCG Region was identified as a “transitional” region at the onset of the OEB defined Regional Planning process in 2013, the Needs Assessment and Scoping Assessment phases were deemed complete and the region was placed into the IRRP phase of the process.

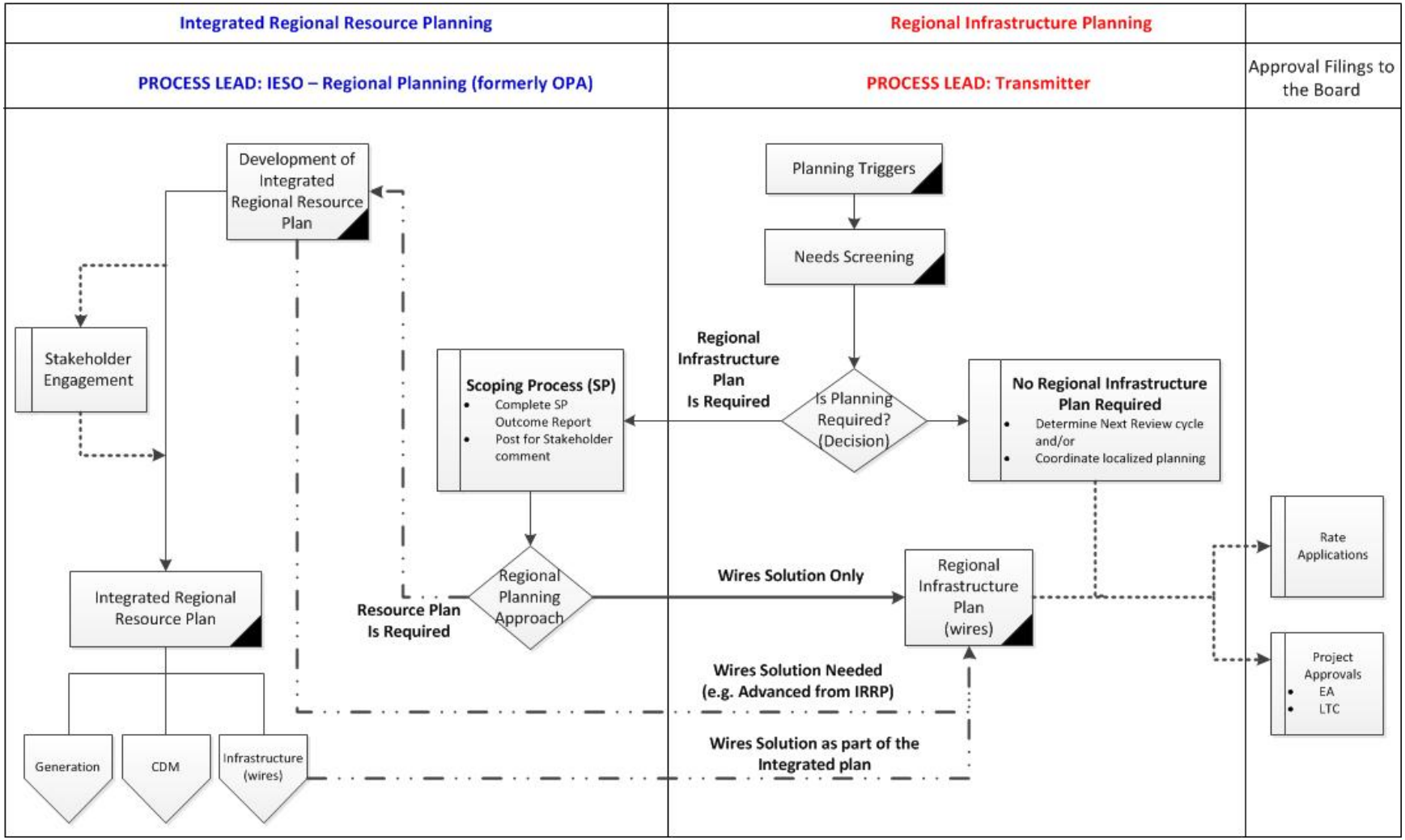


Figure 2-1 Regional Planning Process Flowchart

2.3 RIP Methodology

The RIP phase consists of four steps (see Figure 2-2) as follows:

1) Data Gathering: The first step of the RIP phase is the review of planning assessment data collected in the previous stages of the regional planning process. Hydro One collects this information and reviews it with the Working Group to reconfirm or update the information as required. The data collected includes:
   - Net peak demand forecast at the transformer station level. This includes the effect of any distributed generation or conservation and demand management programs.
   - Existing area network and capabilities including any bulk system power flow assumptions.
   - Other data and assumptions as applicable such as asset conditions; load transfer capabilities, and previously committed transmission and distribution system plans.
2) Technical Assessment: The second step is a technical assessment to review the adequacy of the regional system including any previously identified needs. Additional near and mid-term needs may be identified at this stage.
3) Alternative Development: The third step is the development of wires options to address the needs and to come up with a preferred alternative based on an assessment of technical considerations, feasibility, environmental impact and costs.
4) Implementation Plan: The fourth and last step is the development of the implementation plan for the preferred alternative.

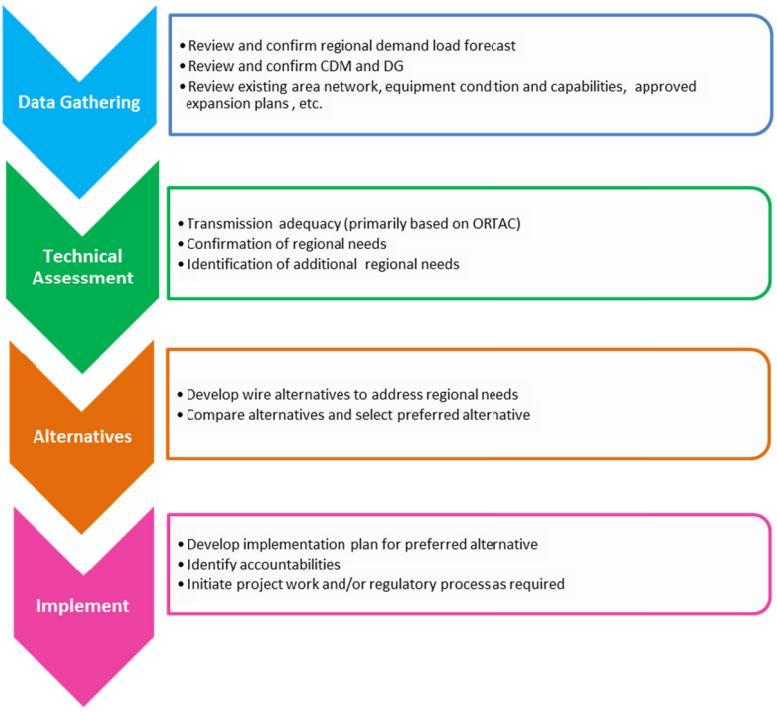


Figure 2-2 RIP Methodology

3. REGIONAL CHARACTERISTICS

THE KWCG REGION COMPRISES OF THE CITIES OF KITCHENER, WATERLOO, CAMBRIDGE AND GUELPH, PORTIONS OF OXFORD AND WELLINGTON COUNTIES AND THE TOWNSHIPS OF NORTH DUMFRIES, PUSLINCH, WOOLWICH, WELLESLEY AND WILMOT AS SHOWN IN FIGURE 3-1.

The main sources of electricity into the KWCG Region are from four Hydro One stations: Middleport TS, Detweiler TS, Orangeville TS and Burlington TS. At these stations electricity is transformed from 500 kV and 230 kV to 230 kV and 115 kV, respectively. Electricity is then delivered to the end users of LDCs and directly-connected industrial customers by 24 step-down transformer stations. Figure 3-2 illustrates these stations as well as the four major regional sub-systems: Waterloo-Guelph 230 kV sub-system, Cambridge-Kitchener 230 kV sub-system, Kitchener-Guelph 115 kV sub-system and South-Central Guelph 115 kV sub-system. Appendix A lists all step-down transformer stations in the KWCG Region, Appendix B lists all transmission circuits in the KWCG Region and Appendix C lists LDCs in the KWCG Region.

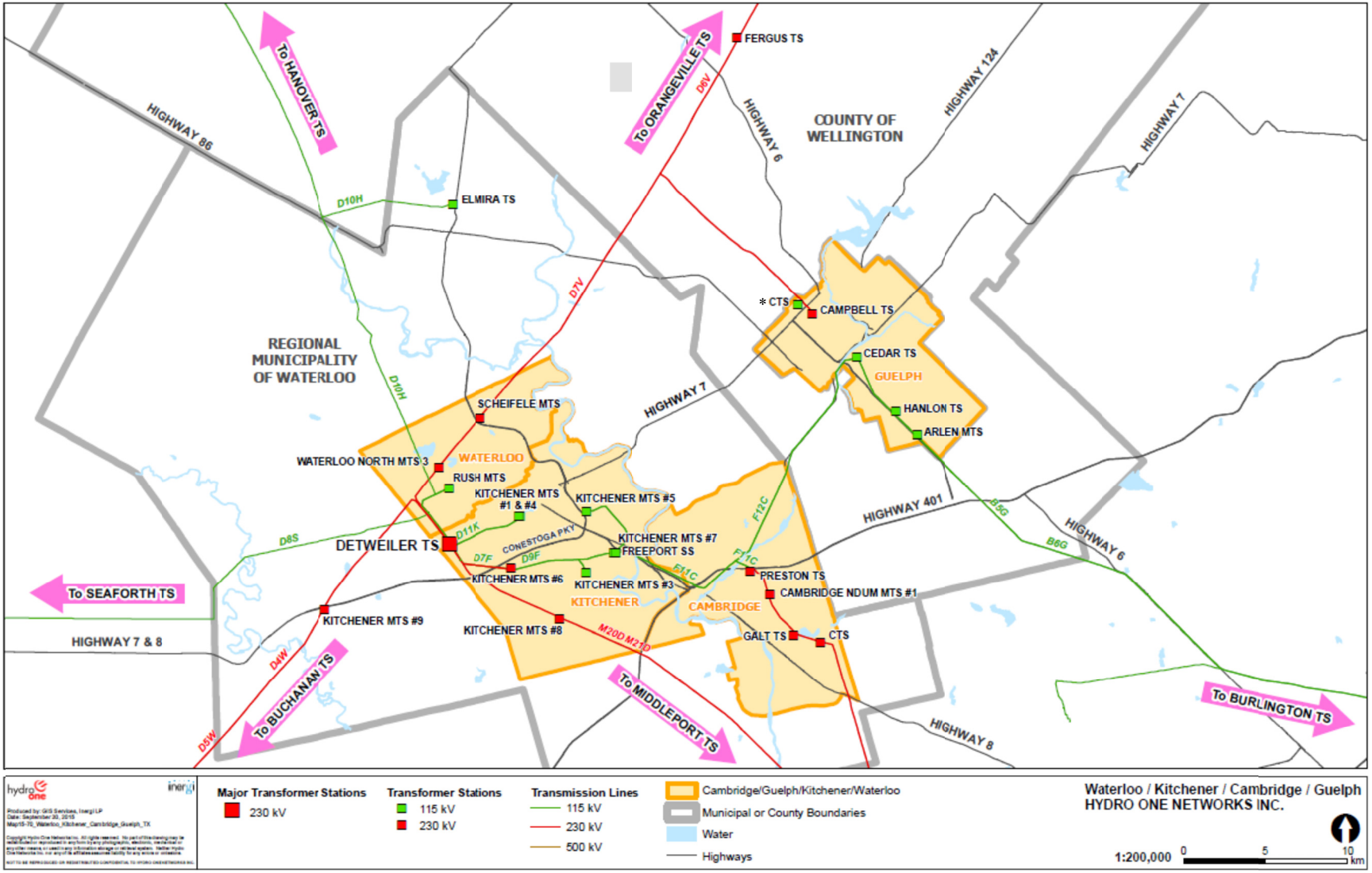


Figure 3-1 Geographical Area of the KWCG Region with Electrical Layout

*CTS relocated to the distribution system as part of the GATR project

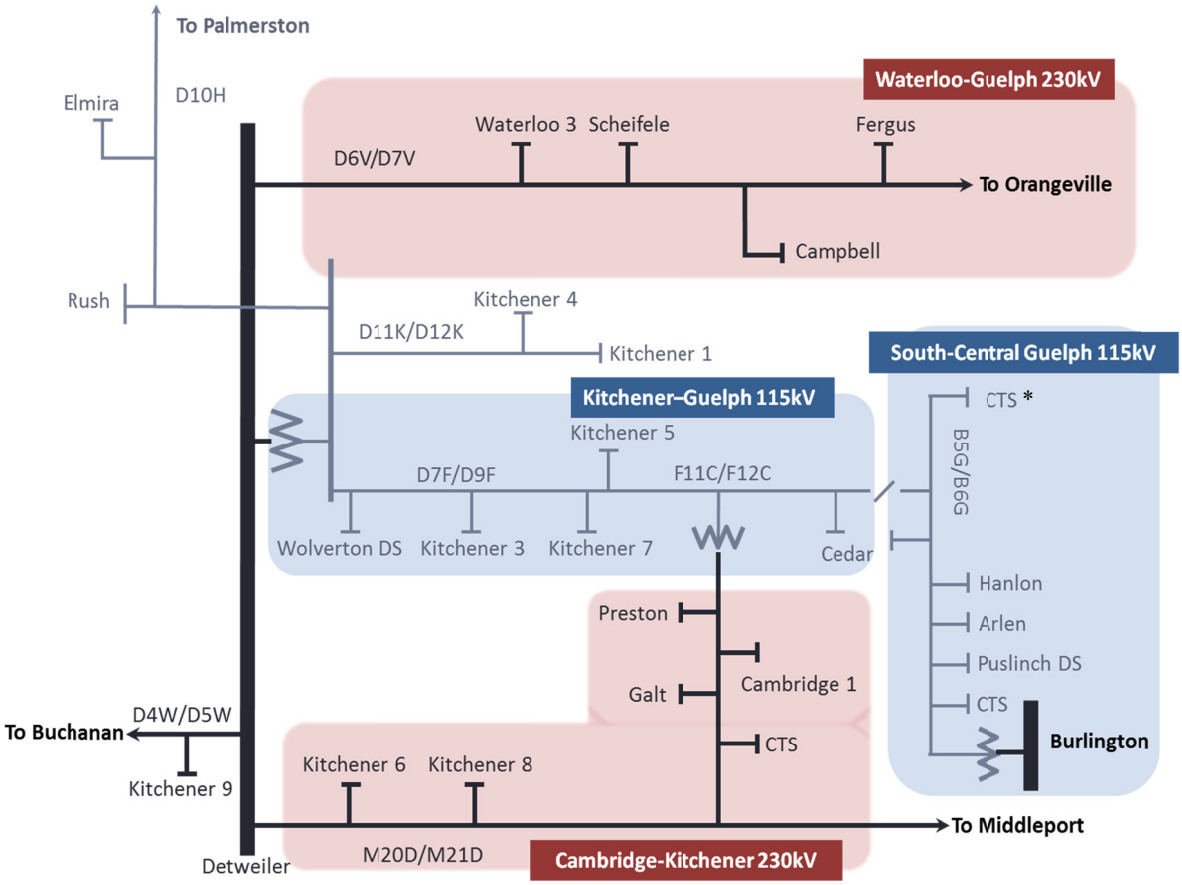


Figure 3-2 KWCG Single Line Diagram

*CTS relocated to the distribution system as part of the GATR project

4. TRANSMISSION FACILITIES COMPLETED OVER LAST TEN YEARS OR CURRENTLY UNDERWAY

OVER THE LAST 10 YEARS A NUMBER OF TRANSMISSION PROJECTS HAVE BEEN COMPLETED BY HYDRO ONE, OR ARE UNDERWAY, AIMED AT IMPROVING THE SUPPLY TO THE KWCG REGION.

These projects were identified as a result of joint planning studies undertaken by Hydro One, IESO and the LDCs; or initiated to meet the needs of the LDCs; and/or to meet Provincial Government policies. A brief listing of the completed projects is given below.

For transmission voltage level transformation capacity needs:

- 250 MVA 230/115 kV autotransformer T4 at Burlington TS replaced in 2006
- 250 MVA 230/115 kV autotransformer T6 at Burlington TS replaced in 2009

For distribution voltage level transformation capacity needs:

- Kitchener MTS#9 connected to replace the Detweiler TS DESN in 2010
- Arlen MTS connected in 2011

For reactive and voltage support needs:

- a 13.8 kV shunt capacitor bank installed at Cedar TS in 2006
- a 230 kV shunt capacitor bank installed at Detweiler TS in 2007
- a 230 kV shunt capacitor bank installed at Orangeville TS in 2008
- a 230 kV shunt capacitor bank installed at Burlington TS in 2010
- a 115 kV shunt capacitor bank installed at Detweiler TS in 2012

For transmission circuit capacity needs:

- M20D/M21D circuit sections capacity increased by sag limit mitigation in 2014

For transmission load security needs:

- Freeport SS installed to sectionalize circuits D7G/D9G (Detweiler TS by Cedar TS) in 2008

For transmission load restoration needs:

- 250 MVA 230/115 kV autotransformer T2 installed at Preston TS in 2007

The following projects are underway:

- Guelph Area Transmission Reinforcement (GATR) project that entails the extension the 230kV circuits D6V/D7V to Cedar TS; the installation of two new 250MVA, 230/115kV

autotransformers at Cedar TS; and the installation of two 230 kV in-line switches onto circuits D6V/D7V at Guelph North Junction. This project reinforces the Kitchener-Guelph and South-Central Guelph 115kV sub-systems as well as improves restoration capability to the Waterloo-Guelph 230 kV sub-system. This project is identified in the IESO KWCG IRRP, reference [1].

- The installation of a 13.8 kV series reactor to mitigate short circuit levels at Arlen MTS. This project was identified in the RIP phase.

- The installation two new 230kV in-line switches onto circuits M20D/M21D near Galt Junction to improve restoration capability in the Cambridge-Kitchener 230 kV sub-system. This project is identified in Hydro One's KWCG Adequacy of Transmission Facilities & Transmission Plan 2016-2025 report, reference [2]/Appendix F as well as reference [1].

5. FORECAST AND OTHER STUDY ASSUMPTIONS

5.1 Load Forecast

The load in the KWCG Region is forecast to increase at an average rate of approximately 1.7% annually between 2015 and 2025. The growth rate varies across the Region with most of the growth concentrated in the cities of Waterloo and Guelph, each at an average rate of 2.5% over the next ten years.

Figure 5-1 shows the KWCG Region's planning load forecast (summer net, regional-coincident extreme weather peak). The regional-coincident (at the same time) forecast represents the total peak load of the 24 step-down transformer stations in the KWCG Region. By 2025 the forecasted coincident regional peak load is approximately 1765 MW.

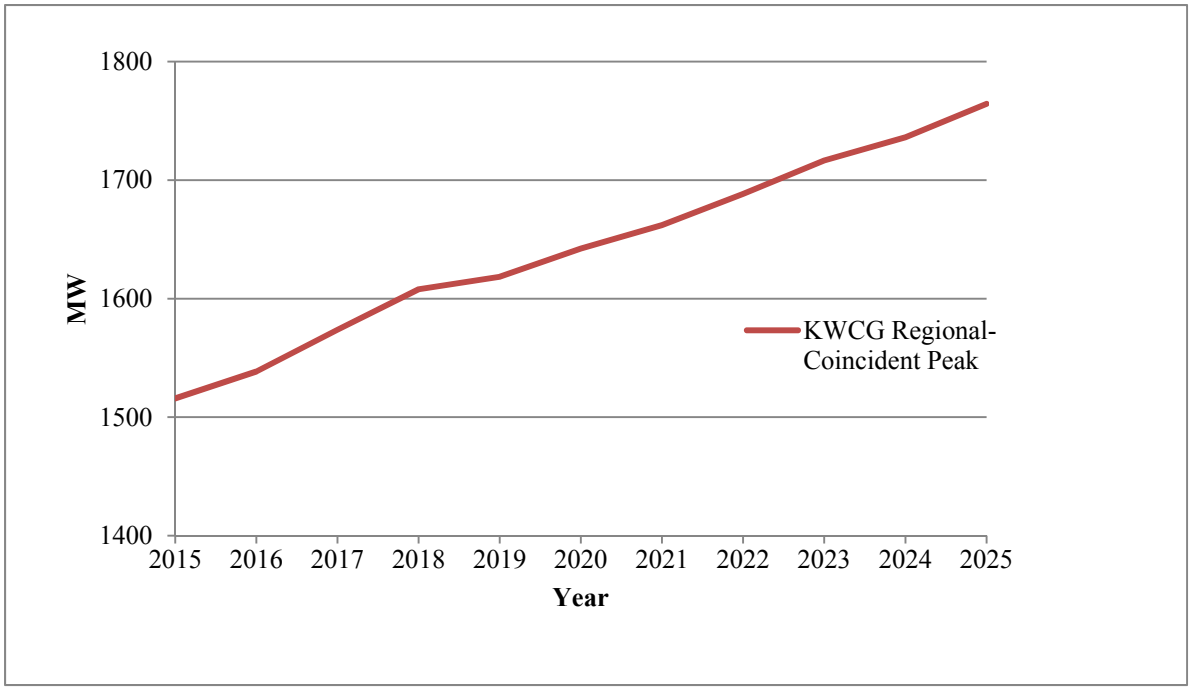


Figure 5-1 KWCG Region's Planning Forecast

The KWCG 2015 RIP planning load forecast is provided in Appendix D and is based upon the KWCG IRRP planning load forecast prepared by the IESO and was reaffirmed by the Working Group upon initiation of the RIP phase. In the IRRP phase, the LDC's provided the IESO with a 10 year gross, normal weather, regional-coincident, peak load forecast in MW. The IESO adjusted the forecast by subtracting the effective CDM capacity, applying an extreme weather factor and then subtracting the effective DG capacity. Further details regarding the CDM and connected DG are provided in reference [1]. The RIP forecast is identical to the IRRP forecast except as otherwise noted in Appendix D.

5.2 Other Study Assumptions

The following other assumptions are made in this report.

1) The Study period for the RIP assessment is 2015-2025.
2) All planned facilities for which work has been initiated and are listed in Section 4 are assumed to be in-service.
3) Summer is the critical period with respect to line and transformer loadings. The assessment is based therefore based on summer peak loads.
4) Station capacity adequacy is assessed by comparing the non-coincident peak load with the station's normal planning supply capacity, assuming a 90% lagging power factor for stations having no low-voltage capacitor banks and 95% lagging power factor for stations having low-voltage capacitor banks.
5) Normal planning supply capacity for Hydro One transformer stations in this Region is determined by the summer 10-Day Limited Time Rating (LTR), while some LDCs use different methodologies for determining transformer station LTR.
6) Adequacy assessment is done as per the Ontario Resource and Transmission Adequacy Criteria ("ORTAC").

6. ADEQUACY OF FACILITIES AND REGIONAL NEEDS OVER THE 2015-2025 PERIOD

THIS SECTION REVIEWS THE ADEQUACY OF THE EXISTING TRANSMISSION SYSTEM AND DELIVERY STATION FACILITIES SUPPLYING THE KWCG REGION AND LISTS THE FACILITIES REQUIRING REINFORCEMENT OVER THE NEAR AND MID-TERM.

Within the current regional planning cycle two regional assessments have been conducted for the KWCG Region. The findings of these studies are input to the RIP. The studies are:

1) IESO's KWCG Integrated Regional Resource Plan – dated April 28, 2015[1]
2) Hydro One's Adequacy of Transmission Facilities and Transmission Plan 2016-2025 – dated April 1, 2015 with revision 1 – dated October 30, 2015[2] (please see Appendix F)

The IRRP identified a number of regional needs to meet the forecast load demand over the near to mid-term. Due to the immediate nature of the needs the Guelph Area Transmission Reinforcement (GATR) project was initiated to provide adequate load supply capability to the KWCG area while the IRRP study was still underway. A detailed description and status of the GATR project and other work initiated or planned to meet these needs is given in Section 7.

This RIP reviewed the loading on transmission lines and stations in the KWCG Region assuming the GATR project is in-service. Sections 6.1-6.4 present the results of this review and Table 6-1 lists the Region's needs identified in both the IRRP and RIP phases.

Table 6-1 Near and Medium Term Regional Needs

Type	Section	Needs	Timing
Needs Identified in the IRRP [1] and the Adequacy Report [2]			
Transmission Circuit Capacity	7.1.1	South-Central Guelph 115 kV sub-system- Capacity of 115kV circuits B5G/B6G	Immediate
	7.1.2	Kitchener–Guelph 115 kV sub-system – Capacity of 115kV circuits D7F/D9F and F11C/F12C	Immediate
Load Restoration	7.1.3	Waterloo-Guelph 230 kV sub-system	Immediate
	7.2.1	Cambridge-Kitchener 230 kV sub-system	Immediate
Step-down Transformation Capacity	7.3.1	Waterloo North Hydro Inc.	2018
Additional Needs identified in RIP Phase			
Station Short Circuit Capability	7.4.1	Arlen MTS: Short Circuit capability	2016

6.1 230 kV Transmission Facilities

All 230 kV transmission circuits in the KWCG Region are classified as part of the Bulk Electricity System ("BES"). They connect the Region to the rest of the Ontario's transmission system and are also part of the transmission path from generation in Southwestern Ontario to the load centers in the Hamilton, Niagara and GTA areas. These circuits also serve local area stations within the Region and the power flow on them depends on the bulk system transfer as well as local area loads. These circuits are as follows (refer to Figure 3-2):

1) Detweiler TS to Orangeville TS 230 kV transmission circuits D6V/D7V – supplies Fergus TS, Campbell TS, Waterloo North MTS#3 and Scheifele MTS
2) Detweiler TS to Middleport TS 230 kV transmission circuits M20D/M21D – supplies Kitchener MTS #6, Kitchener MTS # 8, Cambridge MTS #1, Galt TS, Preston TS and Customer #1 CTS
3) Detweiler TS to Buchanan TS 230 kV transmission circuits D4W/D5W – supplies Kitchener MTS#9.

The RIP review shows that based on current forecast station loadings and bulk transfers, all 230 kV circuits are expected to be adequate over the study period. Refer to section 3.4.2 of Appendix F for the detailed analysis.

6.2 500/230 kV and 230/115 kV Transformation Facilities

Bulk power supply to the KWCG Region is provided by Hydro One's 500 kV to 230 kV and 230 kV to 115 kV autotransformers. The number and location of these autotransformers are as follows:

1) Two 500/230 kV autotransformers at Middleport TS
2) Four 230/115 kV autotransformers at Burlington TS
3) Three 230/115 kV autotransformers at Detweiler TS
4) Two 230/115 kV autotransformers at Cedar TS
5) One 230/115 kV autotransformer at Preston TS

The RIP review shows that based on current forecast station loadings and bulk transfers, the auto-transformation supply capacity is adequate over the study period. Refer to section 3.4.1 of Appendix F for the detailed analysis.

6.3 Supply Capacity of the 115 kV Network

The KWCG Region contains five pairs of double circuit 115 kV lines. This 115 kV network serves local area load. These circuits are as follows (see Figure 3-2):

1) Detweiler TS to Freeport SS 115 kV transmission circuits D7F/D9F – supplies Wolverton DS, Kitchener MTS #3, Kitchener MTS#7
2) Freeport SS to Cedar TS 115 kV transmission circuits F11C/F12C – supplies Kitchener MTS#5 and Cedar T1/T2 transformers
3) Burlington TS to Cedar TS 115 kV transmission circuits B5G/B6G – supplies Puslinch DS, Arlen MTS, Hanlon TS, Customer #2 CTS and Cedar T7/T8 transformers
4) Detweiler TS 115 kV radial transmission circuit D11K/D12K – supplies Kitchener MTS#1 and Kitchener MTS#4
5) Detweiler TS to Seaforth TS/Hanover TS 115 kV transmission circuit D8S/D10H with Normally Open (N/O) points – supplies Rush MTS and Elmira TS

The RIP review shows that based on current forecast station loadings and bulk transfers, the supply capacity of the 115 kV network is adequate over the study period. Refer to section 3.4.3 of Appendix F for the detailed analysis.

6.4 Step-down Transformer Stations

There are 24 step-down transformer stations within the KWCG Region. Twenty-two supply electricity to LDCs and two are transmission-connected industrial customer stations. These stations are listed within the load forecast in Appendix D. Of those 24 stations, 15 of them are owned and operated by the LDCs.

As part of the IRRP, step-down transformation station capacity was reviewed and resulted in the IRRP forecast which was reaffirmed by the Working Group for use in the RIP phase. According to the load forecast, Waterloo North Hydro anticipates requiring additional step-down transformation capacity in 2018.

6.5 Other Items Identified During Regional Planning

6.5.1 Customer Impact Assessment for the GATR project

Based on the Customer Impact Assessment [3] for the GATR project, Guelph Hydro identified the need to mitigate short circuit levels at Arlen MTS in order to ensure the short circuit levels remain within the TSC limits and equipment ratings. The project need date is May 2016 so as to correlate with the completion of the GATR project.

6.5.2 System Impact Assessment for the GATR Project

A System Impact Assessment (“SIA”) [4] was performed for Hydro One’s application to the IESO for the Guelph Area Transmission Reinforcement (GATR) project.

Several findings emanated from the SIA report due to conservative assumptions made for the Bulk Power System. The Working Group has reviewed these findings and recommends that the assumptions be

looked at in greater detail within a Bulk Power System study. If the Bulk Power System study results in regional needs then an early trigger of the next Regional Planning cycle may occur.

6.5.3 Load Restoration to the Cambridge area

The IRRP recommended Hydro One to continue to explore options with Cambridge and North Dumfries Hydro ("CND") to further improve the load restoration capability to the Cambridge area. During the RIP phase Hydro One presented to CND a detailed explanation of its capability to restore power to transformer stations that service the Cambridge area. Based on this discussion, CND and Hydro One have agreed that, at this time, no additional infrastructure is required and the restoration capability afforded by the GATR project and the 230 kV in-line switches at Galt Junction is acceptable for the study period.

6.6 Long-Term Regional Needs

The IRRP examined high-growth and low-growth scenarios to identify long-term needs. Under the high-growth scenario, there is sufficient transmission capacity afforded by the GATR project to meet demand in the long-term; however the need for additional step-down transformation capacity may arise. LDC's to closely monitor their load to determine the timing of potential step-down transformation needs. Under the low-growth scenario, no needs were identified in the long-term.

Consistent with the IRRP, the Working Group did not identify any additional long-term needs during the RIP phase. If new long-term needs were to arise, there is sufficient time to assess them in the next planning cycle which can also be started earlier to make timely investment decisions..

7. REGIONAL PLANS

THIS SECTION DISCUSSES THE ELECTRICAL SUPPLY NEEDS FOR THE KWCG REGION AND SUMMARIZES THE REGIONAL PLANS FOR ADDRESSING THE NEEDS. THESE NEEDS ARE LISTED IN TABLE 6-1 AND INCLUDE NEEDS PREVIOUSLY IDENTIFIED IN THE IRRP AS WELL AS THE NEEDS IDENTIFIED DURING THE RIP PHASE.

7.1 Transmission Circuit Capacity and Load Restoration

7.1.1 South-Central Guelph 115 kV Sub-system

The South-Central Guelph area is supplied by the 115 kV double circuit line B5G/B6G. As per section 6.2.1 of the IRRP, historical peak demand on the B5G/B6G line has already exceeded the 100 MW line Load Meeting Capability ("LMC").

7.1.2 Kitchener-Guelph 115 kV Sub-system

The Kitchener-Guelph area is supplied by two 115 kV double-circuit lines D7F/D9F and F11C/F12C supported by 230/115 kV autotransformers at Detweiler TS and Preston TS. As per section 6.2.1 of the IRRP, the planning forecast peak demand in the Kitchener-Guelph 115 kV sub-system will exceeded the 260 MW line LMC by summer 2014.

7.1.3 Waterloo-Guelph 230 kV Sub-system

As per section 6.2.2 of the IRRP, the transmission infrastructure supplying load in the Waterloo-Guelph 230 kV sub-system does not meet reliability requirements to quickly restore supply in the event of a major outage involving the loss of both transmission circuits, D6V and D7V.

7.1.4 Recommended Plan and Current Status

To address the transmission circuit capacity needs for the South-Central Guelph 115 kV sub-system and the Kitchener-Guelph 115 kV sub-system, the IRRP Working Group recommended reinforcement of the 115 kV transmission system by introducing a new 230 kV – 115 kV injection point. The new injection point is to be located at Cedar TS using two new 230 kV/115 kV autotransformers in conjunction with a 5 km extension of the existing 230 kV double-circuit transmission line, D6V/D7V from Campbell TS to Cedar TS. This reinforcement is covered under the GATR project.

To address the load restoration need of the Waterloo-Guelph 230 kV sub-system, the IRRP Working Group's preferred alternative is to install two new 230 kV in-line switches near Guelph North Junction. The switches will enable Hydro One to quickly isolate a problem and allow the resupply of load to occur expeditiously. This work is also covered under the GATR project.

Current Status of the GATR Project

Hydro One initiated construction on the GATR project in fall 2013 following the OEB approval in September 2013. The project has three components:

- Campbell TS x Cedar TS: Extend the 230 kV D6V/D7V tap from Campbell TS to Cedar TS. This requires replacing approximately a 5 km section of the existing 115 kV double circuit transmission section between CGE Junction and Campbell TS with a new 230 kV double circuit transmission line,
- Cedar TS: Install two new 230/115 kV autotransformers and associated 115 kV switching facilities at Cedar TS. Connect 115 kV switching facilities to the existing B5G/B6G line and the F11C/F12C at Cedar TS.
- Guelph North Junction: Install two in-line 230 kV switches at Guelph North Jct.

This investment will provide for sufficient 230/115 kV autotransformation capacity beyond the study period. The current in-service date of the project is May 2016.

The cost of this project is approximately $95 million. The project is a transmission pool investment as the autotransformers provide supply to all customers in the Region.

7.2 Load Restoration

7.2.1 Cambridge-Kitchener 230 kV Sub-system

As per section 6.2.2 of the IRRP and the section 3.4.8 of the Adequacy of Transmission Facilities report, transmission infrastructure supplying load in the Cambridge-Kitchener 230 kV sub-system does not meet reliability requirements to quickly restore supply in the event of a major outage involving the loss of both transmission circuits, M20D and M21D.

7.2.2 Recommended Plan and Current Status

To address the load restoration need of the Cambridge-Kitchener 230 kV sub-system, the IRRP Working Group's preferred alternative is to install two new 230 kV in-line switches on the M20D/M21D line near Galt Junction. The switches will enable Hydro One to quickly isolate a problem and allow the resupply of load to occur expeditiously. This work is covered under the M20D/M21D Install 230 kV In-line Switches project.

Current Status of the 230 kV In-Line Switches near Galt Junction

Hydro One has established a project to install the two 230 kV in-line switches onto the M20D/M21D double circuit line. One set of switches to be installed onto each circuit. One set of switches to be installed north of the Junction while the other to be installed south of Galt Junction. The switches will enable

Hydro One to quickly isolate a problem on either side of the junction and initiate the restoration of load to the Cambridge-Kitchener 230 kV sub-system.

The project is currently in the detailed design and estimation phase which also includes real estate negotiations. The cost of this project is approximately $6 million and it will be a transmission pool investment. The planned in-service date is May 2017.

7.3 Step-down Transformation Capacity

7.3.1 Waterloo North Hydro

The RIP/IRRP planning load forecast indicates that additional step-down transformation capacity is required by 2018, specifically Waterloo North Hydro's MTS #4.

7.3.2 Recommended Plan and Current Status

To address step-down transformation capacity needs of Waterloo North Hydro, Waterloo North Hydro will, wherever possible, manage load growth by maximizing the utilization of existing stations by increasing distribution load transfer capability between those stations and will continue to explore opportunities for CDM and DG. In addition Waterloo North Hydro will also explore, with other LDCs, opportunities to coordinate possible joint use and development of step-down transformer stations in the Region over the long term. With this in mind, additional step-down transformation capacity is not anticipated prior to 2024. This need will be reviewed in the next cycle of regional planning.

7.4 Station Short Circuit Capability

7.4.1 Arlen MTS

Arlen MTS is a 115/13.8 kV step-down transformer station owned by Guelph Hydro. As a result of the new 230/115 kV injection point afforded by the GATR project, the short circuit levels at Arlen MTS's 13.8 kV bus will exceed the TSC limit and equipment capability.

7.4.2 Recommended Plan and Current Status

To address the station short circuit capability need at Arlen MTS, Guelph Hydro will install series reactors to bring station short circuit levels within TSC limits and within equipment ratings.

Current Status of Short Circuit Mitigation

Guelph Hydro has initiated a project to install series reactors to bring station short circuit levels within TSC limits and equipment ratings. The cost of this project is $0.95 million and the expected completion date is May 2016 so as to correlate with the completion of the GATR project.

8. CONCLUSIONS

THIS REGIONAL INFRASTRUCTURE PLAN REPORT CONCLUDES THE REGIONAL PLANNING PROCESS FOR THE KWCG REGION. THIS REPORT MEETS THE INTENT OF THE PROCESS DESCRIBED IN SECTION 2 WHICH IS ENDORSED BY THE OEB AND MANDATED IN THE TSC AND DSC.

Six near and mid-term needs were identified for the KWCG Region. They are:

I. Transmission capacity in the South-Central Guelph 115 kV sub-system
II. Transmission capacity in the Kitchener-Guelph 115 kV sub-system
III. Load restoration capability in the Waterloo-Guelph 230 kV sub-system
IV. Load restoration capability in the Cambridge-Kitchener 230 kV sub-system
V. Step-down transformation capacity for Waterloo North Hydro
VI. Station Short Circuit Capacity at Arlen MTS

This RIP report addresses all six of these needs. Next Steps, Lead Responsibility, and Timeframes for implementing the wires solutions for the near and mid-term needs are summarized in the Table 8-1 below.

Table 8-1 Regional Plans – Next Steps, Lead Responsibility and Plan In-Service Dates

No.	Project	Next Steps	Lead Responsibility	I/S Date	Cost	Needs Mitigated
1	Guelph Area Transmission Reinforcement	Construction in the final stages	Hydro One	May 2016	$95M	I, II, III
2	Mitigate Short Circuit Levels at Arlen MTS	Construction underway	Guelph Hydro	May 2016	$0.95M	VI
3	M20D/M21D – Install 230 kV In-line Switches	Transmitter to carry out this work	Hydro One	May 2017	$6M	IV
4	Waterloo North Hydro: MTS #4	LDC to monitor growth	Waterloo North Hydro	2024	TBD	V

In accordance with the Regional Planning process, the Regional Plan should be reviewed and/or updated at least every five years. The region will continue to be monitored and should there be a need that emerges due to a change in load forecast or any other reason, the next regional planning cycle will be started earlier to address the need.

9. REFERENCES

[1] Independent Electricity System Operator, Kitchener-Waterloo-Cambridge-Guelph Region Integrated Region Resource Plan, 28 April 2015. http://www.ieso.ca/Documents/Regional-Planning/KWCG/2015-KWCG-IRRP-Report.pdf

[2] Hydro One Networks Inc., Kitchener-Waterloo-Cambridge-Guelph Area – Adequacy of Transmission Facilities and Transmission Plan 2016-2025, 1 April 2015, revised 30 October 2015.

[3] Hydro One Networks Inc., Customer Impact Assessment Guelph Area Transmission Refurbishment Project, 28 May 2013,

[4] Independent Electricity System Operator, System Impact Assessment, CAA ID: 2012-478, Project: Guelph Area Transmission Refurbishment, 17 May 2013. http://www.ieso.ca/Documents/caa/CAA_2012-478_GATR_Final_Report.pdf

Appendix A. Step-Down Transformer Stations in the KWCG Region

Station	Voltage (kV)	Supply Circuits
Waterloo-Guelph 230 kV sub-system		
Fergus TS	230 kV	D6V/D7V
Scheifele MTS	230 kV	D6V/D7V
Waterloo North MTS #3	230 kV	D6V/D7V
Campbell TS	230 kV	D6V/D7V
Cambridge-Kitchener 230 kV sub-system		
Kitchener MTS #6	230 kV	M20D/M21D
Kitchener MTS #8	230 kV	M20D/M21D
Cambridge MTS #1	230 kV	M20D/M21D
Preston TS	230 kV	M20D/M21D
Galt TS	230 kV	M20D/M21D
Customer #1 CTS	230 kV	M21D
Kitchener–Guelph 115 kV sub-system		
Wolverton DS	115 kV	D7F/D9F
Kitchener MTS #3	115 kV	D7F/D9F
Kitchener MTS #7	115 kV	D7F/D9F
Kitchener MTS #5	115 kV	F11C/F12C
Cedar TS (T1/T2)	115 kV	F11C/F12C
South-Central Guelph 115 kV sub-system		
Puslinch DS	115 kV	B5G/B6G
Arlen MTS	115 kV	B5G/B6G
Hanlon TS	115 kV	B5G/B6G
Cedar TS (T8/T7)	115 kV	B5G/B6G
Customer #2 CTS	115 kV	B5G
Other Stations in the KWCG Region		
Kitchener MTS #9	230 kV	D4W/D5W
Rush MTS	115 kV	D8S/D10H
Elmira TS	115 kV	D10H
Kitchener MTS #1	115 kV	D11K/D12K
Kitchener MTS #4	115 kV	D11K/D12K

Appendix B. Transmission Lines in the KWCG Region

Location	Circuit Designations	Voltage (kV)
Detweiler TS – Orangeville TS	D6V/D7V	230 kV
Detweiler TS - Middleport TS	M20D/M21D	230 kV
Detweiler TS - Buchanan TS	D4W/D5W	230 kV
Detweiler TS - Freeport SS	D7F/D9F	115 kV
Freeport SS - Cedar TS	F11C/F12C	115 kV
Burlington TS - Cedar TS	B5G/B6G	115 kV
Detweiler TS – Kitchener MTS #4	D11K/D12K	115 kV
Detweiler TS – Palmerston TS	D10H	115 kV
Detweiler TS – Seaforth TS	D8S	115 kV

Appendix C. Distributors in the KWCG Region

Distributor Name	Station Name	Connection Type
Cambridge and North Dumfries Hydro Inc.	Cambridge NDum MTS#1	Tx
	Galt TS	Tx
	Preston TS	Tx
	Wolverton DS	Dx
Centre Wellington Hydro Ltd.	Fergus TS	Dx
Guelph Hydro Electric System - Rockwood Division	Fergus TS	Dx
Guelph Hydro Electric Systems Inc.	Arlen MTS	Tx
	Campbell TS	Tx
	Cedar TS	Tx
	Hanlon TS	Tx
Halton Hills Hydro Inc.	Fergus TS	Dx
Hydro One Networks Inc.	Fergus TS	Tx
	Elmira TS	Tx
	Puslinch DS	Tx
	Wolverton DS	Tx
	Galt TS	Dx
Kitchener-Wilmot Hydro Inc.	Kitchener MTS#1	Tx
	Kitchener MTS#3	Tx
	Kitchener MTS#4	Tx
	Kitchener MTS#5	Tx
	Kitchener MTS#6	Tx
	Kitchener MTS#7	Tx
	Kitchener MTS#8	Tx
	Kitchener MTS#9	Tx
Milton Hydro Distribution Inc.	Fergus TS	Dx
Waterloo North Hydro Inc.	Elmira TS	Dx
		Tx
	Fergus TS	Dx
	Rush MTS	Tx
	Scheifele MTS	Tx
	Waterloo North MTS #3	Tx
	Preston TS	Dx
	Kitchener MTS#9	Dx
Wellington North Power Inc.	Fergus TS	Dx

Appendix D. KWCG Regional Load Forecast (2015-2025)

Table D-1 RIP Planning Demand Forecast (MW)

Station	LDC	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Cambridge MTS #1	Cambridge & North Dumfries Hydro	92.3	93.8	95.6	98.1	99.7	102.7	101.8	102.1	102.4	102.2	101.6
Galt TS	Cambridge & North Dumfries Hydro	108.1	109.5	112.3	113.7	116.1	119.0	122.8	127.9	134.8	141.9	148.8
Preston TS (1)	Cambridge & North Dumfries Hydro	108.0	100.3	102.0	104.4	105.9	108.7	109.6	111.8	111.9	111.5	111.8
Kitchener MTS #6	Kitchener-Wilmot Hydro	72.8	72.8	73.0	73.0	72.4	72.1	71.7	71.6	71.5	71.1	71.1
Kitchener MTS #8	Kitchener-Wilmot Hydro	44.2	37.6	40.3	43.1	45.3	38.6	41.1	43.5	46.0	48.2	50.6
Kitchener MTS #3	Kitchener-Wilmot Hydro	54.3	64.4	66.5	67.3	67.5	77.0	77.5	78.1	78.7	79.0	79.6
Kitchener MTS #7	Kitchener-Wilmot Hydro	44.9	45.1	45.9	46.0	45.6	45.6	45.6	45.7	39.9	39.8	39.9
Wolverton DS	Hydro One Distribution	21.2	21.4	21.6	21.6	21.6	21.6	21.6	21.7	21.8	21.7	21.9
Cedar TS T1/T2	Guelph Hydro	72.3	74.9	75.8	77.4	78.3	79.5	79.8	82.2	84.6	85.5	87.9
Cambridge MTS # 2 (2)	Cambridge & North Dumfries Hydro	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Kitchener MTS #5	Kitchener-Wilmot Hydro	73.9	73.8	74.6	74.5	73.8	73.5	73.2	73.1	78.8	78.3	78.2
Cedar TS T7/T8	Guelph Hydro	30.2	32.0	32.0	32.8	32.3	33.0	33.7	33.4	34.2	34.8	35.5
Hanlon TS	Guelph Hydro	29.8	30.7	31.6	32.5	33.0	33.7	34.4	35.1	34.9	35.5	35.3
Puslinch DS	Hydro One Distribution	35.6	36.2	36.8	37.3	37.5	37.9	38.3	38.7	39.2	39.5	39.9
Arlen MTS	Guelph Hydro	30.0	33.0	37.0	40.9	33.3	37.9	41.4	43.0	44.6	45.9	47.5
Campbell TS	Guelph Hydro	131.9	136.3	139.0	140.2	141.2	142.8	144.4	148.4	152.2	156.2	160.1
Scheifele MTS	Waterloo North Hydro	169.0	166.0	170.7	150.3	151.2	152.7	154.3	156.2	158.1	153.4	155.4
Waterloo North MTS #3	Waterloo North Hydro	61.9	70.8	72.7	75.3	79.3	64.6	58.0	75.3	76.8	76.9	78.4
MTS #4(2)	Waterloo North Hydro	0.0	0.0	0.0	30.6	35.2	50.9	60.3	61.9	64.4	65.6	68.1
Fergus TS	Hydro One Distribution	108.9	108.8	109.5	109.7	108.5	108.3	108.2	108.5	108.7	108.3	108.7
Kitchener MTS #1	Kitchener-Wilmot Hydro	29.1	29.6	31.1	31.6	31.8	32.1	32.4	32.9	33.3	33.5	33.9
Kitchener MTS #4	Kitchener-Wilmot Hydro	67.8	68.2	69.1	69.3	69.0	69.0	68.9	69.2	69.3	69.1	69.3
Kitchener MTS #9	Kitchener-Wilmot Hydro	33.7	33.9	34.3	34.6	34.5	34.7	34.9	35.0	35.3	35.4	35.5
Elmira TS (3)	Waterloo North Hydro/ Hydro One Distribution	38.0	32.6	33.5	33.3	34.8	35.4	36.0	36.8	38.4	39.0	40.6
Rush MTS	Waterloo North Hydro	54.9	63.8	65.7	67.4	67.4	67.8	69.1	53.0	53.6	60.7	61.3
Customer #1 CTS (4)	Customer Station	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5
Customer #2 CTS	Customer Station (Assumed Values)	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0

Table D1 -is based upon KWCG 2015 IRRP Planning Load Forecast except as noted.

(1) Cambridge and North Dumfries Hydro (“CND”) has confirmed 9.2 MW of cogeneration at a large customer to be accounted for in the Preston TS forecast starting year 2016. The generation plant is expected to run most of the time and would offset the customer's load. This cogeneration was not factored into the KWCG 2015 IRRP Planning Load Forecast.

(2) Both CND and Waterloo North Hydro (“WNH”) are monitoring the load closely to determine the timing of potential transformation needs. For planning purposes, WNH has moved back the in service date of MTS #4 from 2018 to 2024. WNH is closely monitoring the need for additional transformation capacity to determine if the load growth indicated at MTS #4 in the forecast can be managed through a combination of improving transformer station interties, CDM and DG in the Waterloo Region. Where possible, these LDCs are exploring opportunities to coordinate possible joint use and development of step-down transformer station facilities in the KWCG Region over the long term.

(3) Updated to include Hydro One Distribution load

(4) Based on information provided by the transmission-connected customer

Appendix E. List of Acronyms

Acronym	Description
A	Ampere
BES	Bulk Electric System
BPS	Bulk Power System
CDM	Conservation and Demand Management
CIA	Customer Impact Assessment
CGS	Customer Generating Station
CTS	Customer Transformer Station
DESN	Dual Element Spot Network
DG	Distributed Generation
DSC	Distribution System Code
GS	Generating Station
GTA	Greater Toronto Area
HV	High Voltage
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	Kilovolt
LDC	Local Distribution Company
LP	Local Plan
LTE	Long Term Emergency
LTR	Limited Time Rating
LV	Low Voltage
MTS	Municipal Transformer Station
MW	Megawatt
MVA	Mega Volt-Ampere
MVAR	Mega Volt-Ampere Reactive
NA	Needs Assessment
NERC	North American Electric Reliability Corporation
NGS	Nuclear Generating Station
NPCC	Northeast Power Coordinating Council Inc.
NUG	Non-Utility Generator
OEB	Ontario Energy Board
OPA	Ontario Power Authority
ORTAC	Ontario Resource and Transmission Assessment Criteria
PF	Power Factor
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Plan
ROW	Right-of-Way
SA	Scoping Assessment
SIA	System Impact Assessment
SPS	Special Protection Scheme
SS	Switching Station
TS	Transformer Station
TSC	Transmission System Code
UFLS	Under Frequency Load Shedding
ULTC	Under Load Tap Changer
UVLS	Under Voltage Load Rejection Scheme

Appendix F. KWCG Adequacy of Transmission Facilities and Transmission Plan 2016-2025

Revision 1

KITCHENER/WATERLOO/CAMBRIDGE/GUELPH AREA

ADEQUACY OF TRANSMISSION FACILITIES

AND

TRANSMISSION PLAN 2016 – 2025

October 30, 2015

Prepared by Hydro One Networks Inc. in Consultation with the KWCG Working Group

Foreword

This report is the result of a joint study by KWCG Working Group. It has been prepared by Hydro One Networks in consultation with the Working Group.

The working group members were:

Entity	Member
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Waterloo North Hydro Inc.	Herbert Haller David Wilkinson Dorothy Moryc
Cambridge & North Dumfries Hydro	Ron Sinclair Shawn Jackson
Guelph Hydro Electric System Inc.	Michael Wittemund K. Marouf Eric Veneman
Hydro One Distribution	Charlie Lee
Ontario Power Authority	Bob Chow Bernice Chan
Independent Electricity Operator	Peter Drury
Hydro One Networks Inc.	Alessia Dawes Farooq Qureshy Emeka Okongwu Qasim Raza

The preferred plan has been selected based on technical and economic considerations. The issue of cost allocation between utilities was not addressed.

Prepared by: Qasim Raza – Transmission Planning Officer

Reviewed by: Alessia Dawes – Senior Transmission Planning Engineer

Approved by: Farooq Qureshy – Manager, Transmission System Development, Central & East

October 30, 2015

Revision History

Revision	Date	Author	Description of change
1	October 30, 2015	Qasim Raza	Refreshed based on 2015 IRRP/RIP load forecast (April/August2015)
0	April 1, 2015	Alessia Dawes	Original- based on May 2013 forecast

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EXECUTIVE SUMMARY

In 2010 an integrated regional planning study was initiated to assess the electricity supply and reliability over a twenty year period for the Kitchener-Waterloo-Cambridge-Guelph (KWCG) areas and continues to be conducted by a Working Group led by the Ontario Power Authority (OPA) and includes staff from the Independent Electricity System Operator (IESO), Hydro One Networks Inc., Kitchener-Wilmot Hydro, Waterloo North Hydro, Cambridge & North Dumfries Hydro, Guelph Hydro Electric Systems Inc. and Hydro One Distribution.

The early results of the integrated regional planning study identified the need to reinforce supply capacity for the South-Central Guelph and the City of Cambridge over the near and medium term. It also identified the need to minimize the impact of double circuit interruptions in the area[1]. As a result, the Working Group recommended two transmission projects in conjunction with conservation and distributed generation:

1. The Guelph Area Transmission Reinforcement (GATR) project – comprising a new 230/115kV autotransformer station at Guelph Cedar TS, upgrading the circuit section between Campbell TS and CGE Junction to 230 kV and in-line switching on the Orangeville TS x Detweiler TS 230kV circuits D6V/D7V – to reinforce supply to South Central Guelph,
2. The Preston TS Autotransformer Project – comprising the installation of a second 230/115kV autotransformer at Preston TS - to reinforce supply to the City of Cambridge.

Work on the GATR project was started in 2014 following approval from the Ontario Energy Board and the Ministry of Environment. The project's planned in-service date is June 2016.

For the Preston project, the OPA issued Hydro One a hand off letter to develop a "Wires" solution to improve the supply to the Cambridge area and to facilitate the connection of a future Cambridge and North Dumfries Hydro transformer station by 2018.

This report presents the results of Hydro One led "Wires" study of the adequacy of supply to the City of Cambridge and the wider KWCG area based on the planned in-service of the GATR project in summer 2016. The main conclusions of the report are as follows:

- The supply capability to the KWCG 115kV area has been significantly increased to meet all 2025 forecast loads by the addition of the GATR project. The need for the Preston autotransformer can be deferred to beyond 2025.
- There is inadequate load restoration capability for load connected to Middleport TS x Detweiler TS 230kV double circuit line M20D and M21D

This report recommends that the most cost effective plan to improve load restoration capability for load connected to circuits M20/21D is to install 230 kV in-line switches onto circuits M20/21D.

[1] OPA Submission to the OEB for the GATR Project – Document EB-2013-0053 dated March 8, 2013 entitled, "Kitchener-Waterloo-Cambridge-Guelph Area

1.0 INTRODUCTION

This transmission adequacy assessment focused on the electrical supply to the municipalities of Kitchener, Waterloo, Cambridge and Guelph and their surrounding areas of Ontario, collectively referred to as the KWCG area in this report. Its primary focus was to confirm the near and mid-term transmission needs for the area and to provide a 10-year transmission plan in order satisfy those Needs.

Geographically, the KWCG area consists of 4 municipalities – Kitchener, Waterloo, Cambridge, Guelph and portions of two counties - Perth and Wellington. Hydro One Networks Inc. is the sole high voltage transmitter in the KWCG area; however the low voltage distribution of electricity in the KWCG area is carried out by Cambridge and North Dumfries Hydro Inc., Guelph Hydro Electric System Inc., Hydro One Distribution, Kitchener-Wilmot Hydro Inc., and Waterloo North Hydro. A geographic map of the area is shown in Appendix A, Map 1 while an electrical map of the area is shown in Appendix A, Map 2.

The KWCG area is a major regional load centre in Ontario. The area has a well-established history in manufacturing and technology. The area peak load is approximately 1400 MW.

This report presents the results of the Hydro One led “Wires” study of the adequacy of supply to the City of Cambridge and the wider KWCG area based on the planned in-service of the GATR project in summer 2016.

2.0 EXISTING TRANSMISSION INFRASTRUCTURE

2.1 TRANSMISSION IN KWCG

Electrical Supply in this area is provided through 230 kV and 115 kV transmission lines and step down transformation facilities (transmission stations, TS) as show in Appendix A, Map 2.

The main sources of electricity into the KWCG Region are Middleport TS, Detweiler TS, Orangeville TS, Cedar TS and Burlington TS. At these stations electricity is transformed from 500 kV and 230 kV to 230 kV and 115 kV, respectively. The KWCG Region transmission system is connected as follows:

- Two 230 kV circuits (D6V/D7V) that run North-East from Detweiler TS to Orangeville TS that supply five load serving stations;
- Two 230 kV circuits (M20/21D) that run South-East from Detweiler TS to Middleport TS that supply five load serving stations and one transmission-connected customer;
- Two 230 kV circuits (D4W/D5W) that run South-West from Detweiler TS to Buchanan TS (in the "London area") that supply one load serving station;
- Four 115 kV circuits (D7F/D9F, F11C/F12C) that run East-West: D7/9F from Detweiler TS to Freeport SS that supply three load serving stations and F11/12C from Freeport SS to Cedar TS that supply one load serving station;
- Two 115 kV circuits (B5G/B6G) that run North-West from Burlington TS to Cedar TS that supply three load serving stations and one transmission-connect customer;
- Two 115 kV radial circuits (D11K/D12K) emanating East from Detweiler TS that supply two load serving stations; and,
- Two 115 kV circuit (D8S and D10H) emanating North from Detweiler TS that supply two load serving stations in the KWCG area.

Voltage support is provided in the area by:

- Four high voltage shunt capacitor banks and one SVC at Detweiler TS
- Four high voltage shunt capacitor banks at Middleport TS
- Three high voltage shunt capacitor banks at Burlington TS
- One high voltage shunt capacitor bank at Orangeville TS
- 43.2 MVar low voltage station shunt capacitor at Galt TS
- 21.6 MVar low voltage station shunt capacitors at Campbell TS
- 59.81 MVar low voltage station shunt capacitors at Cedar TS
- 9.92 MVar low voltage station shunt capacitors at Elmira TS
- Low voltage feeder shunt capacitors were lumped at: C&ND MTS#1, Waterloo North Hydro MTS #3, Scheifele MTS

All stations in the KWCG Region were considered in the analysis to determine the adequacy of the existing transmission system. Transformation capacity at individual load serving stations was previously analyzed by the OPA as part of the Integrated Regional Resource Plan (IRRP). The result of that analysis was a load forecast that included proposed new stations, as shown in Appendix C. Therefore, transformation capacity at individual load serving stations was not considered in this study.

2.2 TRANSMISSION-CONNECTED GENERATION

There are no existing large-scale transmission-connected generation plants in the KWCG area; however two contracted renewable transmission-connected wind farms were included in the study area and are listed in Appendix B.

3.0 ADEQUACY OF EXISTING TRANSMISSION INFRASTRUCTURE IN KWCG AREA

3.1 STUDY ASSUMPTIONS

Assumptions were made in order to assess the effects of contingencies to verify the adequacy of the transmission system. The assumptions used in the study were:

1. A 10 year load forecast: years 2016 to 2025; shown in Appendix C
2. Forecasted loads were provided by the LDC's in MW. The MVAR portion of the load was set to 40% of the MW load which is a reasonable assumption to achieve a power factor of 0.9 at the defined meter point of load serving transformer stations (TS, CTS, MTS)
3. A summer assessment was performed as the KWCG area is summer load peaking while the equipment is at its lowest rating during summer ambient conditions. This was deemed to be the most conservative approach;
4. Equipment continuous and Limited Time Ratings (LTR) were based on an ambient temperature of 35°C for summer and a wind speed of 4 km/hour;
5. The Guelph Area Transmission Reinforcement (GATR) project would be in-service in June 2016;
6. Circuits M20D and M21D are assigned their updated long-term emergency rating (LTE) based on a maximum temperature of 127°C;
7. Simulation of year 2025 load forecast was performed as it was the maximum loading of the area for the duration of the study period; year 2016 was simulated as necessary;
8. Waterloo North Hydro's Snider MTS #4 (MTS #4) will connect to 230 kV circuit D6/7V between Scheifele MTS and Guelph North Jct., projected in-service date 2024 (refer to Note 2 in Appendix C, Table C1)
9. The flows on Ontario's major internal transmission interfaces were assumed as follows:
    - FETT ~ 4500 MW
    - FS ~1250 MW
    - FABCW ~ 5800MW
    - NBLIP ~ 1650 MW (the slightly high NBLIP was offset by the lower FABCW)
    - QFW ~ 1550 MW

3.2 STUDY CRITERIA

The adequacy of the transmission system is assessed as per the IESO Ontario Resource and Transmission Assessment Criteria, Issue 5.0.

3.3 LOAD FORECAST

The load forecast used in this assessment is the KWCG 2015 RIP forecast as shown in Appendix C. This summer forecast is an extreme weather, area coincident, net, peak load forecast.

The KWCG 2015 RIP forecast is based upon the KWCG 2015 IRRP forecast. The LDC's provided the IESO with a 20 year gross, normal weather, area coincident, peak load forecast in MW. The IESO adjusted the forecast by subtracting the effective conservation and demand management (CDM) capacity, applying an extreme weather factor and then subtracting the effective Distribution Generation (DG) capacity.

3.4 SUPPLY CAPACITY NEEDS

Single element contingencies were considered in assessing the adequacy and reliability of the local transmission system that serves the KWCG area. Figure 1 summarizes the local KWCG area Needs for the 10-year period under study. Appendices D, F and G detail the technical study and results.

At stations, within the KWCG area, classified as NPCC Bulk Power System (BPS) additional contingencies were considered to establish their impact to the local KWCG area. Appendix E details the technical study and results.

3.4.1 AUTO-TRANSFORMATION SUPPLY CAPACITY

There is no major generation station in the KWCG area. Hence, the majority of supply to the load is provided by Hydro One's 500 kV to 230 kV and 230 kV to 115 kV auto-transformers. The number and location of these auto-transformers are as follows:

- Two 500/230 kV autotransformers at Middleport TS
- Four 230/115 kV autotransformers at Burlington TS[2]
- Three 230/115 kV autotransformers at Detweiler TS
- Two 230/115 kV autotransformers at Cedar TS
- One 230/115 kV autotransformer at Preston TS

Single autotransformer contingencies were performed to assess the adequacy of the transmission system to supply bulk power into the KWCG area via the autotransformers for year 2025 loading.

The results indicate that there are no thermal overloads and no voltage violations for the loss of a single autotransformer.

[2] The loading of the autotransformers at Burlington TS is mainly driven by the load connected in the Burlington to Nanticoke area. Only a small percentage of the autotransformer load is due to local Guelph load and as such, analysis of the Burlington TS autotransformers was undertaken in the 'Burlington to Nanticoke' Regional Infrastructure Plan.

3.4.2 SUPPLY CAPACITY OF THE 230 KV NETWORK

The KWCG area contains three pairs of double circuit 230 kV lines: M20D/M21D, D6V/D7V and D4W/D5W.

Single circuit contingencies were performed to assess the adequacy of the local 230 kV transmission system for year 2025 loading[3].

As indicated in Appendix D there are no thermal overloads and no voltage violations for the loss of a single 230 kV circuit.

3.4.3 SUPPLY CAPACITY OF THE 115 KV NETWORK

The KWCG area contains five pairs of double circuit 115 kV lines: D7F/D9F, F11C/F12C, B5G/B6G, D11K/D12K and D8S/D10H.

Single circuit contingencies were performed to assess the adequacy of the local 115 kV transmission system for year 2025 loading.

As indicated in Appendix D there are no thermal overloads and no voltage violations for the loss of a single 115 kV circuit. Appendix H details supply capacity on circuit D8S and D10H as request by the LDC.

3.4.4 VOLTAGE PERFORMANCE

Single circuit contingencies as well as single element HV shunt capacitor bank contingencies were performed to determine the overall voltage performance of the KWCG area for year 2025 loading.

As indicated in Appendix D there are no thermal overloads and no voltage violations for these contingencies. Appendix H details voltage performance at Elmira TS and Rush MTS as request by the LDC.

3.4.5 LOAD SECURITY ANALYSIS

The most stringent load security criterion that applies to the KWCG area states that with any two elements out of service:

- Voltage must be within applicable emergency ratings and equipment loading must be within applicable short-term emergency ratings;
- Load transfers to meet the applicable long-term emergency ratings must be able to be made in the time afforded by short-time ratings;
- Planned load curtailment or load rejection in excess of 150 MW is not permissible (except for local generation outages) and;

[3] Note, if another element such as an autotransformer, circuit or capacitor bank shared the same “switching position” and/or zone of protection with the circuit under contingency, both were removed from service.

- Not more than 600 MW of load may be interrupted by configuration and by planned load curtailment or load rejection excluding voluntary demand management with any two transmission elements out of service.

There are three pairs of 230 kV double circuit lines and five pairs of 115 kV double circuit lines in the KWCG area. While one circuit of a double circuit line is out of service, the loss of the companion circuit in the pair would result in the loss of all load stations connected to the pair by configuration. Tables F1 and F2 in Appendix F illustrate the load lost due to configuration in both years 2016 and 2025.

There are five stations in the KWCG area that have autotransformers. Overlapping autotransformer contingencies were taken and Table F3 in Appendix F illustrates any load transfer requirements due to two overlapping autotransformer outages.

As seen in Appendix F, the load forecasted on all circuit pairs is less than 600 MW within the 10-year study period and the loss of two autotransformers within this local area does not result in equipment loading beyond their applicable emergency ratings; therefore there is no concern with Load Security in the KWCG area for the study period.

3.4.6 LOAD RESTORATION CAPABILITY ANALYSIS

The load restoration criteria requires that the transmission system be planned such that following local area design criteria contingencies, the affected loads can be restored within the restoration times indicated below[4]:

- All load lost must be restored within 8 hours;
- Load lost in excess of 250 MW must be restored within 30 min; and
- Load lost between the amount of 150 MW and 250 MW must be restored within 4 hours.

Each pair of double circuit 230 kV and 115 kV lines were assessed to verify their load restoration capability. This assessment is detailed in Appendix G.

The results indicated the existing transmission system can adequately restore load to each circuit pair with the exception of M20/21D. Therefore, improvement to the restoration capability of load connected to circuits M20D and M21D is required.

3.4.7 IMPACT OF CONTINGENCIES ON THE BPS TO THE KWCG AREA

Northeast Power Coordinating Council (NPCC) Bulk Power System stations in the KWCG area are:

- Middleport TS 500 kV bus
- Middleport TS 230 kV bus
- Detweiler TS 230 kV bus

[4] As per ORTAC: “These approximate restoration times are intended for locations that are near staffed centres. In more remote locations, restoration times should be commensurate with travel times and accessibility.”

All elements connected to BPS buses are considered BPS facilities. Elements refer to circuit breakers, transmission lines, generators, transformers and reactive devices (e.g. SVC or capacitor bank).

Appendix E: Technical Results-Bulk Power System Considerations provides a list of BPS contingencies and the results. A *limited* number of BPS contingencies were performed in order to establish the impact of contingencies on the BPS to the local KWCG area.

Three NPCC Directory 1 contingency events were utilized in this study:

1. Simultaneous loss of two adjacent transmission circuits on a multiple circuit tower
2. Loss of any element with delayed fault clearing (a.k.a. Breaker Failure)
3. Loss of a critical element, followed by system adjustment, then loss of a critical element.

These BPS contingency events were applied to BPS buses only. The results can be summarized as follows:

- As per Table E3 and E5 when two of the three auto-transformers at Detweiler TS are not available the remaining auto-transformer may become overloaded. Since the loading of the remaining auto-transformer is within its 15-minute Short-Term Emergency Rating (STE) operational control actions can be taken to reduce the loading to within acceptable limits. Control actions could entail isolation of the faulted element e.g. circuit breaker, bus or transformer, and placing back in-service a healthy auto-transformer (at Detweiler TS and/or Preston TS). Another control action could entail opening of 115kV breakers at Freeport SS to redirect flows through the Cedar TS autotransformers.

3.4.8 SUMMARY OF NEEDS

Figure 1 illustrates the Needs timeline for the KWCG region.



Figure 1: Transmission Needs in the KWCG Area

4.0 OPTIONS TO ADDRESS THE NEED

Options were considered to address the insufficient load restoration capability for loads connected to circuits M20D and M21D. These options are shown in Table 1. Although there are several metrics that can be utilized to measure and compare options, the simple metric “initial capital cost/MW of load restored” was selected because it compares the unit costs of remedial measures. This was deemed sufficient in order to select the preferred option

Table 1: Options to Improve M20/21D Load Restoration

Option	**Options to Improve Restoration**	**Fault on the Main Line – Restorable Load** (Note 1)	**Fault on the Tap – Restorable Load** (Note 1)	**Initial Capital Cost** (Note 3)	**Initial Capital Cost/ MW Load Restored**
--	Existing (Benchmark)	100 MW (Preston TS only)	100 MW (Preston TS only)	0	$0/MW
1	230 kV in-line switches on M20/21D at **Preston Junction**	100 MW (C&ND load only-Note 2)	100 MW (C&ND load only-Note 2)	$6M	$60k/MW
2	230 kV in-line switches on M20/21D at **Galt Junction** (main line)	368 MW - 484 MW	234 MW (100 MW via existing Preston Auto)	$6M	$12k/MW to $26k/MW
3	One 230 kV cap bank at Preston TS plus 230 kV in-line switches on MxD at **Preston Junction**	140 MW (Note 4) (C&ND load only-Note 2)	140 MW (Note 4) (C&ND load only-Note 2)	$11M	$79k/MW
4	2nd autotransformer at Preston TS plus 230 kV in-line switches on MxD at **Preston Junction**	200 MW (Note 4) (C&ND load only-Note 2)	200 MW (Note 4) (C&ND load only-Note 2)	$21M	$105k/MW
5	2nd autotransformer at Preston TS plus 230 kV in-line switches on MxD at **Preston Junction** plus two 230 kV cap banks at Preston TS	280 MW (Note 4) (C&ND load only-Note 2)	280 MW (Note 4) (C&ND load only-Note 2)	$31M	$111k/MW

NOTE 1 Restorable load values are approximate values only as the actual amount of restorable load will depend on the prevailing system conditions and Operating/Control Centre protocols and priorities

NOTE 2 "C&ND load only" means that only those customers connected to Galt TS, C&ND MTS#1 and Preston TS will benefit. Cambridge and North Dumfries Hydro customers are the sole customers of these three stations.

NOTE 3 All prices are based on historical data: taxes extra, overhead extra, no escalation considered, no assumptions are made to feasibility or constructability, no assumptions made as to space requirements, real estate and environmental cost extra

NOTE 4 Restoration of 230 kV load (Cambridge and North Dumfries load) via the Preston TS auto-transformer may require operational measures on the 115 kV system to secure the transmission system to handle a subsequent contingency e.g. open the low voltage bus-tie breakers/switches at 115kV connected stations

5.0 DISCUSSION OF PREFERRED OPTIONS

5.1 PREFERRED OPTION TO IMPROVE RESTORATION TO M20/21D LOAD

Currently, loads connected to circuits M20/21D do not meet the restoration criteria.

Of the five options, option #2: 230 kV in-line switches on M20/21D at/near Galt Junction is the preferred option to satisfy the Need as it will provide the capability to restore the most load supplied from M20/21D.

Not only does Option #2 allow for more load to be restored, it provides for better operational flexibility; and is the most economical solution. As option 2 substantially meets the need by significantly improving the existing restoration capability, it is therefore the preferred option.

6.0 DEVELOPMENT PLAN

The transmission infrastructure development plan for the KWCG area is as followings:

1) Immediate Action: Install 230 kV In-Line Switches

Install 230 kV Load Interrupter type in-line switches on circuits M20D and M21D on the main line near Galt Junction. Note that load interrupter type switches cannot be used to interrupt fault current.

7.0 CONCLUSIONS

The following conclusions can be reached from the analysis performed by this study.

Local Area Performance

1. Improvement to the load restoration capability of transmission-connected customers on circuits M20D and M21D is required. The preferred option can be implemented by summer 2017.

BPS Performance

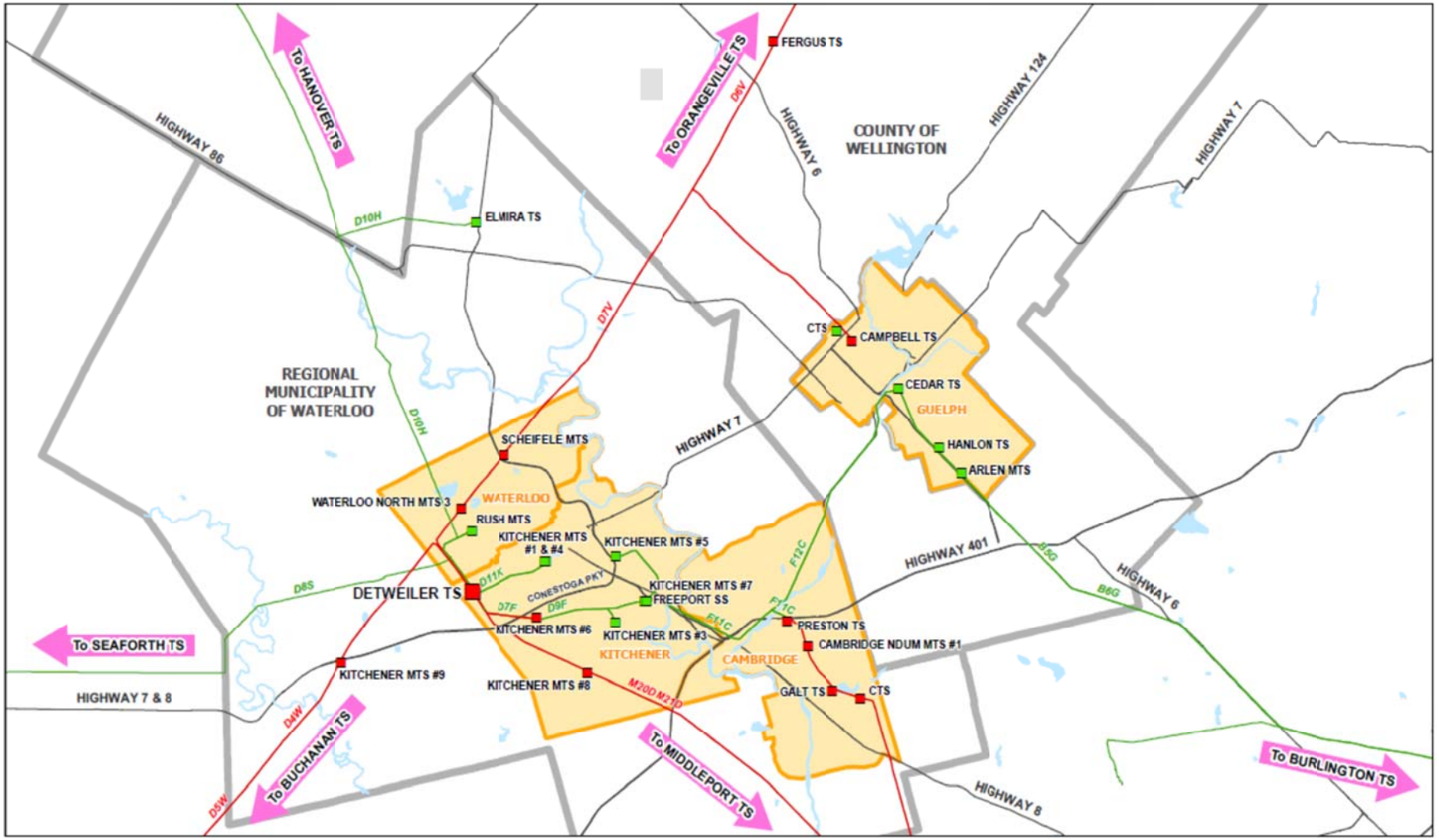
2. Autotransformer T2 at Detweiler TS is expected to be at 104.4% of LTE loading for year 2016 for the following contingency:
    i. Detweiler T4 outage plus Detweiler T3 with M20D (includes Preston T2 via Preston SPS). Since the post-contingency flow is below the auto-transformer STE, operational control actions can be taken to reduce loading to within the LTE rating.

8.0 RECOMMENDATIONS

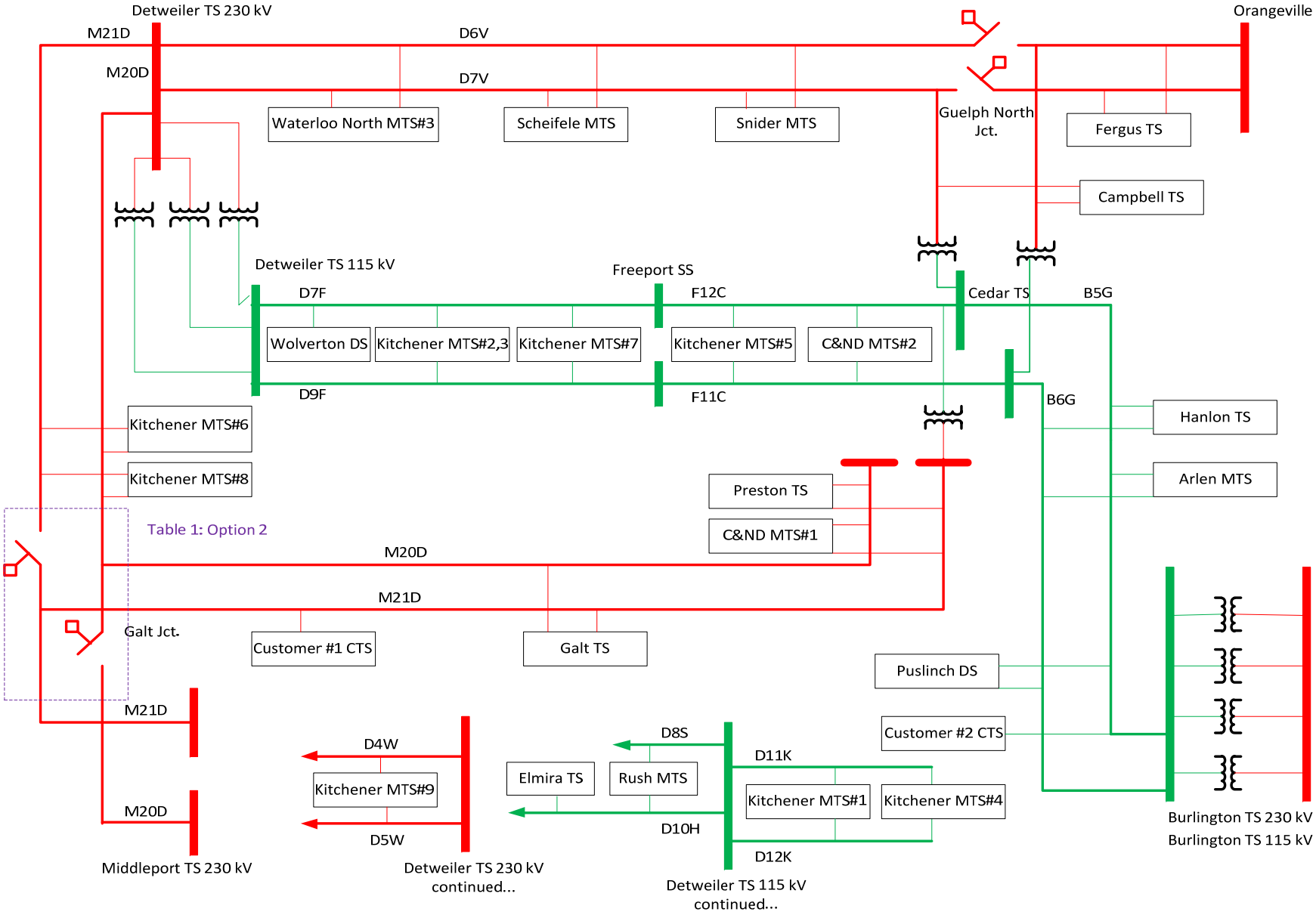
The following recommendations are to address the transmission infrastructure deficiencies within the study period for the KWCG area. These recommendations are:

1. Hydro One Networks to install a set of 230 kV in-line switches onto the main line of circuits M20D and M21D near Galt Junction as soon as possible.
2. Hydro One Networks, the LDCs and the IESO to review the KWCG local area in 2019 with updated KWCG load forecasts to decide on appropriate actions to meet longer-term needs as they emerge.

APPENDIX A: KWCG MAPS



Map 1: Geographical Area of KWCG with Electrical Layout



Map 2: KWCG Electrical Single-Line

APPENDIX B: TRANSMISSION-CONNECTED GENERATION IN THE KWCG AREA

Name	Installed Capacity	Peak Capacity Contribution[5]	Location	Existing or Contracted
Dufferin Wind Farm	97	13.6	Orangeville TS	Existing
Conestoga Wind Farm	67	10.8	D10H	Contracted (future i/s date unknown)

[5] Percentage of installed capacity is 14 % for wind generation

APPENDIX C: KWCG CUSTOMER & LDC LOAD FORECASTS

Table C1: KWCG 2015 RIP Load Forecast*

TS	LDC	Load Forecast	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Cambridge MTS #1	Cambridge & North Dumfries Hydro	Planning Demand	92.3	93.8	95.6	98.1	99.7	102.7	101.8	102.1	102.4	102.2	101.6
Galt TS	Cambridge & North Dumfries Hydro	Planning Demand	108.1	109.5	112.3	113.7	116.1	119.0	122.8	127.9	134.8	141.9	148.8
Preston TS-Note 1	Cambridge & North Dumfries Hydro	Planning Demand	108.0	100.3	102.0	104.4	105.9	108.7	109.6	111.8	111.9	111.5	111.8
Cambridge MTS # 2-Note	Cambridge & North Dumfries Hydro	Planning Demand	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Kitchener MTS #6	Kitchener-Wilmot Hydro	Planning Demand	72.8	72.8	73.0	73.0	72.4	72.1	71.7	71.6	71.5	71.1	71.1
Kitchener MTS #8	Kitchener-Wilmot Hydro	Planning Demand	44.2	37.6	40.3	43.1	45.3	38.6	41.1	43.5	46.0	48.2	50.6
Kitchener MTS #3	Kitchener-Wilmot Hydro	Planning Demand	54.3	64.4	66.5	67.3	67.5	77.0	77.5	78.1	78.7	79.0	79.6
Kitchener MTS #7	Kitchener-Wilmot Hydro	Planning Demand	44.9	45.1	45.9	46.0	45.6	45.6	45.6	45.7	39.9	39.8	39.9
Kitchener MTS #5	Kitchener-Wilmot Hydro	Planning Demand	73.9	73.8	74.6	74.5	73.8	73.5	73.2	73.1	78.8	78.3	78.2
Detweiler TS	Kitchener-Wilmot Hydro	Planning Demand	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Kitchener MTS #4	Kitchener-Wilmot Hydro	Planning Demand	67.8	68.2	69.1	69.3	69.0	69.0	68.9	69.2	69.3	69.1	69.3
Kitchener MTS #9	Kitchener-Wilmot Hydro	Planning Demand	33.7	33.9	34.3	34.6	34.5	34.7	34.9	35.0	35.3	35.4	35.5
Kitchener MTS #1	Kitchener-Wilmot Hydro	Planning Demand	29.1	29.6	31.1	31.6	31.8	32.1	32.4	32.9	33.3	33.5	33.9
Wolverton DS	Hydro One Distribution	Planning Demand	21.2	21.4	21.6	21.6	21.6	21.6	21.6	21.7	21.8	21.7	21.9
Fergus TS	Hydro One Distribution	Planning Demand	108.9	108.8	109.5	109.7	108.5	108.3	108.2	108.5	108.7	108.3	108.7
Puslinch DS	Hydro One Distribution	Planning Demand	35.6	36.2	36.8	37.3	37.5	37.9	38.3	38.7	39.2	39.5	39.9
Cedar TS T1/T2	Guelph Hydro	Planning Demand	72.3	74.9	75.8	77.4	78.3	79.5	79.8	82.2	84.6	85.5	87.9
Cedar TS T7/T8	Guelph Hydro	Planning Demand	30.2	32.0	32.0	32.8	32.3	33.0	33.7	33.4	34.2	34.8	35.5
Hanlon TS	Guelph Hydro	Planning Demand	29.8	30.7	31.6	32.5	33.0	33.7	34.4	35.1	34.9	35.5	35.3
Arlen MTS	Guelph Hydro	Planning Demand	30.0	33.0	37.0	40.9	33.3	37.9	41.4	43.0	44.6	45.9	47.5
Campbell TS	Guelph Hydro	Planning Demand	131.9	136.3	139.0	140.2	141.2	142.8	144.4	148.4	152.2	156.2	160.1
Scheifele MTS	Waterloo North Hydro	Planning Demand	169.0	166.0	170.7	150.3	151.2	152.7	154.3	156.2	158.1	153.4	155.4
Waterloo MTS #3	Waterloo North Hydro	Planning Demand	61.9	70.8	72.7	75.3	79.3	64.6	58.0	75.3	76.8	76.9	78.4
Snider MTS-Note 2	Waterloo North Hydro	Planning Demand	0.0	0.0	0.0	30.6	35.2	50.9	60.3	61.9	64.4	65.6	68.1
Bradley MTS-Note 2	Waterloo North Hydro	Planning Demand	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Elmira TS	Waterloo North Hydro	Planning Demand	30.4	25.1	26.0	25.8	27.4	28.1	28.8	29.6	31.3	31.9	33.6
Rush MTS	Waterloo North Hydro	Planning Demand	54.9	63.8	65.7	67.4	67.4	67.8	69.1	53.0	53.6	60.7	61.3
Customer #1 CTS-Note 3	Customer Tx Stations	Planning Demand	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5
Customer #2 CTS	Customer Tx Stations (Assumed values)	Planning Demand	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0

Planning demand (MW) = ((Gross-CDM) x Extreme Weather Factor) – DG

*Based upon KWCG 2015 IRRP Planning Load Forecast except where otherwise noted.

Note 1: The LDC has confirmed 9.2 MW of cogeneration at a large customer to be accounted for in the Preston TS forecast starting year 2016. The generation plant is expect to run most of the time and would offset the customer's load. This cogeneration was not factored into the KWCG 2015 IRRP Planning Load Forecast.

Note 2: The LDC has confirmed that additional transformation capacity (Snider/Bradley TS) would not be required until after 2024. The exact location and timing of these TS's have not been determined at this time. The load growth indicated at Snider and Bradley in the forecast can be managed by existing TS's/impact of CDM/DG in the Waterloo Region. LDCs are monitoring the load closely to determine the timing of potential transformation needs. Where possible, these LDCs are exploring opportunities to coordinate use and development of TS facilities in the KWCG Region over the long term. Cambridge #2 is assumed to be supplied off the KWCG 115kV system

Note 3: Slight modification from KWCG 2015 IRRP Planning forecast based on information provided by the transmission-connected customer

Note: Guelph CTS 1 forecast was removed as the LDC confirmed the load was already accounted for within their forecast

APPENDIX D: TECHNICAL RESULTS – LOCAL AREA ANALYSIS

Single element contingencies were considered in order to determine the presence of thermal overload and/or voltage violations.

Table D1: Single Element Contingencies (single zone of protection)

Loss of a Single Circuit (N-1)					
D11K	D12K	D8S	D10H	D7F	D9F
F11C	F12C	B5G	B6G	D4W	D5W
M20D*	M21D**	D6V***	D7V****		
Loss of a Single Autotransformer (N-1)					
Detw. T2	Detw. T3♦	Detw. T4♦♦	Cedar T3♦♦♦	Cedar T4♦♦♦♦	Preston T2**
Middleport T3♦♦♦♦♦		Middleport T6♦♦♦♦♦♦			
Loss of a Single HV Reactive Element (N-1)					
Detweiler 230 kV cap. bank	Middleport 230 kV cap. bank(K1D1)	Orangeville 230 kV cap. bank	Burlington 230 kV cap. bank		
Detweiler 230 kV SVC	Middleport 230 kV cap. bank(K2D2)	Detweiler 115 kV cap bank	Burlington 115 kV cap bank		

*M20D (includes Detweiler T3 and Preston T2 via Preston Special Protection Scheme)

**M21D (includes Preston T2)

***D6V (includes Detweiler T4 and Cedar T3)

****D7V (includes Cedar T4)

♦Detweiler T3 (includes circuit M20D and Preston T2 via Preston SPS)

♦♦Detweiler T4 (includes circuit D6V and Cedar T3)

♦♦♦Cedar T3 (includes circuit D6V and Detweiler T4)

♦♦♦♦Cedar T4 (includes circuit D7V)

♦♦♦♦♦Middleport T3 (includes circuit N580M and V586M due to Line End Open)

♦♦♦♦♦♦Middleport T6 (includes circuit N581M and M585M due to Line End Open)

Results: Thermal Overload and Voltage Violations

Table D3: Thermal Analysis (>100% LTE), year 2025

Element	Contingency	%LTE
All circuits and auto-transfers are within ratings		

Table D4: Voltage Analysis, year 2025

Element	Contingency	%Voltage Decline	Voltage kV
All voltages are within criteria			

APPENDIX E: TECHNICAL RESULTS – BULK POWER SYSTEM CONSIDERATIONS

Applicable contingencies were considered on BPS elements to establish their impact on the local area.

Table E1: N-2 Contingencies

Loss of a Double Circuit Line (N-2) emanating from a BPS station		
B22D and B23D	D4W and D5W	M20D and M21D
D6V and D7V	--	--
Breaker Failure (B/F) Contingencies at BPS station (N-2)		
Detweiler TS 230 kV bus	B/F of AL6	Loss of: D6V, Cedar T3, Detw T4, M21D, Preston T2
	B/F of AL7	Loss of: D7V, Cedar T4, M21D, Preston T2
	B/F of L7L20	Loss of: D7V, Cedar T4, M20D, Detw T3, Preston T2
	B/F of HT1A	Loss of: M21D, Preston T2, SVC1
	B/F of ACS21	Loss of : M21D, Preston T2, SC21
	B/F of HL20	Loss of: M20D, Detw T3, D5W, SC22
	B/F of T2SC21	Loss of: Detw T2, SC21
	B/F of HT2	Loss of: Detw T2, SC21, D5W
	B/F of DL22	Loss of: B22D, D6V, Cedar T3, Detw T4
Middleport TS 500 kV bus	Covered under Loss of Middleport T3 and T6 autotransformers for the local area analysis (Appendix D)	
Middleport TS 230 kV bus	There are no B/F conditions that would be critical to the supply to the KWCG area.	

Table E2: N-1-1 Contingencies

Loss of a Critical Element, System Adjustment, Loss of a Critical Element (N-1-1)
Loss of: Detw T4 plus Detw T3 (plus M20D by configuration which also includes the loss of Preston T2 via Preston SPS)
Loss of: Preston T2 plus D7V (plus Cedar T4 by configuration)

Note that during the simulations no System Adjustment was afforded; this is considered a conservative approach.

Results: Thermal Overloads and Voltage Violations

As per Table E3 and E5: Detweiler TS 230/115 kV autotransformer T2 will become overloads when Detweiler TS autotransformer T4 is out-of-service followed by the loss of Detweiler TS autotransformer T3 in conjunction with circuit M20D by configuration. Preston TS autotransformer T2 is also removed from service via the Preston SPS.

Table E3: Thermal Analysis (>95% LTE), year 2016

Element	Contingency	%LTE
Detweiler TS T2 autotransformer	Detweiler T4 plus Detweiler T3 with M20D (includes Preston T2 via Preston SPS)	104.4 (74.2% STE*) %

*STE rating of Detweiler T2 auto-transformer is 396 MVA.

Table E4: Voltage Analysis, year 2016

Element	Contingency	%Voltage Decline	Voltage kV
All voltages are within criteria			

Table E5: Thermal Analysis (>95% LTE), year 2025

Element	Contingency	%LTE
Detweiler TS T2 autotransformer	Detweiler T4 plus Detweiler T3 with M20D (includes Preston T2 via Preston SPS)	114.2 (81.4%STE*)

*STE rating of Detweiler T2 auto-transformer is 396 MVA.

Table E6 Voltage Analysis, year 2025

Element	Contingency	%Voltage Decline	Voltage kV
All voltages are within criteria			

APPENDIX F: LOAD SECURITY ANALYSIS

Load connected to each circuit pair that is lost by configuration following an [N-2] double circuit contingency is:

Table F1: Load Lost Due to Configuration, year 2016

Circuit Pair	MW
M20/21D	420
D6/7V	482
D4/5W	34
D7/9F	131
F11/12C	74
B5/6G	105
D11/12K	98
D8S/D10H	89

Table F2: Load Lost Due to Configuration, year 2025

Circuit Pair	MW
M20/21D	489
D6/7V	571
D4/5W	36
D7/9F	141
F11/12C	78
B5/6G	128
D11/12K	103
D8S/D10H	95[6]

Table F1 illustrates that none of the double circuit contingencies result in more than 482 MW of load lost in year 2016.

Table F2 illustrates that none of the double circuit contingencies result in more than 571 MW of load lost in year 2025.

[6] D8S and D10H emanate out of Detweiler TS as a double circuit line however after ~ 5 km they each become a single circuit 115 kV line. Based on their N/O open points, the loss of the double circuit line within the 5 km span out of Detweiler TS, will results in approximately 95 MW of load lost.

Table F3: Two Elements Out of Service

Loss of a Double Circuit Line				
D7F and D9F		F11C and F12C		B5G and B6G
D4W and D5W		M20D and M21D		D11K and D12K
D6V and D6V				
Loss of Two Autotransformers[7]				
Station	**Detweiler Auto**	**Preston Auto**	**Cedar Auto**	**Burlington Auto**
Detweiler Auto	N/A	Detweiler T3 + Preston T2	Cedar T3 + Detweiler T4	Burlington T6 + Detweiler T3
Preston Auto	Detweiler T3 + Preston T2	N/A	Cedar T4 + Preston T2	Burlington T6 + Preston T2
Cedar Auto	Cedar T3 + Detweiler T4	Cedar T4 + Preston T2	Cedar T3 + Cedar T4	Burlington T6 + Cedar T3
Burlington Auto	Burlington T6 + Detweiler T3	Burlington T6 + Preston T2	Burlington T6 + Cedar T3	N/A

Results: Thermal Overload and Voltage Violations

Table F5: Thermal Analysis (>100% STE), year 2025

Element	**Contingency**	**%STE**
All circuits and auto-transfers are within ratings		
Element	**Contingency**	**%LTE**
All circuits and auto-transfers are within ratings		

Table F6: Voltage Analysis (> emergency ratings), year 2025

Element	**Contingency**	**%Voltage Decline**	**Voltage kV**
All voltages are within criteria			

[7] For stations that have three or more autotransformers connected in parallel typical operating practice after the loss of one autotransformer is to make load transfers to other interconnected autotransformer station(s) such that the remaining load at the affected station would be at or below the station's reduced Limited Time Rating (LTR). It is assumed the in this case that sufficient time between single autotransformer contingencies is available for such load transfers to be carried out by operator response.

APPENDIX G: LOAD RESTORATION ANALYSIS

Restoration of Load Connected to M20/21D

By year 2025 the total forecasted load connected to circuits M20/21D is 489 MW. Loss of this double circuit line would result in the loss of all 489 MW. In order to restore load to these stations at least one circuit would have to be placed back in service**,** noting that to restore Customer #1 CTS circuit M21D must specifically be placed back in service due to the customer's single-circuit transmission-connection

Based on criteria:

Load Required to be Restored	Duration
239MW	30 min.
100 MW	Within 4 hrs.
150 MW	Within 8 hrs.

Existing infrastructure allows for only the restoration of 100 MW of load in approximately 30 min. This can be accomplished by opening the M20/211D line disconnect switches at Preston TS and back-feed Preston TS T2 230-115 kV autotransformer to supply load at Preston TS only.

Therefore, the existing restoration capability to loads connected to M20/21D does not meet criteria for the duration of the study period.

Restoration of Load Connected to D6/7V

By year 2025 the total forecasted load connected to D6/7V is 571 MW. Loss of this double circuit line would result in the loss of all 571 MW. As part of the Guelph Area Transmission Reinforcement project, two 230 kV in-line switches will be installed in year 2016 on the main line between Detweiler TS and Orangeville TS at Guelph North Junction. To restore load to these stations, the operator will utilize these switches to isolate the problem and return to service the remaining healthy circuit sections. These switches allow for more flexibility to restore load to the affected stations in a timely fashion.

Based on criteria:

Load Required to be Restored	Duration
321MW	30 min.
100 MW	Within 4 hrs.
150 MW	Within 8 hrs.

Depending on:

1. the severity of the double circuit contingency;
2. the prevailing system conditions and

3. the relative distance from the nearest field maintenance centre[8]

the load restoration criterion is substantially met. Therefore, no additional transmission restoration capability is warranted at this time.

Restoration of Load Connected to D4/5W

By year 2025 the total forecasted load connected to D4/5W is 36 MW. Loss of this double circuit line would result in the loss of all 36 MW. To restore load to this station at least one circuit would have to be placed back in service.

Based on criteria:

Load Required to be Restored	Duration
36 MW	Within 8 hrs.

Depending on:

1. the severity of the double circuit contingency;
2. the prevailing system conditions and
3. the relative distance from the nearest field maintenance centre

the load restoration criteria can be met. Therefore, no additional transmission restoration capability is warranted at this time.

Restoration of Load Connected to D7/9F

By year 2025 the total forecasted load connected to D7/9F is 141 MW. Loss of this double circuit line would result in the loss of all 141 MW. To restore load to these stations at least one circuit would have to be placed back in service.

Based on criteria:

Load Required to be Restored	Duration
141 MW	Within 8 hrs.

Depending on:

1. the severity of the double circuit contingency;
2. the prevailing system conditions and
3. the relative distance from the nearest field maintenance centre

the load restoration criteria can be met. Therefore, no additional transmission restoration capability is warranted at this time.

[8] The KWCG area is considered an urban area and as such, access to transmission facilities, repair materials and personnel in order to make a repair within 8 hours is realistic. A Hydro One field maintenance centre is located in Guelph.

Restoration of Load Connected to F11/12C

By year 2025 the total forecasted load connected to F11/12C is 78 MW. Loss of this double circuit line would result in the loss of all 78 MW. To restore load to these stations at least one circuit would have to be placed back in service.

Based on criteria:

Load Required to be Restored	Duration
78 MW	Within 8 hrs.

Depending on:

1. the severity of the double circuit contingency;
2. the prevailing system conditions and
3. the relative distance from the nearest field maintenance centre

the load restoration criteria can be met. Therefore, no additional transmission restoration capability is warranted at this time.

Restoration of Load Connected to B5/6G

By year 2025 the total forecasted load connected to B5/6G is 128 MW. Loss of this double circuit line would result in the loss of all 128 MW. To restore load to Enbridge Westover CTS's circuit B5G must be placed back in service due to the CTS's single-circuit transmission connection. To restore load at the other stations at least one circuit would to be placed back in service.

Based on criteria:

Load Required to be Restored	Duration
128 MW	Within 8 hrs.

Depending on:

1. the severity of the double circuit contingency;
2. the prevailing system conditions and
3. the relative distance from the nearest field maintenance centre

the load restoration criteria can be met. Therefore, no additional transmission restoration capability is warranted at this time.

Restoration of Load Connected to D11/12K

The total forecasted load serviced by radial circuits D11/12K will not exceed 103 MW by 2025. Loss of this double circuit line would result in the loss of all 103 MW. To restore load to these stations at least one circuit would have to be placed back in service.

Based on criteria:

Load Required to be Restored	Duration
103 MW	Within 8 hrs.

Depending on:

1. the severity of the double circuit contingency;
2. the prevailing system conditions and
3. the relative distance from the nearest field maintenance centre

the load restoration criteria can be met. Therefore, no additional transmission restoration capability is warranted at this time.

Restoration of Load Connected to D8S/D10H

The total forecasted load serviced by these radially operated 115 kV circuits will not exceed approximately 95 MW by year 2025. Loss of this double circuit line would result in loss of all 95MW. To restore Rush MTS either circuit can be placed back into service or the station could possibly be fed via circuit L7S out of Seaforth TS; however to restore Elmira TS circuit D10H must be placed back in service due to Elmira TS's single-circuit transmission-connection.

Based on criteria:

Load Required to be Restored	Duration
95 MW	Within 8 hrs.

Depending on:

1. the severity of the double circuit contingency;
2. the prevailing system conditions and
3. the relative distance from the nearest field maintenance centre

the load restoration criteria can be met. Therefore, no additional transmission restoration capability is warranted at this time.

APPENDIX H: SUPPLY TO ELMIRA TS AND RUSH MTS

Study Results:

Table H1: Station Capacity: Summer Ratings and Summer Load Forecast

Station	Transformer Capacity (10-day LTR)	Year 2025 Load Forecast
Rush MTS	69 MVA*	61.3 MW / 69.9 MVA (0.88 pf** at defined meter point, 115 kV side)
Elmira TS	58.5 MVA	33.6 MW / 37.1 MVA*** (0.91 pf at defined meter point, 115 kV side)

*The limiting component is a low voltage cable; when required the limiting component will be modified and the rating to be 75 MVA

** Power factor at the defined meter point improves to 0.92 when 5.4 MVar of installed feeder capacitor banks assumed lumped at the LV bus and results in 66.8 MVA loading

*** A 9.2 MVar @ 27.6 kV shunt capacitor bank is installed at Elmira TS not in-service; when in-service power factor improves and loading through the transformers decrease.

Table H2: Transmission Capacity of circuits D8S and D10H

Year	Contingency	D10H – Detweiler TS x Waterloo Jct. *590 A Continuous* *640 A Long-Term Emergency (LTE)* *660 A Short-Term Emergency (15-min.)*	D8S – Detweiler TS x Leong Jct. *590 A Continuous* *640 A Long-Term Emergency (LTE)* *660 A Short-Term Emergency (15-min.)*
2016	Pre	287 A	285 A
	Loss of D8S	454 A	--
	Loss of D10H	--	459 A
2025	Pre	319 A /	302 A
	Loss of D8S	511	--
	Loss of D10H	--	500 A

-assume all St. Mary's TS load is supplied by D8S (as this is more conservative for the study), assume Conestogo Wind Farm not-service (as it would displace load on D10H) and the normally-open point on D10H is between Elmira TS and Palmerston TS

Table H3: Voltage Profile at Rush MTS and Elmira TS

Year	Contingency	Rush MTS 115 kV D8S	Rush MTS 115 kV D10H	Rush MTS 13.8 kV	Elmira TS 115 kV	Elmira TS 27.6 kV
2016	Pre	122.2	122.2	14.4	120.8	27.2
	Loss of D8S	--	121.8	13.7	120.6	27.1
	Loss of D10H	121.5	--	13.7	--	--
2025	Pre	123.2	123.1	14.2	121.6	27.3
	Loss of D8S	--	122.6	13.6	121.1	27.2
	Loss of D10H	122.4	--	13.6	--	--

-assume all St. Mary's TS load is supplied by D8S (as this is more conservative for the study), assume Conestogo Wind Farm not-service (as it would displace load on D10H) and the normally-open point on D10H is between Elmira TS and Palmerston TS

Analysis:

D8S

Circuit D8S has a normally open point at St. Mary's TS separating the circuit from circuit L7S. D8S normally supplies half the load at Rush MTS and half the load at St. Mary's TS. The other half of the load at Rush MTS is normally supplied by circuit D10H and the other half of the load at St. Mary's TS is normally supplied by L7S. Referring to Table H2, for the loss of circuit D10H, circuit D8S has sufficient capacity to supply all load at Rush MTS and St. Mary's TS for year 2025 and beyond.

D10H

Circuit D10H runs between Detweiler TS and Hanover TS and has a normally open point between Elmira TS and Palmerston TS. Elmira TS is normally supplied from Detweiler TS while Palmerston TS is normally supplied from Hanover TS. Referring to Table H2, D10H has sufficient capacity to supply all load at Elmira TS for year 2025 and beyond. When circuit D8S is out of service, D10H has sufficient capacity to supply all load at Elmira TS and Rush MTS (while St. Mary's TS is supplied by circuit L7S).

Rush MTS

Since this station is a Municipal owned station, Waterloo North Hydro is to ensure there is sufficient transformation capacity to accommodate load growth. According to load forecasts and referring to Table H1, over the next 10-years load will fluctuate above and below the year 2025 forecast but will be remain within the station's Limited Time Rating (LTR). Waterloo North Hydro is to inform Hydro One if the connection requires

modification and/or if a new station connection is required in order to accommodate load growth. Waterloo North Hydro has already incorporated their future Snider MTS and Bradley MTS into the KWCG regional plan to cater for load growth.

Rush MTS is supplied by two 115 kV circuits, D8S and D10H. Referring to Tables H2 and H3, when one of these circuits is out of service, the voltage profile at Rush MTS is healthy and the other circuit has sufficient capacity to supply all load to Rush MTS.

Elmira TS

According to the forecast and referring to Table H1, transformers at Elmira TS have sufficient capacity for year 2025 loading and beyond.

Elmira TS is supplied by one 115 kV circuit, D10H. Referring to Tables H2 and H3, the voltage profile at Elmira TS is healthy and the circuit has sufficient capacity to supply load to Elmira TS for year 2025 loading and beyond.

When circuit D10H out of Detweiler TS is unavailable, Elmira TS may also be supplied by D10H out of Hanover TS (by closing the normally open point between Palmerston TS and Elmira TS). Assuming Palmerston TS is at its forecasted year 2025 normal weather peak load, approximately 25 MW of load at Elmira TS may be supplied out of Hanover TS. The limiting factor being the 115 kV voltage profile on D10H as Elmira TS is nearly 80 circuit km from Hanover TS.

Appendix D: KWCG Needs Assessment Report (2nd Cycle)

Hydro One Networks Inc.
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Toronto, Ontario
M5G 2P5

NEEDS ASSESSMENT REPORT

Kitchener - Waterloo - Cambridge - Guelph (KWCG) Region

Date: December 19, 2018

Prepared by: KWCG Region Study Team

Disclaimer

This Needs Assessment Report was prepared for the purpose of identifying potential needs in the KWCG Region and to recommend which need may require further assessment and/or regional coordination to develop a preferred plan. The results reported in this Needs Assessment are based on the input and information provided by the Study Team.

The Study Team participants, their respective affiliated organizations, and Hydro One Networks Inc. (collectively, "the Authors") shall not, under any circumstances whatsoever, be liable to each other, to any third party for whom the Needs Assessment Report was prepared ("the Intended Third Parties") or to any other third party reading or receiving the Needs Assessment Report ("the Other Third Parties"). The Authors, Intended Third Parties and Other Third Parties acknowledge and agree that: (a) the Authors make no representations or warranties (express, implied, statutory or otherwise) as to this document or its contents, including, without limitation, the accuracy or completeness of the information therein; (b) the Authors, Intended Third Parties and Other Third Parties and their respective employees, directors and agents (the "Representatives") shall be responsible for their respective use of the document and any conclusions derived from its contents; (c) and the Authors will not be liable for any damages resulting from or in any way related to the reliance on, acceptance or use of the document or its contents by the Authors, Intended Third Parties or Other Third Parties or their respective Representatives.

Executive Summary

REGION	Kitchener - Waterloo - Cambridge - Guelph (KWCG) Region		
LEAD	Hydro One Networks Inc. ("HONI")		
START DATE	September 17, 2018	**END DATE**	December 19, 2018

1. INTRODUCTION

The first cycle of the Regional Planning process for the KWCG Region an Integrated Regional Resource Plan ("IRRP") was published in April 2015 which identified a number of near- and mid-term needs in the KWCG region. The planning process was completed in December 2015 with the publication of the Regional Infrastructure Plan ("RIP") which provided a description of needs and recommendations of preferred wires plans to address near-term needs. The RIP also identified some near- and mid-term needs that will be reviewed during this Regional Planning cycle.

The purpose of this Needs Assessment ("NA") is to identify any new needs and to reaffirm needs identified in the previous KWCG Regional Planning cycle.

2. REGIONAL ISSUE/TRIGGER

In accordance with the Regional Planning process, the regional planning cycle should be triggered at least every five years. In light of the timing of the needs identified in the previous Integrated Regional Resource Plan ("IRRP") and RIP reports as well as new replacement/ refurbishment needs in the KWCG Region, the 2nd Regional Planning cycle was triggered for this Region.

3. SCOPE OF NEEDS ASSESSMENT

The scope of this NA includes:

- Review and reaffirm needs/plans identified in the previous RIP; and
- Identification and assessment of system capacity, reliability, operation, and aging infrastructure needs.

The Study Team may also identify additional needs during the next phases of the planning process, namely Scoping Assessment ("SA"), IRRP and RIP, based on updated information available at that time.

4. INPUTS/DATA

The Study Team representatives from Local Distribution Companies ("LDC"), the Independent Electricity System Operator ("IESO"), and Hydro One provided input and relevant information for the KWCG Region regarding capacity needs, reliability needs, operational issues, and major assets/facilities approaching end-of-life ("EOL"). In addition, community energy plans in the region have also been scanned and reviewed.

5. ASSESSMENT METHODOLOGY

The assessment's primary objective is to identify the electrical infrastructure needs, recommend further mitigation or action plan(s) to address these needs, and determine whether further regional coordination or broader study would be beneficial.

The assessment reviewed available information including load forecasts, conservation and demand management ("CDM") and distributed generation ("DG") forecasts, reliability needs, operational issues, and major high

voltage equipment identified to be at or near the end of their useful life and requiring replacement/refurbishment. A technical assessment of needs was undertaken based on:

- Current and future station capacity and transmission adequacy;
- Reliability needs and operational concerns; and
- Any major high voltage equipment reaching the end of its useful life.

6. NEEDS

I. Station & Transmission Supply Capacity

- Campbell TS (T3/T4) DESN Overloading is forecasted in the 2021-2022.
- Future need for Waterloo North Hydro MTS #4
- Future need for Energy+ MTS #2

A contingency analysis was performed and due to reduced forecasts no issues were found.

II. System Reliability & Operation

- D10H 115 kV line reliability and restoration of Elmira TS loads.

III. Aging Infrastructure – Transformer Replacements and line Section Refurbishment

- Projects in execution:
  - i. Campbell TS – T1 (2018)
  - ii. Detweiler TS -Auto T2 &T4 (2021-2022)
  - iii. 115 kV B5C/ B6C Circuits (2019-2020) [1]
- New projects:
  - i. 115 kV D7F/ D9F Circuits (2019-2020)[2]
  - ii. 230 kV D6V/ D7V Circuits (2019- 2020)[3]
  - iii. Hanlon TS - T1 & T2 (2023-2024)
  - iv. Kitchener MTS #5 - T9 & T10 (2023-2024)
  - v. Cedar TS - T7 & T8 (2024-2025)
  - vi. Scheifele MTS - T1 & T2 (2024-2026)
  - vii. Preston TS - T3 & T4 (2025-2026)

IV. Other Planning Considerations

The local municipalities in the region are extremely engaged and actively pursuing innovative ways to manage and/or reduce their energy needs over the next 10-20 Years. For example, several community energy plans have been developed in the region.

[1] Burlington TS to a CTS Line Section
[2] Tower 157 to Freeport Switching Station Line Section
[3] Guelph North Junction to Fergus TS Line Section

7. RECOMMENDATIONS

The Study Team's recommendations for the above identified needs are as follows:

a) The replacement of EOL station supply transformers at Campbell TS, Hanlon TS, Cedar TS, Kitchener MTS #5 and Preston TS along with the EOL auto transformers at Detweiler to proceed. Hydro One and the concerned LDCs will coordinate replacement of above equipment and develop replacement plans.

b) The refurbishment of EOL line sections 115 kV B5C/ B6C, D7F/ D9F and 230 kV D6V/ D7V to proceed. Hydro One will coordinate refurbishment of these line sections with affected LDCs/ Customer.

c) Hydro One will continue to work with Waterloo North Hydro Inc. to address the supply reliability issue at Elmira TS.

d) The Study Team has recommended that Hydro One Transmission and the Guelph Hydro Electric System Inc. to closely monitor the loading at the T3/T4 Campbell TS DESN and to balance the loads between these DESNs when required.

e) The Study Team recommends that the supply capacity needs with regards to Energy + MTS #2 and WNH MTS #4 be further assessed for optimization in the SA phase of regional planning. Once the optimization options are complete, Waterloo North Hydro and Energy+ shall conduct a technical and economic assessment in consultation with Hydro One.

f) The Study Team has recommended that community energy plans will be further considered in the SA phase of the regional planning process.

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1 INTRODUCTION

The first cycle of the Regional Planning process for the KWCG Region was completed in December 2015 with the publication of the Regional Infrastructure Plan ("RIP"). The RIP provided a description of needs and recommendations of preferred wires plans to address near- and medium-term needs. Waterloo North Hydro MTS #4 was the only need to be reviewed in this planning cycle.

The purpose of this Needs Assessment ("NA") is to identify new needs and to reconfirm needs identified in the previous KWCG regional planning cycle. Since the previous regional planning cycle, some new needs in the region have been identified.

This report was prepared by the KWCG Region Study Team ("Study Team"), led by Hydro One Networks Inc. Participants of the Study Team are listed below in Table 1. The report presents the results of the assessment based on information provided by the Hydro One, the Local Distribution Companies ("LDC") and the Independent Electricity System Operator ("IESO").

Table 1: KWCG Region Study Team Participants

Company
Centre Wellington Hydro
Energy+
Guelph Hydro Electric System Inc.
Halton Hills Hydro
Hydro One Networks Inc. (Lead Transmitter)
Hydro One Networks Inc. (Distribution)
Independent Electricity System Operator ("IESO")
Kitchener Wilmot Hydro Inc.
Milton Hydro
Waterloo North Hydro Inc.
Wellington North Power Inc.

2 REGIONAL ISSUE/TRIGGER

In accordance with the Regional Planning process, the Regional Planning cycle should be triggered at least every five years. In light of the timing of the needs identified in the previous IRRP and RIP reports as well as new replacement/ refurbishment identified needs in the KWCG Region, the 2nd Regional Planning cycle was triggered for the KWCG region.

3 SCOPE OF NEEDS ASSESSMENT

The scope of this NA covers the KWCG Region and includes:

- Identification of new needs based on latest information provided by the Study Team; and,
- Confirmation/updates of existing needs and/or plans identified in the previous planning cycle.

The Study Team may identify additional needs during the next phases of the regional planning process, namely Scoping Assessment ("SA"), Local Planning ("LP"), IRRP, and/or RIP.

4 REGIONAL DESCRIPTION AND CONNECTION CONFIGURATION

The KWCG Region covers the cities of Kitchener, Waterloo, Cambridge and Guelph, portions of Oxford and Wellington counties and the townships of North Dumfries, Puslinch, Woolwich, Wellesley and Wilmot. Electrical supply to the Region is provided from eleven 230 kV and thirteen 115 kV step-down transformer stations. The summer 2018 non-coincident regional loads were about 1390 MW. The approximate boundaries of the KWCG Region are shown below in Figure 1.

The main sources of electricity into the KWCG Region are from five Hydro One stations: Middleport TS, Buchanan TS, Detweiler TS, Orangeville TS and Burlington TS. At these stations electricity is transformed from 500 kV and 230 kV to 230 kV and 115 kV levels, respectively. Electricity is then delivered to the end users of LDCs and directly-connected industrial customers through 26 (TS/ MTS/ CTS) step-down transformer stations. Figure 2 illustrates these stations as well as the four major regional sub-systems: Waterloo-Guelph 230 kV sub-system, Cambridge-Kitchener 230 kV sub-system, Kitchener-Guelph 115 kV sub-system and South-Central Guelph 115 kV sub-system.

The summer non-coincident regional load forecast is provided as Appendix A. Appendix B lists all step-down transformer stations, Appendix C transmission circuits and Appendix D LDCs in the KWCG Region.

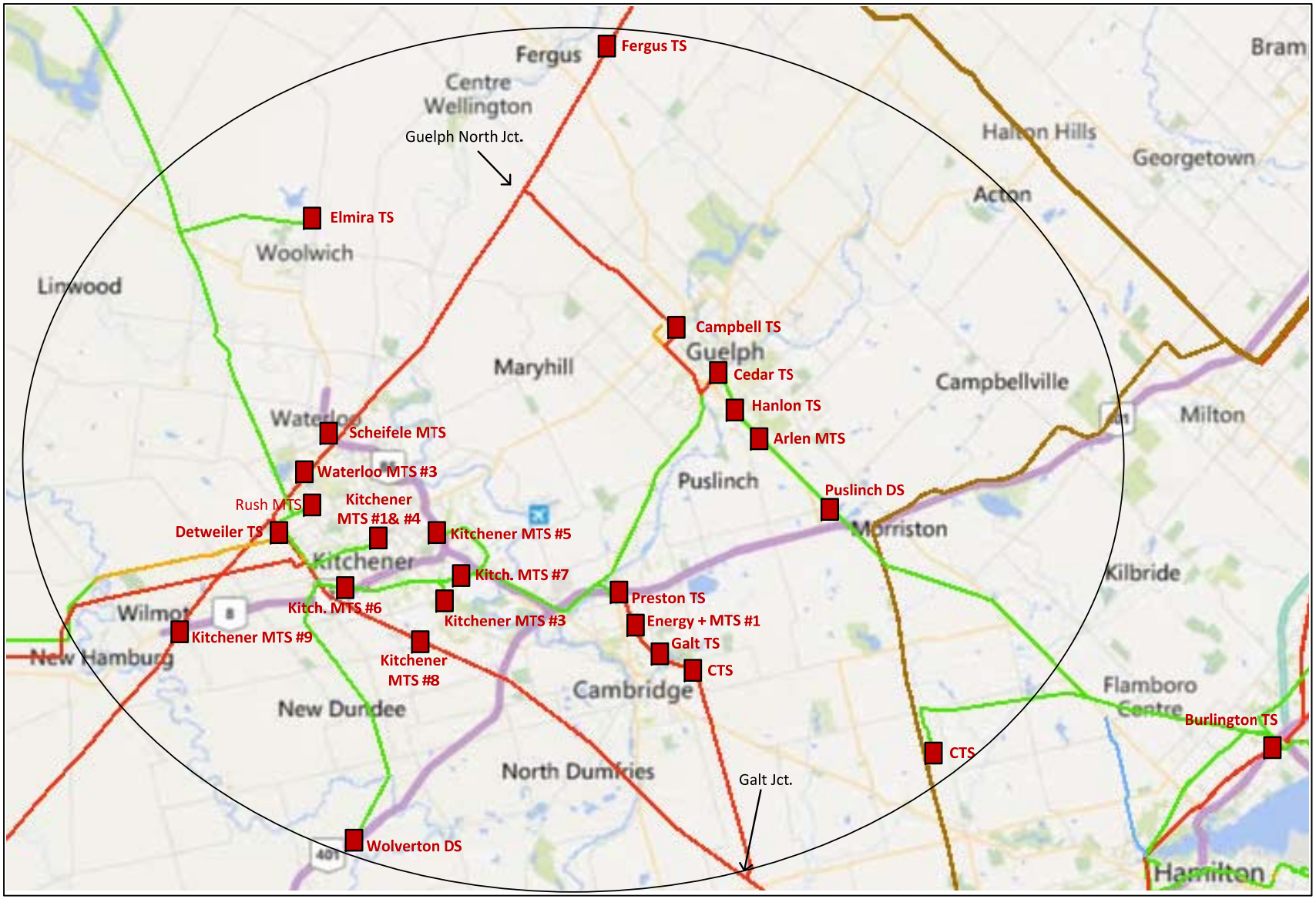


Figure 1: Geographical Area of the KWCG Region with Electrical Layout

An electrical single line diagram for the KWCG Region facilities is shown below in Figure 2.

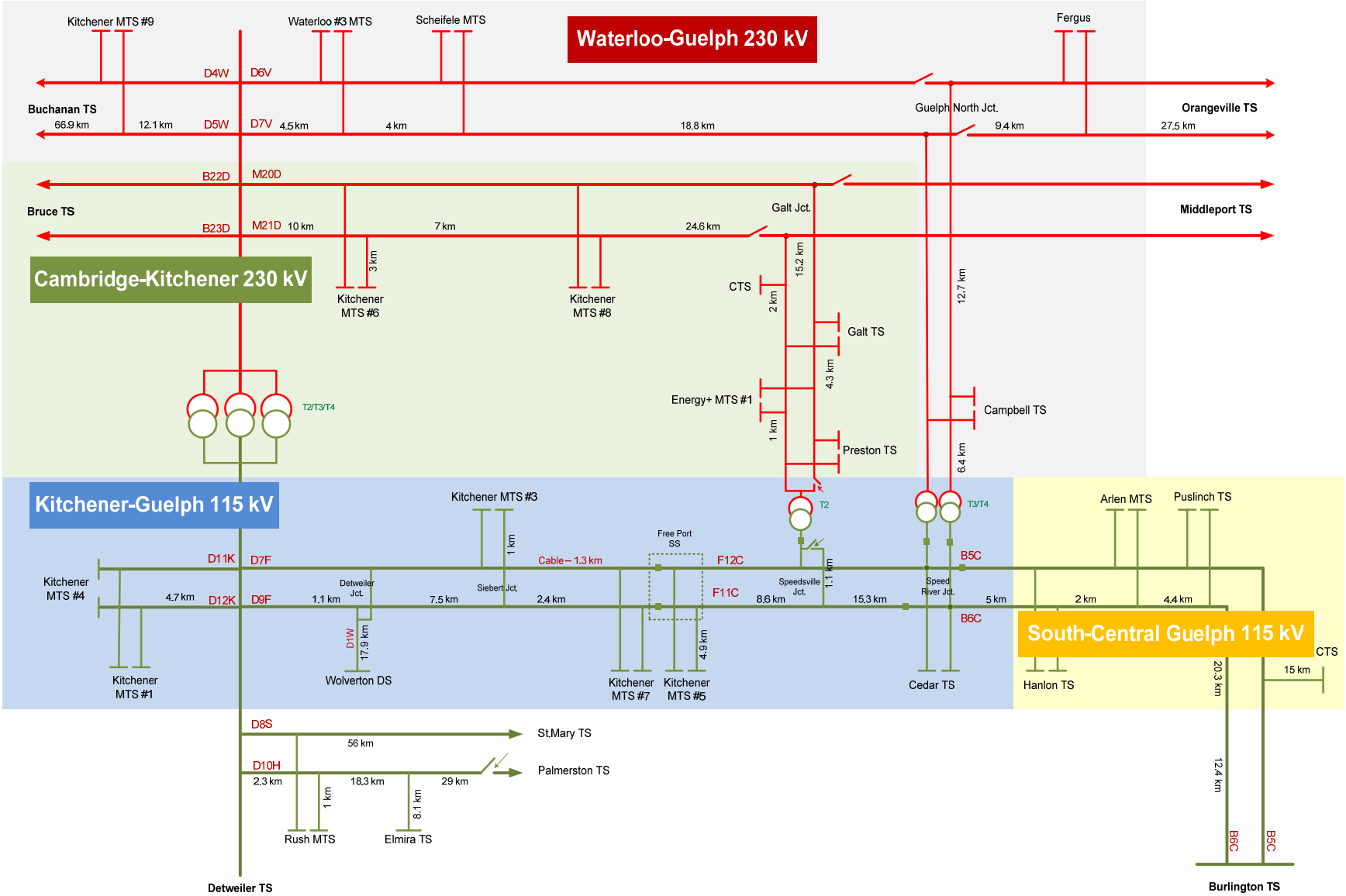


Figure 2: KWCG Region (Single Line Diagram)

5 INPUTS AND DATA

Study Team participants, including representatives from LDCs, IESO, and Hydro One provided information and input for the KWCG Region NA. The information provided includes the following:

- KWCG Load Forecast for all supply stations;
- Known capacity and reliability needs, operating issues, and/or major assets approaching the end of their useful life ("EOL"); and
- Planned/foreseen transmission and distribution investments that are relevant to regional planning for the KWCG Region.

6 ASSESSMENT METHODOLOGY

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

Information gathering included:

i. Load forecast: The relevant LDCs provided load forecasts for all the stations supplying their loads in the KWCG region for the 10 year study period. The IESO provided a Conservation and Demand Management ("CDM") and Distributed Generation ("DG") forecast for the KWCG region. The region's extreme summer non-coincident peak gross load forecast for each station were prepared by applying the LDC load forecast load growth rates to the actual 2018 summer peak extreme weather corrected loads. The extreme summer weather correction factors were provided by Hydro One. The net extreme weather summer load forecasts were produced by reducing the gross load forecasts for each station by the % age CDM and then by the amount of effective DG capacity provided by the IESO for that station. These extreme weather summer load forecast for the individual stations in the KWCG region is given in Appendix A;

ii. Relevant information regarding system reliability and operational issues in the region; and

iii. List of major HV transmission equipment planned and/or identified to be refurbished and/or replaced due to the end of their useful life which is relevant for regional planning purposes. This includes HV transformers, autotransformers, HV Breakers, HV underground cables and overhead lines.

A technical assessment of needs was undertaken based on:

- Current and future station capacity and transmission adequacy;
- System reliability and operational concerns; and
- Any major high voltage equipment reaching the end of its useful life.

In addition, Hydro One has reviewed the Community Energy Plans in the region. It is worth noting that there are several community energy plans in the region and some of them are meant to sustain at the

current level or reduce the community's reliance on the provincial electric system by meeting future electricity needs with local, distributed resources and/or community-based solutions. These plans may have potential to supplement and/or defer future transmission infrastructure development needs.

7 NEEDS

This section describes emerging needs identified in the KWCG Region, and also reaffirms the near, mid, and long-term needs already identified in the previous regional planning cycle.

The recent load forecast prepared for this report is lower than that of the previous cycle of regional planning. A contingency analysis was performed for the region and due to reduced load forecasts, as expected; no new system needs were identified.

The newly identified/emerging needs pertaining to this NA will be discussed further in the following sub-sections, while the status of the previously identified needs is summarized in Table 2 below.

Table 2: Needs Identified in the Previous Regional Planning Cycle

Type of Needs identified in the previous RP cycle	Needs Details	Current Status
115kV System Supply Capacity	**GATR Project** Two new additional 230/115kV autotransformers at Cedar TS to reinforce supply to both 115kV sub-systems in the region.	Completed
230kV Load Restoration Needs	**GATR Project** Two new additional 230 kV in-line switches on D6V/D7V circuits to improve restoration capability of Waterloo-Guelph 230 kV sub-system.	Completed
	Galt Junction Two new additional 230kV in-line switches on M20D/M21D circuits to improve restoration capability of the Cambridge-Kitchener 230 kV sub-system.	Completed
Station Short Circuit Capacity	**Arlen MTS** Install 13.8 kV series reactors to mitigate LV bus short circuit levels.	Completed
Station Transformation Capacity	New Waterloo North Hydro: MTS #4 (2024).	Need is now expected beyond 2029.

7.1 End-Of-Life (EOL) Equipment Needs

Hydro One and LDCs have provided high voltage asset information under the following categories that have been identified at this time and are likely to be replaced over the next 10 years:

- Autotransformers
- Power transformers
- HV breakers
- Transmission line requiring refurbishment where an uprating is being considered for planning needs and require Leave to Construct (i.e., Section 92) application and approval
- HV underground cables where an uprating is being considered for planning needs and require EA and Leave to Construct (i.e., Section 92) application and approval

Accordingly, following major high voltage equipment has been identified as approaching its end of useful life over the next 10 years.

Table 3: End-of-Life Equipment – KWCG Region

EOL Asset Replacement/ Refurbishment	Replacement/ Refurbishment Timing	Details
Projects in Execution		
Campbell TS (T1/T2 DESN): T1 Supply Transformer	2018	These Project are discussed further in Section 7.1.1
Detweiler TS: 230/ 115 kV T2/ T4 Auto-transformers	2021-2022	
115 kV B5C/ B6C: Burlington TS to Westover CTS Line Sections	2019-2020	
New Identified Projects		
115 kV D7F/ D9F : Tower #157 to Freeport SS Line Section	2019-2020	These Project are discussed further in Section 7.1.2
230 kV D6V/ D7V: Guelph North Jct. to Fergus Jct. Line Section	2019-2020	
Kitchener MTS #5[1]: T9/T10 Supply Transformers	2023-2024	
Hanlon TS: T1/T2 Supply Transformers	2023-2024	
Cedar TS: T7/T8 Supply Transformers	2024-2025	
Scheifele MTS[1]- T1/T2 Supply Transformers	2024-2026	
Preston TS: T3/T4 Supply Transformers	2025-2026	

[1] LDC owned assets

The end-of-life assessment for the above high voltage equipment typically included consideration of the following options:

1. Maintaining the status quo;
2. Replacing equipment with similar equipment of lower ratings and built to current standards;
3. Replacing equipment with lower ratings and built to current standards by transferring some load to other existing facilities;
4. Eliminating equipment by transferring all of the load to other existing facilities;
5. Replacing equipment with similar equipment and built to current standards (i.e., "like-for-like" replacement);
6. Replacing equipment with higher ratings and built to current standards; and
7. Station reconfiguration

Maintaining status quo is not an option for any of the above EOL autotransformer, station transformer or line sections due to risk of equipment failure, would result in increased maintenance cost and customer outages. Replacing "Like-for-Like" with nonstandard transformers would result in complexity with failures and difficulty in getting similar spare equipment along with their installation. Nonstandard equipment also poses serious safety risk for employees under normal and emergency situations.

No other lines or HV station equipment in the KWCG region have been identified for major replacement/ refurbishment at this time. If and when new and/or additional information is available, it will be provided during the next planning phase underway at the time.

7.1.1 Projects in Execution

The following end-of-life refurbishment needs are under execution. This region was deemed to be in transition and NA for this region was deemed complete. Hence, following projects were not listed or discussed in the first cycle of regional planning and are currently in execution:

Campbell TS – T1 Transformer

Campbell TS is located in the city of Guelph supplying Guelph Hydro Electric System Inc. loads. Campbell TS has two 230/ 13.8 kV DESNs T1/T2 and T3/T4 of 75 MVA transformers with an LTR of 105 MVA (94 MW @ 0.9 PF) and 63 MVA (56 MW @ 0.9 PF) respectively. The loads on these two DESNs are currently forecasted to be about 87 MW and 66 MW respectively by the end of study period.

The 75 MVA T1/T2 DESN transformer T2 failed in 2017 and was replaced with a new standard 100 MVA unit and transformer T1 is also being replaced with a similar unit. In 2021-2022, Hydro One in addition plans to replace the secondary equipment limiting the station LTR. This will result in sufficient LTR of about 130 MVA for T1/T2 DESN, over the study period.

The replacement of T1 transformer is currently in execution and expected to be completed by the end of year 2018.

Detweiler TS - T2 & T4 Autotransformers

Detweiler TS is a Bulk System, major switching and autotransformer station located in the city of Kitchener. Detweiler TS facilities include a 230 kV switchyard, three 230/115 kV autotransformers (T2/T3/T4) and a 115 kV switchyard.

The Detweiler TS autotransformers T2/T3/ T4 were built in 1959, 2004 and 1963 respectively. The condition assessment has identified T2 and T4 autotransformers as EOL requiring replacement. At this time none of other HV equipment at this station has been identified as approaching EOL over the next 5-10 years.

Not replacing these auto transformers would increase risk of failure due to asset condition, maintenance expenses and reduce supply reliability to the customers. The replacement of both the EOL Detweiler TS T2 and T4 autotransformers with similar units is in execution expected to be completed in 2021-22. This will address the 230/ 115 kV transformation needs at Detweiler TS and maintain station's operability and reliability of supply.

Any Detweiler TS 230 kV system reconfiguration needs will be studied under bulk system planning expected to commence in early 2019.

115 kV B5C/ B6C Line Sections

The 115 kV B5C/B6C circuits consist of about 45 km of double circuit line and 15 km of single circuit line supplying South-Central Guelph 115 kV loads. About 12 km of double circuit line section from Burlington TS to Harper's Jct. and about 15 km B5C 115 kV line tap from Harper's Jct. to a Westover Jct. requires refurbishment.

Not refurbishing these line sections would increase risk of failure due to asset condition, maintenance expenses and reduce supply reliability to the customers.

The refurbishment of this 27 km long 115 kV B5C/B6C line sections from Burlington TS to a CTS is currently under execution and the work is planned to be completed by the end of year 2019.

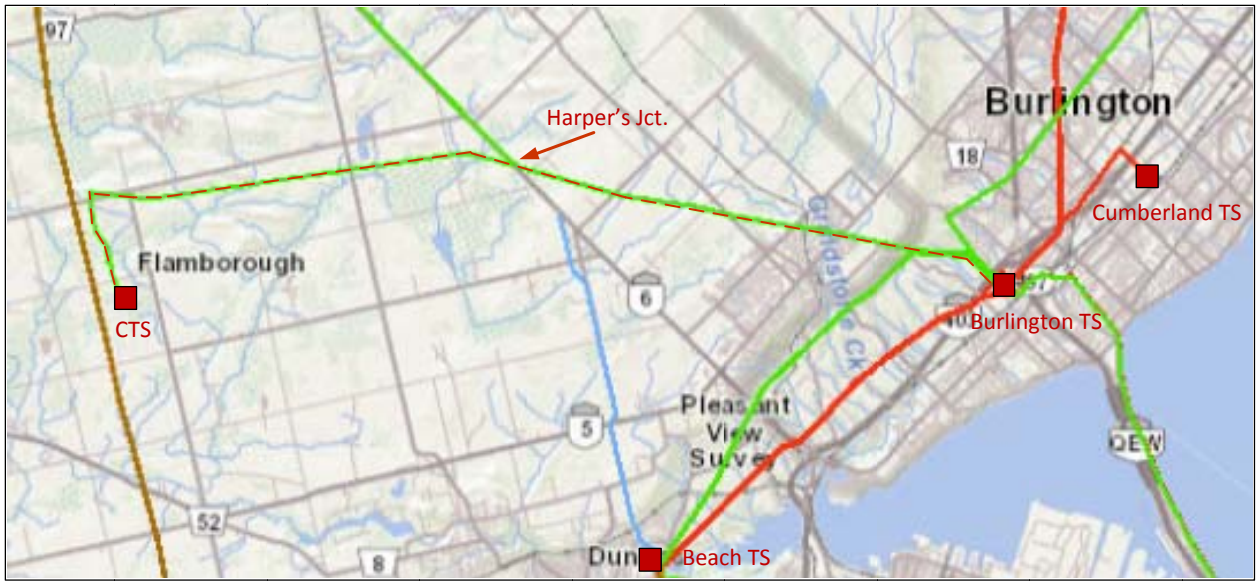


Figure 3: Burlington TS to Harper's Jct. to CTS B5C/ B6C Line Sections

7.1.2 New Needs

The following end-of-life refurbishment needs have been identified in this regional planning cycle:

115 kV D7F/D9F Line Section

The 115 kV D7F/ D9F double circuit line is about 12 km long supplying Kitchener- Guelph 115 kV loads. The 115 kV D7F/ D9F double circuit 450 meter line section from Tower 157 to Freeport Switching Station was built in 1951. It is approaching end of life and requires refurbishment.

Not refurbishing this line section would increase risk of failure due to asset condition, maintenance expenses and reduce supply reliability to the customers.

Therefore the Study Team recommends Hydro One to continue with refurbishment of the 450 meter long 115 kV D7F/ D9F end of life line section from Tower 157 to Freeport Switching Station. This project is currently under estimating and is planned to be completed by the end of year 2019.

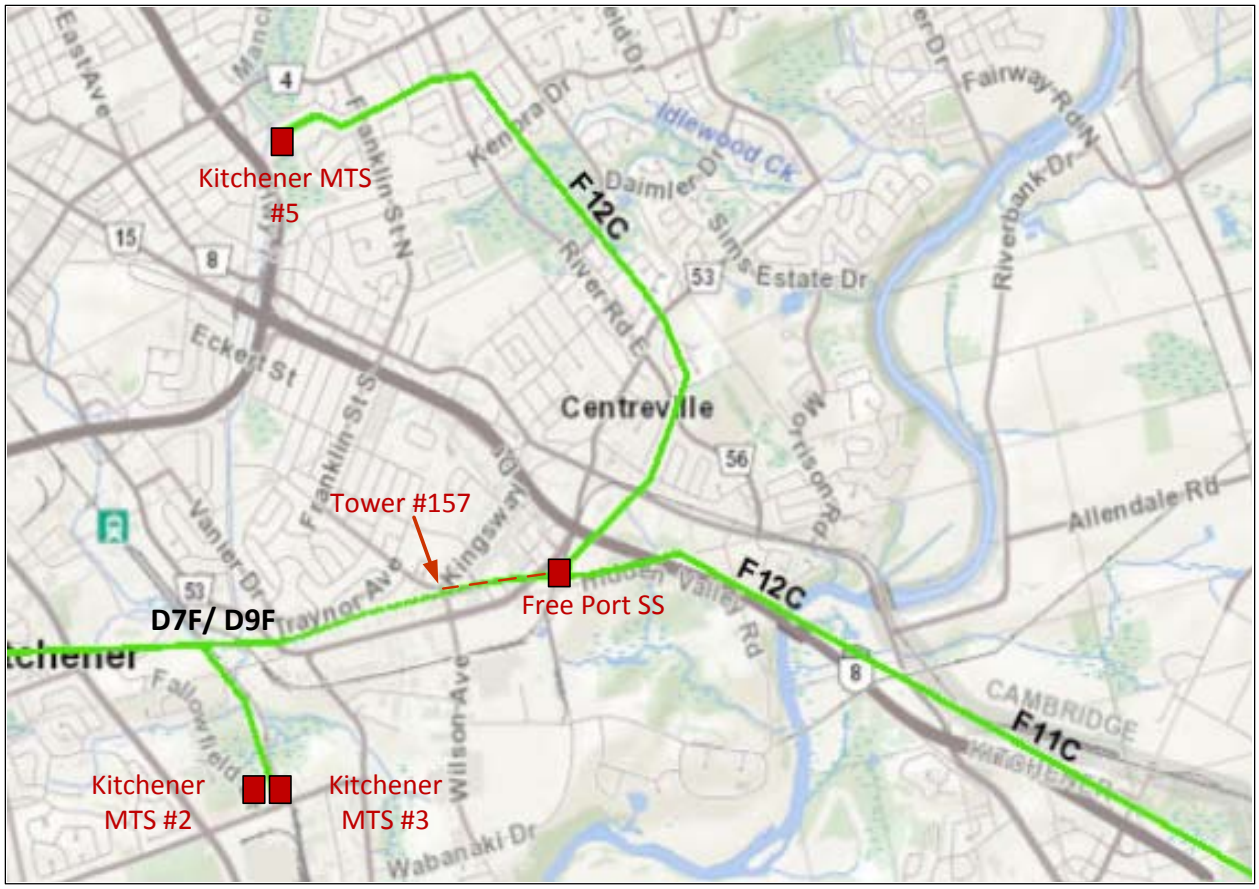


Figure 4: Tower #157 Jct. to Freeport SS F11C/ F12C Line Section

230 kV D6V/D7V Line Section

The 230 kV D6V/D7V double circuit line is about 84 km long and is part of bulk power system supplying loads in the Waterloo Guelph 230kV and South Central Guelph 115 kV loads. A 230 kV D6V/ D7V 9.5 km double circuit line section from Guelph North junction to Fergus TS was built in 1950's and its conductor is approaching end of life. It requires refurbishment.

Not refurbishing this line section would increase risk of failure due to asset condition, maintenance expenses and reduce supply reliability to the customers.

Therefore the Study Team recommends to refurbish this the 9.5 km long 230 kV D6V/D7V end of life line section from Guelph North Junction to Fergus TS. This project is currently under estimating and is planned to be completed by the end of year 2019.



Figure 5: Guelph North Jct. to Fergus TS D6V/ D7V Line Section

Kitchener MTS #5 T9/T10 Transformers

Kitchener MTS #5 is located in the city of Kitchener supplying Kitchener-Wilmot Hydro Inc. loads. Kitchener MTS #5 is a 115/ 13.8 kV single T9/T10 DESN station of 83 MVA nonstandard transformers having a LTR of 89 MVA (80 MW @ 0.9 PF), currently supplying 67 MW of peak load. The loads at Kitchener MTS #5 are currently forecasted to remain flat over the entire study period. The supply capacity of this station is therefore expected to be sufficient over and beyond the study period.

Both the T9/T10 transformers at this station have been identified as approaching end of life requiring replacement. At this time none of other HV/LV equipment at this station has been identified as approaching EOL over the next 5-10 years.

The station cannot be downsized or eliminated because there is no nearby supply station/s to Kitchener MTS #5 having surplus capacity where this station's loads can be transferred. The Study Team recommends replacing the T9/T10 nonstandard transformers with standard units of similar size is the preferred option. Kitchener-Wilmot Hydro Inc. and Hydro One will coordinate the replacement plan of these transformers. The replacement of the EOL equipment is expected to be completed by 2023-2024.

Hanlon TS T1/T2 Transformer

Hanlon TS is located south of the city of Guelph supplying Guelph Hydro Electric System Inc. loads. Hanlon TS is a single T1/T2 DESN station of 33 MVA nonstandard transformers having a LTR of 48

MVA (43 MW @ 0.9 PF). This station is currently supplying about 27 MW of peak load. The loads at Hanlon TS are currently forecasted to remain flat over the entire study period. The supply capacity of this station is therefore expected to be sufficient over and beyond the study period.

The T1/T2 transformers are of 1955/ 56 built and have been identified as EOL requiring replacement. At this time none of other HV/LV equipment at this station has been identified as approaching EOL over the next 5-10 years.

There is no nearby supply station/s to Hanlon TS having surplus capacity where this station's loads can be transferred therefore Hydro One plans to replace these EOL transformers with standard size units of 42 MVA in 2023-2024.

Cedar TS – T7/ T8 Transformers

Cedar TS is located in the city of Guelph supplying Guelph Hydro Electric System Inc. loads. Cedar TS has two 115/ 13.8 kV DESN units T1/T2 and T7/T8 of 75 MVA with a LTR of 115 MVA (103 MW @ 0.9 PF) and 37 MVA with a LTR of 44 MVA (40 MW @ 0.9 PF), currently supplying 67 MW and 36 MW of peak loads respectively. The loads at both Cedar TS DESNs are currently forecasted to remain almost flat over the entire study period. The supply capacity of this station is therefore expected to be sufficient over and beyond the study period.

The T7/T8 DESN 38 MVA nonstandard transformers are of 1958 built have been identified for replacement. The T1/T2 transformers are relatively newer and were built in early 1990s. At this time none of other HV/LV equipment at this station has been identified as approaching EOL over the next 5-10 years.

The station cannot be downsized or eliminated because there is no nearby supply station/s to Cedar TS having surplus capacity where this station's loads can be transferred therefore Hydro One plans to replace these EOL transformers with standard size units of 42 MVA in 2024-2025 timeframe.

Cedar TS and Hanlon TS Optimization with Neighbouring Stations

After performing an analysis of the current distribution situation, it was determined that there are not enough spare feeder positions at HONI and GHESI stations to reallocate DESN loads in the sub-system without significant distribution system and neighboring station upgrades.

Over loading of Campbell DESN T3/T4 will be effectively managed by load transfer to DESN T1/T2 after 2021/22. Following that there will be no additional capacity at these two DESNs.

Secondly, Hanlon TS DESN has eight (8) feeders with three (3) being dedicated underground infrastructure to existing customers, two (2) feeders supplying the industrial load in the Hanlon Industrial Park, two (2) feeder circuits supplying residential load north of Hanlon TS and one (1) feeder to be utilized for planned future load growth at Gordon/ Clair. In addition, due to technical limitations at 13.8 kV distribution voltage and density of load on certain feeders sections, it is not possible to supply existing

loads from any other station without significant transmission and distribution investments. Therefore there are little or no significant optimization opportunity is present at this point in time. Option considered for load transfer will require significant new investment; for example:

- The two residential distribution feeders supplying loads north of Hanlon TS could be transferred to existing feeders out of Cedar TS. These load transfers will result in increased line losses and reduced capacity (due to voltage drop)
- Another option could be transferring remaining Hanlon TS load to Arlen MTS. This load transfer will require an additional DESN and underground infrastructure at Arlen MTS.

Hence, the Study Team recommends that Hydro One undertakes replacement of Cedar TS T7/T8 and Hanlon TS T1/T2 transformers with 42 MVA standard size units, being technically and economical most suitable solution. The replacement of EOL equipment is expected to be completed by 2023-2025 timeframe for both stations.

Scheifele MTS – T1/ T2 Transformers

Scheifele MTS is located in the city of Waterloo supplying Waterloo North Hydro Inc. loads. Scheifele MTS has four 230/ 13.8 kV transformers T1 and T2 of 67 MVA, and T3 and T4 of 83 MVA currently supplying 145 MW of peak loads. The load at this station is forecasted to remain almost flat over the entire study period. The total supply capacity of Scheifele MTS is 161 MW expected to be sufficient over the study period.

The T1/T2 transformers based on their age have been identified by Waterloo North Hydro Inc. as approaching end of life potentially requiring replacement in the 2024- 2026 timeframe. Waterloo North Hydro will be monitoring the condition of these transformers to assess their replacement need. At this time none of other HV/LV equipment at this station has been identified as approaching EOL over the next 5-10 years.

The station cannot be downsized or eliminated because there is no nearby supply station/s to Scheifele MTS having surplus capacity where this station's loads can be transferred. The Study Team recommends that Waterloo North Hydro continue monitoring the condition of these T1/T2 transformers at Scheifele MTS and this need to be reassessed in the next regional planning cycle.

Preston TS T3/T4 Transformers

Preston TS (DESN) is located in the city of Cambridge supplying Energy+ loads. Preston TS is a single T3/T4 DESN station of 125 MVA transformers with no additional LTR capability available i.e. 125 MVA (113 MW @ 0.9 PF). This station is currently supplying about 92 MW of peak load. The loads at Preston TS are currently forecasted to peak at about 102 MW during the study period.

The T3/T4 transformers are almost 50 years old, having been built in 1968. Condition assessment has identified that both T3/T4 transformers at their EOL requiring replacement. At this time none of other HV/LV equipment at this station has been identified as EOL over the next 5-10 years.

The station cannot be downsized or eliminated because there is no nearby supply station/s to Preston TS having spare supply capacity where this station's loads can be transferred. The Study Team recommends replacing the existing 125 MVA 230/ 27.6 kV T3/T4 transformers at Preston TS with 125 MVA standard units. This will also result in an increased supplying capacity at Preston TS required to meet the future Energy+ needs in the Cambridge distribution area. The replacement plan for the equipment will be developed by Hydro One and coordinated with the affected LDC and/or customers and it is expected to be completed by 2025-2026.

7.2 Supply Reliability Needs

Supply reliability of Elmira TS –D10H 115 kV Line

The 115 kV D10H circuit between Detweiler TS and Hanover TS supplies loads at Rush MTS, Elmira TS and Palmerston TS. The D10H circuit has a normally open point just south of Palmerston TS through a motorized disconnect switch. The northern section of D10H is supplied from Hanover TS radially supplying Palmerston TS loads. The southern section of D10H supplied from Detweiler TS radially supplies Waterloo North Hydro's 34 MW Elmira TS peak loads. D10H also supplies Rush MTS which is also supplied by 115 kV D8S circuit from Detweiler TS.

The normally open motorized switch near Palmerston TS helps restore the loads at Elmira TS from Hanover TS in-case supply from Detweiler TS is interrupted and similarly helps restoring Palmerston TS loads from Detweiler if supply from Hanover is interrupted.

In last three years, supply to Elmira TS from Detweiler TS resulted in 3 outages due to faults on the D10H line section between Elmira TS tap and Detweiler TS. The Elmira TS load restoration from Hanover TS is slower due to manually operated disconnect switches at Elmira TS tap location.

Hydro One is currently assessing the condition of line and will continue to work with Waterloo North Hydro to address the supply reliability at Elmira TS. The developed mitigation plan to improve supply reliability of Elmira TS loads will be included in the final RIP report.

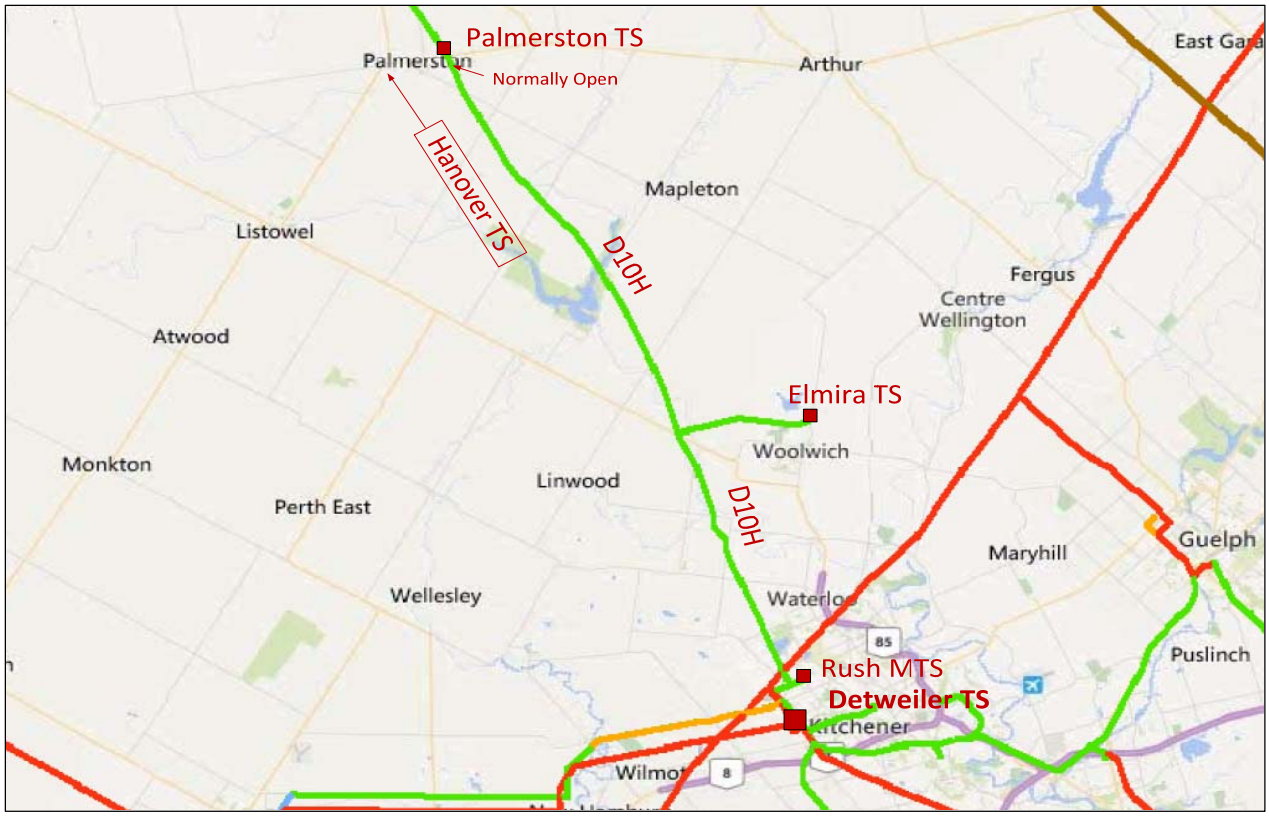


Figure 6: D10H 115 kV Line (Burlington TS to Elmira TS)

7.3 Station and Transmission Capacity Needs in the KWCG Region

The following Station and Transmission supply capacities needs have been identified in the KWCG region during the study period of 2019 to 2028.

7.3.1 Campbell TS (T3/T4) DESN Overloading

There are two DESN stations inside Campbell TS boundary. Both the T1/T2 and T3/T4 DESNs are 230 kV/ 13.8 kV having supply capacities of 94 MW and 56 MW, currently supplying 84 MW and 52 MW of loads respectively. The 75 MVA transformer T2 recently failed and was replaced with a Hydro One standard 100 MVA unit. The transformer T1 is also being replaced with a similar 100 MVA unit by the end of 2018. The load at T3/T4 DESN is forecasted to exceed its supply capacity of 56 MW in the 2021-2022 timeframe.

At Campbell TS, after replacement of T1 transformer and secondary equipment there will be sufficient spare supply capacity on T1/T2 DESN where excess T3/T4 DESN loads can be transferred. Hydro One Transmission and the Guelph Hydro Electric System Inc. will monitor the loading at the T3/T4 Campbell TS DESN and will balance the loads between the two DESNs, when required. The Study Team therefore recommends that no further action is required at this time.

7.3.2 Waterloo North Hydro MTS #4

During the last regional planning cycle a need for a new MTS #4 DESN was identified in the 2024 timeframe. The current load forecast defers this need beyond the needs assessment study period.

7.3.3 Energy+ MTS #2

Energy+ has initially identified a future need for a new DESN station (MTS #2) in the city of Cambridge near Preston TS. This station need is due to a potential new load center growth in their service territory. The additional supply capacity due to EOL transformer replacement and available new feeder positions at Preston TS, will defer this new MTS need beyond the study period of current regional planning cycle.

WNH MTS #4 and Energy+ MTS #2 Optimization

The Preston TS like-for-like transformer replacement is critical for local supply needs and will proceed according to the current plan. However, study team recommends that the supply capacity needs with regards to Energy + MTS #2 and WNH MTS #4 be further assessed for optimization in the next phases of regional planning. Once the optimization options are complete, Waterloo North Hydro and Energy+ shall conduct a technical and economic assessment in consultation with Hydro One.

7.4 Other Planning Considerations in the KWCG Region

Municipalities in KWCG region have developed their community energy plans with a primary focus to reduce their energy consumption by local initiatives over next 25 to 30 years. With respect to electricity, these communities are planning for an increased reliance on community energy sources such as distributed generation, generation behind the meters like rooftop solar systems and local battery storage systems to reduce cost and for improved reliability of electricity supply.

There are situations where behind the meter battery storage cannot be connected due to technical constraints. The LDCs in this region and Hydro One, outside the regional planning forum, can undertake the task of exploring the issue to assess technical constraints and /or other solutions that can facilitate connection of additional battery storage.

Communities are also working towards self-sufficiency by improving efficiencies of existing local energy systems i.e. reducing energy consumption and losses by means of utilizing smarter buildings, houses, efficient heating, cooling, appliances, equipment, and processes for all community needs. Ultimately, the objective of these energy plans in the region is to be a net zero carbon community.

Community energy plans may have potential to supplement and/or defer future transmission infrastructure development needs. The Study Team therefore recommends reviewing the community energy plans in the SA phase.

8 CONCLUSION AND RECOMMENDATIONS

Hydro One and Waterloo North Hydro Inc. will develop a supply reliability improvement plan for Elmira TS loads. The developed local plan to improve supply reliability of Elmira TS loads will be included in the final RIP report.

At Campbell TS, after replacement of T1 transformer and addressing the secondary equipment limitations there will be sufficient spare supply capacity on T1/T2 DESN to accommodate T3/T4 DESN overloading. Hydro One and the LDC will work together to balance loads between the two Campbell TS DESNs, when required.

The distribution system in the Cedar TS, Hanlon TS and Arlen MTS supply area is already optimized and there are not enough spare feeder positions at any of the stations to reallocate DESN loads without significant distribution system investments and upgrades at neighboring stations.

The Study Team's recommendations for the above identified needs are as follows:

a) The replacement of EOL station supply transformers at Campbell TS, Hanlon TS, Cedar TS, Kitchener MTS #5 and Preston TS along with the EOL auto transformers at Detweiler to proceed. Hydro One and the concerned LDCs will coordinate replacement of above equipment and develop replacement plans.

b) The refurbishment of EOL line sections 115 kV B5C/ B6C, D7F/ D9F and 230 kV D6V/ D7V to proceed. Hydro One will coordinate refurbishment of these line sections with affected LDCs/ Customer.

c) Hydro One will continue to work with Waterloo North Hydro Inc. to address the supply reliability issue at Elmira TS.

d) The Study Team has recommended that Hydro One Transmission and the Guelph Hydro Electric System Inc. to closely monitor the loading at the T3/T4 Campbell TS DESN and to balance the loads between these DESNs when required.

e) The Study Team recommends that the supply capacity needs with regards to Energy + MTS #2 and WNH MTS #4 be further assessed for optimization in the SA phase of regional planning. Once the optimization options are complete, Waterloo North Hydro and Energy+ shall conduct a technical and economic assessment in consultation with Hydro One.

f) The Study Team has recommended that community energy plans will be further considered in the SA phase of the regional planning process.

9 REFERENCES

[1] KWCG Regional Infrastructure Plan - December 2015

[2] Planning Process Working Group Report to the Ontario Energy Board - May 2013

[3] Ontario Resource and Transmission Assessment Criteria (ORTAC) – Issue 5.0 -August 2007

Appendix A: KWCG Region Non-Coincident Summer Load Forecast

* LTR based on 0.9 power factor

Transformer Station		Summer 10 Day LTR*	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Arlen MTS	Gross	45	24.44	25.17	25.92	26.70	27.50	28.33	29.18	30.05	30.95	31.88	32.84	33.82
	CDM		0.00	0.22	0.28	0.44	0.57	0.79	1.12	1.50	2.05	2.71	3.40	3.99
	DG		0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
	Net		24.42	24.94	25.64	26.25	26.92	27.53	28.04	28.54	28.89	29.16	29.43	29.83
Campbell TS (T1/T2)	Gross	94	83.46	84.71	85.98	87.27	88.58	89.91	91.26	92.63	94.02	95.43	96.86	98.31
	CDM		0.00	0.72	0.91	1.44	1.83	2.50	3.51	4.63	6.22	8.11	10.03	11.59
	DG		0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
	Net		83.45	83.98	85.06	85.82	86.75	87.40	87.74	87.99	87.78	87.30	86.82	86.72
Campbell TS (T3/T4)	Gross	56	51.62	53.42	55.29	57.23	59.23	61.30	63.45	65.67	67.97	70.35	72.81	75.36
	CDM		0.00	0.46	0.59	0.94	1.22	1.70	2.44	3.28	4.50	5.98	7.54	8.88
	DG		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Net		51.62	52.97	54.71	56.28	58.01	59.60	61.01	62.39	63.47	64.37	65.27	66.48
Cedar TS (T1/T2)	Gross	103	67.35	67.69	68.03	68.37	68.71	69.05	69.40	69.75	70.09	70.44	70.80	71.15
	CDM		0.00	0.58	0.72	1.13	1.42	1.92	2.67	3.49	4.64	5.99	7.33	8.38
	DG		0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
	Net		67.30	67.06	67.26	67.19	67.24	67.09	66.68	66.21	65.40	64.41	63.42	62.72
Cedar TS (T7/T8)	Gross	40	35.63	35.80	35.98	36.16	36.34	36.53	36.71	36.89	37.08	37.26	37.45	37.63
	CDM		0.00	0.31	0.38	0.60	0.75	1.01	1.41	1.85	2.45	3.17	3.88	4.44
	DG		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Net		35.63	35.50	35.60	35.57	35.59	35.51	35.29	35.05	34.62	34.09	33.57	33.20
Elmira TS	Gross	55	34.19	34.62	35.04	35.38	35.73	36.06	36.39	36.71	37.05	37.40	37.75	38.10
	CDM		0.00	0.30	0.37	0.58	0.74	1.00	1.40	1.84	2.45	3.18	3.91	4.49
	DG		0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
	Net		34.17	34.31	34.65	34.78	34.98	35.04	34.97	34.86	34.58	34.20	33.83	33.60
Energy+ MTS #1	Gross	102	84.03	84.87	85.72	86.58	87.44	88.53	89.64	90.76	91.90	93.05	94.21	95.39
	CDM		0.00	0.73	0.91	1.43	1.80	2.46	3.45	4.54	6.08	7.91	9.75	11.24
	DG		0.32	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49
	Net		83.71	83.65	84.31	84.65	85.15	85.58	85.70	85.73	85.32	84.64	83.96	83.65
Fergus TS	Gross	154	87.52	88.57	89.62	90.27	90.96	91.52	92.07	92.62	93.20	93.83	94.45	95.05
	CDM		0.00	0.76	0.95	1.49	1.87	2.54	3.54	4.63	6.17	7.98	9.78	11.20
	DG		0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
	Net		87.47	87.77	88.62	88.73	89.03	88.92	88.48	87.94	86.98	85.80	84.62	83.80
Galt TS	Gross	169	113.56	114.69	115.84	117.00	118.17	119.64	121.14	122.65	124.19	125.74	127.31	128.90
	CDM		0.00	0.98	1.23	1.93	2.44	3.32	4.66	6.14	8.22	10.69	13.18	15.19
	DG		0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21
	Net		113.35	113.51	114.40	114.86	115.53	116.11	116.27	116.31	115.76	114.84	113.93	113.51
Hanlon TS	Gross	43	26.85	27.25	27.66	28.08	28.50	28.93	29.36	29.80	30.25	30.70	31.16	31.63
	CDM		0.00	0.23	0.29	0.46	0.59	0.80	1.13	1.49	2.00	2.61	3.23	3.73
	DG		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Net		26.85	27.02	27.37	27.62	27.91	28.12	28.23	28.31	28.25	28.09	27.94	27.90
Kitchener MTS # 1	Gross	54	31.31	33.64	34.72	35.81	36.90	37.76	38.60	39.46	40.31	41.16	42.02	42.87
	CDM		0.00	0.29	0.37	0.59	0.76	1.05	1.49	1.97	2.67	3.50	4.35	5.05
	DG		0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
	Net		31.28	33.33	34.33	35.19	36.11	36.68	37.09	37.47	37.62	37.64	37.65	37.79
Kitchener MTS # 3	Gross	108	46.73	45.03	45.34	46.05	46.78	47.49	48.22	48.93	49.64	50.37	51.08	51.81
	CDM		0.00	0.38	0.48	0.76	0.96	1.32	1.86	2.45	3.29	4.28	5.29	6.11
	DG		0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
	Net		46.71	44.63	44.83	45.27	45.79	46.15	46.34	46.46	46.34	46.06	45.77	45.68

Transformer Station		Summer 10 Day LTR*	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Kitchener MTS # 4	Gross	90	58.39	59.76	60.63	61.49	62.36	63.05	63.73	64.41	65.09	65.77	66.46	67.13
	CDM		0.00	0.51	0.64	1.01	1.29	1.75	2.45	3.22	4.31	5.59	6.88	7.91
	DG		0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
	Net		58.34	59.19	59.93	60.43	61.02	61.24	61.22	61.14	60.73	60.12	59.52	59.17
Kitchener MTS #5	Gross	80	66.56	67.94	68.82	69.70	70.58	71.28	71.96	72.66	73.35	74.03	74.73	75.42
	CDM		0.00	0.58	0.73	1.15	1.45	1.98	2.77	3.63	4.86	6.29	7.74	8.89
	DG		0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06
	Net		66.50	67.31	68.03	68.49	69.07	69.24	69.14	68.97	68.43	67.68	66.94	66.47
Kitchener MTS #6	Gross	90	64.17	62.22	62.97	63.71	64.47	65.21	65.96	66.70	67.44	68.19	68.93	69.68
	CDM		0.00	0.53	0.67	1.05	1.33	1.81	2.54	3.34	4.46	5.80	7.14	8.21
	DG		0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09
	Net		64.08	61.60	62.21	62.57	63.04	63.30	63.33	63.27	62.88	62.30	61.70	61.38
Kitchener MTS #7	Gross	54	42.79	43.98	44.69	45.38	46.08	46.77	47.47	48.16	48.85	49.55	50.24	50.95
	CDM		0.00	0.38	0.48	0.75	0.95	1.30	1.83	2.41	3.23	4.21	5.20	6.00
	DG		0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
	Net		42.77	43.59	44.19	44.61	45.11	45.45	45.63	45.73	45.60	45.32	45.03	44.92
Kitchener MTS #8	Gross	54	38.68	39.94	41.18	42.44	43.70	45.62	47.53	49.45	51.38	53.30	55.21	57.13
	CDM		0.00	0.34	0.44	0.70	0.90	1.27	1.83	2.47	3.40	4.53	5.71	6.73
	DG		0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06
	Net		38.62	39.54	40.69	41.68	42.74	44.30	45.65	46.92	47.92	48.71	49.44	50.34
Kitchener MTS #9	Gross	90	30.16	30.72	31.28	31.83	32.39	32.94	33.50	34.05	34.61	35.17	35.73	36.27
	CDM		0.00	0.26	0.33	0.52	0.67	0.92	1.29	1.70	2.29	2.99	3.70	4.27
	DG		0.23	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50
	Net		29.94	29.96	30.45	30.80	31.22	31.53	31.71	31.85	31.82	31.68	31.53	31.50
Preston TS	Gross	113	92.38	95.15	98.00	100.94	103.97	105.27	106.59	107.92	109.27	110.63	112.02	113.42
	CDM		0.00	0.81	1.04	1.67	2.14	2.92	4.10	5.40	7.23	9.41	11.60	13.37
	DG		0.00	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19
	Net		92.38	94.14	96.76	99.08	101.63	102.15	102.29	102.33	101.84	101.03	100.23	99.86
Puslinch DS	Gross	56	28.49	29.24	30.01	30.45	30.92	31.30	31.68	32.05	32.45	32.88	33.31	33.72
	CDM		0.00	0.25	0.32	0.50	0.64	0.87	1.22	1.60	2.15	2.80	3.45	3.97
	DG		0.02	0.02	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15
	Net		28.47	28.98	29.54	29.80	30.14	30.29	30.31	30.30	30.16	29.94	29.71	29.60
Rush MTS	Gross	68	45.33	46.24	47.16	48.11	49.07	50.05	51.05	52.07	53.11	54.17	55.26	56.36
	CDM		0.00	0.40	0.50	0.79	1.01	1.39	1.97	2.60	3.52	4.61	5.72	6.64
	DG		0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
	Net		45.30	45.81	46.63	47.28	48.03	48.63	49.06	49.44	49.57	49.54	49.51	49.69
Scheifele MTS	Gross	161	144.78	146.96	149.16	151.39	153.67	155.98	158.32	160.69	163.11	165.55	168.04	170.56
	CDM		0.00	1.26	1.59	2.50	3.17	4.33	6.10	8.04	10.80	14.08	17.39	20.10
	DG		0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08
	Net		144.70	145.62	147.49	148.81	150.42	151.56	152.14	152.57	152.23	151.40	150.56	150.38
WNH MTS #3	Gross	77	56.29	57.42	58.57	59.74	60.93	62.15	63.39	64.66	65.95	67.27	68.62	69.99
	CDM		0.00	0.49	0.62	0.99	1.26	1.73	2.44	3.23	4.37	5.72	7.10	8.25
	DG		0.06	0.06	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15
	Net		56.23	56.87	57.80	58.61	59.53	60.28	60.81	61.28	61.44	61.41	61.37	61.60
Wolverton DS	Gross	54	18.42	18.73	19.05	19.19	19.35	19.47	19.59	19.71	19.83	19.98	20.12	20.25
	CDM		0.00	0.16	0.20	0.32	0.40	0.54	0.75	0.99	1.31	1.70	2.08	2.39
	DG		0.00	0.00	0.00	0.00	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19
	Net		18.41	18.57	18.84	18.87	18.76	18.74	18.64	18.53	18.33	18.08	17.84	17.67
CTS	Net		9.80	9.80	9.80	9.80	9.80	9.80	9.80	9.80	9.80	9.80	9.80	9.80

Appendix B: Lists of Step-Down Transformer Stations

Sr. No.	Transformer Stations
1.	Arlen MTS
2.	Campbell TS (T1/T2)
3.	Campbell TS (T3/T4)
4.	Cedar TS (T1/T2)
5.	Cedar TS (T7/T8)
6.	Elmira TS
7.	Energy+ MTS #1
8.	Fergus TS
9.	Galt TS
10.	Hanlon TS
11.	Kitchener MTS # 1
12.	Kitchener MTS # 3
13.	Kitchener MTS # 4
14.	Kitchener MTS #5
15.	Kitchener MTS #6
16.	Kitchener MTS #7
17.	Kitchener MTS #8
18.	Kitchener MTS #9
19.	Preston TS
20.	Puslinch DS
21.	Rush MTS
22.	Scheifele MTS
23.	Waterloo North MTS 3
24.	Wolverton DS
25.	CTS - 1
26.	CTS - 2

Appendix C: Lists of Transmission Circuits

Sr. No.	Circuit ID	From Station	To Station	Voltage (kV)
1.	D6V/ D7V	Detweiler TS	Orangeville TS	220
2.	M20D/ M21D	Detweiler TS	Middleport TS	220
3.	D4W/ D5W	Detweiler TS	Buchanan TS	220
4.	B22D/ B23D	Detweiler TS	Bruce TS	220
5.	D7F/ D9F	Detweiler TS	Free Port SS	115
6.	F11C/ F12C	Free Port SS	Cedar TS	115
7.	B5C/ B6C	Cedar TS	Burlington TS	115
8.	D11K/ D12K	Detweiler TS	Kitchener MTS #4	115
9.	D8S	Detweiler TS	St. Mary TS	115
10.	D10H	Detweiler TS	Hanover TS	115

Appendix D: Lists of LDCs in the KWCG Region

Sr. No.	Company	Connection Type (TX/DX)
1.	Centre Wellington Hydro	Dx
2.	Energy+	Tx/ Dx
3.	Guelph Hydro Electric System Inc.	Tx/ Dx
4.	Halton Hills Hydro	Dx
5.	Hydro One Networks Inc. (Distribution)	Tx/ Dx
6.	Kitchener Wilmot Hydro Inc.	Tx
7.	Milton Hydro	Dx
8.	Waterloo North Hydro Inc.	Tx/ Dx
9.	Wellington North Power Inc.	Dx

Appendix E: Acronyms

Acronym	Description
A	Ampere
BES	Bulk Electric System
BPS	Bulk Power System
CDM	Conservation and Demand Management
CIA	Customer Impact Assessment
CGS	Customer Generating Station
CSS	Customer Switching Station
CTS	Customer Transformer Station
DESN	Dual Element Spot Network
DG	Distributed Generation
DS	Distribution Station
GS	Generating Station
HV	High Voltage
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	Kilovolt
LDC	Local Distribution Company
LP	Local Plan
LTE	Long Term Emergency
LTR	Limited Time Rating
LV	Low Voltage
MTS	Municipal Transformer Station
MW	Megawatt
MVA	Mega Volt-Ampere
MVAR	Mega Volt-Ampere Reactive
NA	Needs Assessment
NERC	North American Electric Reliability Corporation
NGS	Nuclear Generating Station
NPCC	Northeast Power Coordinating Council Inc.
NUG	Non-Utility Generator
OEB	Ontario Energy Board
OPA	Ontario Power Authority
ORTAC	Ontario Resource and Transmission Assessment Criteria
PF	Power Factor
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Plan
SA	Scoping Assessment
SIA	System Impact Assessment
SPS	Special Protection Scheme
SS	Switching Station
STG	Steam Turbine Generator
TS	Transformer Station

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Appendix H-1:
KWHI Renewable Generation (REG) Investments Plan

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Renewable Energy Generation Investments Plan 2017

Kitchener-Wilmot Hydro Inc.

September 6th, 2017

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1. Executive Summary

In accordance with the Ontario Energy Board's (OEB) filing requirements for Electricity Transmission and Distribution Applications, Chapter 5, Consolidated Distribution System Plan Filing Requirements, under condition of Licence, Kitchener-Wilmot Hydro Inc. ("KWHI") has prepared the following Renewable Energy Generation (REG) Investment Plan. The following sections provide a current assessment of KWHI's distribution system along with currently connected distributed generation projects. It also provides an overview of expected distributed generation project connections for 2018 through 2023.

The Ontario Power Authority ("OPA") launched the Feed-In Tariff ("FIT") program in 2009. The FIT/microFIT program generated a lot of interest. KWHI's renewable generation demand has grown from 6MW connected in 2009 to 18.5MW connected and pending in 2017. Currently there are 659 FIT/microFIT projects which have been connected or are in the process of being connected. There are also a number of FIT/microFIT applications in the IESO queue that are proposed to be connected in KWHI's distribution system, but waiting for a contract with the OPA.

KWHI's distribution system is a robust network serving the City of Kitchener and the Township of Wilmot. Past planning and proactive infrastructure projects have made the distribution network well equipped to handle REG connections. Indirect REG investments such as replacing end-of-life 8.32kV systems to support voltage conversion to 27.6kV provides secondary benefit of allowing additional REG connections.

There are two REG constraints present in KWHI's distribution system. One transformer station has reached its short-circuit capacity limit. At Kitchener MTS #3 Bus B52B62, the available current short-circuit capacity at the feeder breakers (474MVA) has exceeded the short-circuit capacity of the bus (15kV, 18kA, 467MVA). This is a result of the replacement of the power transformer T5 at KWHI's No. 5 Transformer Station, Hydro One's transmission system upgrade as part of the GATR (Guelph Area Transmission Reinforcement) project, and the fault contribution from the existing DG projects connected to the transformer station bus (non-renewable, 4075kW),

Secondly, parts of the downtown of the City of Kitchener is supplied by a low voltage (125/216V) secondary grid network which consists of protective devices (network protectors) that are designed to automatically trip on detection of reverse power flowing through them. KWHI currently disallow any distributed generation connection to the secondary downtown grid network, including all FIT and microFIT projects, unless the DG proponent is willing to install special protective devices at their end to prevent the reversed power flow into the secondary grid network.

Based on KWHI's 2018-2023 renewable energy forecast data, the calculated remaining system capacity and the infrastructure renewal projects being proposed, it is estimated that KWHI has enough remaining station capacity and distribution infrastructure to accommodate

the demand for REG projects under FIT/microFIT/Net Metering programs between 2018 and 2023.

2. Introduction

Kitchener-Wilmot Hydro is preparing the Cost of Service Rate Application as set out in the report of the Board: Renewed Regulatory Framework for Electricity (RRFE), for rates to be in effect January 01, 2019. In accordance with the Ontario Energy Board's (OEB) filing requirements for Electricity Transmission and Distribution Applications – Chapter 5 – Consolidated Distribution System Plan (DS Plan) Filing Requirements (EB-2010-377), KWHI has prepared this Renewable Energy Generation (REG) Investments Plan.

This REG Investments Plan identifies investment requirements for accommodating Renewable Energy Generation connections, provides information to the OEB and interested stakeholders regarding the readiness of KWHI's distribution system to connect Renewable Energy Generation, including any expansion or reinforcement necessary to remove grid constraints to accommodate these connections for the period 2018 to 2023. This plan will also provide detail on existing REG connections, available capacity and proposed REG connections.

3. Current Assessment

3.1 Kitchener-Wilmot Hydro Inc. Distribution System

Kitchener-Wilmot Hydro Inc. (KWHI) is a local distribution company responsible for the distribution of electricity to approximately 94,000 homes and businesses within the City of Kitchener and the Township of Wilmot. It is a subsidiary of Kitchener Power Corporation whose shareholders are the City of Kitchener and the Township of Wilmot, with ownership interests of 92.25% and 7.75% respectively. It receives power from Hydro One Networks Inc. and delivers electricity to its customers via eight (8) high voltage transformer stations (TS) and seven (7) distribution stations (DS). KWHI owns all the transformer stations that supply its service territory.

The transformer stations have primary voltage of 115kV and 230kV and secondary voltage of 13.8kV and 27.6kV, while the distribution stations have primary voltage of 27.6kV and secondary voltage of 8.32kV. KWHI has begun plans to eliminate end-of-life 8.32kV distribution stations and assets to support system voltage conversion to 27.6kV. This voltage conversion program will have the added benefit of facilitating additional REG connections.

3.2 Existing Renewable Distributed Generators

As of June 30th, 2017, KWHI has connected 678 Distributed Generation projects for a total capacity of 22.921MW, including 673 renewable energy generation projects for a total capacity of 18.476MW. Among the renewable energy generation projects, there are 39 Feed-In Tariff (FIT) projects (6.69MW), 620 microFIT projects (5.21MW), one Renewable Energy Standard Offer Program (RESOP) project (6.23MW), and 13 Net Metering projects (0.35MW), as shown in Table 1.

Table 1: KWHI Connected Renewable Energy Projects (by June. 30th, 2017)

Transformer Station	Connected FIT		Connected MicroFIT		Connected RESOP		Connected Net Metering	
	Number	Total Capacity (kW)	Number	Total Capacity (kW)	Number	Total Capacity (kW)	Number	Total Capacity (kW)
1TS	2	300	31	239.4	0	0	1	1.2
3TS Bus B51B61	2	325	2	20	0	0	0	0
3TS Bus B52B62	7	1226	38	304.6	0	0	0	0
4TS Bus B71B81	1	250	19	146.1	0	0	1	7.6
4TS Bus B72B82	3	542.8	36	292.9	0	0	0	0
5TS Bus B91B101	3	410	56	422.0	0	0	1	2.2
5TS Bus B92B102	5	756	44	361.6	0	0	1	10
6TS Bus B111B121	6	980	52	441.9	0	0	1	250
6TS Bus B112B122	1	250	69	546.9	0	0	0	0
7TS	5	1125	27	224.8	0	0	1	10
8TS	2	210	75	624.6	0	0	0	0
9TS (direct)	0	0	30	262.2	1	6225	0	0
9TS (indirect,8kV)	2	320	141	1323.5	0	0	7	64.8
Total:	39	6694.8kW	620	5210.6kW	1	6225kW	13	345.8kW

3.3 Estimated Remaining Capacity Summary

Station Capacity:

The estimated remaining station capacity at each transformer station is shown in Appendix A. Most transformer stations have sufficient short-circuit capacity to accommodate the typical distributed generations. The only exception is Kitchener MTS #3 Bus B52B62. As of today, most of the renewable energy projects proposed in KWHI's service area are inverter-based with insignificant fault contribution to KWHI's distribution system. It is unlikely that the fault contribution from the renewable distributed generation will cause the transformer stations to reach the short-circuit capacity limits. For all other KWHI transformer stations, the station capacity is limited by the thermal capacity of the station transformers. Dual-winding transformers are installed at Kitchener #3, #4, #5 and #6 MTS. These dual-winding transformers cannot sustain reverse flow, thus the station thermal capacity is determined by the minimum station load.

Limiting Factors:

One transformer station has reached the short-circuit capacity limit. At Kitchener MTS #3 Bus B52B62, due to the replacement of the power transformer T5 and Hydro One's transmission system upgrade as part of the GATR (Guelph Area Transmission Reinforcement) project, and considering the fault contribution from the existing DG (non-renewable, 4075kW), the current short-circuit capacity at feeder breakers (474MVA) has exceeded the short-circuit capacity of the bus (15kV, 18kA, 467MVA).

Parts of the downtown of the City of Kitchener is supplied by a secondary grid network, i.e. a low voltage 125/216V 3-phase secondary network fed by four 13.8kV parallel feeders from Kitchener #1 MTS, consisting of 41 transformers with interconnected secondaries. See Figure 1 for a typical secondary network configuration. This secondary network covers a small 0.5 square kilometer area between Francis Street and Eby Street from west to east, and between Weber Street and Charles Street from north to south. It supplies the load customers with demand less than 500kW. The customers with demand larger than 500kW in the same area are supplied by another 13.8kV underground loop feeder from Kitchener #1 MTS.

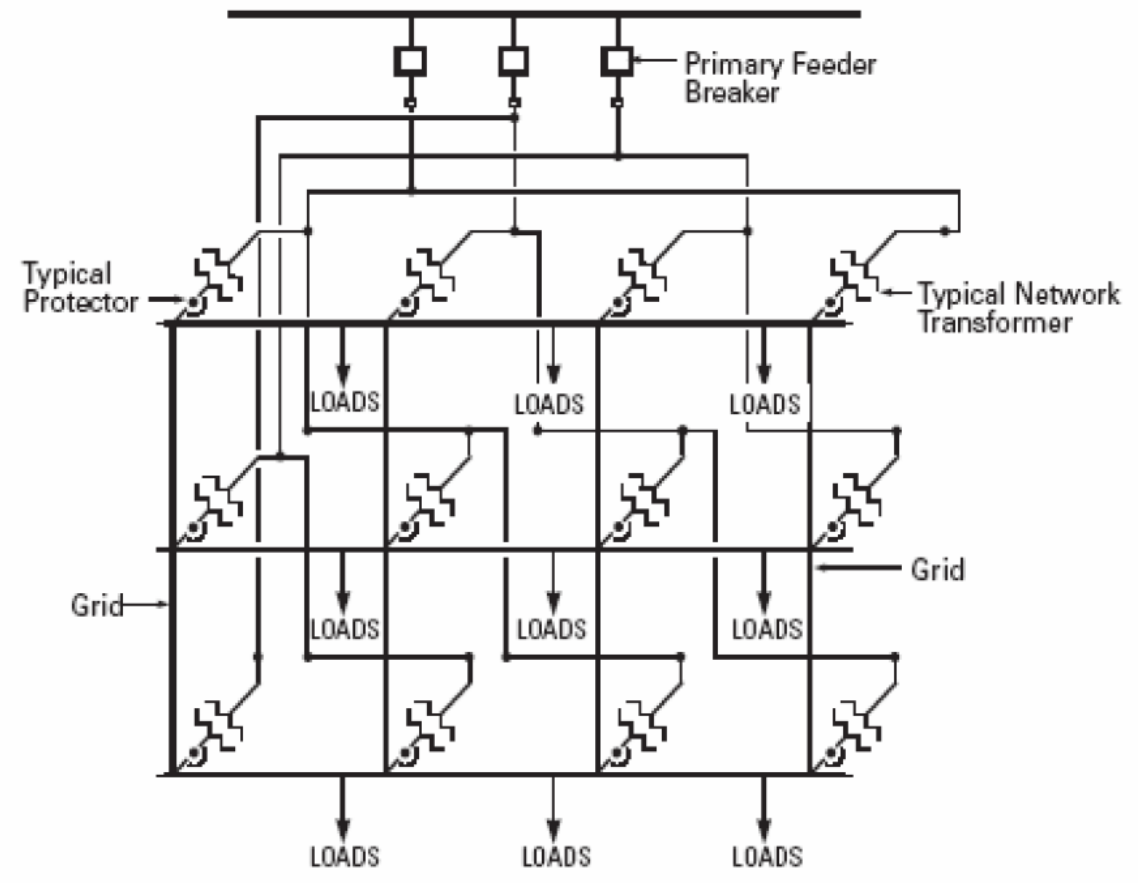


Figure 1 Schematic of a Typical Grid Secondary Network

It is technically challenging to integrate the distributed generators into the secondary grid networks due to the protection mechanism and philosophy used to protect the network transformer by design. A Secondary Network is a complex power grid with a web of multiple parallel sources of power to each customer. The design of a secondary network does not allow customers to export power to the grid due to safety and technical reasons (the change of power flow direction may cause the secondary network protector to malfunction resulting in inadvertent loss of load). In order to prevent export into KWHI's secondary network system, a customer's protection and control (P&C) system must be designed to sense the power flow at the customers' main service Point of Common Coupling and trip out the generator's main breaker or trip out the customer's main breaker at a pre-determined minimum import level or during P&C alarm conditions. Like most other utilities, KWHI's current practice is to disallow any distributed generation connection to the secondary downtown grid network, including all FIT and microFIT projects, unless the DG proponents are willing to install special protective devices at their end to prevent the reversed power flow into the secondary grid network. KWHI will keep this policy until more technical research is completed.

For the proposed FIT projects in this area, KWHI also offers the option to connect the distributed generation project to the 13.8kV underground loop feeder.

System Challenges:

KWHI requires remote monitoring of any FIT projects greater than 250kW to maintain communication with KWHI's control room via wired/wireless communication. The customer is required to install a remote terminal unit (RTU) on site. The SCADA system at KWHI's control room will need re-programming/wiring change to accommodate the additional signals.

For any generator larger than 1MW, Transfer Trip is required. Normally, the existing feeder protection is not configured to output the trip signal to the remote generator. Feeder relay programing change and control wiring change are required at the KWHI transformer station.

There is currently one connected FIT project greater than 250kW. KWHI has received a few renewable energy inquiries that were larger than 250kW in KWHI's service area.

4. Planned Development

4.1 Projected Renewable Generation Growth

Between 2009 and June 30th 2017, KWHI connected 620 microFIT projects, 39 FIT projects and 12 Net Metering projects. So far, the Renewable Generation installations in KWHI's service area consist mainly of rooftop solar PV and ground mounted solar PV projects smaller than 250kW. Table 2 below summarizes the REG connections on KWHI's distribution system between 2009 and 2017.

Table 2: KWHI Renewable Energy Project Connection (2009-2017)

Year	FIT Projects	FIT Capacity (KW)	MicroFIT Projects	MicroFIT Capacity (kW)	Net Metering Projects	Net Metering Capacity (kW)
2009	0	0	1	2.8	0	0
2010	0	0	48	342.6	0	0
2011	3	1000	98	791.9	0	0
2012	3	355	80	657.6	0	0
2013	7	1126	106	851.7	2	8.3
2014	12	1825	67	537.8	2	251.3
2015	13	2189	100	923.8	2	13
2016	1	200	66	640.0	5	43.27
2017 (as of Jun 30th)	0	0	54	462.5	1	10
Total	**39**	**6695**	**620**	**5210.7**	**12**	**325.87**

Based on KWHI's FIT/microFIT data and the future assumptions, it is estimated that the connection of Renewable Energy projects will remain steady beyond 2017. Although the province will close out FIT and microFIT programs by end of 2017, requests for Net Metering projects is anticipated to increase. The following table outlines the expected FIT/microFIT/Net Metering connections.

Table 3: KWHI Renewable Energy Generation Projects Connection Forecast (2018-2023)

Year	FIT/Net Metering projects (>10kW)	MicroFIT/Net Metering projects (<=10kW)
2018	5-10 (1-2MW)	50-100 (0.4-1MW)
2019	3-8 (0.2-1MW)	50-100 (0.4-1MW)
2020	3-8 (0.2-1MW)	50-100 (0.4-1MW)
2021	3-8 (0.2-1MW)	50-100 (0.4-1MW)
2022	3-8 (0.2-1MW)	50-100 (0.4-1MW)
2023	3-8 (0.2-1MW)	50-100 (0.4-1MW)
Total	**20-50 (2-7MW)**	**300-600 (2.4-6MW)**

In general, it is estimated that KWHI has enough remaining station capacity and distribution infrastructure to accommodate the demand for renewable energy projects between 2018-2023 (See Appendix A).

5. Proposed Investments to Facilitate Renewable Energy Generation Connections

Under the rules for connecting renewable energy projects in the Distribution System Code, KWHI will be responsible for funding new feeder assets required to connect FIT generators to a maximum of $90,000 per MW. To date, there has been very little interest in FIT generation projects that would require construction of new feeder assets. KWHI has reviewed the need for capital and OM&A expenditures for the purpose of expanding the distribution system to enable future REG connections. Based on historical trends and anticipated future REG connections, no expenditure is anticipated between 2018 and 2023 that will be required for constructing feeder assets to specifically accommodate renewable energy connections. However, end-of-life 8.32kV assets will be replaced and upgraded to 27.6kV and will support additional REG connections.

To accommodate the connection of renewable generation projects larger than 250kW, SCADA programming and station protection upgrading will be required.

Appendix A: KWHI DG Capacity at each Transformer Station (As of Jun. 30, 2017)

Station Name	Bus Name	Feeder Name	Nominal Voltage (kV)	Max. Allowable DG SC Capacity (MVA)	Max. Allowable DG Thermal Capacity (kW)	Existing DG Non Renewable (kW)	Existing DG Renewable (kW)	Existing Remaining Capacity (kW)	Proposed Applications FIT 3.X and 4.0 (KW)**
Kitchener #1 MTS	B1B2	1M1, 1M3, 1M4, 1M5, 1M6, 1M7, 1M8, 1M9	13.8	OK	32,000	0	540.6	31,480	0
Kitchener #3 MTS	B51B61	3M11, 3M13, 3M14,3M15, 3M16, 3M18	13.8	OK	3,400	0	345	3,075	0
	B52B62	3M20, 3M21, 3M22, 3M23, 3M24, 3M26, 3M27, 3M28, 3M29, 3M210, 3M211, 3M212	13.8	0 MVA	4,400	4,080*	1530.6	0	250
Kitchener #4 MTS	B71B81	4M11, 4M12, 4M13, 4M14, 4M15, 4M16, 4M17, 4M18	13.8	OK	10,400	0	403.7	9,996	0
	B72B82	4M21, 4M22, 4M23, 4M24, 4M25, 4M26, 4M27, 4M28	13.8	OK	4,400	0	835.7	3,568	0
Kitchener #5 MTS	B91B101	5M11, 5M12, 5M13, 5M14, 5M15, 5M16, 5M17, 5M18	13.8	OK	7,500	0	834.2	6,752	385
	B92B102	5M21, 5M22, 5M23, 5M24, 5M25, 5M26, 5M27, 5M28	13.8	OK	7,200	180	1127.6	6,142	570
Kitchener #6 MTS	B111B121	6M11, 6M12, 6M13, 6M14, 6M15, 6M16, 6M17, 6M18	13.8	OK	8,100	0	1671.9	6,492	0
	B112B122	6M21, 6M22, 6M23, 6M24, 6M25, 6M26, 6M27, 6M28	13.8	OK	9,200	0	796.9	8,475	100
Kitchener #7 MTS	B13B14	7M1, 7M2, 7M3, 7M4, 7M5, 7M6, 7M7, 7M8, 7M9, 7M10	13.8	OK	3,3400	0	1359.8	32,020	0
Kitchener #8 MTS	B15B16	8M1, 8M2, 8M3, 8M4, 8M5, 8M6, 8M7, 8M8, 8M9, 8M10	13.8	OK	32,600	0	834.6	31,868	0
Kitchener Wilmot #9 TS	B17B18	9M1, 9M2, 9M3, 9M4, 9M5, 9M6,9M7, 9M8, 9M9, 9M10	27.6	OK	50,000	0	8195.5	41,846	1,877

Notes:

*: The DG is not counted against the station thermal capacity, as the customer only runs the DG a few hours per year and only during the system peak time as a DR participant.

**: As indicated by the IESO, projects that have passed TAT/DAT process previously and still have a valid FIT contract.

Appendix B: Approved small FIT applications * under FIT 3.X and FIT 4.0 in KWHI's service area (provided by the IESO)

FIT Batch #	Transformer Station	Distribution Feeder	Proposed Capacity (kW)
FAME 3.x	KITCHENER MTS#5	5M23	80
FAME 3.x	KITCHENER MTS#5	5M25	140
FAME 3.x	KITCHENER MTS#3	3M27	250
FAME 4.0	KITCHENER MTS#9	9M4	67
FAME 4.0	KITCHENER MTS#9	9M4	60
FAME 4.0	KITCHENER MTS#9	9M3	250
FAME 4.0	KITCHENER MTS#9	9M3	250
FAME 4.0	KITCHENER MTS#5	5M25	250
FAME 4.0	KITCHENER MTS#5	5M17	250
FAME 4.0	KITCHENER MTS#5	5M25	100
FAME 4.0	KITCHENER MTS#9	9M4	500
FAME 4.0	KITCHENER MTS#9	9M7	150
FAME 4.0	KITCHENER MTS#6	6M26	100
FAME 4.0	KITCHENER MTS#5	5M15	135
FAME 4.0	KITCHENER MTS#9	9M4	125
FAME 4.0	KITCHENER MTS#9	9M3	250
FAME 4.0	KITCHENER MTS#9	9M4	225
	TOTAL	**17**	**3,180**

Note:

*as indicated by the IESO, projects that have passed TAT/DAT process previously and still have a valid FIT contract.

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Appendix H-2:
IESO Comment Letter for KWHI's Renewable Generation (REG) Investments Plan

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IESO Letter of Comment

Kitchener-Wilmot Hydro Inc.

Renewable Energy Generation Investments Plan 2017

November 6, 2017

ieso
Independent Electricity System Operator

Introduction

On March 28, 2013, the Ontario Energy Board ("the OEB" or "Board") issued its Filing Requirements for Electricity Transmission and Distribution Applications; Chapter 5 – Consolidated Distribution System Plan Filing Requirements (EB-2010-0377). Chapter 5 implements the Board's policy direction on 'an integrated approach to distribution network planning', outlined in the Board's October 18, 2012 Report of the Board - A Renewed Regulatory Framework for Electricity Distributors: A Performance Based Approach.

As outlined in the Chapter 5 filing requirements, the Board expects that the Ontario Power Authority[1] ("OPA") comment letter will include:

- the applications it has received from renewable generators through the FIT program for connection in the distributor's service area;
- whether the distributor has consulted with the OPA, or participated in planning meetings with the OPA;
- the potential need for co-ordination with other distributors and/or transmitters or others on implementing elements of the REG investments; and
- whether the REG investments proposed in the DS Plan are consistent with any Regional Infrastructure Plan.

Kitchener-Wilmot Hydro Inc. – Renewable Energy Generation Investments Plan

On October 2, 2017 Kitchener-Wilmot Hydro Inc. ("KWHI") provided its Renewable Energy Generation Investments Plan 2017 ("Plan") to the IESO as part of its 5-year Distribution System Plan. The IESO has reviewed KWHI's Plan and has provided its comments below.

OPA FIT/microFIT Applications Received

The Plan indicates that of its renewable energy generation projects, KWHI has connected 39 FIT projects for a total capacity of 6.69 MW, and 640 microFIT projects totalling 5.21 MW of capacity. The Plan also states that one Renewable Energy Standard Offer Program ("RESOP") project of 6.23 MW and 13 Net-Metering projects of 0.35 MW are also connected to KWHI's system.

According to the IESO's information, as of September 30, 2017, the IESO has offered contracts to 51 FIT projects representing a capacity of 8.89 MW, of which 39 FIT projects totalling 6.69 MW of capacity have come into operation. The IESO has also offered contracts to 638 microFIT projects totalling 5.3 MW of capacity in KWHI's service territory and one RESOP project of 6.23 MW. The renewable energy generation connections information in KWHI's Plan is therefore reasonably consistent with that of the IESO.

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

Independent Electricity System Operator
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Consultation / Participation in Planning Meetings; Coordination with Distributors / Transmitters / Others; Consistency with Regional Plans

The IESO notes that KWHI is part of "Group 1" in the Kitchener, Waterloo, Cambridge and Guelph ("KWCG") Region for regional planning purposes.

KWHI has participated in ongoing planning meetings since 2010, when an integrated regional planning study began to assess the electricity supply and reliability for the KWCG areas. KWHI has, and continues to consult regularly with the IESO, the other LDCs and Hydro One Networks Inc. ("Hydro One") on electricity and regional planning related matters.

KWHI was part of the Working Group ("Working Group") for the Integrated Regional Resource Plan ("IRRP") that was published at the end of April, 2015. The IRRP was led by the IESO in partnership with Hydro One (Distribution and Transmission), KWHI, Waterloo North Hydro Inc., Cambridge North Dumfries Hydro Inc., and Guelph Hydro Electric Systems Inc. KWHI also participated on the study team to the subsequent December 2015 Regional Infrastructure Plan led by Hydro One.

As no distribution or grid constraints were identified by KWHI, it has planned no REG investments for the Plan period 2018-2023. This is consistent with the KWCG RIP.

The first regional planning cycle for the KWCG Region is now complete. The expectation is that within the next 3-5 years the planning process will be initiated again, unless there is sufficient load growth, or an event that triggers the requirement to initiate the regional planning process earlier.

The IESO looks forward to continuing its work with KWHI on regional planning issues and appreciates the opportunity to comment on the information provided as part of its Distribution System Plan at this time.

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Appendix I:
2017 KWHI Scorecard

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Scorecard - Kitchener-Wilmot Hydro Inc.

9/24/2018

Performance Outcomes	Performance Categories	Measures	2013	2014	2015	2016	2017	Trend	Target: Industry	Target: Distributor
Customer Focus Services are provided in a manner that responds to identified customer preferences.	Service Quality	New Residential/Small Business Services Connected on Time	91.30%	90.90%	90.30%	92.50%	98.93%	↑	90.00%	
		Scheduled Appointments Met On Time	96.10%	95.30%	96.20%	97.50%	97.93%	↑	90.00%	
		Telephone Calls Answered On Time	78.60%	80.40%	78.10%	78.40%	92.80%	↑	65.00%	
	Customer Satisfaction	First Contact Resolution		98.6%	98.9	99.4	99.6			
		Billing Accuracy		100.00%	100.00%	100.00%	99.58%	↓	98.00%	
		Customer Satisfaction Survey Results	A	A	A	A	A			
Operational Effectiveness Continuous improvement in productivity and cost performance is achieved; and distributors deliver on system reliability and quality objectives.	Safety	Level of Public Awareness			83.00%	83.00%	83.00%			
		Level of Compliance with Ontario Regulation 22/04 [1]	C	C	C	C	C	→		C
		Serious Electrical Incident Index — Number of General Public Incidents	0	1	0	0	0	→		0
		Serious Electrical Incident Index — Rate per 10, 100, 1000 km of line	0.000	0.526	0.000	0.000	0.000	→		0.000
	System Reliability	Average Number of Hours that Power to a Customer is Interrupted [2]	0.87	0.72	0.57	1.11	0.92	↓		0.87
		Average Number of Times that Power to a Customer is Interrupted [2]	0.69	1.03	0.77	1.11	1.03	↑		0.92
	Asset Management	Distribution System Plan Implementation Progress		In Progress	In Progress	In Progress	In Progress			
	Cost Control	Efficiency Assessment	2	2	2	2	2			
		Total Cost per Customer [3]	$466	$483	$481	$494	$487			
		Total Cost per Km of Line [3]	$22,062	$23,132	$23,150	$23,866	$23,707			
Public Policy Responsiveness Distributors deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements imposed further to Ministerial directives to the Board).	Conservation & Demand Management	Net Cumulative Energy Savings [4]			20.68%	36.61%	83.39%			105.71 GWh
	Connection of Renewable Generation	Renewable Generation Connection Impact Assessments Completed On Time	100.00%	100.00%	100.00%	100.00%	100.00%			
		New Micro-embedded Generation Facilities Connected On Time	100.00%	100.00%	100.00%	100.00%	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)	2.14	1.95	1.97	1.96	1.99			
		Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio	0.69	0.65	0.61	0.57	0.54			
		Profitability: Regulatory Return on Equity — Deemed (included in rates)	9.85%	9.36%	9.36%	9.36%	9.36%			
		Profitability: Regulatory Return on Equity — Achieved	8.94%	10.87%	11.47%	10.18%	9.59%			

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

Legend:

5-year trend: ↑ up ↓ down → flat

Current year: target met; target not met

2017 Scorecard Management Discussion and Analysis ("2017 Scorecard MD&A")

The link below provides a document titled "Scorecard - Performance Measure Descriptions" that has the technical definition, plain language description and how the measure may be compared for each of the Scorecard's measures in the 2017 Scorecard MD&A:
http://www.ontarioenergyboard.ca/OEB/_Documents/scorecard/Scorecard_Performance_Measure_Descriptions.pdf

Scorecard MD&A – General Overview

Kitchener-Wilmot Hydro Inc. (KWHI) has been a part of the local community for more than 100 years. As the energy industry continues to grow and evolve, KWHI remains committed to its promise to deliver safe, reliable and efficient electricity distribution services at a reasonable cost to its customers.

In 2017, KWHI exceeded industry targets for most Scorecard measures, achieving exceptional ratings in customer satisfaction and system quality, and realized improvements in reliability. KWHI also had the 5th lowest total cost per customer out of 65 distributors across the province. KWHI continues to carefully pace and prioritize capital investments to effectively manage distribution system assets, complete necessary infrastructure improvements, and reduce outage frequency and outage duration to improve customer experience.

With a service territory of more than 425 square kilometres, a staff of 187 and more than 95,000 customers, KWHI continues to effectively manage a distribution system that includes more than 1,900 kilometres of overhead and underground distribution lines, more than 23,000 power poles, more than 11,100 transformers and 8 transformer stations.

Service Quality

- **New Residential/Small Business Services Connected on Time**

  In 2017, KWHI connected more than 1,900 low-voltage residential and small business customers within the five-day timeline prescribed by the Ontario Energy Board (OEB). This is an increase of 220 connections over 2016. By undertaking a thorough review of processes, KWHI improved its 2017 performance by 6.5% percent over 2016, connecting 98.9% of its total service connections on time.

- **Scheduled Appointments Met On Time**

  In 2017, KWHI had more than 3,100 scheduled customer appointments where the customer or representative was required to be present, and once again both exceeded the industry standard of 90% of scheduled appointments met on time, and improved its performance over 2016, from 97.5% to 97.9%.

- **Telephone Calls Answered On Time**

  In 2017, KWHI's Customer Service team responded to more than 71,000 telephone calls, a 20% decrease in the number of calls from 2016. 92.8% of customer calls were answered within 30 seconds, which exceeds the industry standard of 65% as set by the Ontario Energy Board. The decrease in phone calls can be attributed to the moratorium on disconnections and an 11% increase in email communications. KWHI remains committed to finding new ways for customers to connect with its staff quickly and easily to reduce wait times and call volumes.

Customer Satisfaction

- **First Contact Resolution**

  In 2014, utilities were given an opportunity to define this measure in the manner that provides the most meaningful assessment. KWHI defines First Contact Resolution as all telephones calls resolved by the Call Centre on first contact. As this measure is evolving, KWHI will continue to monitor its progress and track best practices of other LDCs in an effort to improve its own customer service offering.

KWHI strives to handle each customer interaction quickly, efficiently and to the customer's satisfaction. In 2017, 99.6% of phone calls received by the Call Centre achieved First Contact Resolution due to the excellent service provided by KWHI's Customer Service staff.

- **Billing Accuracy**

In 2017, KWHI continued to exceed the standard of billing accuracy achieving 99.6%, a decrease from 2016. In 2017, KWHI issued more than 1,148,000 electricity bills to over 95,000 customers, an increase of 5% over 2016. KWHI bills all its customers on a monthly basis.

- **Customer Satisfaction Survey Results**

In 2017, KWHI engaged a third party to conduct a customer satisfaction survey, which invited customers to provide feedback on a variety of areas including customer service, reliability, service value, billing and outages. The data collected from this survey is used as a baseline to guide customer service improvements. KWHI received an "A" for its overall performance.

KWHI continues to use customer feedback to enhance its customer service offering and give customers an effortless experience.

Safety

- **Public Safety**

In 2017, KWHI provided electrical safety education to students, the Kitchener Fire Department and to contractors in KWHI's service territory, and sponsored a conference for the local Workplace Safety Prevention Services that addressed electrical safety messaging.

On an ongoing basis, KWHI shares public electrical safety messages through radio and newspaper advertising, on its website, and social media channels, and other outlets, providing businesses, seniors, farmers, volunteers, parents, and children in its service area with seasonally relevant public safety reminders. KWHI also provides funding for electrical safety education at the Waterloo Regional Police Service's Children's Safety Village, and sponsors the Children's Hero Award. In 2017, KWHI led a partnership to create six one-minute animated videos featuring "Lucky the Squirrel" who learns how to be safe around electricity. These safety videos are shared on a regular basis and have well over 10,000 views.

KWHI delivered an extensive customer outreach program to continue educating customers on overhead power line safety, underground electrical contact/locate safety and emergency preparedness including participation in the Electrical Safety Authority's Powerline Safety Week.

- **Component A – Public Awareness of Electrical Safety**

This component of the public safety measure is intended to measure the level of safety awareness of the general public within the electricity distributor's service territory.

The score of 83% is the result of a standard survey performed by a third party in February 2018. KWHI is using the information gathered in this survey to develop and target its safety messages going forward.

- **Component B – Compliance with Ontario Regulation 22/04**

This component of the public safety measure is expected to address the level of distributor compliance to Ontario Regulation 22/04, which governs the safe design and construction of electrical distribution systems. Measurement includes an audit and declaration of compliance submitted by the distributor and due diligence inspections completed by the Electrical Safety Authority. KWHI fully complies with Ontario Regulation 22/04 safety standard.

- **Component C – Serious Electrical Incident Index**

A Serious Electrical Incident is defined as electrical contact, fire or explosion or equipment failure in the distribution system that causes loss of life or critical injury to a member of the general public. This component of Public Safety measures the number of serious electrical incidents involving members of the general public in KWHI's service territory. KWHI had no serious electrical incidents in 2017. KWHI continues to make public safety a priority through its educational activities and programs.

System Reliability

In 2017, KWHI continued its program of focused investments in animal control and vegetation management to improve system reliability. In addition, faulted or end-of-life equipment is replaced with new components with better performance – such as polymer insulators and switches. During 2017, KWHI fully implemented its new outage management system that will help crews locate and identify outage locations more quickly and provide customers with up-to-date outage information.

- **Average Number of Hours that Power to a Customer is Interrupted**

KWHI had a reduction in the average number of hours a customer was without power during the year. KWHI continues to investigate longer than usual outages to determine the root causes and to evaluate ways to minimize the impacts on customers in the future.

- **Average Number of Times that Power to a Customer is Interrupted**

The average number of times a KWHI customer was without power during the year also decreased in 2017. KWHI remains below the provincial average for this measure and continues to carefully monitor and assess its investments to maintain the high reliability standards KWHI's customers have come to expect.

Asset Management

- **Distribution System Plan Implementation Progress**

KWHI has a long-term asset management plan that allows it to effectively pace infrastructure replacement and investments. KWHI is incorporating elements of its ongoing asset management plan into a Distribution System Plan (DSP) that will be submitted to the OEB in its next Cost of Service rate filing.

Cost Control

The following section commentary is based on figures generated by the Ontario Energy Board based on total cost benchmarking analysis conducted by the Pacific Economics Group Research LLC. The model used by the OEB is based on econometrics. This model establishes relationships between business conditions (i.e. number of customers, kWh deliveries, length of lines) and distributor cost. Many adjustments are made to ensure fair comparison between distributors.

- **Efficiency Assessment**

The efficiency assessment measure compares distributors' actual costs to costs predicted by the OEB model described above. Those LDCs with lower actual costs than predicted costs are considered to be better cost performers and therefore given a lower stretch factor assignment for efficiency improvements. KWHI ranked 5th in the province for lowest cost per customer in 2017, and has maintained its Group 2 cost efficiency level for the past six years while continuing to provide excellent customer service and high reliability performance.

- **Total Cost per Customer**

KWHI's total cost per customer compares favourably to other LDC's providing distribution services to its customers. Distribution services includes design, maintenance and construction of infrastructure, customer services and customer education. KWHI's total cost per customer of $484 per year is lower than the provincial average.

- **Total Cost per Km of Line**

KWHI's total cost per kilometre of line compares favourably to other LDC's providing distribution services to its customers. KWHI's total cost per kilometre of line of $23,707 is lower than the provincial average.

Conservation & Demand Management

The year 2017 marked the third year of a new six-year Conservation First Framework. In this Conservation First Framework 2015-2020, KWHI has been allocated an electricity savings target of 105.7 GWh of energy savings to be achieved through a suite of energy efficiency programs under the Save On Energy brand offered to both residential and commercial customers.

KWHI's annual savings results from 2015-2020 will be made available on the IESO website.

- **Energy Savings**

KWHI achieved 83% of its six-year energy savings target. Some highlights from 2017 program performance include:

Residential

- 1,845 furnaces and central air conditioners were replaced through the Heating and Cooling Incentive Program
- 434,864 coupons were used by customers to purchase energy savings technologies such as LED lights

Commercial

- 321 commercial businesses completed energy savings projects through the Retrofit Program achieving 26,661 MWh in energy savings

Connection of Renewable Generation

- **Renewable Generation Connection Impact Assessments Completed on Time**

In 2017, KWHI performed seven connection impact assessments (CIA) and all were completed within the prescribed time limit. KWHI has consistently met 100% of its CIA reviews on time over the past 5 years.

- **New Micro-embedded Generation Facilities Connected On Time**

In 2017, KWHI connected 132 micro-embedded generation facilities within the prescribed time limit. KWHI has consistently met 100% of its micro-embedded generation facilities connections on time, well above the industry target of 90%.

Financial Ratios

- **Liquidity: Current Ratio (Current Assets/Current Liabilities)**

  The current ratio is a liquidity ratio that measures a company's ability to pay short-term and long-term obligations. To gauge this financial metric, the current ratio considers the total current assets of a company relative to that company's total current liabilities. KWHI is maintaining a current ratio that allows it to have a margin of safety to cover financial obligations on a timely basis.

- **Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio**

  The OEB uses a deemed capital structure of 60% debt and 40% equity for distributors when establishing rates. This equates to a debt to equity ratio of 1.5. KWHI's actual debt to equity ratio of 0.54 maintains a strong balance sheet.

- **Profitability: Regulatory Return on Equity – Deemed (included in rates)**

  KWHI's current distribution rates were approved by the OEB effective January 1, 2018 and include an expected (deemed) regulatory return on equity of 9.36%. The OEB allows a distributor to earn within +/- 3% of the expected return on equity.

- **Profitability: Regulatory Return on Equity – Achieved**

  KWHI's regulatory return on equity - achieved in 2017 was 9.59%, which exceeds the deemed regulatory return on equity but is well within the +/-3% range allowed by the OEB. The average return over the past 5 years was 10.21% which is also well within return included in KWHI's approved rates. KWHI achieved returns higher than the deemed rate in 2017 due to lower than planned operating costs during the year. KWHI is mindful of lower revenues as a result of lower kW demand and energy consumption and actively seeks productivity savings arising from related process improvement initiatives.

Note to Readers of 2017 Scorecard MD&A

The information provided by distributors on their future performance (or what can be construed as forward-looking information) may be subject to a number of risks, uncertainties and other factors that may cause actual events, conditions or results to differ materially from historical results or those contemplated by the distributor regarding their future performance. Some of the factors that could cause such differences include legislative or regulatory developments, financial market conditions, general economic conditions and the weather. For these reasons, the information on future performance is intended to be management's best judgement on the reporting date of the performance scorecard, and could be markedly different in the future.

Appendix J:
2018 Worst Performing Feeder Report

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Kitchener-Wilmot Hydro Inc. 2018 Reliability Report

Worst Perform Feeder Analysis

19-February-2019

File: 7558-09-04

Definitions

Interruption/Outage – the loss of service to one or more customers.

Loss of Supply – customer interruptions due to problems in the bulk electricity system.

Major Event Day (MED) – an event that is beyond the control of the distributor and is characterized as; unforeseeable, unpredictable, unpreventable, and unavoidable.

Momentary Interruption/Outage – An interruption/outage with duration less than one minute.

Planned/Schedule Outage – customer interruptions due to the disconnection at a selected time for the purpose of construction or preventive maintenance.

Sustained Interruption/Outage – an interruption/outage with duration of one minute or more.

Worst Performing Feeders

There are no pre-defined regulatory metrics used to determine worst performing feeders (WPF). In assessing feeders that contribute negatively to reliability, KWHI use the following metrics; Customer Hours Interrupted (CHI), and number of Customers Interrupted (CI). These two metrics are directly related to SAIDI and SAIFI respectively. Planned outages, Loss of Supply, and MEDs are excluded from the outage data. Abnormal feeder configurations were not excluded. Abnormal feeder configuration occurs when additional customers are temporarily added to a feeder in order to support construction or maintenance work performed on an adjacent circuit.

KWHI used two years of outage data (2017-2018) to develop the worst performing feeders list. The reasons for using two years are two-fold. First, since it typically takes two years to design and implement measures to improve reliability on feeders that perform poorly in the prior years, the number of years for outage data should not be too long. That is, if there are too many years the list may contain feeders that have been previously addressed. Second, the new outage management system was commissioned in April 2016 resulting in the data set for 2016 being from two different systems. Hence, the choice of two years of outage data.

KWHI's focus on developing the worst performing feeders list is based on the feeders' contribution to overall system reliability as opposed to the reliability experienced by an average customer on the feeder.

Table 1: Ten Worst Performing Feeders Based on CHI - 2017-2018

Feeder	Customers on Feeder (Typ.)	SAIDI	SAIFI	CHI	# of Outages	Customers Interrupted
5M16	2500	0.1610	0.0848	15,488	6	8,218
6M17	1470	0.0936	0.0814	9,011	23	7,852
3M26	2500	0.0806	0.1339	7,730	15	12,869
9M4	4000	0.0798	0.1556	7,686	10	15,046
7M9	1500	0.0687	0.0934	6,594	16	9,007
4M26	2100	0.0570	0.0665	5,550	11	6,471
5M13	1500	0.0570	0.1054	5,524	12	10,126
5M27	2600	0.0526	0.0606	5,038	26	5,804
6M27	2200	0.0524	0.0793	5,002	25	7,589
5M23	1950	0.0496	0.0413	4,788	10	3,997
Total	**22320**	**0.7522**	**0.9021**	**72,411**	**154**	**86,979**

Table 2: Ten Worst Performing Feeders Based on Customers Interrupted - 2017-2018

Feeder	Customers on Feeder (Typ.)	SAIDI	SAIFI	CHI	# of Outages	Customers Interrupted
9M4	4000	0.0798	0.1556	7,686	10	15,046
3M26	2500	0.0806	0.1339	7,730	15	12,869
5M13	1500	0.0570	0.1054	5,524	12	10,126
7M8	1500	0.0396	0.1015	3,802	24	9,777
7M9	1500	0.0687	0.0934	6,594	16	9,007
4M11	2400	0.0198	0.0858	1,896	28	8,221
5M16	2500	0.1610	0.0848	15,488	6	8,218
6M17	1470	0.0936	0.0814	9,011	23	7,852
6M27	2200	0.0524	0.0793	5,002	25	7,589
6M11	1535	0.0430	0.0770	4,160	24	7,474
Total	**21105**	**0.6954**	**0.9981**	**66,895**	**183**	**96,179**

As seen in Table 1 and Table 2, there are seven (7) feeders, highlighted in red, that occurred on both lists of WPF. Feeders 5M16, 6M17, 3M26, 9M4, 7M9, 5M13 and 6M27 appear on both lists. The following is a brief analysis of the main driver(s) for these feeders contributing significant outage minutes to overall system reliability.

5M16

This feeder is mostly residential serving approximately 2,500 customers. The main cause for outages on this feeder during the two-year period was Adverse Weather that occurred on October 15, 2017 (outage ID 10093) resulting in a large tree falling and damaging section of the overhead distribution feeder. This resulted in 1,272 CHI. Due to the large number of customers served by this feeder, adding automated reclosers to sectionalize the feeder and transfer load to adjacent feeders during an outage will help with improving reliability. The second largest outage was caused by Defective Equipment (outage ID 16195), a porcelain switch broke resulting in the energized conductor coming in contact with an equipment that

was grounded and causing a feeder lockout. KWHI has a policy to replace all porcelain insulators with polymeric insulators on structures that are adjacent to other structure that crews are performing work on. In addition, only polymeric insulators are used in new constructions.

6M17

This feeder is mostly residential serving approximately 1,470 customers. The main cause for outages on this feeder during the two-year period was Foreign Interference that occurred on December 21, 2017 (outage ID 10882 & 10883) where a motor vehicle accident resulted in a broken pole and broken conductors. There were 7,083 CHI. These types of events are difficult to mitigate against. Having numerous isolation points on a feeder can help with reducing the impact of these outages. The second largest outage (outage ID 8664) was caused by Foreign Interference, where a squirrel made contact with line equipment resulting in a defective switch, insulator and surge arrestor. These outages can be mitigated by the installation of animal guards and pro-active tree trimming.

3M26

This feeder is mostly residential serving approximately 2,500 customers in Doon South, Kitchener. The main cause for outages on this feeder during the two-year period is Adverse Weather that occurred on August 15, 2017 (outage ID 9357 and 9358) resulting in a large tree falling and damaging section of the overhead feeder. This resulted in 6,750 CHI. The second largest outage was caused by a Defective Equipment (outage id 13797), a pad-mounted transformer that failed due to leaking of oil. These outages can be mitigated by pro-active field inspection and replacement of equipment before failure.

9M4

This feeder is a 27.6 kV rural distribution and sub-transmission circuit that normally supply three to four 8.32 KV distribution substations and direct connected loads in Wilmot Township. These distribution substations supply 3,000 - 4,000 customers that are mostly residential. The main cause for outages on this feeder during the two-year period was a lightning storm that occurred on September 19, 2017 (outage ID 9787) causing the 9M4 feeder to lockout along with other distribution substations (1DS1 and 8DS3). This resulted in 4,036 CHI. Automated reclosers installed in the field were used to re-route power and reduce the impact of this outage prior to crews being able to patrol the feeder and identify the cause of the fault.

The second largest outage on this feeder was also due a lightning storm that occurred on July 27, 2018 (outage ID 14153) resulting in flash over of line insulators. This resulted in a feeder lockout and 1,881 CHI. KWHI has began rebuilding sections of pole line that are part of feeder 9M4. During the rebuild process, distribution surge arresters are added at fixed intervals along the line to aid in improving lightning performance. There is also an active program of installing automated line reclosers on 27.6 kV feeders in Wilmot Township to aid in sectionalizing, faster restoration and reduction in number of customers impacted by forced outages.

7M9

This feeder serves approximately 1,500 customers which represent a mix of residential and commercial customers. The main cause for outages on this feeder during the two-year period was Foreign Interference that occurred on March 4, 2017 (outage ID 7549) where a motor vehicle accident resulted in a broken pole and broken conductors. There were 2,300 CHI. These types of events are difficult to mitigate against and the feeder supply loads that are located in the eastern part of Kitchener and at the

fringe of the service territory with travel time of about 30 minutes from the service centre. Having automated switches/reclosers installed on these feeders can help with reducing the impact of these outages. The second largest outage (outage ID 14227) was caused by Foreign Interference, where an Osprey nest made contact with the overhead line resulting in a feeder outage and 1,705 CHI. These outages can be mitigated by installation of alternative nesting structures for these large birds that live along the Grand River. During pole line rebuilds, platforms are installed to facilitate nesting of Ospreys along the Grand River.

5M13

This feeder serves approximately 1,500 customers which represent a mix of residential and commercial customers. The main cause for outages on this feeder during the two-year period was a pole fire on July 13, 2018 (outage ID 13905) resulting in 2,744 CHI. Pole fire related outages can be mitigated by proactive insulator washing and replacement of porcelain insulators, that caused tracking, with polymeric insulators. Both programs are actively undertaken by KWHI. Insulator washing normally focuses on 13.8 kV lines that are in close proximity to highways with high speed limits (90 km/h and above) and all 27.6 kV lines. Replacement of porcelain insulators occurred during rebuild and when crews are working adjacent to poles with porcelain insulators.

The second largest outage (outage ID 13809) was caused by Foreign Interference, where a squirrel made contact with the distribution overhead lines resulting in a feeder outage and 1,820 CHI. These outages can be mitigated by installation of animal guards on distribution lines and equipment.

6M27

This feeder is mostly residential serving approximately 2,200 customers. The main cause for outages on this feeder during the two-year period was Foreign Interference that occurred on August 30, 2017 (outage ID 9521) where a raccoon made contact with an overhead distribution switch resulting in a feeder outage and 2,535 CHI. These outages can be mitigated by installation of animal guards on distribution lines and equipment. The second largest outage was caused by Defective Equipment (outage ID 6979), a submersible transformer failed while section of the underground loop feeder was out resulting in no alternative supply point to restore power to the other transformers on the loop. These outages can be mitigated by pro-active field inspection and reducing the length of time that other equipment is out of service.

A more in-depth analysis will be conducted to determine the root cause of these outages and the best measures, both short-term and long-term, that can be implemented to mitigate the reliability performance of these feeders.

Impact of the Worst Performing Feeders

There are 105 active feeders (83 – 13.8kV, 4 – 27.6 kV, 18 – 8.32 kV) supplying KWHI's service territory of approximately 96,000 customers. The ten worst performing feeders (10% of total feeder count and 20% of total customers) are responsible for approximately 50% of the total customer minutes interrupted during 2017 and 2018. Therefore, by focusing on these feeders, there is the potential to positively impact reliability performance for KWHI's customers. Not all outage causes are controllable, such as motor vehicle accidents and severe weather. However, measures can be implemented to reduce the impact of outages caused by these events.

Outages that occurred on worst performing feeders are analyzed to determine the nature and root causes of the outages, the condition of assets involved in the outages, and the capabilities for load transfer including outage restoration time. Based on the cause(s) that is responsible for the poor performance of a feeder, the typical work performed to mitigate poor reliability performance includes; installing new automated line reclosers, replacing overhead and underground conductors, installing new fault indicators, reframing poles to increase phase separation, installing animal/bird guards, repairing or replacing deteriorated equipment, installing surge arresters on distribution lines, and proactive trimming of trees.

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Appendix K:
KWHI’s Asset Management Policy

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Kitchener-Wilmot Hydro Inc.
Policy & Procedure

SUBJECT: Asset Management Policy – Distribution System

Department: All	Revision: New	Number: E-1
V-P Operations: W. Meston V-P Engineering & IT: G. Cameron	Issue Date: March 26, 2019 Revision Date: N/A	Page 1 of 2

1. Purpose

Kitchener-Wilmot Hydro Inc. (KWHI) is committed to delivering safe and reliable services to its customers in a financially and operationally effective manner. KWHI utilizes its distribution system assets to deliver services in its service area. The distribution system assets are capital-intensive and have long, useful lives. Providing good quality, valued, reliable and sustainable services depends on having the distribution system assets in good condition. KWHI has developed an asset management policy to ensure a continual and consistent focus on delivering services in a way that balances risk and long-term costs. The policy establishes the core asset management principles that drive KWHI's planning framework to achieve its business objectives and corporate plan.

2. Scope

The Asset Management Policy focuses primarily on the management of physical distribution system assets as listed below. Other assets such as information technology assets, financial assets, building, and vehicles support these physical assets and are managed otherwise. The Policy provides guidelines on current and future business needs while considering risks and opportunities and making efficient use of resources.

Physical Asset Class	Description
Transmission and Distribution Stations	Power and auxiliary transformers, circuit breakers, switches, protection and control systems, infrastructure and buildings that make up a TS and DS.
Overhead Distribution System	Wood pole and concrete pole lines together with all their accessories such as switches, capacitors, etc.
Underground Distribution System	High voltage and low voltage cables installed below grade together with their accessories such as switches, vaults, pull boxes, ducts, capacitors, etc.
Distribution Transformers	Overhead, underground and network transformers.
Metering Equipment	Wholesale & Retail revenue metering equipment.

3. Policy

It is KWHI's policy that all assets used in the distribution system shall be planned, designed, procured, constructed, operated, maintained, renewed and retired in an efficient manner that:

i. Supports KWHI's corporate goals, business plan and asset management objectives;
ii. Supports the OEB's Renewed Regulatory Framework for Electricity outcomes;
iii. Implements KWHI's investment plan as documented in the Distribution System Planning Report;
iv. Complies with regulatory and statutory requirements
    a. Health and safety of workers and the public;
    b. Electricity supply quality and reliability;
    c. Environmental Protection;
    d. Good Utility Practice;
    e. Financial and IFRS accounting policies and practices;
v. Effectively controls and balances service levels with asset lifecycle costs and risks;
vi. Pace and prioritizes the long-term replacement of critical assets in a balanced and measured approach that reconciles with KWHI's investment strategies and financing capabilities;
vii. Effects timely corrective actions based on regular inspections, monitoring and condition assessment of the assets; and
viii. Provides a framework for the continuous improvement of the asset management system.

It is the responsibility of the President & CEO to ensure there are established roles, responsibilities, authorities and controls to achieve the asset management policy, strategy, objectives and plans. Responsibility for asset management is held from the CEO to the Vice Presidents.

The V-P of Engineering and V-P of Operations have overall responsibility for reviewing the policy on a regular basis and update if required, developing KWHI's Asset Management System (Policies, Strategies, and Plans) and reporting on the status and effectiveness of the Asset Management System.

Appendix L:
2018 Asset Condition Assessment Report

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METSCO

MAKING IT POSSIBLE



KITCHENER WILMOT HYDRO INC.

ASSET CONDITION ASSESSMENT REPORT 2018

Prepared by

P-17-222

October 19, 2018

Disclaimer

This 2018 report has been prepared by METSCO Energy Solutions Inc. ("METSCO") for Kitchener Wilmot Hydro Inc. ("KWHI"). Neither KWHI, nor METSCO, nor any other person acting on their behalf makes any warranty, expressed or implied, or assumes any legal responsibility for the accuracy of any information or for the completeness or usefulness of any process disclosed or results presented, or accepts liability for the use, or damages resulting from the use, thereof. Any reference in this report to any specific process or service by trade name, trademark, manufacturer, or otherwise does not necessarily constitute or imply its endorsement or recommendation by KWHI or METSCO.

SUMMARY

This Asset Condition Assessment (ACA) report is prepared for Kitchener-Wilmot Hydro Inc.'s (KWHI's) distribution assets. The report provides estimates of assets' conditions based on data provided by KWHI between March and June 2018. Asset's with provided data were assessed within this report.

A risk-based asset management strategy determines the optimal timing and scope of investments into asset renewal, determined by the condition of the asset and consequences of its failures in service. A brief outline of implementing a risk-based asset management is documented in Section 2. The first step towards implementation of a risk-based asset management approach is to develop a yard stick, such as a Health Index, that could be employed to measure and benchmark the health and condition of in-service assets. A comprehensive methodology has been developed and documented in Section 3 of the report for assets targeted within the scope of this analysis. METSCO Energy Solutions Inc.'s Health Index Formulation is applied to better reflect the accuracy of an asset's condition for risk management. Section 4 provides recommended improvements to KWHI's inspection data collection and recommended replacement plan. Implementing the recommendations can lead to further data quality improvements in future ACA.

The Asset Condition Assessment is based on data compiled between March and June 2018 and covers the following assets owned by KWHI:

- Substation Transformers
- Station Circuit Breakers and Reclosers
- Station Protection Relays
- Capacitor Banks
- Station Batteries
- Wood Poles
- Concrete Poles
- Overhead Conductors
- Underground Cables
- Distribution Transformers
- Switches

For each asset group, available data was assessed, and the Health Index is calculated with the provided data. Assets are classified in one of five conditions: Very Good, Good, Fair, Poor, or Very Poor. The results of the Asset Condition Assessment are summarized in Figure A.

Table A presents the summary of the Health Index results. For each asset class the following details are given: the total population, average Data Availability Indicator and the Health Index distribution.

Table B presents summary of recommended replacement plan per asset. KWHI is recommended to continue inspection/testing on these assets to determine the optimal replacement plan.

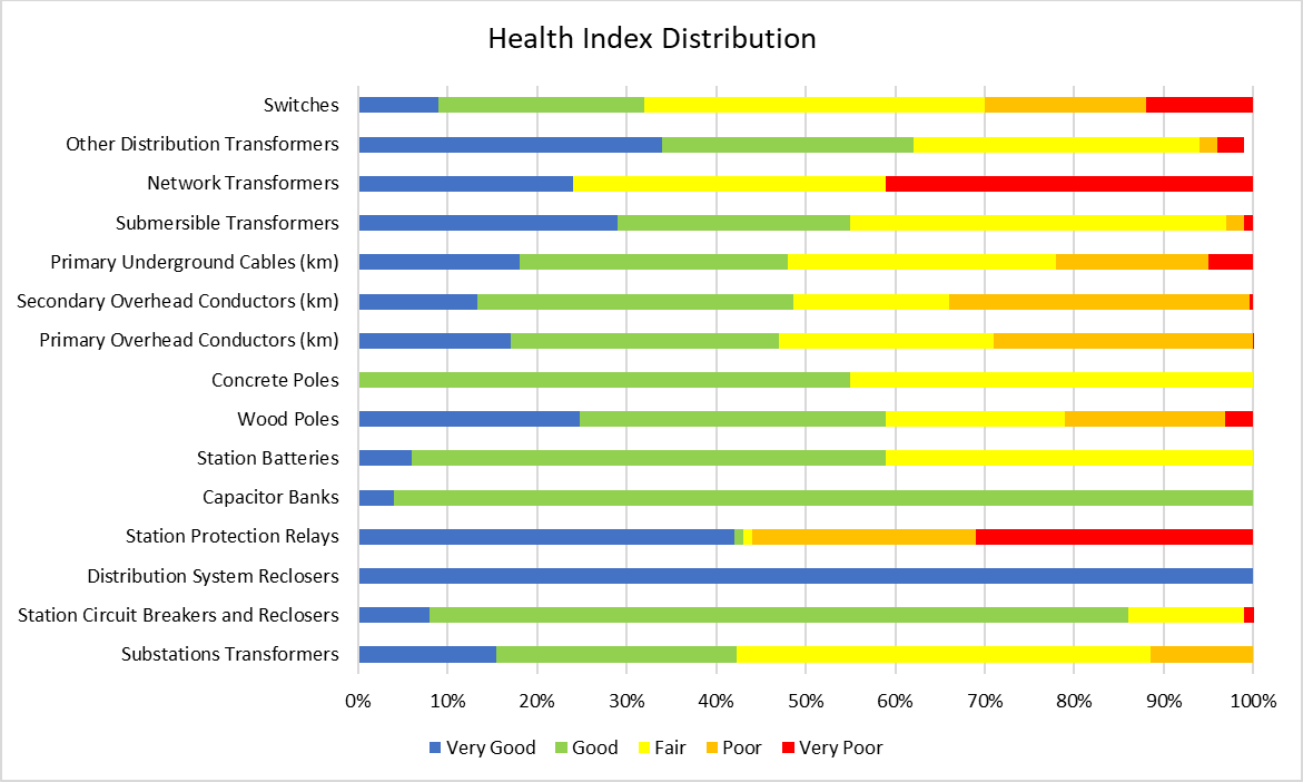


Figure A: Health Index Distribution

Table A: Summary of Condition Results

Asset Category	Pop.	Health Index Distribution (%)					Avg. DAI	Average DAI Target
		Very Good	Good	Fair	Poor	Very Poor		
Substation Transformers	26	15%	27%	46%	12%	0%	82%	100%
Station Circuit Breakers and Reclosers	169	8%	78%	13%	0%	2%	84%	100%
Distribution System Reclosers	28	100%	0%	0%	0%	0%	NA	100%
Station Protection Relays	281	42%	1%	1%	25%	31%	100%	100%
Capacitor Banks	73	4%	96%	0	0	0	NA	-
Station Batteries	16	6%	53%	41%	0%	0%	NA	-
Wood Poles	15977	25%	34%	20%	18%	3%	58%	60%
Concrete Poles[1]	7130	0%	55%	45%	0%	0%	100%	100%
Primary Overhead Conductors (km)	1040	17%	30%	24%	29%	1%	NA	-
Secondary Overhead Conductors (km)	327	13%	35%	17%	34%	0.4%	NA	-
Primary Underground Cables (km)	957	18%	30%	30%	17%	5%	NA	(sample)
Submersible Transformers	3704	29%	26%	42%	2%	1%	99%	100%
Network Transformers	34	24%	0%	35%	0%	41%	66%	100%
Other Distribution Transformers	7309	34%	28%	32%	2%	3%	92%	100%
Switches	4263	9%	23%	38%	18%	12%	NA	-

*NA: Not applicable refers to “Age Only” data available

Note 1: The HI results for concrete poles is not very accurate since inspection data is not available yet

Table B-Summary of Recommended Replacement Plan

Recommended Replacement Plan						
Year	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
Substation Transformers	0	0-1	0-1	0-1	0-1	0
Station Circuit Breakers and Reclosers	0-1	1-2	0-1	0	0-1	0-1
Distribution System Reclosers	0	0	0	0	0	0
Station Protection Relays	0-2	5-7	30-35	0-9	25-29	20-25
Capacitor Banks	0	0	0	0	0	0
Station Batteries	0	0	0	0	0	0
Wood Poles	425-450	425-450	425-450	425-450	425-450	425-450
Concrete Poles*	NA	NA	NA	NA	NA	NA
Primary Underground Cables (km)	10-12	10-12	10-12	10-12	15-17	15-17
Submersible Transformers	10-20	4-14	20-22	20-22	20-22	20-22
Network Transformers	4-6	8-10	0	0	0	1-2
Other Distribution Transformers	80-85	80-85	80-85	40-45	40-45	40-45
Switches	100-108	100-108	130-140	130-140	150-160	150-160

*NA: Recommended replacement plan for concrete poles is not provided since the HI results are based on assumptions and KWHI is in the process of collecting actual inspection data.

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1 INTRODUCTION

This document reports the results of an Asset Condition Assessment (ACA) study carried out by METSCO on behalf of Kitchener Wilmot Hydro Inc. (KWHI) with the objective of establishing the health and condition of station and distribution assets and making recommendations for future process improvement.

The Asset Condition Assessment methodology was applied for different categories of fixed assets that are employed on KWHI's distribution system. A key component of this methodology is periodic asset inspections and the collection of condition data to identify the assets most at risk, requiring focused investments and risk mitigation.

The assets covered in the report include the following fixed assets:

- Station Transformers
  - Transformer station transformers
  - Distribution station transformers
- Station Circuit Breakers and Reclosers
- Station Protection Relays
- Station Capacitors
- Station Batteries
- Poles
  - Wood poles
  - Concrete poles
- Distribution Transformers
  - Pad-mounted distribution transformers
  - Pole-mounted distribution transformers
  - Submersible Transformers
  - Network Transformers
- Switches
- Overhead Conductors
  - Primary Overhead Conductors
  - Secondary Overhead Conductors
- Underground Cables
  - Primary Underground Cables
  - Secondary Underground Cables

The information contained within this report was compiled based on available data as of June 2018.

The report is organized into four (4) sections including this introductory section:

- Section 2 outlines the strategic asset management plan, summarizing standards PAS-55 and ISO 55000/55001/55002, an overview of the METSCO methodology and the ACA process.

- Section 3 presents the KWHI Health Index (HI) framework, Data Availability Index (DAI), and results including age demographics and condition assessment for each asset class.

- Section 4 presents METSCO's recommendations on process improvements directed at improving data availability towards enhancing the value of HI results and recommended replacement plan.

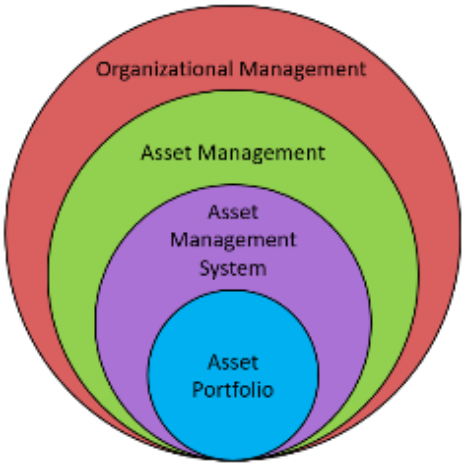
2 STRATEGIC ASSET MANAGEMENT PLAN

2.1 INDUSTRY STANDARD FOR ASSET MANAGEMENT PLANNING

The Industry Standard for Asset Management Planning is outlined in standards documents comprising the ISO 5500X framework. Asset Management (AM) is generally applied to one of three groups of entities: those looking to establish and set up an asset management system, those looking to realize more value from an asset base, and those looking to review an asset management system already in place for to explore opportunities of improvement. Given this breadth of potential utilization pathways, ISO 5500X is broadly applicable across organizations adjusting, as necessary, for the purpose, operating context, and financial constraints. Stakeholders should be of primary concern when applying or analysing any new or updated AM framework.[1]

An asset is any item or entity that has a value to the organization. This can be actual or potential value, in a monetary or other form (i.e. public safety). The hierarchy of an AM framework is as follows: an asset portfolio, containing all known information regarding the assets, sits as the fundamental core of an organization. Around the asset portfolio is the AM system, which represents a set of interacting elements to establish policy, objectives, and the processes to achieve those objectives. The AM system is comprised of AM practices, which are executed in a coordinated fashion to realize the maximum value of the organization's assets. Finally, the organizational management organizes and executes the elements of the underlying hierarchy.[1]

Figure 2.1: Relationship between key Asset Management terms[1]



Asset management is fundamentally grounded in a risk-based evaluation approach. The overarching goal of an AM process it to quantify all assets risk by their probability and impact

[1] ISO 55000 – Asset management – Overview, principles and terminology

(where possible) and then look to minimize these risks through asset management operations and procedures. Rigorous application of AM processes can produce multiple types of benefits for an organization including, but not limited to: realized financial profits, better defined, classified and managed risks across the asset base, more informed investment decisions, demonstrated compliance across the asset base, increased public and worker safety, and corporate sustainability.[1]

Asset management processes are ideally integrated throughout an entire organization. This requires a well-documented AM framework that is shared between all relevant agents. In this way, the organization stands to benefit the most from its own on-hand resources, whether via technical experts, those operating and maintaining the assets, or those with an understanding of the financial operations and constraints on the organization as a whole. Organizations usually, document the key AM principles in a Strategic Asset Management Plan (SAMP). The SAMP should be used as a guide for the organization to apply its asset management principles and practices to its specific-use cases. Distribution of the SAMP should be open within an organization and updated on regular basis in order to best quantify the most current and comprehensive asset management practices being implemented within the organization. Just as the asset base performance is subject to in-depth review, the asset management process and system should be reviewed with the same rigor.[1]

Well executed AM hinges on an organization's ability to classify its asset via comprehensive and extensive data collection and analysis procedures. This includes but is not limited to: collection and storage of technical specifications, historical asset performance, projected asset behaviour and degradation, configuration of an asset or asset-group within the system, the operational relation of one asset to another, etc. In this way, AM systems should be focused on the techniques and procedures in which data can be most efficiently extracted from its asset base and stored to allow for further analysis and insights to be made. With more asset data on hand, better-informed decisions can be made to realize greater benefits and reduce the risk across the asset portfolio.[2]

AM practices can help quantify and drive strategic decisions. A better understanding of the condition of asset portfolio within an organization can enable for fluid reorganization or changes in management processes to realize tangible benefits to the organization. This is largely due to AM being a fundamentally risk-based approach, which lends it to be a sound framework for creating financial plans driven by evidence from the field. AM practices should also have goals in mind when framing asset investments, changes in asset configuration, or acquisition of new assets. This can include: better technical compliance, increased safety, increased reliability, or increased financial performance of the asset base. ISO 5500X states explicitly that all asset

[2] ISO 55002 – Asset management – Management systems – Guidelines for the application of ISO 55001

portfolio improvements should be assessed using a risk-based approach prior to being implemented.[2]

Finally, asset management should be considered a fluid, flexible process subject to future enhancements and revisions. Adopting a framework and an optimized set of practices does not bind the organization or restrict its agency in the future as the operating r strategic context evolves. With time, the goal of any asset management system is to continually improve and realize benefits within the organization through better management of its asset portfolio. Continually improved asset data and data collection procedures, updated Strategic Asset Management Plans (SAMPs), and further integration of into all aspects of an organization's activities as it grows and changes over time should be the goal of any AM framework.[2]

An Asset Condition Assessment (ACA) represents the first step in fully integrating the AM framework outlined by ISO 55000. By evaluating the current set of available data related to the condition of in-service assets within an asset portfolio, condition scores for each asset are determined. The level of degradation of an asset, knowledge of its configuration within the system, and its corresponding likelihood of failure feed directly into a risk-based assessment. The fundamental purpose of an ACA is to collect, consolidate, and present the results framed by the current organizational dynamics for the purposes of properly quantifying and managing the risks of its asset portfolio. An ACA should provide insights into the current state of an organization's asset base, the risks associated with the degradation of portions of the assets in the system and approaches as to optimal utilization of these results to extract maximum value from the asset portfolio going forward.

2.2 OVERVIEW OF METSCO'S METHODOLOGY

2.2.1 OVERALL ASSET MANAGEMENT STRATEGY

Decisions involving investment into fixed assets play a major role in determining the optimal performance of distribution system fixed assets. The majority of the investments in fixed assets are triggered by either declining performance in the areas of supply system reliability, power quality or safety; or increasing operating and maintenance costs associated with aging assets; or anticipated growth in demand requiring capacity upgrades. In either case, investments that are either oversized or made too far in advance of the actual system need may result in non-optimal investment. On the other hand, investment not made on time when warranted by the system needs raise the risk of missing performance targets and would not result in optimized investment. Optimal operation of the distribution system is achieved when "right sized" investments into renewal and replacement (capital investments) and into asset repair, rehabilitation and preventative maintenance are planned and implemented based on a "just-in-time" approach. In summary, the overarching objective of the Asset Management Strategy is to find the right balance between capital investments in new infrastructure and operating and maintenance costs so that the combined total cost over the life of the asset is minimized.

METSCO is a proponent of a Risk-Based Asset Management Strategy, which determines the risk of asset failure based on the condition of the asset, which is commonly measured with the "Asset Health Indices" and computes the valuation of the risk based on consequences of asset failure and identifies the optimal risk mitigation alternative through an evaluation of all available options. Asset management covers the full life cycle of a fixed asset, from preparation of the asset specification and installation standards - to the scope and frequency of preventative maintenance during the asset's service life – and finally to the determination of the assets end-of- life and retirement from service. At each stage of an asset's life cycle, decisions are made to achieve the right balance between achieving maximum life expectancy, highest operating performance, lowest initial investment (capital costs) and lowest operating costs. The best-in-class asset management strategies employ integrated processes that allow optimal levels of financial and operating performance to be achieved, using transparent and objective criteria that can easily be audited and inspected by regulators.

The overarching objective is to develop a prioritized capital and preventative maintenance investment plans, which are implemented over periods of ten to twenty-five years and optimize system performance. Corporate objectives and performance requirements are incorporated in the model by placing appropriate weights and costs on project drivers as shown in Figure 2-2.

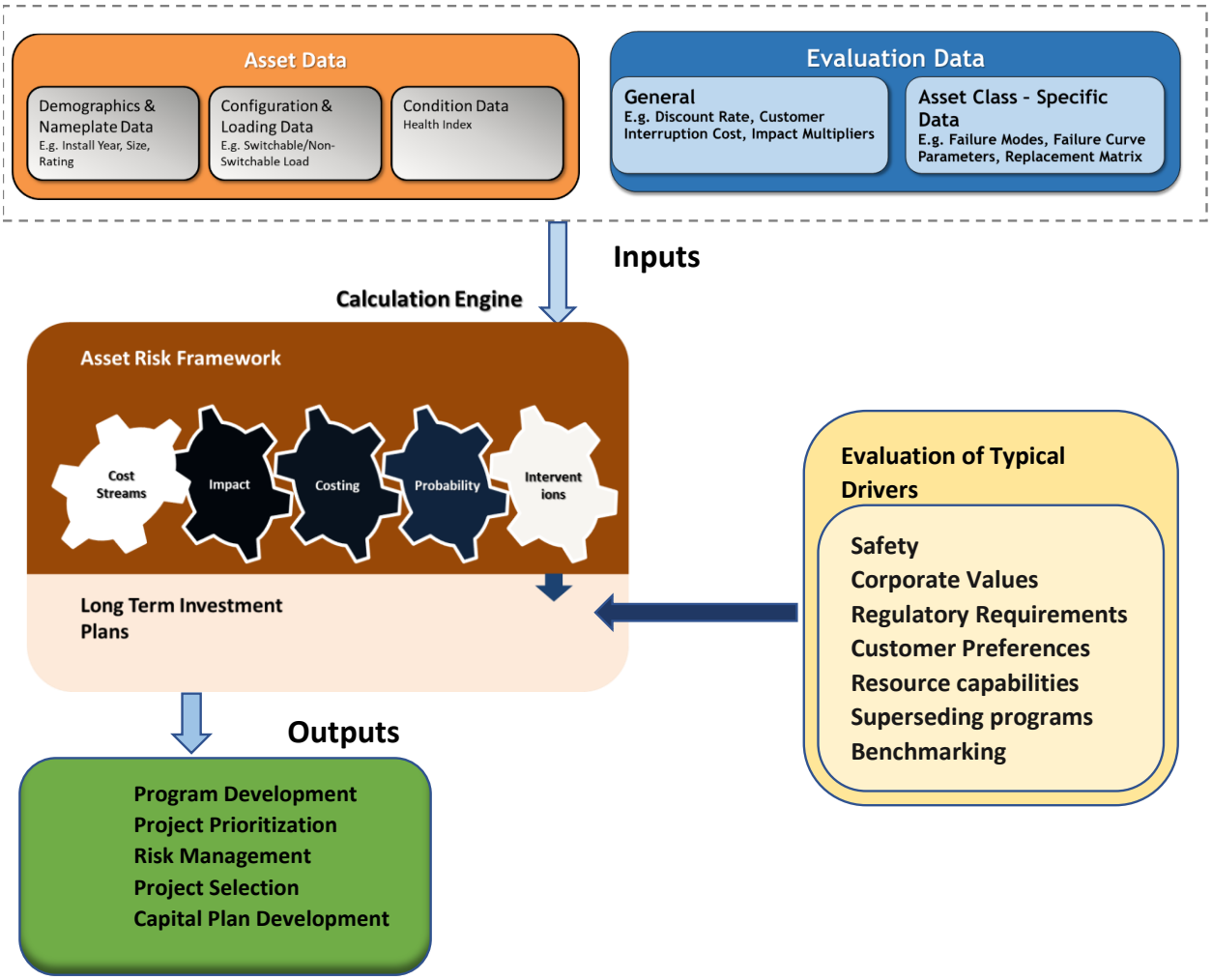


Figure 2-2: Model to Identify Assets with Highest Risks

METSCO's overall asset management approach includes executing and assessment within the 5 frameworks as presented in Figure 2-3. Under the asset health index framework development an Asset Condition Assessment is performed. ACA is used to produce the HI, which is a quantified condition score of the asset. HI score is ultimately calculated using asset age and inspection data. With this technique, condition-based failure probability can be determined. Different assets have different failure curves that are calibrated using their failure data. In risk calculations, failure probability is used to determine the likelihood of failure of an asset of a given age in a given year. Failure mode and impact framework development calculates the consequence cost values for various failure modes considering customer impacts, collateral damage impact, environmental impact, etc. Once the probability and impact of asset failure have been determined, the risk cost can be calculated, along with the life-cycle costs of the asset. Assets will be recommended for optimal replacement when an optimal balance is achieved between capital spending and risk mitigated.

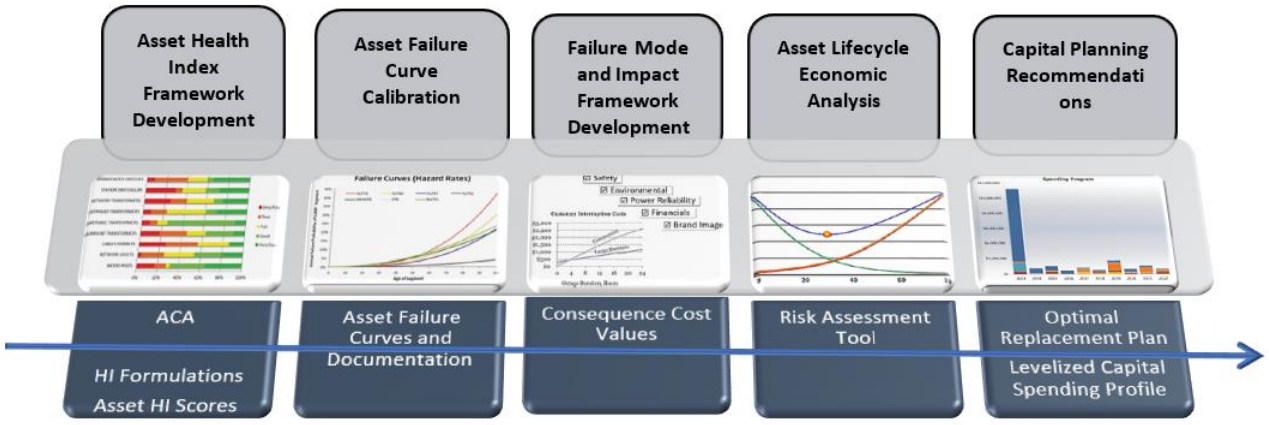


Figure 2-3: Overall AM approach

2.2.2 Asset Condition Assessment Process

The major steps in the ACA are briefly discussed below:

1. Identify Asset Classes: Identify asset classes to be considered in the asset condition assessment study
   Typical asset classes in the distribution system include:
   - Station Transformers
   - Station Circuit Breakers
   - Station Batteries
   - Capacitors
   - Controls and Protective Relays
   - Overhead Primary Conductors
   - Underground Primary Cables
   - Distribution Transformers
   - Switches
   - Poles

2. Data Analysis:
   - Collection of asset related data such as GIS records, asset demographics, inspection/testing records, etc.
   - Validate the accuracy of data, e.g. check for data discrepancies between files
   - Develop a "Recommended Health Index Formulation" (RHIF) for each asset based on the available data, published best practice information and expert assessment of the

data parameters which are reasonably obtained and are most indicative of asset end of life.

- Identify additional asset data needed to determine and evaluate asset condition and assess the potential of collecting additional useful asset condition information to improve accuracy of the asset condition assessment results.
- Make recommendation on collecting additional data that is reasonably available. [The methods to obtain additional data typically include inspection, testing, sampling, collection of paper records, field work to collect asset data, adopting advanced technology to record inspection/testing data, etc.]

3. Collect additional condition information specific to each asset class.

4. Calculate Data Availability Indicator (DAI): DAI is a percentage of availability of condition parameter data for an asset, as measured against the condition parameters considered in the RHIF. DAI is calculated as a ratio of sum of weighted condition parameters score of available condition parameters to sum of weighted condition parameters score from the recommended HI formulation.

$$DAI = \left(\frac{\sum_{i=1}^{N} Weight_i * CPAF_i}{\sum_{i=1}^{N} Weight_i}\right) x\ 100$$

Where i corresponds to the condition number, *N* is the total number of condition parameters considered in the HI calculation, and *CPAF* is the Condition Parameter Availability Factor which is equal to 1 if the condition parameter data is available for the asset otherwise equal to 0.

DAI of 100% for an asset indicates successful population of values for all condition parameters defined in the Recommended Health Index Formulation for the asset and is therefore a measure of the success in meeting its intentioned data collection. Typically, the targets for DAI are less than 100% for "sampled" assets such as cables and wood poles or where the costs to collect additional data are not warranted such as for low risk assets.

In addition, there is a data set representing the "Best Practice Health Index Formulation", which an asset owner may be moving towards. In this case the recommendation for process improvements may include the effort to be taken to collect additional condition parameters defined in the Best Practice Health Index Formulation for the entire population of assets. This is expected to increase the accuracy of ACA results.

5. Asset Condition Assessment:

A health index is an indicator of asset remaining life given as a percentage. A new asset should have a health index of 100% and an asset in very poor health should have a health index below 30%. Table 2-1 presents the health index ranges and the corresponding asset condition.

Table 2-1: Asset condition based on health index

Health Index	Condition	Description	Requirements
85–100	Very Good	Some ageing or minor deterioration of a limited number of components	Normal maintenance
70–85	Good	Significant deterioration of some components	Normal maintenance
50–70	Fair	Widespread significant deterioration or serious deterioration of specific components	Increase diagnostic testing; possible remedial work or replacement needed depending on criticality
30–50	Poor	Widespread serious deterioration	Start planning process to replace or rehabilitate considering risk and consequences of failure
0–30	Very Poor	Extensive serious deterioration	Asset has reached its end-of-life; immediately assess risk; replace or refurbish based on assessment

To determine the health index for an asset, formulations are developed based on conditions that lead to asset end of life. A weight is assigned to each condition to indicate the amount of influence the condition has on the overall asset health.

When presented with a health index formulation such as:

Table 2-2: Health Index Calculation Example

#	Condition	Weight	Ranking	Numerical Grade	Max Grade
1	Condition example 1	4	A,B,C,D,E	4,3,2,1,0	16
2	Condition example 2	6	A,C,E	4,2,0	24
3	Condition example 3	6	A,B,C,D,E	4,3,2,1,0	24
Total					**64**

Each condition is ranked from A to E and each rank corresponds to a numerical grade:

A – 4	Best Condition
B – 3	Normal Wear
C – 2	Requires Remediation
D – 1	Rapidly Deteriorating
E – 0	Beyond Repair

The Health Index is then calculated as follows:

$$HI = \left(\frac{\sum_{i=1}^{N} Weight_i * Numerical\ Grade_i}{Total\ Score}\right) x\ 100$$

Where i corresponds to the condition number, N is the total number of condition parameters considered in the HI calculation and the health index is a percentage representing the remaining life of the asset.

Figure 2-4 shows the example graph representation of HI conditions for an asset class categorizing assets into Very Poor to Very Good condition.

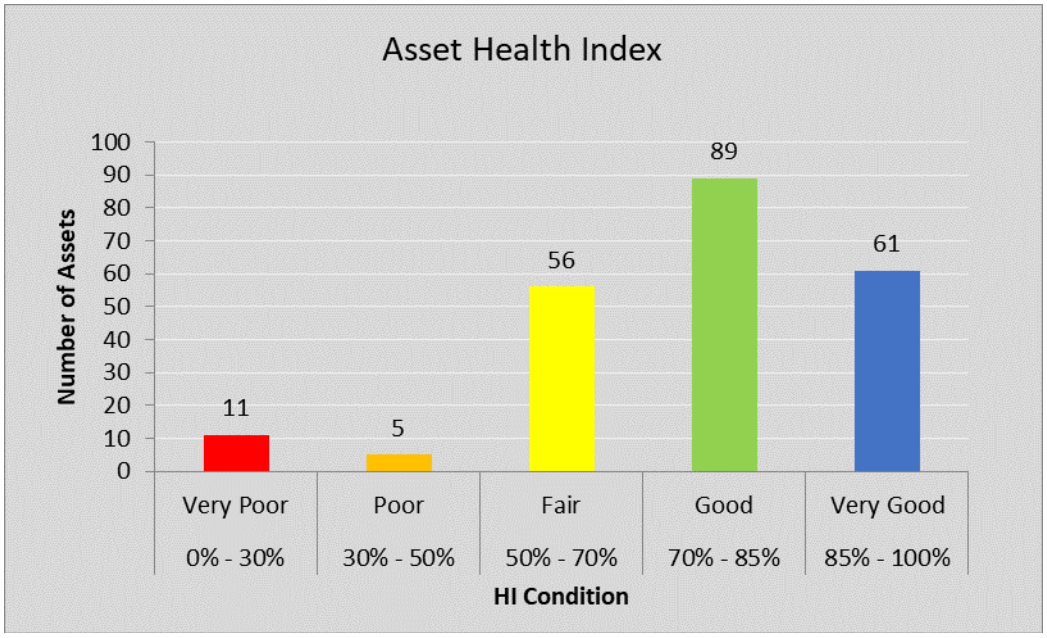


Figure 2-4: Asset Health Index Graph-Example

6. Demographic Assessment:
   A useful cross-reference to a Health Index, is a representation of asset demographics. Assets are charted based on age from installation date, and other pertinent demographics such as material or manufacturer/type etc. Since many people still consider age when making

replacement plans, it is important to document any significant variations from the age-base results and the condition-based Health Index. As an example, cables are known to have different life expectancies based on the technology available at the time of installation or in other cases equipment of a certain manufacture may be known to be reaching end of life and failing at a higher than predicted rate.

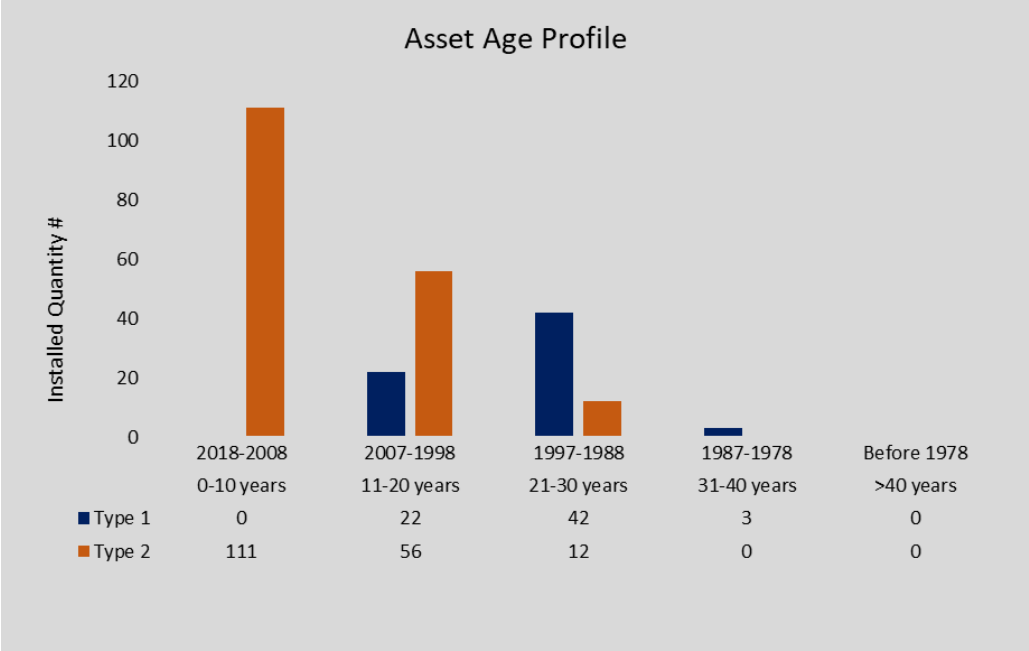


Figure 2-5: A Typical Demographic Chart

Figure 2-6 presents the example expected relation between the HI condition and the service age. It is expected that the HI conditions should gradually change from Very Good to Very Poor as the service age of an asset increases.

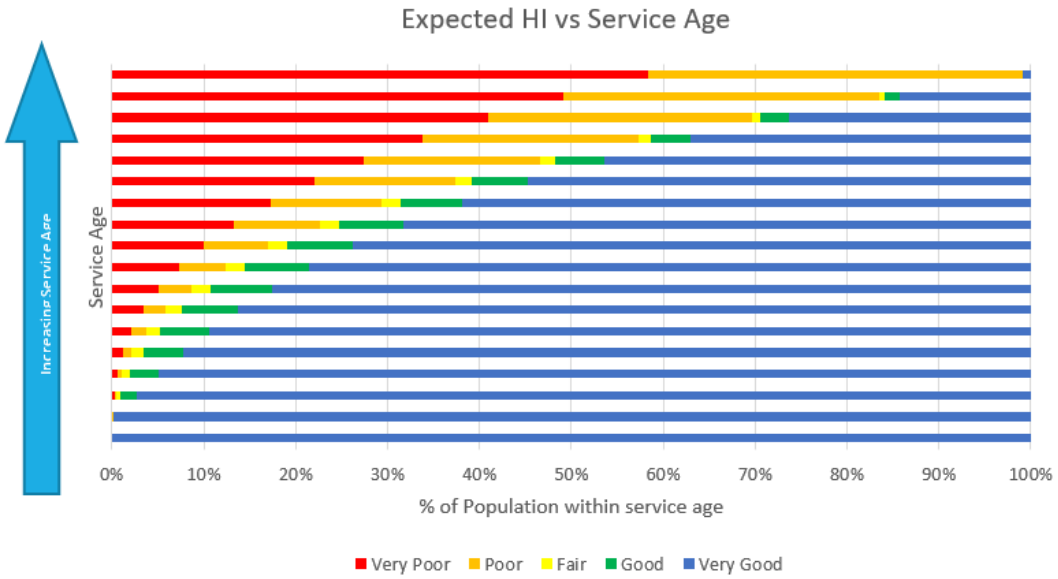


Figure 2-6: Expected HI Vs Service Age Trend-Example

7. Recommendations: The last stage of the ACA process provides recommendations to the organization on data collection process improvements that are expected to increase the validity of HI results.

3 HEALTH INDICES

3.1 SUBSTATION TRANSFORMERS

3.1.1 CONDITION ASSESSMENT METHODOLOGY

3.1.1.1 Health Index Calculation

Computing the Health Index of a transformer requires developing end-of-life criteria for its various components. Each criterion represents a factor critical in determining the component's condition relative to potential failure. Based on the available data, best practise information and the METSCO's expert opinion, the table below describes the RHIF for Substation Transformers.

Table 3-1: Substation Transformers Recommended Health Index Parameters

#	Condition	Weight	Ranking	Numerical Grade	Max Grade
1	DGA Testing	10	A,B,C,D,E	4,3,2,1,0	40
2	Load History	10	A,B,C,D,E	4,3,2,1,0	40
3	Insulation Power Factor	10	A,B,C,D,E	4,3,2,1,0	40
4	Age of transformer	6	A,B,C,D,E	4,3,2,1,0	24
5	Oil Quality	6	A,C,E	4,2,0	24
6	Visual inspection (Overall Condition)	2	A,B,C,D,E	4,3,2,1,0	8
7	Oil Level	1	A,B,C,D,E	4,3,2,1,0	4
8	Oil Leaks	1	A,B,C,D,E	4,3,2,1,0	4
Total					**184**

1. Dissolved Gas Analysis

Dissolved Gas Analysis (DGA) determines the quantities of various gases dissolved in oil. DGA often serves as a primary means to assess insulation and to identify faults such as insulation aging and overheating, arcing in oil, and partial discharge damage. The following 3 tables are to be considered when determining the final HI score for the DGA condition degradation factor. The DGA test provides gas concentrations (in ppm) for the 8 gases as listed within Table 3-2. Using Table 3-2, the worst-case condition score (i.e. condition 1-4) is chosen based on the DGA test results. The second step in producing the health index score is to use the gas rate of change (in ppm/day) for the 7 recorded gas concentrations. Using the threshold limits within Table 3-3, a score of either Low, Low to High or High can then be recorded based on the gas rate of change. With these 2 parameters established, Table 3-4 provides the matrix that scores the two parameters to produce the final grade score for a given asset.

Table 3-2: Gas concentration (ppm) to condition rating conversion

Condition	H_2	CH_4	C_2H_2	C_2H_4	C_2H_6	CO	CO_2	TDCG
Condition 1	<100	<120	<1	<50	<65	<350	<2500	<686
Condition 2	101-700	121-400	2-9	51-100	66-100	351-570	2500-4000	687-1879
Condition 3	701-1800	401-1000	10-35	101-200	101-150	571-1400	4001-10000	1880-4585
Condition 4	>1800	>1000	>35	>200	>150	>1400	>10000	>4585

Table 3-3: Gas rate of change limits (ppm/day)

Gas	Lower Limit	Higher Limit
H_2	1.46	4.37
CH_4	1.75	5.25
C_2H_2	0.01	0.04
C_2H_4	0.73	2.19
C_2H_6	0.95	2.84
CO	5.10	15.31
CO_2	36.4	109
TDCG	10.00	30.00

Table 3-4: Station Power Transformer gas concentration & rate of change condition grade matrix

Gas Condition	Gas Generation Rate		
	Low	**Low to High**	**High**
Condition 1	A	A	B
Condition 2	B	B	C
Condition 3	C	C	D
Condition 4	D	D	E

The worst score out of all the measured gases is to be taken as the overall DGA grade.

2. Load History

Option 1: Monthly Peak Loading History

The rate of insulation degradation is directly related to the operating temperature and operating temperature is directly related to loading levels. Peak loading level of the transformers expressed in % of nameplate rating can therefore be employed as an indicator of transformer health. The recorded monthly load peaks can be used to calculate the load history contribution to HI

calculations within the Ideal Health Index framework. The load history is categorized into 5 groups as listed below

Load Factor = Monthly Peak Load/ Nameplate Rated Load

$$LS = \frac{\sum_{i=0}^{4}(4-i) \times N_i}{\sum_{i=0}^{4} N_i}$$

N_0 is the number of months with LF ≤ 0.6
N_1 is the number of months with 0.6 < LF ≤ 1
N_2 is the number of months with 1 < LF ≤ 1.3
N_3 is the number of months with 1.3 < LF ≤ 1.5
N_4 is the number of months with LF >1.5

Table 3-5: Station Power Transformer load history condition grading

Grade	Corresponding Condition
A	LS ≥ 3.5
B	2.5 ≤ LS < 3.5
C	1.5 ≤ LS < 2.5
D	0.5 ≤ LS < 1.5
E	LS < 0.5

This ACA uses Option 1 for rating Peak loading of transformers.

Option 2: Transformer Peak Load
When only the station peak loading information is available, a simplified approach is to score the transformer based on the following table.

Table 3-6: Station Power Transformers – Peak Load Based Health Scoring

Grade	Peak Loading Condition
A	Peak load less than 50% of its rating
B	Peak load of 50% to 75% of its rating
C	Peak load of 75% to 100% of its rating
D	Peak load of 100% to 125% of its rating
E	Peak load of greater than 125% of its rating

3. Insulation Power Factor

The power factor or dissipation factor measurement is an importance source of data to monitor transformer and bushing condition. This test is performed to determine the condition of capacitive insulation between different windings and compartments. The test is performed in a

number of different configurations and the highest score of the set is considered as the insulation power factor score.

Table 3-7: Station Power Transformer power factor condition grading

Grade	Corresponding Condition
A	$PF_{MAX} < 0.5$
B	$0.5 \leq PF_{MAX} < 1$
C	$1 \leq PF_{MAX} < 1.5$
D	$1.5 \leq PF_{MAX} < 2$
E	$PF_{MAX} \geq 2$

4. Age of Transformer

Since the service age provides a reasonably good measure of the remaining life of transformers, it is employed as an assessment parameter, with the following scores:

Table 3-8: Station Transformers – Age Related Health Score

Grade	Station Transformer Age
A	0 to 10 years
B	10 to 20 years
C	20 to 30 years
D	30 to 50 years
E	50 years or older

5. Oil Quality

A combination of electrical, physical and chemical tests is performed to establish preventive maintenance procedures, avoid premature failure and costly shutdown and plant maintenance such as oil reclamation or replacement. Testing for power transformer oil quality consists of measuring breakdown voltage, and other physical and chemical properties of samples of the oil.

Table 3-9: Station Power Transformer oil quality test condition grading

Test	Station Transformer Voltage Class			Grade
	U ≤ 69 kV	69 kV < U < 230 kV	U ≥ 230 kV	
Acid number	≤0.05	≤0.04	≤0.03	**A**
	0.05-0.20	0.04,3,2,1,0.15	0.03-0.10	**C**
	≥0.20	≥0.15	≥0.10	**E**
Interfacial Tension, IFT, [mN/m]	≥30	≥35	≥36	**A**
	25-30	30-35	32-36	**C**
	≤25	≤30	≤32	**E**
Dielectric strength [kV]	>23 (1mm gap) >40 (2 mm gap)	>28 (1mm gap) >47 (2mm gap)	>30 (1mm gap) >50 (2mm gap)	**A**
	≤23 (1mm gap) ≤40 (2 mm gap)	≤28 (1mm gap) ≤47 (2mm gap)	≤30 (1mm gap) ≤50 (2mm gap)	**E**
Water content [ppm]	<35	<25	<20	**A**
	≥35	≥25	≥20	**E**

6. Visual Inspections (Overall Condition)

Visual inspections can provide a good indication of the physical condition of transformers, which can be ranked as indicated below:

Table 3-10: Station Transformers – Health Score Based on Visual Inspections

Grade	Corresponding Condition
A	Station transformer is externally clean and corrosion free. All monitoring, protection and control, pressure relief, gas accumulation and silica gel devices, and auxiliary systems mounted on the station transformer are in good condition. No external evidence of overheating or internal overpressure. Appears to be well maintained with service records readily available.
B	Normal signs of wear with respect to the above characteristics.
C	One or two of the above characteristics are unacceptable.
D	More than two of the above characteristics are unacceptable – repairable.
E	More than two of the above characteristics are unacceptable – damaged beyond repair.

KWHI's Transformer Station inspections incorporate several activities on a daily, weekly and monthly basis and generally include the following:

1. Daily Transformer Inspections
2. Daily Switchgear Building Inspection
3. Weekly General Inspections

4. Monthly Tapgear Counter Readings and Assessment of Station Service Transformers
5. Monthly Emergency Equipment Inspections

7. Oil Level

Oil level inspection is noted during the routine inspection. The oil level is noted numerically and is collected monthly. Below table presents the oil level condition grading

Table 3-11: Station Power Transformer oil level condition grading

Grade	Corresponding Condition
A	Transformer oil level is acceptable with insignificant variation from the previous inspection.
B	Transformer oil level is acceptable with noticeable variation from the previous inspection.
C	Transformer oil level is acceptable, but considerable variation from the previous inspection.
D	Transformer oil level is unacceptable. Topped up during inspection.
E	Transformer oil level is unacceptable and could not be topped up; and/or oil level indicates unsafe transformer operation or hazardous rate of oil loss.

8. Oil Leaks

Inspections of substations also include the visual identification of oil leaks present. Table 3-12 presents the grading scheme for oil leaks.

Table 3-12: Station Power Transformer oil leaks condition grading

Grade	Corresponding Condition
A	No oil leakage or water ingress at any of the bushing-metal interfaces or at gaskets, weld seals, flanges, valve fittings, gauges, monitors.
B	Minor oil leaks evident, but no moisture ingress is likely.
C	Clear evidence of oil leaks but rate of loss is not likely to cause any operational or environmental impacts.
D	Major oil leakage and probable moisture ingress. If left uncorrected it could cause operational and/or environmental problems.
E	Oil leaks or moisture ingress have resulted in complete failure or damage/degradation beyond repair.

3.1.2 RESULTS ANALYSIS

3.1.2.1 Assumptions

KWHI's 2017 oil test reports for station transformers do not include values for water content. In the calculation of oil quality HI grade, it is assumed that water content was within the normal range or that it would have been reported otherwise. Therefore, a grade of "A" is assigned which is not impactive as the formulation accounts only for the worst condition factor from Table 3-9.

For the KWHI's station transformer oil, gas rate of change limit is assumed to be low (non-impactive) for this study.

The current substation inspection form of KWHI has only 2-parameter condition grading for oil level and oil leak, they are: 'Ok' and 'Not Ok'. Therefore, following assumptions have been considered:

- Ok- Assumed to be in Good condition and given a grade of B
- Not Ok- Assumed to be in Poor condition and given a grade of D

3.1.2.2 Age and Demographics

There are 8 KWHI-owned Transformer Stations (TSs) operating at 115 kV to 13.8 kV or 230 kV to 13.8 kV or 230 kV to 27.6 kV. There are 7 KWHI-owned Distribution Stations (DSs) operating at 27.6 kV to 8.32 kV. There are 764 customer-owned substations, of which 609 house transformers owned by KWHI while the remaining house customer-owned transformers.

The key role of station transformers is to step down transmission or sub-transmission voltage to distribution voltage. KWHI has 19 TS transformers of which 3 are spare power transformers and 7 Distribution Station (DS) transformers. Figure 3-1 presents the age distribution of TS and DS transformers. Of 19 TS transformers 15 are less than 30 years old and 4 are between 31-50 years. 1 of the DS transformers is in-service for more than 50 years.

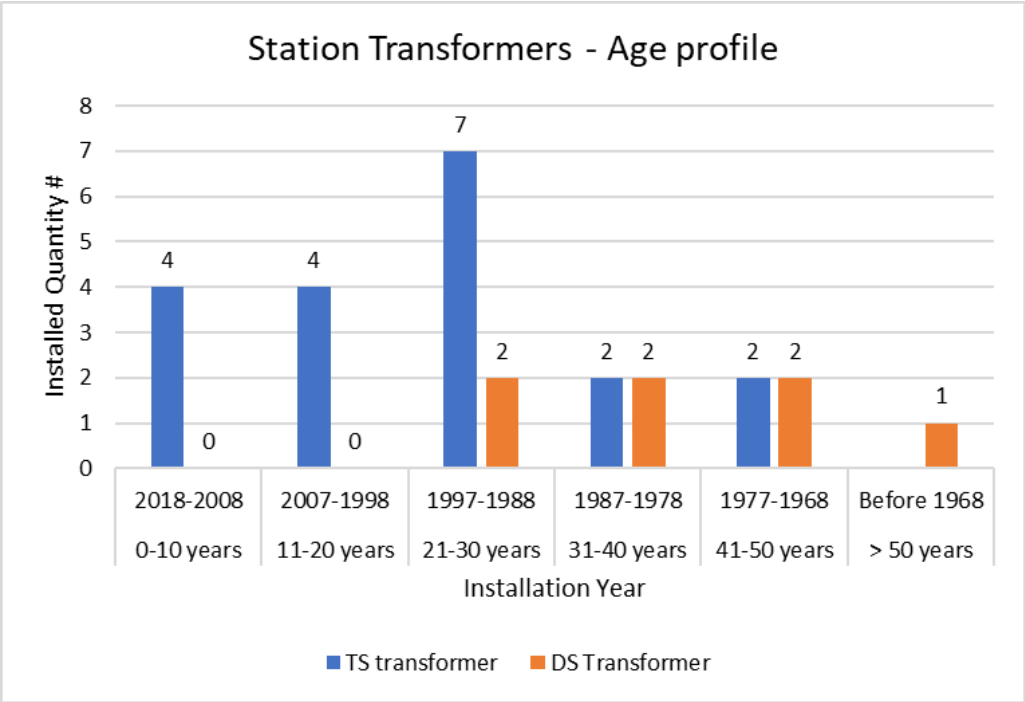


Figure 3-1: Station Transformers- Age Profile

3.1.2.3 DAI

The Data Availability Indicator (DAI) is created to measure the reasonably collected data by the utility for completion regarding parameters used in the Health Index formulation. The average DAI for Substation Transformer data is 82%.

The average DAI for TS transformers is 94% which indicates that KWHI has successfully populated condition data for majority of their assets. The average DAI for DS transformers is 51% due to the missing insulation PF, oil quality, and peak loading data. This DAI can be improved by collecting data for all the assets.

3.1.2.4 Condition Assessment

Health Index is calculated using the parameters listed in Table 3-1 and Figure 3-2 presents the station transformer HI condition. Based on this HI calculation, about 12% of the station transformers are in Poor Condition, 46% are in Fair Condition and remaining 42% are in Good or Very Good Condition.

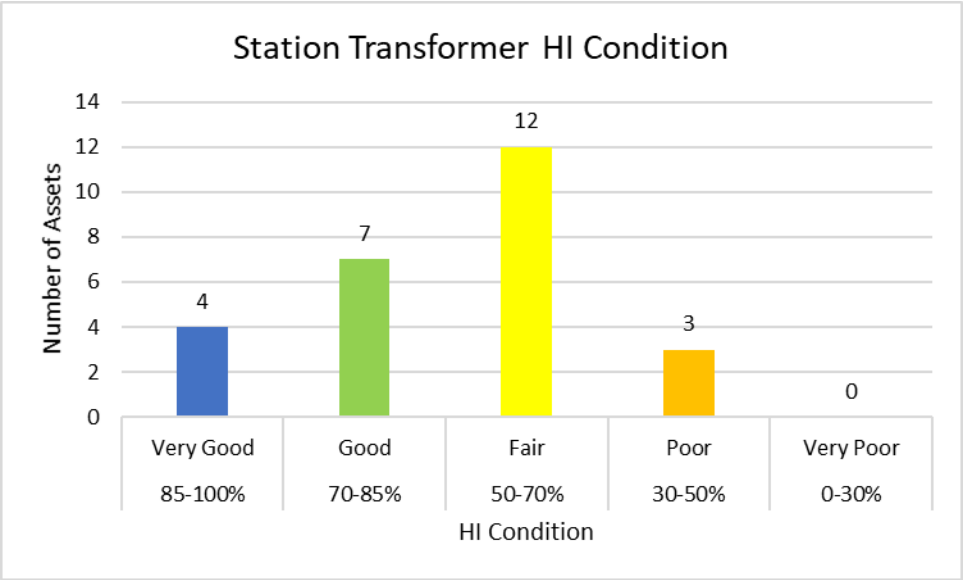


Figure 3-2: Station Transformer HI Condition

3.2 STATION CIRCUIT BREAKERS AND RECLOSERS

3.2.1 CONDITION ASSESSMENT METHODOLOGY

3.2.1.1 Health Index Calculation

The operating mechanism of circuit breakers and reclosers consists of numerous moving parts that are subject to wear and tear during operation. Because circuit breakers are required to frequently "make" and "break" heavy currents, the contacts are subjected to arcing that accompanies such operations. Each time a circuit breaker opens or closes, the contact surfaces undergo some degradation and degraded contacts produces higher degree of arcing in subsequent operations. Heat produced during contact arcing also decomposes the metal surface from the contacts as well as the insulation medium and the by-products so decomposed are deposited in surrounding insulation materials. The mechanical energy required to generate high contact velocities also results in wear and tear of the mechanical parts in operating mechanism.

Several factors influence the overall rate of wear and severity of degradation of circuit breakers, including type of the insulating medium, design of the contacts, operating environment, and the duty cycle of the circuit breaker. Load current switching or fault current interruption seldom lead

to sudden failure of circuit breakers, but repeated operations result in overall wear and tear which lead to eventual end of life.

Circuit breakers mounted outdoors may experience adverse environmental conditions that may further contribute to the rate and severity of degradation. The following factors represent environmental degradation of outdoor mounted circuit breakers:

- Corrosion of enclosures and metal parts;
- Potential ingress of moisture into operating parts and insulating system;
- Bushing/insulator deterioration under the influence of moisture, fog, ice; and
- Deterioration of mechanical parts;

Based on the available data, best practise information and the METSCO's expert opinion, the table below describes the RHIF for Circuit Breakers and Reclosers.

Table 3-13: Circuit Breakers /Reclosers Recommended Health Index Parameters

#	Condition	Type	Weight	Ranking	Numerical Grade	Max Grade
1	Age	All	4	A,B,C,D,E	4,3,2,1,0	16
2	Visual Inspection	All	3	A,B,C,D,E	4,3,2,1,0	12
3	Contact Resistance	All	2	A,B,C,D,E	4,3,2,1,0	8
4	Pressure Test	SF6	4	A,B,C,D,E	4,3,2,1,0	16
Total						**52**

1. Service Age

Service age provides a reasonably good measure of the remaining life of circuit breakers and reclosers. Since the outdoor mounted reclosers exposed to the weather elements experience a faster rate of aging, two separate sets of criteria are provided for outdoor and indoor mounted circuit breakers / reclosers:

Table 3-14: Outdoor Circuit Breakers/Reclosers – Age Related Health Score

Grade	Age
A	0 to 7 years
B	8 to 15 years
C	16 to 24 years
D	25 to 32 years
E	33 years or older

Table 3-15: Indoor Circuit Breakers/Reclosers – Age Related Health Score

Grade	Age
A	0 to 10 years
B	11 to 20 years
C	21 to 30 years
D	31 to 40 years
E	41 years or older

2. Visual Inspection

This equipment lends itself to visual inspections because key components are visible and accessible. Visual inspections can detect external contamination, corrosion, evidence of overheating, misalignment, plus cracks and leaks on bushings, support insulators, tanks, enclosures, drives, linkages and fittings.

Table 3-16: Station Breaker/Recloser overall condition grading

Grade	Corresponding Condition
A	Breaker/Recloser is externally clean and corrosion free. All connections are in good condition. No external evidence of overheating. Counter readings for number of breaker operations and run timer readings on auxiliary motors are in the below average range for the age of the breaker. Appears to be well maintained with service records readily available.
B	Normal signs of wear with respect to the above characteristics.
C	One or two of the above indicated characteristics are unacceptable.
D	More than two of the above indicated characteristics are unacceptable.
E	The circuit breaker is damaged or degraded beyond repair.

3. Contact Resistance

Table 3-17: Station Breaker/Recloser contact resistance test condition grading

Grade	Corresponding Condition
A	Contact resistance values well within specifications with high margins.
B	Contact resistance values close to specification (little or no margin).
C	Contact resistance values do not meet specification by a small amount.
D	Contact resistance values do not meet specification by a significant margin.
E	Contact resistance values do not meet specification and cannot be brought into specification condition.

The contact resistance grading is modified as shown below to use the values from test reports provided by KWHI.

Table 3-18: Modified Contact resistance test condition grading

Grade	Corresponding Condition
A	All pole contact resistance < 40 micro ohms
B	40 < Any pole contact resistance <80 micro ohms
C	One pole contact resistance > 80 micro ohms
D	Two pole contact resistance > 80 micro ohms
E	Contact resistance values do not meet specification and cannot be brought into specification condition.

4. Pressure Testing

Table 3-19: SF6 Pressure Test condition grading

Grade	Corresponding Condition
A	No SF_6 leakage at any of the bushing-metal interfaces, tank or piping interfaces, as determined by inspection of SF_6 pressure gauge and SF_6 refill maintenance records.
B	Minor SF_6 leakage, not more than 0.5%, per year, by weight, of the total quantity of SF_6 in the breaker, as determined by inspection of SF_6 pressure gauge and refill maintenance records.
C	SF_6 leakage of up to 1.5%, per year, by weight, of the total quantity of SF_6 in the breaker, as determined by inspection of SF_6 pressure gauge and refill maintenance records.
D	SF_6 leakage of up to 2%, per year, by weight, of the total quantity of SF_6 in the breaker, as determined by inspection of SF_6 pressure gauge and refill maintenance records.
E	SF_6 leakage exceeding 2%, per year, by weight, of the total quantity of SF_6 in the breaker, as determined by inspection of SF_6 pressure gauge and refill maintenance records.

3.2.2 RESULTS ANALYSIS

3.2.2.1 Assumptions

All CBs and reclosers are inspected as part of the regular maintenance program except for the breakers at 9TS as they are gas insulted and not accessible. KWHI's current inspection report does not employ condition grading for visual inspection. Therefore, the comments reported in the inspection form is used to grade visual inspection. The following grading has been followed for visual inspection:

Grade	Comment
B	Breakers maintained, and no problems found
C	Breakers maintained and found minor problems but has been fixed
E	Breaker failed inspection

3.2.2.2 Age and Demographics

KWHI's distribution system employs a total of 168 CBs of which, 149 are either vacuum type or SF6 type in the TS and 20 are reclosers or air breakers in the DS. The age distribution of these breakers and reclosers are presented in Figure 3-3. All the Vacuum CBs at the TS of KWHI are in-service for less than 20 years. SF6 CBs are between 21-40 years old. There are 3 air breakers in-service at 6 DS for about 36 years and 17 Reclosers between the age of 21 to 30 years at other DS.

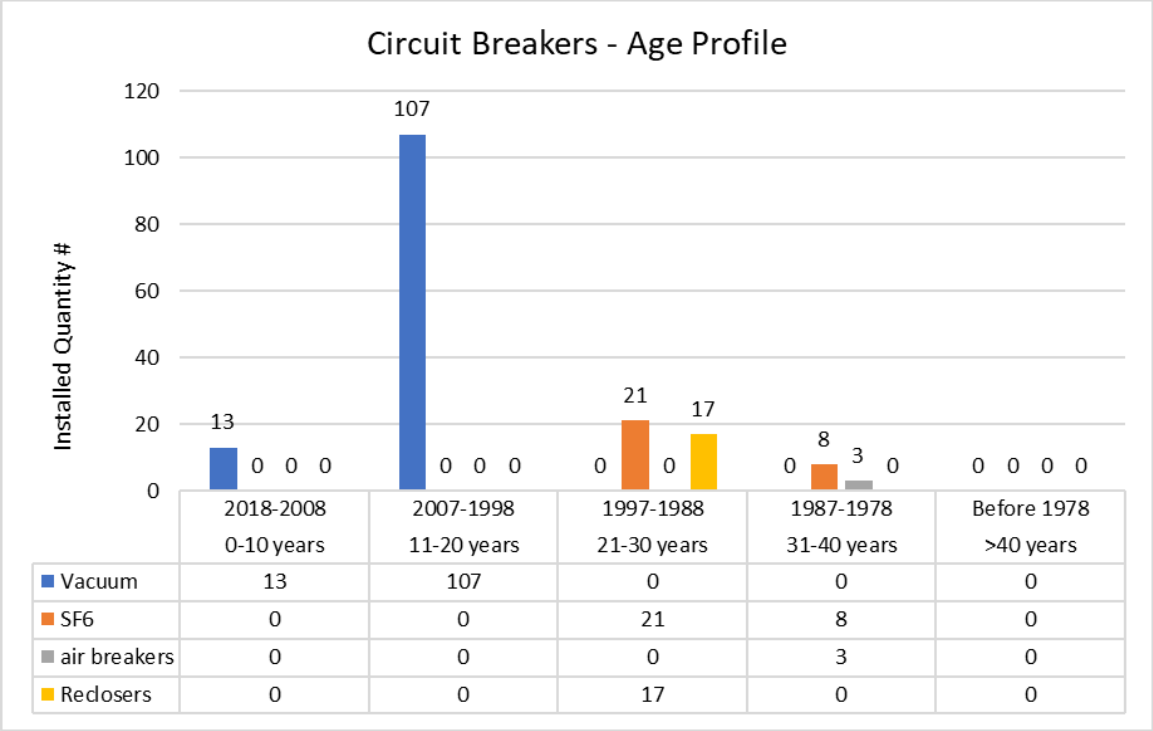


Figure 3-3: Circuit Breakers- Age profile

KWHI owns a total of 28 distribution reclosers installed in their distribution system at 27.6 or 13.8 kV level. All the reclosers are quite new with less than 5 years in service.

3.2.2.3 DAI

The Data Availability Indicator (DAI) is created to measure the reasonably collected data by the utility for completion regarding parameters used in the Health Index formulation. The average DAI for Circuit Breakers data is 84%. DAI can be improved by collecting data for all the assets. Section 4 provides further recommendations on data gaps.

3.2.2.4 Condition Assessment

Health Index is calculated using the above formulation and assumptions and Figure 3-4 presents the circuit breakers HI condition. Based on this HI calculation, about 2% of the circuit breakers are in Very Poor Condition- mainly due to service age parameter, nearly 13% are in Fair Condition and remaining 85% are in Good or Very Good Condition.

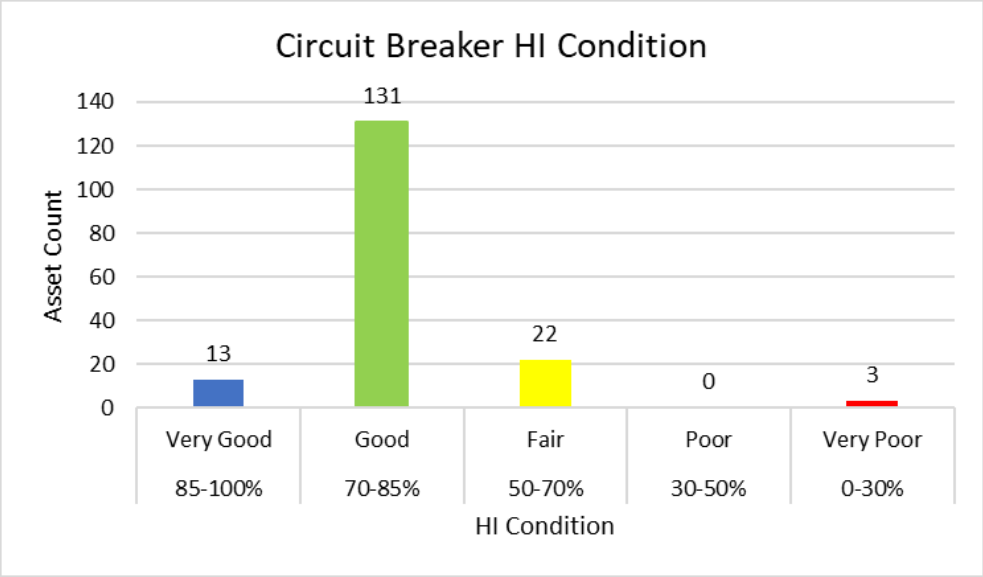


Figure 3-4: Circuit Breakers HI Condition

All the reclosers in the distribution system are new and hence assumed to be in Very Good condition.

3.3 STATION PROTECTION RELAYS

3.3.1 CONDITION ASSESSMENT METHODOLOGY

3.3.1.1 Health Index Calculation

The function of protection relays on distribution systems is to detect and annunciate abnormal operating conditions and initiate circuit breaker or recloser trip to isolate faulty circuits from

healthy circuits. Protection relays obtain their input from instrument transformers, process the information and automatically take corrective action with adequate speed and selectivity.

KWHI's distribution system has three types of relays: digital, electronic and electromechanical. KWHI does test their protection relays on a regular basis. Current practice has not adopted condition grading method and therefore there are no condition data for visual inspection and defect and test report. The relays are tested and if found to be working correctly, are placed back in service or if found to be not working within settings, are replaced. Based on the available data, best practise information and the METSCO's expert opinion, the RHIF for Protection Relays is based on age, and non-discretionary obsolescence.

Table 3-20: Substation Protection Relays Recommended Health Index Parameters

#	Condition	Weight	Ranking	Numerical Grade	Max Grade
1	Non-Discretionary Obsolescence	5	A,E	4,0	20
2	Service Age	4	A,B,C,D,E	4,3,2,1,0	16
Total					**36**

1. Age Related Scoring

Service age provides a reasonably good measure of the remaining life of protection relays. Since the relays are either installed indoors or outdoors in weatherproof cabinets, they are protected from the weather elements.

Table 3-21: Protection Relays – Age Based Health Score

Grade	Age
A	0 to 10 years
B	11 to 20 years
C	21 to 30 years
D	31 to 40 years
E	41 years or older

2. Non-Discretionary Obsolescence

Grade	Corresponding Condition
A	The device has available spare parts and meets present system design needs
E	The device does not have available spare parts or does not meet present system design needs

3.3.2 *Results Analysis*

3.3.2.1 Assumptions

KWHI has identified number of oldest relays to be obsolete and these obsolete relays have been given a grade of "E".

3.3.2.2 Age and Demographics

KWHI employs a total of 281 protection relays in its transformer and distribution stations. Figure 3-5 presents the age demographics of these relays by their types, digital, electronic, and electromechanical. 11 protection relays are in-service for 31-40 years. Oldest relays in-service are 2 electromechanical relays of 38 years old. Majority of the digital relays are installed in the last 10 years.

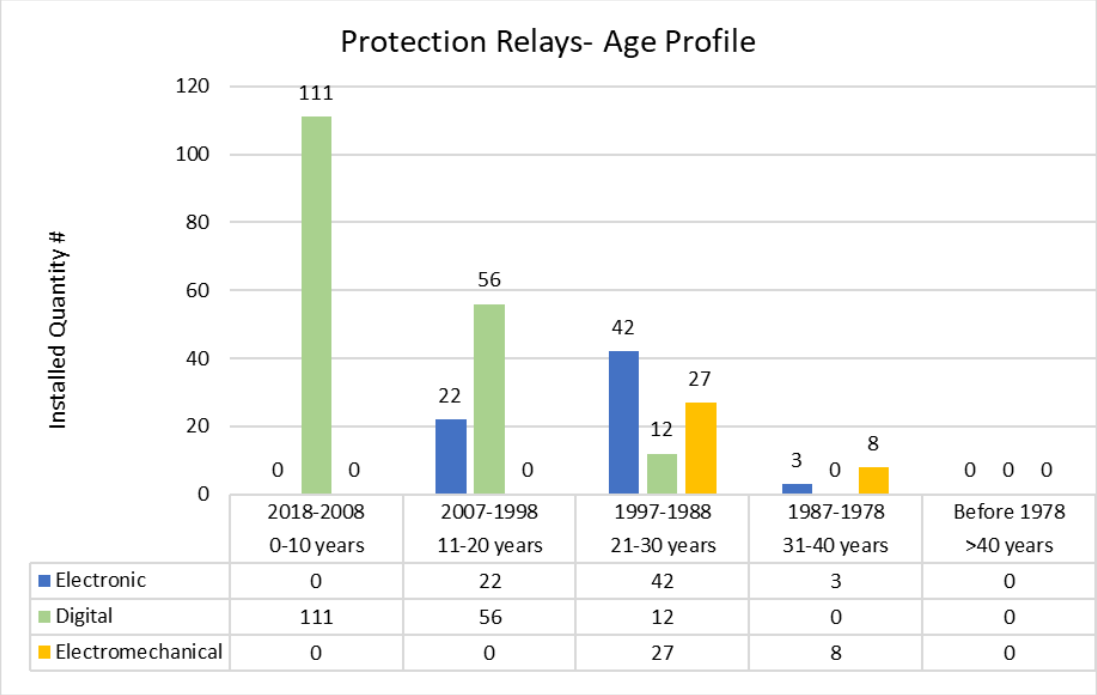


Figure 3-5: Protection Relays Age Profile

3.3.2.3 DAI

Age and obsolete relays data is available for all the protection relays and therefore the average DAI is 100%. It is recommended to collect condition grading of inspection/test results to improve the HI accuracy. Section 4 provides more insights regarding the data collection recommendation.

3.3.2.4 Condition Assessment

Figure 3-6 presents the HI condition of protection relays calculated using the age and obsolete data. As seen in the chart, about 31% of the relays are in Very Poor condition. The main factors driving these relays into Very Poor condition are non-discretionary obsolescence parameter. KWHI has identified number of oldest relays to be obsolete. About 25% of the protection relays are in Poor Condition, and 1% are in Fair Condition. Remaining 43% are in Good or Very Good Condition. Using the condition grading data for inspection/test results would increase the accuracy of this condition assessment result.

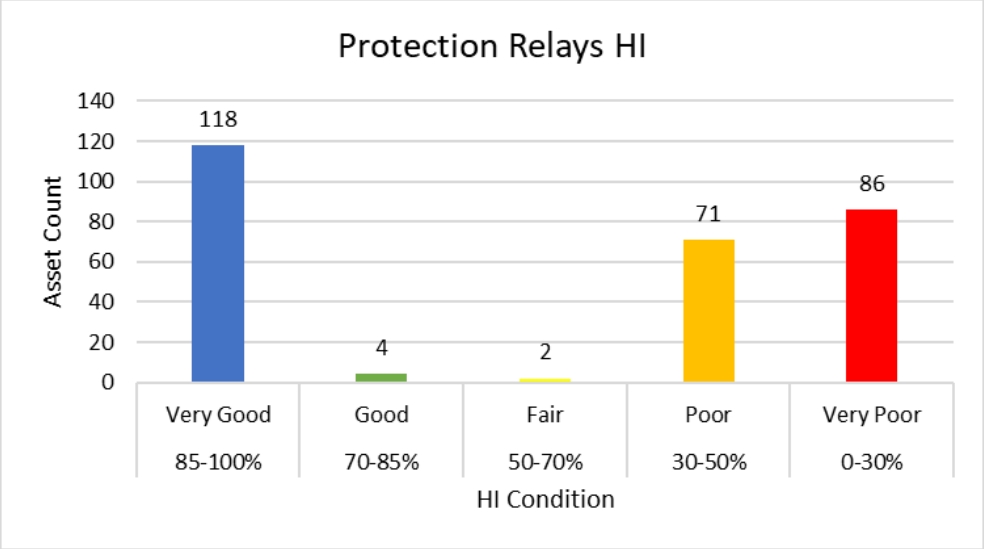


Figure 3-6: Protection Relays HI Condition

3.4 CAPACITOR BANKS

3.4.1 CONDITION ASSESSMENT METHODOLOGY

Shunt capacitors, connected in parallel to the line load, are employed to provide VAR compensation for power factor improvement and they provide the benefits of improved voltage, reduced kVA demand, reduced line current and reduced system loss. The main components in shunt capacitor bank installations include capacitor units, fuses, support insulators, metal structures and concrete foundations.

Capacitor units are static devices with no moving parts and do not require, nor receive significant maintenance during their service life, except for periodic inspections, cleaning, unit capacitance measurements and replacement of failed units and fuses. The equipment is, however, vulnerable

to damage from thermal stresses. Random failures may be caused by exposure to over-voltage or over-current, when protection and control elements fail to perform their protective functions.

The life expectancy of capacitor units is considered halved for every 10° C (18° F) increase in operating temperature above 50°C (122° F). The rise in operating temperature results from the heating effect of current as well as dielectric loss in capacitor packs. The aging of capacitor dielectric with higher operating temperatures is further amplified if impurities or contaminants are present in paper or film dielectric. Presence of moisture and oxygen has the strongest impact on dielectric aging. Because capacitors exhibit lower impedance to higher order harmonics, presence of harmonics in the source voltage results in disproportionately higher current in capacitors and rise in operating temperature.

3.4.1.1 Health Index Calculation

At the time of this ACA study, KWHI has only the age data and no condition data are available for their capacitor banks. Therefore, based on the available data, best practise information and the METSCO's expert opinion, the RHIF is solely age based. Typical Useful Life (TUL) of 30 years for capacitors is assumed, consisted with Kinectrics' TUL report for Ontario Energy Board.

Table 3-22: Overhead Capacitor Bank Service Age condition grading

Grade	Corresponding condition
A	0 to 10 years
B	11 to 20 years
C	21 to 30 years
E	Over 30 years

3.4.2 RESULTS ANALYSIS

3.4.2.1 Assumptions

There are no assumptions made in the process of HI calculation.

3.4.2.2 Age and Demographics

KWHI employs 73 OH capacitor banks in ground wye configuration. Approximately 92% of the population are fixed type banks and the remaining 8% are switched types. Figure 3-7 presents the age profile of capacitor banks. All the capacitors are less than 20 years of age.

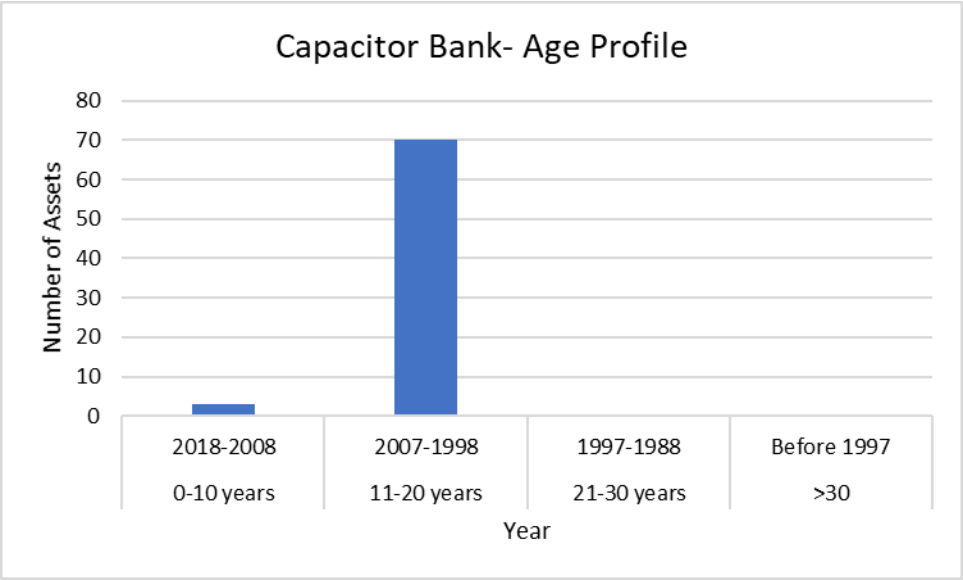


Figure 3-7: Capacitor Bank Age Profile

3.4.2.3 DAI

Since only the age information is available DAI was not calculated. It is recommended to collect more degradation parameters to improve the HI accuracy. Section 4 provides more insights regarding the data collection recommendation.

3.4.2.4 Condition Assessment

HI condition is directly determined using the age data and Figure 3-8 presents the HI condition of capacitors. As seen in the HI chart, all the capacitors are in either Good or Very Good HI Condition.

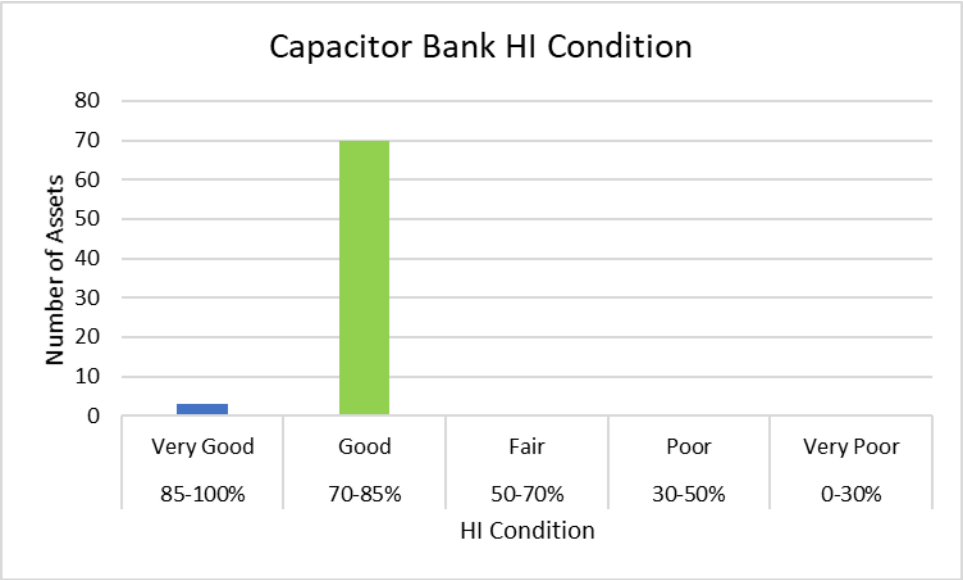


Figure 3-8: Capacitor Bank HI Condition

3.5 STATION BATTERIES

3.5.1 CONDITION ASSESSMENT METHODOLOGY

3.5.1.1 Health Index Calculation

The purpose of substation control batteries is to provide power for critical control functions such as trip coils of circuit breakers. KWHI's distribution system commonly uses lead acid batteries. Batteries are carefully sized to store adequate energy for system operation during an AC power failure.

Both the electrodes and electrolyte in control batteries undergo aging with repeated charge and discharge cycles, which result in gradual reduction of battery storage capacity. The end of life is reached when the battery is no longer able to retain adequate charge for required functions.

Battery chargers can experience component failures, but these can be easily replaced and as a result the charger often outlasts the battery. Based on the available data, best practise information and the METSCO's expert opinion, the table below describes the RHIF for Station Batteries.

Table 3-23: Station Batteries- Health Index

#	Condition	Weight	Ranking	Numerical Grade	Max Grade
1	Age of Battery/Charger	4	A,B,C,D,E	4,3,2,1,0	16
2	Testing	4	A,C,E	4,2,0	16
Total					**32**

1. Age Related Scoring

Since different types of batteries can have significantly different life expectancy, age related scoring needs to be measured in terms of the manufacturer's recommended life expectancy divided as shown in Table below.

Table 3-24: Control Batteries and Chargers – Age Related Health Score

Grade	Actual Battery Age
A	Less than 25% of manufacturer recommended age
B	25 - 50% of manufacturer recommended age
C	50 - 75% of manufacturer recommended age
D	75 - 100% of manufacturer recommended age
E	Age exceeds manufacturer recommended age

2. Condition Rating Based on Evaluation of the Tests

Table 3-25: Control Batteries and Chargers – Test Based Health Score

Grade	Test Results
A	Battery capable of storing full rated energy
C	Battery stores marginally less than full rated energy, but still adequate for required functions
E	Battery stores significantly less than the full rated energy, inadequate for required functions

3.5.2 Results Analysis

3.5.2.1 Assumptions

KWHI test their station batteries using Bite3 tester. Since there are no records of 'Fail' test results for the batteries, a grade of "B" i.e. Good is assigned for the Testing parameter.

3.5.2.2 Age and Demographics

Figure 3-9 shows the age demographics of station batteries. Majority of the batteries are less than 10 years old. The average manufacturer recommended life expectancy for majority of these batteries is 20 years.

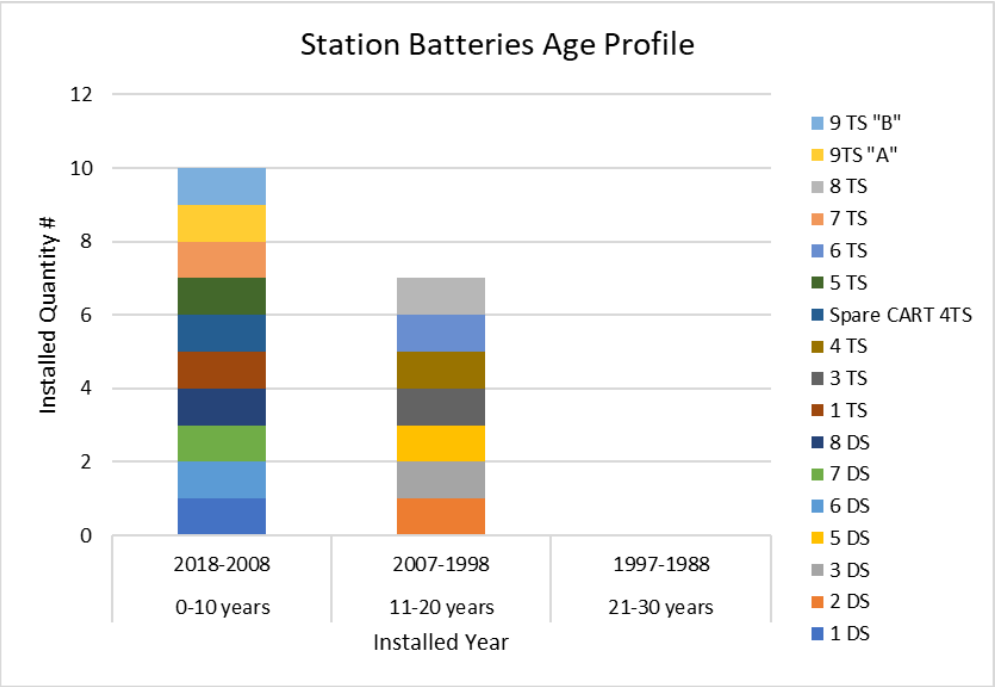


Figure 3-9: Station Batteries Age profile

3.5.2.3 DAI

Since only the age information is available DAI was not calculated. It is recommended to collect more degradation parameters to improve the HI accuracy. Section 4 provides more insights regarding the data collection recommendation.

3.5.2.4 Condition Assessment

The Health Index is calculated using the age data and the assumptions made as stated above. Figure 3-10 presents the HI condition of station batteries and majority of the batteries are Good Condition followed by Fair condition.

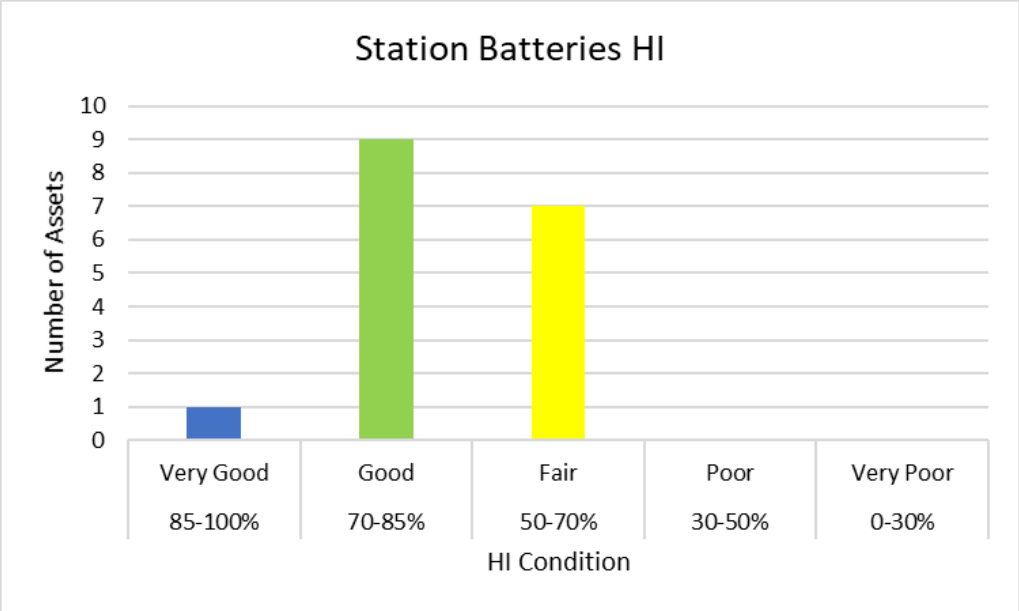


Figure 3-10: Station Batteries HI Condition

3.6 WOOD POLES

3.6.1 CONDITION ASSESSMENT METHODOLOGY

3.6.1.1 Health Index Calculation

Based on the available data, best practise information and the METSCO's expert opinion, the table below describes the RHIF for Wood Poles.

Table 3-26: Wood Pole Recommended Health Index Parameters

#	Condition	Weight	Ranking	Numerical Grade	Max Grade
1	Age	3	A,B,C,D,E	4,3,2,1,0	12
2	Pole treatment	1	A,C,E	4,2,0	4
3	Visual inspection of poles	1	A,B,C,D,E	4,3,2,1,0	4
4	Pole testing (strength)*	4	A,B,C,D,E	4,3,2,1,0	16
Total					**36**
				**Where Strength =E*	*HI/2*

1. Age Related Score

Since the service age provides a reasonably good measure of the remaining service life of wood poles, it is employed as an assessment parameter, with the following scores:

Table 3-27: Wood Poles – Age Related Health Score

Grade	Age
A	0 to 10 years
B	11 to 30 years
C	31 to 40 years
D	41 to 50 years
E	51 years or older

2. Pole treatment

Since the rate of pole degradation is affected by the effectiveness of the preservative treatment, wood pole treatment is employed in Health Index formulation of line sections, as indicated in the table below:

Table 3-28: Wood Poles – Pole Treatment Based Health Score

Grade	Corresponding Condition
A	Fully treated
C	Butt treated
E	No treatment

3. Visual Inspection

Annual visual inspections of KWHI-owned poles are conducted internally, allowing each pole to be visited on a 3-year cycle and satisfying the inspection requirements of the Distribution System Code. Different components of the pole line, including wood poles, cross-arms, hardware, insulators and pole grounding are visually inspected by qualified staff during line patrols. By considering the results of these inspections, the health and condition of each component is scored in accordance with the following table:

Table 3-29: Wood Poles - Visual Inspections Based Health Score

Grade	Component Condition
A	Component is in “as new” condition
B	Component has normal wear expected with age
C	Component has many minor problems or a major problem that requires close attention and monitoring
D	Component has many problems and the potential for its failure would rapidly escalate unless preventative maintenance is performed
E	Component requires immediate replacement

4. Pole Remaining Strength

Remaining strength is one of the most important factors in planning pole replacement; the percentage of pole remaining strength can be employed in Health Index formulations of wood poles, as indicated in the table below:

Table 3-30: Wood Poles – Remaining Strength Based Health Score

Grade	Remaining strength
A	91% to 100%
B	82% to 90 %
C	73% to 81%
D	60% to 72%
E	Less than 60%

KWHI tests the condition of poles more than 40 years old and uses the condition assessments to prioritize its pole replacement program. The strategy is to test and confirm the integrity of poles greater than 40 years old and to consider the test results when prioritizing pole replacements.

3.6.2 RESULTS ANALYSIS

3.6.2.1 Assumptions

The HI calculation for the inspected poles uses all the available inspection and testing data, and for the remaining poles the best available data (i.e. Age only) is used.

The visual inspection parameter grading considers the mechanical condition of poles provided in the inspection files. The mechanical condition reflects the condition of components as slight, moderate, and extensive. It is assumed that poles are in very good condition when no comments are given unless the other inspection/testing (pole strength, pole treatment) reflects defective pole.

Assuming the pole species data is correct in the inspection files, the remaining pole strength is calculated using the pole strength data against the rated pole strength for the respective species.

3.6.2.2 Age and Demographics

KWHI owns 15977 wood poles. Figure 3-11 presents the age demographics of wood poles and Figure 3-12 shows the age demographics of wood pole by pole type. Of the 5802 single-phase poles, 39% are above 50 years old, 18% are between 31 to 50 years, and 43% are in-service for less than 30 years. Of the 5081 three-phase poles, 18% are above 50 years old, 13% are between 31 to 50 years, and 69% are less than 30 years old. KWHI owns about 2275 secondary poles, of

which, 46% are in-service for more than 50 years, 15% are in-service between 31 to 50 years and 39% are in-service for less than 30 years.

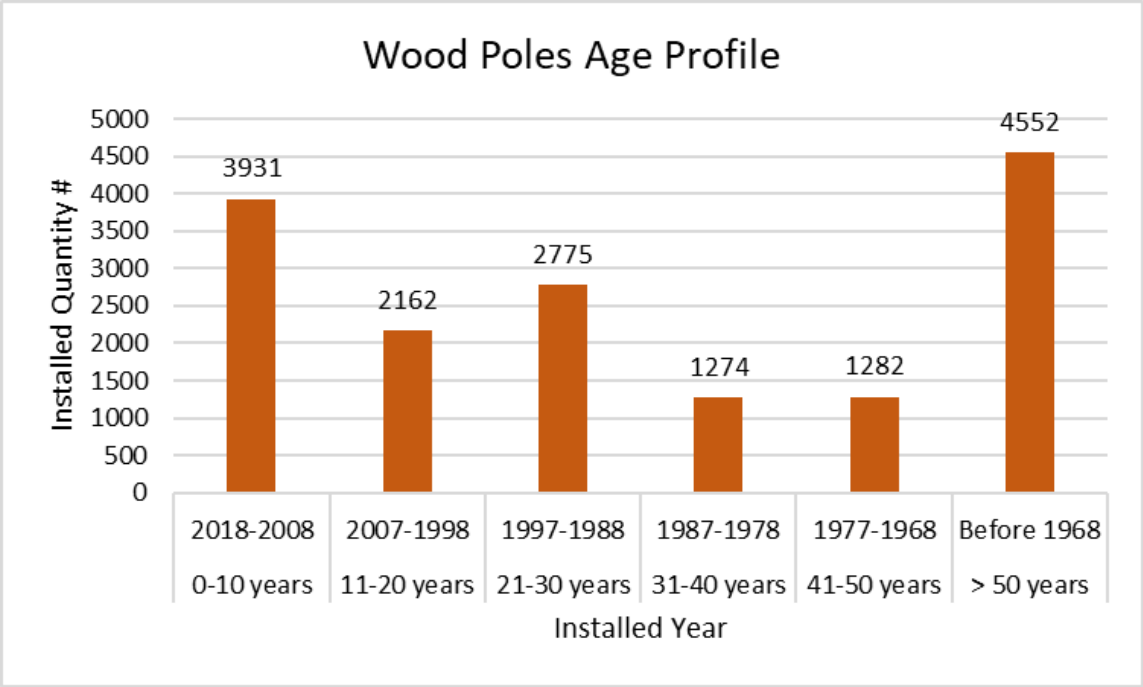


Figure 3-11: Wood Poles Age Profile

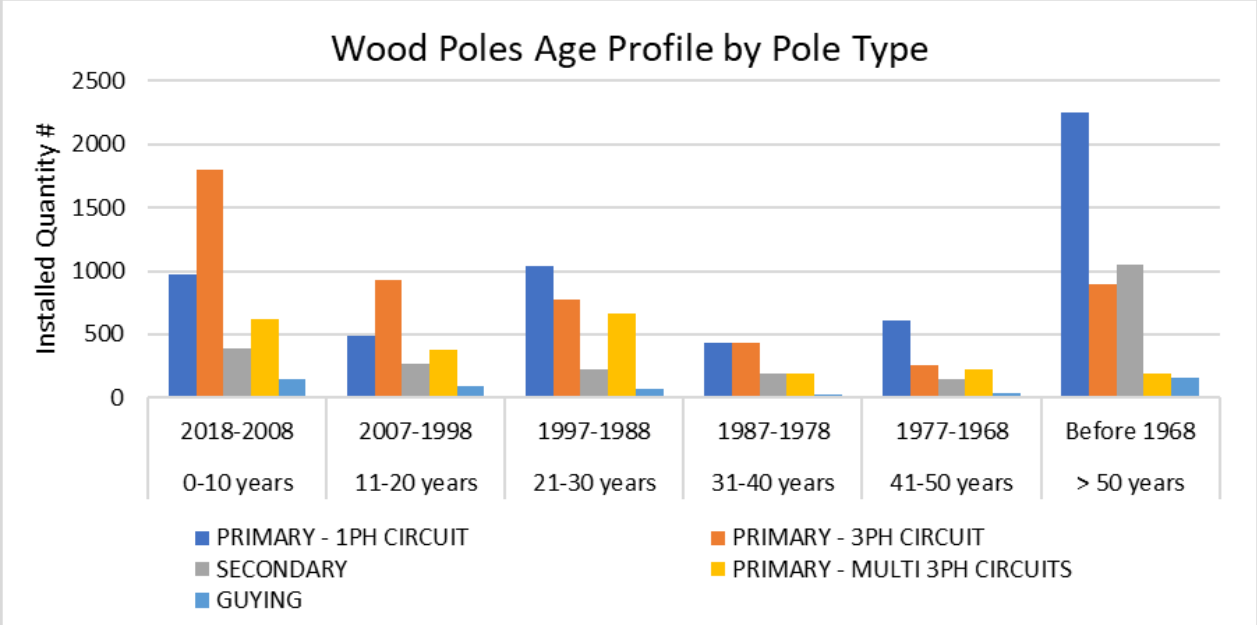


Figure 3-12: Wood Poles Age Profile by Pole Type

3.6.2.3 DAI

The Data Availability Indicator (DAI) is created to measure the reasonably collected data by the utility for completion regarding parameters used in the Health Index formulation. The average DAI for Wood Poles data is 58%.

The total number of poles inspected in the years 2011-2013, 2017 and in 2018 is approximately 77% of the population of which about 50% are unique poles. Additionally, close to 10% of these poles have pole ID discrepancies between the GIS and the inspection file and therefore the 100% DAI is expected for only about 40% of the poles. The remaining 60% of the poles are expected to have DAI of 33% (using Table 3-26) since only the age parameter is available. Therefore, the expected average DAI of all poles is only 60%. Since some of the inspected poles do not have all the inspection/ testing parameter values, the average DAI is 58% which does meet the expected value. DAI can be improved by inspecting/testing more poles and collecting all the inspection/test results.

3.6.2.4 Condition Assessment

Health Index is calculated for 6159 wood poles considering all the available inspection/test results. Figure 3-13 presents the HI conditions for the inspected wood poles. Majority of these inspected poles are more than 40 years old. As seen in the figure, about 6% of the inspected poles are in Very Poor condition and 47% are in Poor condition, which is approximately 2% and 18% respectively, of the entire wood pole population.

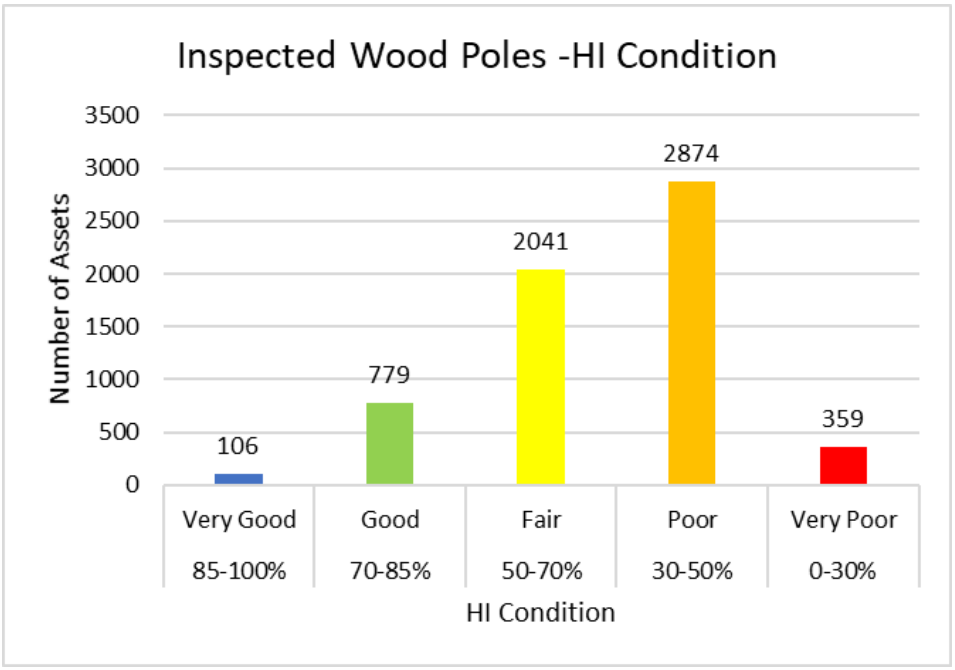


Figure 3-13: Inspected Wood Poles HI Condition

Figure 3-14 presents the HI Conditions for all the wood poles. Here, the inspected poles use all the available condition parameters in the HI calculation and the non-inspected poles use only the age data. As seen in the figure, about 3% of the poles are found to be in Very Poor Condition. 2% of poles in the Very Poor Condition are the inspected poles and the remaining 1% are more than 40 years old and non-tested poles. KWHI should test these poles to verify their actual condition. 18% of the poles showing Poor Condition are the inspected poles as discussed above.

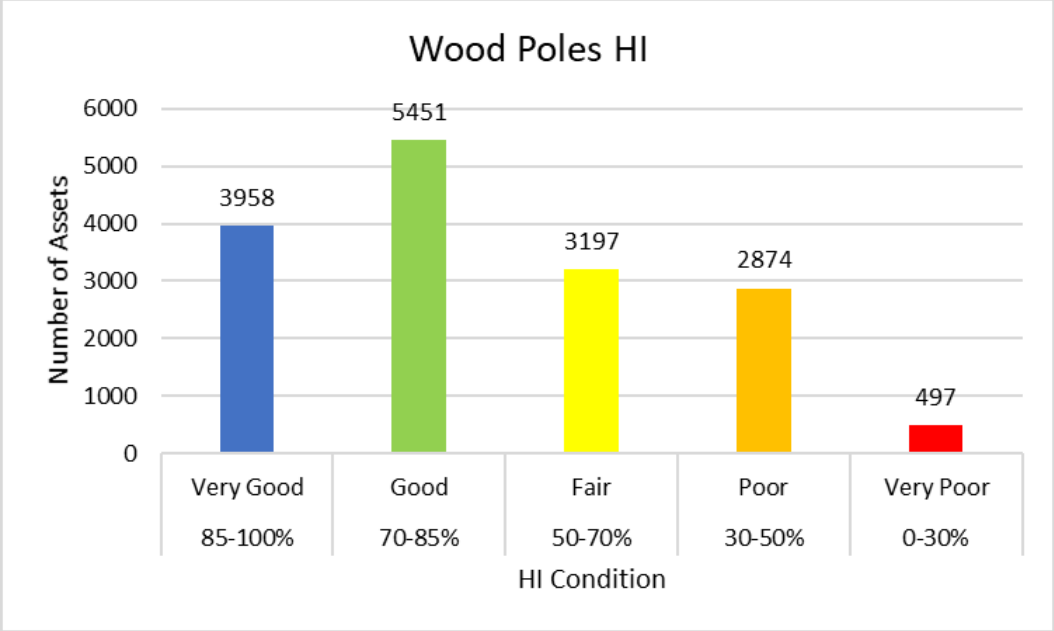


Figure 3-14: Wood Poles HI Condition- All Wood Poles

3.7 CONCRETE POLES

3.7.1 CONDITION ASSESSMENT METHODOLOGY

3.7.1.1 Health Index Calculation

Based on the available data, best practise information and the METSCO's expert opinion, the table below describes the Recommended Health Index Formulation for Concrete Poles.

Table 3-31: Concrete/Steel Poles – Recommended Health Index Parameters

#	Condition	Weight	Ranking	Numerical Grade	Max Grade
1	Visual Inspection	8	A,B,C,D,E	4,3,2,1,0	32
2	Service age	3	A,B,C,D,E	4,3,2,1,0	12
Total					44

1. Visual Inspection

Annual visual inspections of KWHI-owned poles are conducted internally, allowing each pole to be visited on a 3-year cycle and satisfying the inspection requirements of the Distribution System Code. Visual inspection can be ranked as indicated below:

Table 3-32: Concrete Poles- Visual Inspection Grading

Grade	Corresponding condition
A	There is no sign of rusting/corrosion on the pole and the pole is in like new condition
B	Minor signs of rusting/corrosion on the pole, does not require corrective action. Minimal deterioration
C	Significant signs of rusting/corrosion on the pole, requiring planned corrective action. Significant deterioration
D	Major signs of rusting/corrosion on the pole requiring immediate emergency repairs. Major deterioration
E	Serious signs of rusting/corrosion on the pole. Serious deterioration

Since typically concrete poles have longer life, the visual inspection can provide better understanding of the actual condition at any time of their life and hence a higher weight (i.e. 8) is assigned to this parameter.

2. Age related scoring

Typical Useful Life (TUL) of sixty years for concrete poles is assumed, consistent with Kinectrics' TUL report for Ontario Energy Board. Table 3-33 is used to translate the concrete pole service age into a condition rating.

Table 3-33: Concrete Poles – Age Condition Grading

Grade	Age
A	0 to 10 years
B	11 to 30 years
C	31 to 40 years
D	41 to 60 years
E	61 years or older

Some of the KWHI's concrete poles are on Arterial Roads, which are expected to be exposed to salt spray from roads that impacts the life of the concrete poles. Based on KWHI's experience, the TUL of these concrete poles are lowered to 40 years as shown in Table 3-34.

Table 3-34: Concrete Poles on the Arterial Roads – Age Condition Grading

Grade	Age
A	0 to 10 years
B	11 to 20 years
C	21 to 30 years
D	31 to 40 years
E	41 years or older

3.7.2 Results Analysis

3.7.2.1 Assumptions

KWHI's inspection records include mainly the wood pole inspection results. However, since the poles are inspected on a 3-year cycle, it is assumed that any significant deterioration would be reported. Therefore, since there are no records of any defects, it is assumed that all poles are in 'Good' Condition.

KWHI is in the process of collecting actual inspection data for concrete poles. However, at the time of this ACA since data is not available, the above assumption is considered.

3.7.2.2 Age and Demographics

KWHI owns 7130 concrete poles. Figure 3-15 presents the age demographics of concrete poles and Figure 3-16 present the age demographics of concrete poles by pole types. Of the 717 single-phase poles, 1% are above 50 years old, 24% are between 31 to 50 years, and 75% are in-service for less than 30 years. Of the 4487 three-phase poles, 1% are above 50 years old, 31% are between 31 to 50 years, and 68% are less than 30 years old. KWHI owns about 764 secondary concrete poles, of which, 2% are in-service for more 50 years, 18% are in-service between 31 to 50 years and 80% are in-service for less than 30 years. All 785 primary-multi 3-phase poles are

in-service for less than 50 years, of which, 24% are in-service between 31 to 50 years, and remaining 76% are in-service for less than 30 years.

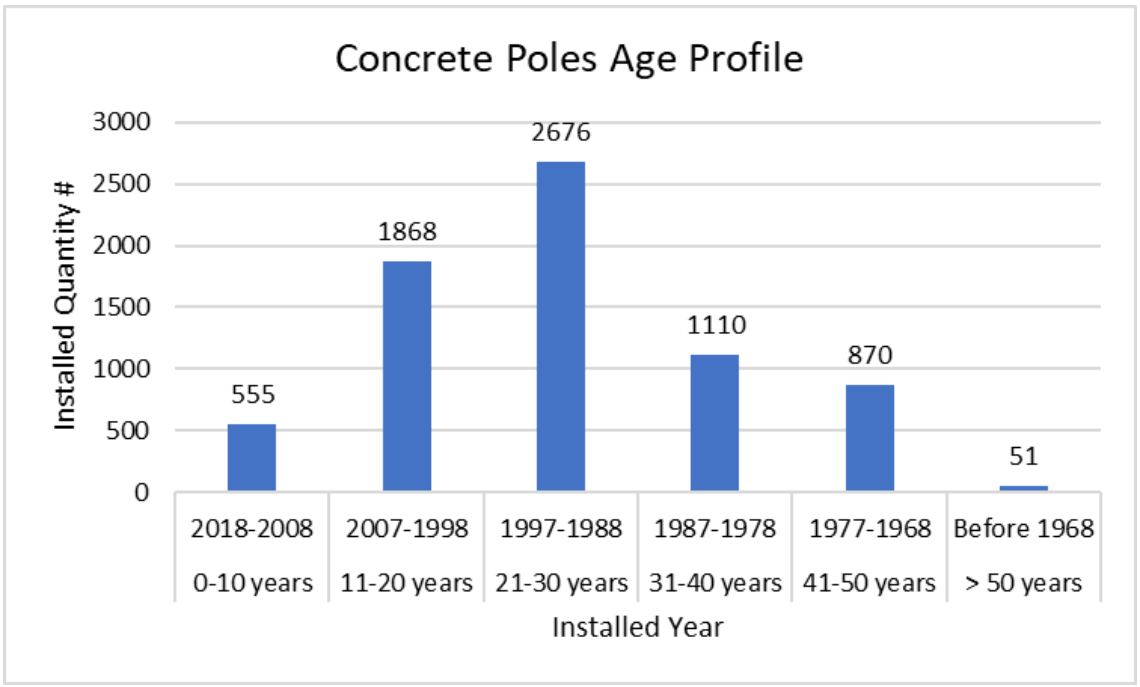


Figure 3-15: Concrete Poles Age Profile

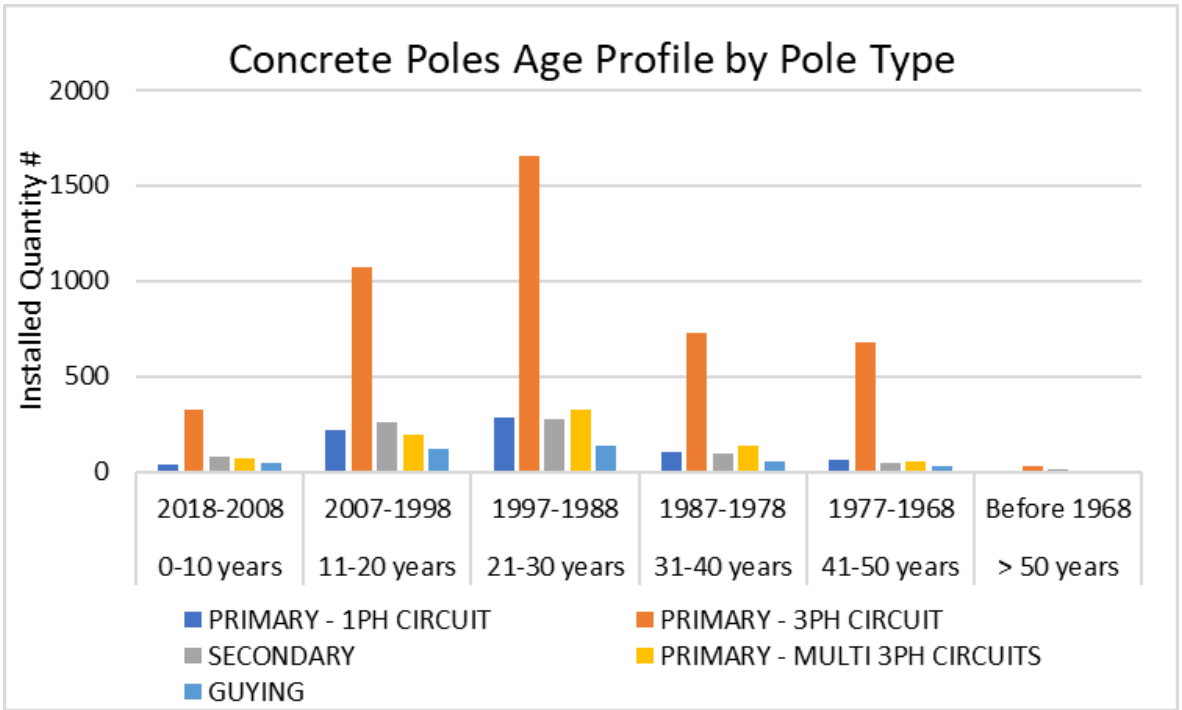


Figure 3-16: Concrete Poles Age Profile by Pole Type

3.7.2.3 DAI

The Data Availability Indicator (DAI) is created to measure the reasonably collected data by the utility for completion regarding parameters used in the Health Index formulation. The average DAI for concrete pole data is 100% using the assumption made on the visual inspection.

3.7.2.4 Condition Assessment

HI is calculated using the service age and the visual inspection parameters and Figure 3-17 presents the HI condition of concrete poles. As seen in figure, poles are either in Good or Fair Condition. It should be noted that this result is based the assumption of 'Good' result for visual inspection of all concrete poles. Some of these poles from Good or Fair Condition could be in Poor or Very Poor Condition. Collecting visual inspection records of poles more than 40 years of age could verify if any of these poles are in Poor or Very Poor Condition.

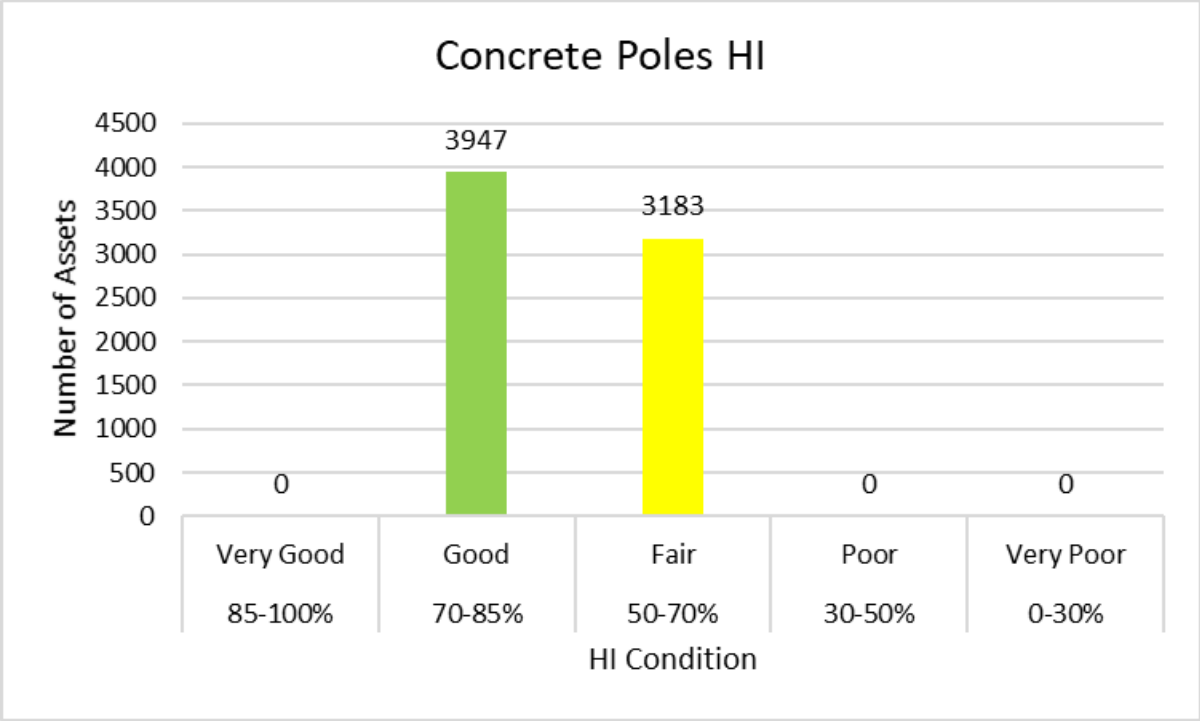


Figure 3-17: Concrete Poles HI Condition

3.8 OVERHEAD CONDUCTORS

3.8.1 CONDITION ASSESSMENT METHODOLOGY

3.8.1.1 Health Index Calculation

KWHI inspects its overhead conductors as part of the 3-year cycle pole inspection program for any defects. Conductors on distribution lines often outlive the poles and are not usually on the critical path to determine end of life for a line section. KWHI has the record of only installed year. Based on the available data, best practise information and the METSCO's expert opinion, the RHIF is solely age based.

Service age provides a reasonably good measure of the remaining strength of conductors and the following grading criteria is used in the HI calculation. Conductor condition is rarely a driver for asset renewal and therefore increased levels of testing and data collection are not beneficial.

Table 3-35: Overhead Conductor Service Age condition grading

Grade	Age
A	0 to 10 years
B	11 to 30 years
C	31 to 50 years
D	51 to 70 years
E	Over 70 years

3.8.2 RESULTS ANALYSIS

3.8.2.1 Assumptions

For some of the overhead conductors, the installation date is populated based on the age of the connected assets such as poles.

3.8.2.2 Age and Demographics

3.8.2.2.1 Overhead Primary Conductors

Overhead cable length is measured in kilometres of circuit, where a 1-km run of three-phase cable is measured as 1 km rather than 3 km. KWHI owns 1040 km of primary overhead cables across its distribution system. The installation year is known for 1034 km of cables – or 99% of the population. Figure 3-18 presents the overhead primary conductor age profile. 30% of the cable length is more than 50 years old, 24% are in-service for about 31 to 50 years and 46% cable length is in-service for less than 30 years.

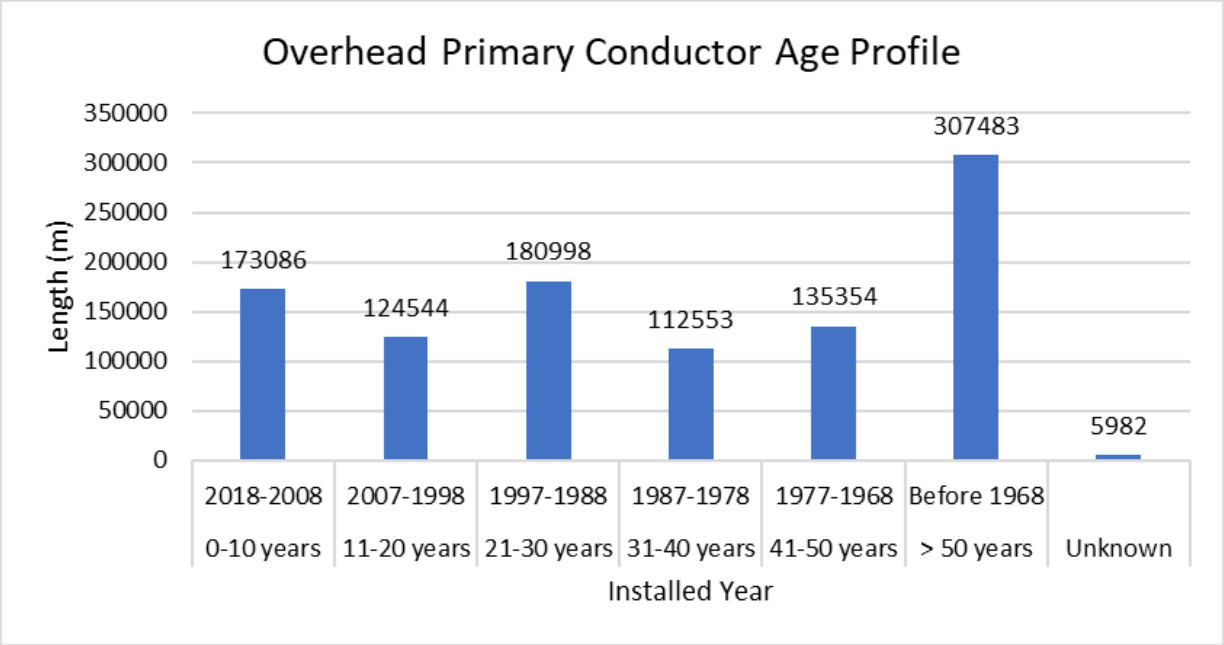
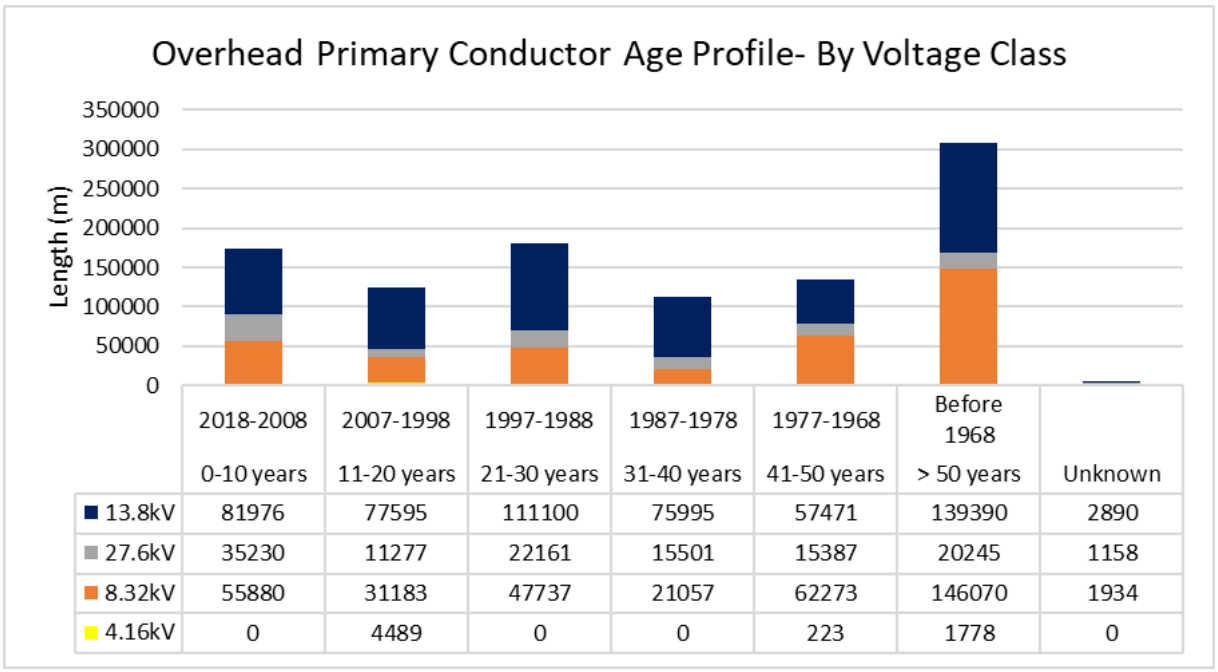


Figure 3-18: Overhead Primary Conductor Age Profile

Figure 3-19 presents the overhead primary conductor age distribution by voltage class. Majority of the KWHI's overhead primary conductors are at 13.8 kV followed by 8.32 kV.



	2018-2008 0-10 years	2007-1998 11-20 years	1997-1988 21-30 years	1987-1978 31-40 years	1977-1968 41-50 years	Before 1968 > 50 years	Unknown
13.8kV	81976	77595	111100	75995	57471	139390	2890
27.6kV	35230	11277	22161	15501	15387	20245	1158
8.32kV	55880	31183	47737	21057	62273	146070	1934
4.16kV	0	4489	0	0	223	1778	0

Figure 3-19: Overhead Primary Conductor Age Profile by Voltage Class

3.8.2.2.2 Overhead Secondary Conductors

KWHI's distribution system employs 327 km of secondary conductors. The age information is known for 99% of the populations which was populated using the age of connected pole. Figure 3-20 presents the age distribution of these conductors by length (m). About 34% of the population is in-service for more than 50 years.

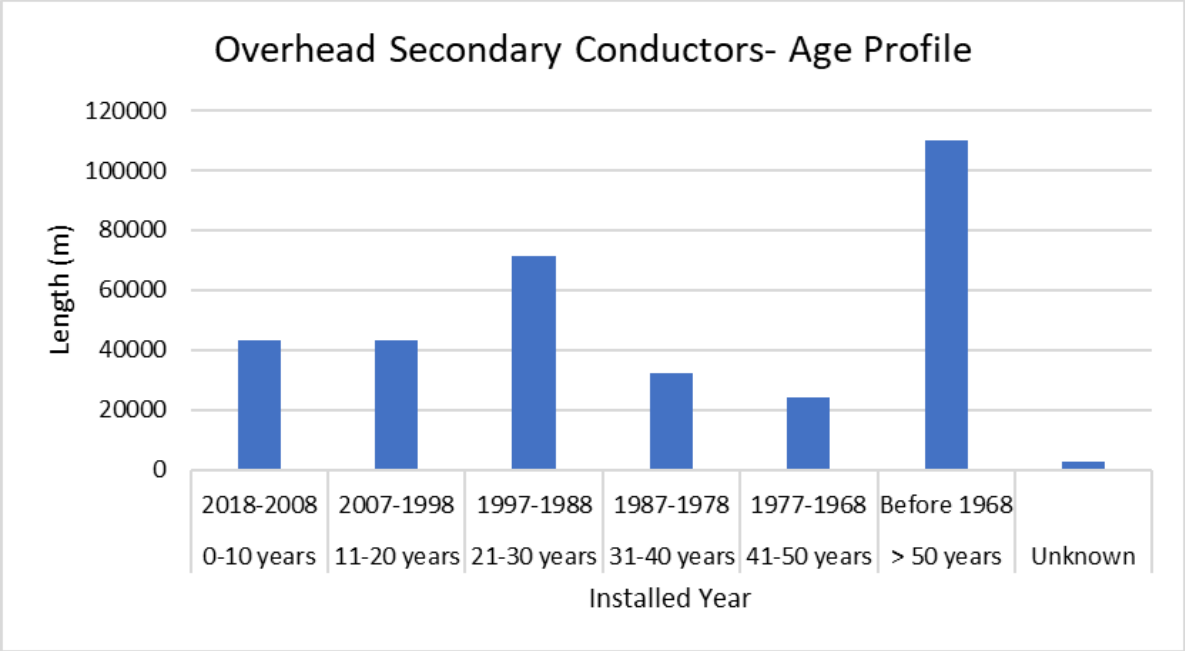


Figure 3-20: Overhead Secondary Conductors Age Profile

3.8.2.3 DAI

Since only the age information is available DAI was not calculated. Section 4 provides more insights regarding the data collection recommendation.

3.8.2.4 Condition Assessment

Health Index for the overhead conductors are calculated directly by using the age information. Overhead conductors are typically replaced during the overhead line rebuild or pole replacement.

3.8.2.4.1 Overhead Primary Conductors

Figure 3-21 presents the HI condition for Overhead Primary Conductors. About 1% of the population are in Very Poor Condition, 29% are in Poor Condition, 24% are in Fair Condition, and 46% are in Good or Very Good Condition.

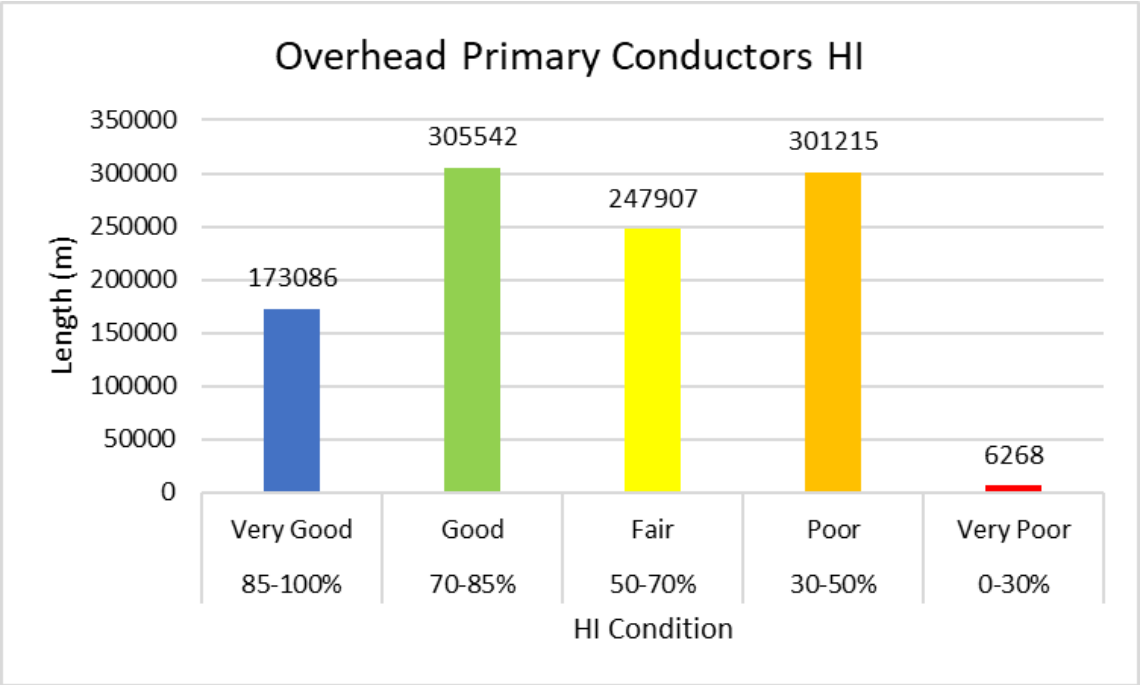


Figure 3-21: Overhead Primary Conductors HI Condition

3.8.2.4.2 Overhead Secondary Conductors

Figure 3-22 presents the HI condition for Overhead Secondary Conductors. About 0.4% of the population are in Very Poor Condition, 34% are in Poor Condition, 17% are in Fair Condition, and 49% are in Good or Very Good Condition.

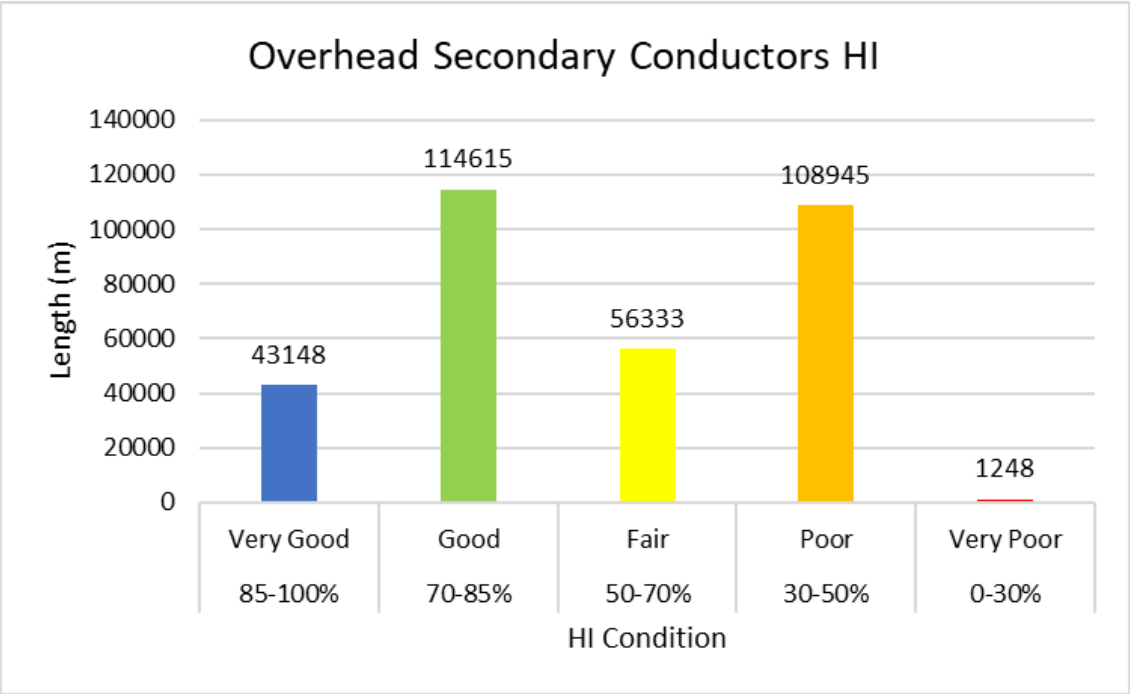


Figure 3-22: Overhead Secondary Conductors HI Condition

3.9 PRIMARY UNDERGROUND CABLES

3.9.1 CONDITION ASSESSMENT METHODOLOGY

3.9.1.1 Health Index Calculation

Distribution underground cables are one of the more challenging assets on electricity systems from a condition assessment and asset management viewpoint. Although several test techniques, such as partial discharge (PD) testing have become available over the recent years, it is still very difficult and expensive to obtain accurate condition information for buried cables. The standard approach to managing cable systems has been monitoring of cable failure rates and the impacts of in-service failures on reliability and operating costs and when the costs associated with in-service failures, including the cost of repeated emergency repairs and customer outage costs become higher than the annualized cost of cable replacement, the cables are replaced.

KWHI tracks the location of high voltage cable faults within its GIS to help identify patterns of failures that require attention. Cables that have a history of failures will be scheduled for replacement. Also, KWHI started a new program for cable testing in 2017 where 28 aged cables (installed between 1974 and 1984) were tested using DC Polarization/Depolarization Current Measurement System. The test results show that majority of the tested cable segments are in Fair condition. However, since only the installation date is available for majority of population,

the current RHIF formulation is solely age-based. Table 3-36 shows the age condition grading criteria for underground cables.

Table 3-36: Underground Cable Service Age condition grading

Grade	Age
A	0 to 10 years
B	10 to 20 years
C	20 to 30 years
D	30 to 40 years
E	40 to 50 years or older

3.9.2 Results Analysis

3.9.2.1 Assumptions

There are no assumptions made in the HI analysis for underground cables.

3.9.2.2 Age and Demographics

Underground cable length is measured in kilometres of circuit, where a 1-km run of three-phase cable is measured as 1 km rather than 3 km. KWHI owns 957 km of primary underground cables across its distribution system. The installation year is known for about 928 km of cables – or 97% of the length. Figure 3-23 presents the underground primary cables age profile. Majority of the cables were installed within the last 50 years, 21% are in-service for about 31 to 50 years and 76% cable length is in-service for less than 30 years.

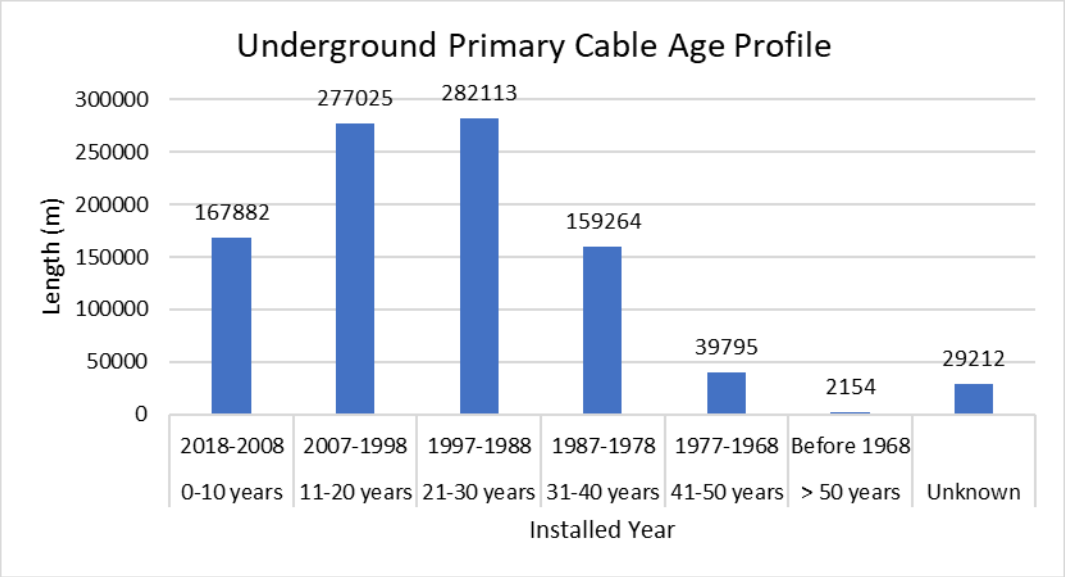
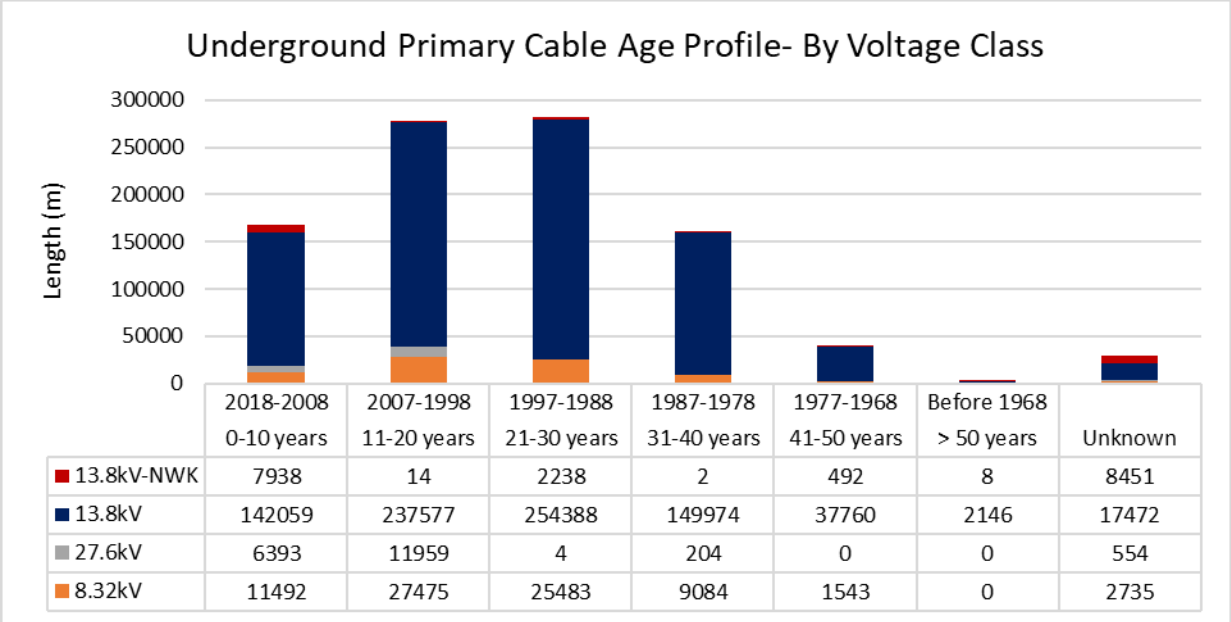


Figure 3-23: Underground Primary Cables Age Profile

Figure 3-24 presents the underground primary cable age distribution by voltage class. Majority of the cables are rated 13.8 kV.



	2018-2008 0-10 years	2007-1998 11-20 years	1997-1988 21-30 years	1987-1978 31-40 years	1977-1968 41-50 years	Before 1968 > 50 years	Unknown
13.8kV-NWK	7938	14	2238	2	492	8	8451
13.8kV	142059	237577	254388	149974	37760	2146	17472
27.6kV	6393	11959	4	204	0	0	554
8.32kV	11492	27475	25483	9084	1543	0	2735

Figure 3-24: Underground Primary Cables Age Profile by Voltage Class

3.9.2.3 DAI

Since only the age information is available DAI was not calculated. It is recommended to collect more degradation parameters to improve the HI accuracy. Section 4 provides more insights regarding the data collection recommendation.

3.9.2.4 Condition Assessment

Figure 3-25 presents the HI condition for Underground Primary Cables. About 5% of the population are in Very Poor Condition, 17% are in Poor Condition, 30% are in Fair Condition, and 48% are in Good or Very Good Condition.

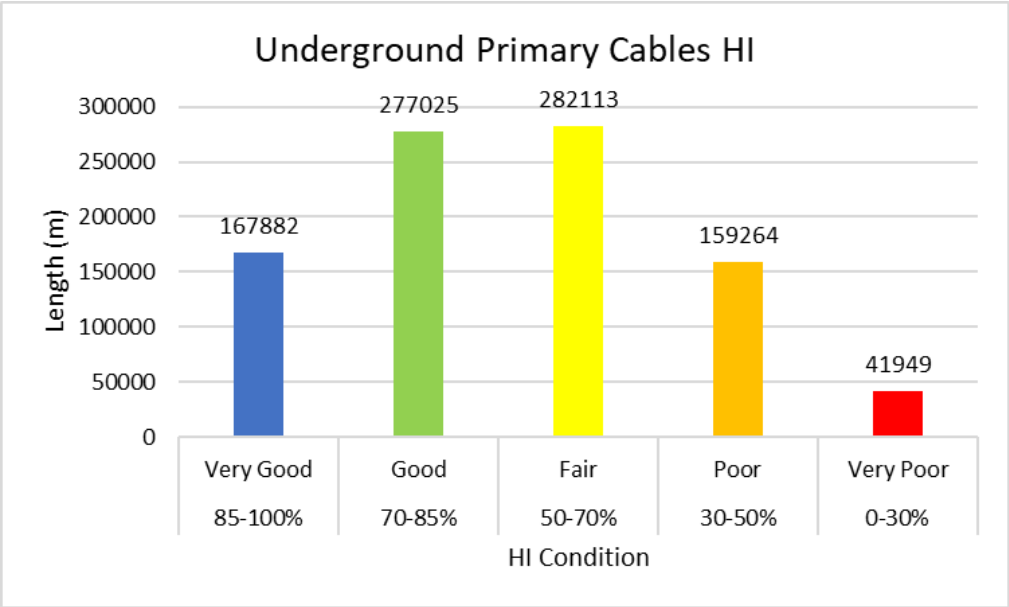


Figure 3-25: Underground Primary Cables HI Condition

3.10 DISTRIBUTION TRANSFORMERS

3.10.1 CONDITION ASSESSMENT METHODOLOGY

3.10.1.1 Health Index Calculation

KWHI's distribution transformers are categorized as pad-mount, pole-mount, customer owned, overhead bank, underground, underground bank, submersible, and network. The transformers step voltages down from primary (27.6/13.8 / 8.32/4.16 kV) to secondary (typically 120/240 V, but up to 600 V). Both overhead and underground transformers on KWHI's system are visually inspected during the patrol inspection on a 3-year cycle. Also, infrared scanning is performed annually for the overhead assets and as needed in the known problem areas for the underground assets. However, at the time of this ACA, only the service age and the transformer peaks data are available. Based on the available data, best practice information and the METSCO's expert opinion, the table below describes the RHIF for Distribution Transformers.

Table 3-37: Distribution Transformers Recommended Health Index Parameters

#	Condition	Type	Weight	Ranking	Numerical Grade	Max Grade
1	Age of transformer	All	6	A,B,C,D,E	4,3,2,1,0	24
2	Peak loading	All	6	A,B,C,D,E	4,3,2,1,0	24
3	Oil Quality	Network Transformer	6	A,B,C,D,E	4,3,2,1,0	24
Total						72

1. Age Related Scoring

Since the service age provides a reasonably good measure of the remaining life of transformers, it is employed as an assessment parameter, with the following scores:

Table 3-38: Padmount and Polemount Distribution Transformers – Age Based Health Scoring

Grade	Distribution Transformer Age
A	0 to 10 years
B	10 to 20 years
C	20 to 30 years
D	30 to 40 years
E	40 years or older

Table 3-39: Network Transformers- Age Based Health Scoring

Grade	Network Transformer Age
A	0 to 10 years
B	10 to 20 years
C	20 to 25 years
D	25 to 35 years
E	Over 35 years

Table 3-40: Submersible Transformers- Age Based Health Scoring

Grade	Submersible Transformer Age
A	0 to 10 years
B	10 to 20 years
C	20 to 25 years
D	25 to 35 years
E	Over 35 years

2. Condition Assessment Based on Loading Level

The rate of insulation degradation is directly related to the operating temperature and operating temperature is directly related to loading levels. Peak loading level of the transformer expressed in percentage of the nameplate rating can therefore be employed as an indicator of transformer health:

Table 3-41: All Distribution Transformers – Load Based Health Scoring

Grade	Peak Loading Condition
A	Peak load less than 50% of its rating
B	Peak load of 50% to 75% of its rating
C	Peak load of 75% to 100% of its rating
D	Peak load of 100% to 125% of its rating
E	Peak load of greater than 125% of its rating

3. Oil Quality

Table 3-42: Network Transformer oil quality test condition grading

Test	Network Transformer Voltage Class			Grade
	U ≤ 69 kV	69 kV < U < 230 kV	U ≥ 230 kV	
Acid number	≤0.05	≤0.04	≤0.03	**A**
	0.05-0.20	0.04,3,2,1,0.15	0.03-0.10	**C**
	≥0.20	≥0.15	≥0.10	**E**
IFT [mN/m]	≥30	≥35	≥36	**A**
	25-30	30-35	32-36	**C**
	≤25	≤30	≤32	**E**
Dielectric strength [kV]	>23 (1mm gap) >40 (2 mm gap)	>28 (1mm gap) >47 (2mm gap)	>30 (1mm gap) >50 (2mm gap)	**A**
	≤23 (1mm gap) ≤40 (2 mm gap)	≤28 (1mm gap) ≤47 (2mm gap)	≤30 (1mm gap) ≤50 (2mm gap)	**E**
Water content [ppm]	<35	<25	<20	**A**
	≥35	≥25	≥20	**E**

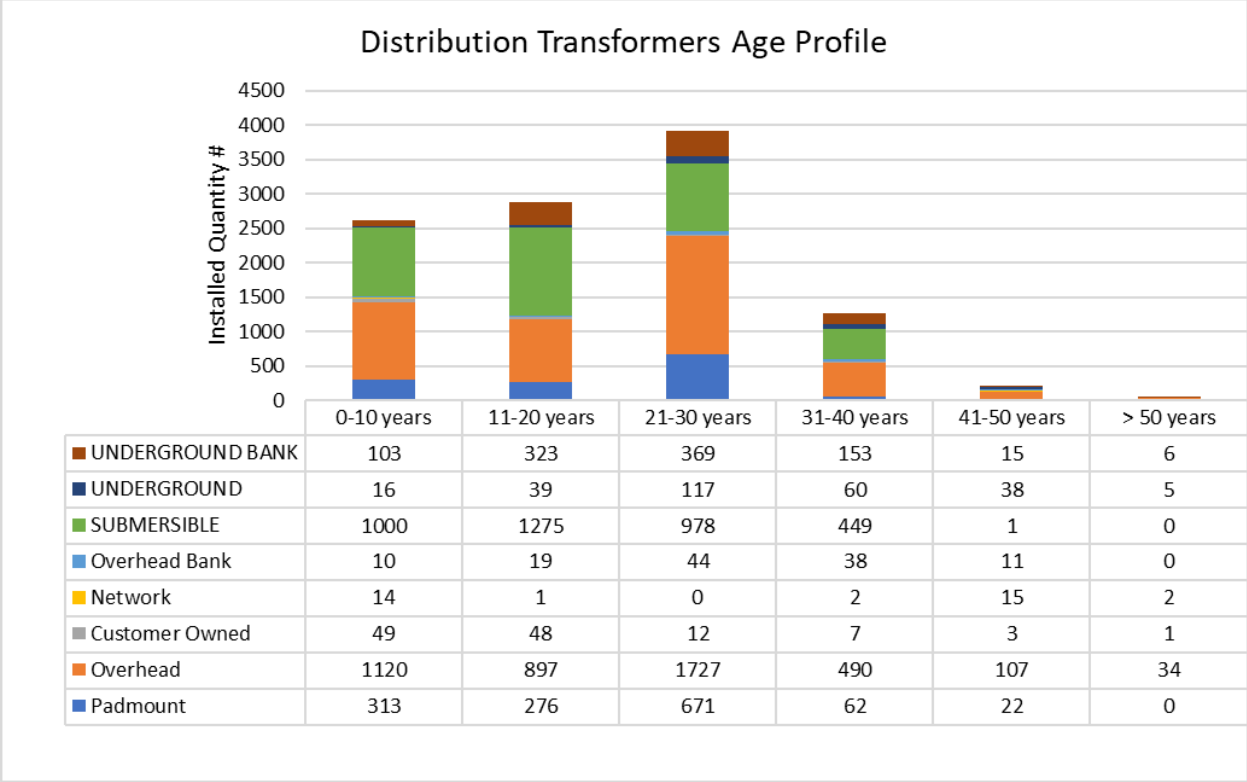
3.10.2 Results Analysis

3.10.2.1 Assumptions

For Network Transformers, the oil quality parameter uses the typical formulation for condition grading. However, if the oil quality report reflects 'Fail' from visual examination of oil, a score of "D" or "1" is assigned.

3.10.2.2 Age and Demographics

KWHI's distribution system has 11,137 distribution transformers. Figure 3-26 presents the age distribution of distribution transformers for various types. Service age data is available for 10942 -or 98% of transformers. As seen in the age profile, majority of the transformers are in-service for less than 30 years. Approximately 0.4% of the known age transformer population is more than 50 years old. The oldest transformer in-service is 66 years old overhead transformer.



	0-10 years	11-20 years	21-30 years	31-40 years	41-50 years	> 50 years
UNDERGROUND BANK	103	323	369	153	15	6
UNDERGROUND	16	39	117	60	38	5
SUBMERSIBLE	1000	1275	978	449	1	0
Overhead Bank	10	19	44	38	11	0
Network	14	1	0	2	15	2
Customer Owned	49	48	12	7	3	1
Overhead	1120	897	1727	490	107	34
Padmount	313	276	671	62	22	0

Figure 3-26: Distribution Transformers Age Profile

3.10.2.3 DAI

The Data Availability Indicator (DAI) is created to measure the reasonably collected data by the utility for completion regarding parameters used in the Health Index formulation. The average DAI for submersible distribution transformer is about 99%. The average DAI for network transformer is approximately 66%- peak loading data is missing for all the network transformers. The average DAI for remaining distribution transformer is about 92%- a nearly completed data set exists for the current Health Index formulation.

3.10.2.4 Condition Assessment

3.10.2.4.1 Submersible Transformer

Health Index for submersible transformers is calculated using both age and peak loading data and Figure 3-27 presents the HI Condition. About 1% of the submersible transformers are in Very Poor Condition, 2% are in Poor Condition, 42% are in Fair Condition and the remaining 55% are in Good or Very Good condition.

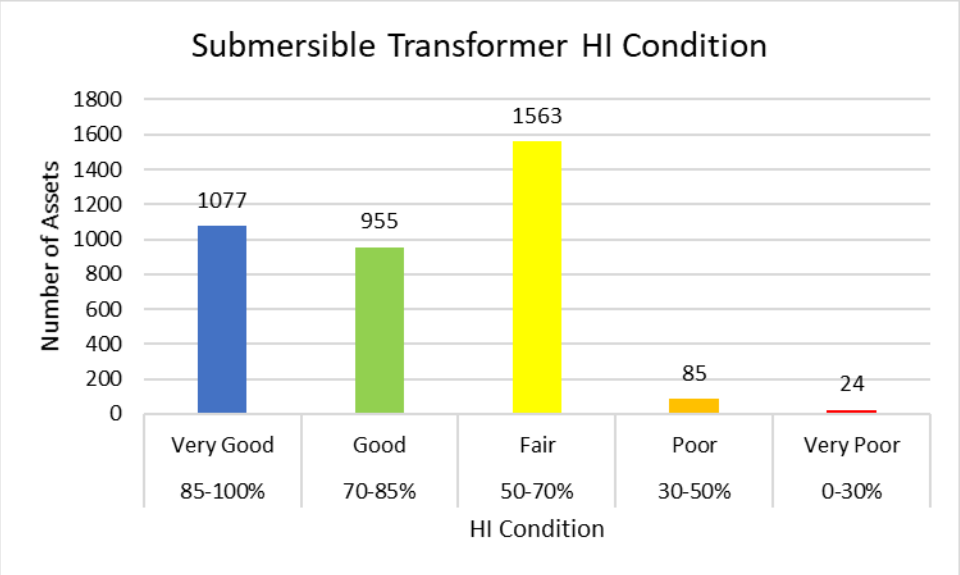


Figure 3-27: Submersible Transformer HI Condition

3.10.2.4.2 Network Transformer

Peak loading data is not available for network transformers, therefore, Health Index is calculated using age and the oil quality information. Figure 3-28 presents the HI Condition. About 41% of the population are in Very Poor Condition- mainly due to service age and the failed visual examination. Nearly 35% are in Fair Condition, and the remaining 24% are in Very Good Condition.

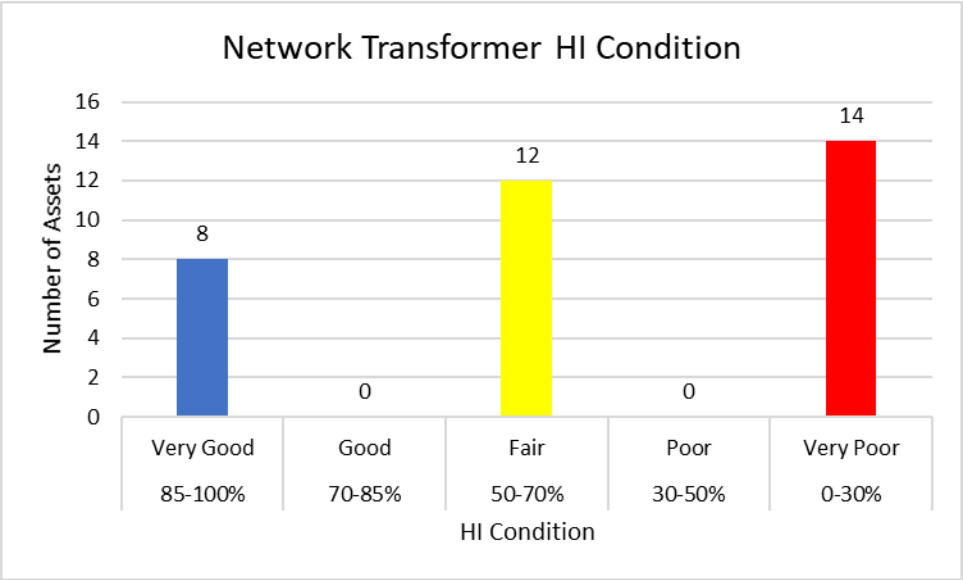


Figure 3-28: Network Transformer HI Condition

3.10.2.4.3 Remaining Distribution Transformers

Health Index for the remaining distribution transformers is calculated using both age and the peak loading information and Figure 3-29 presents the HI Condition. About 3% of the population are in Very Poor Condition, another 2% are in Poor Condition, nearly 32% are in Fair Condition, and the remaining 62% are in Good or Very Good Condition. Table 3-43 presents the breakdown of HI condition by transformer types.

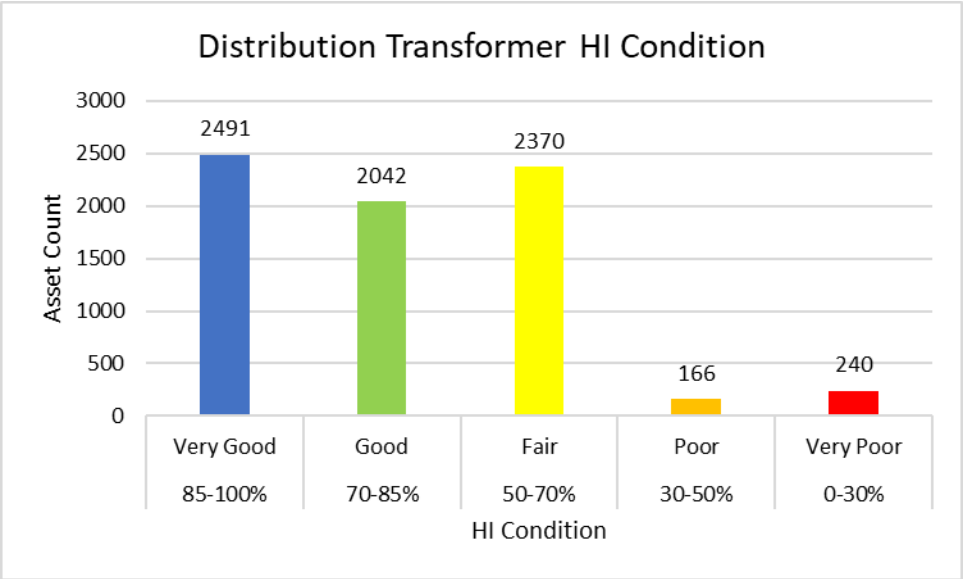


Figure 3-29: Remaining Distribution Transformers HI Condition

Table 3-43: Distribution Transformer HI Condition Breakdown by Transformer Type

Transformer Type	HI Condition				
	Very Poor	Poor	Fair	Good	Very Good
Padmount	10	22	585	348	379
Overhead	130	137	1403	1088	1642
Customer Owned	9	0	10	30	150
Network	14	0	12	0	8
Overhead Bank	7	2	51	37	25
Submersible	24	85	1563	955	1077
Underground	6	5	102	111	51
Underground Bank	78	0	219	428	244

3.11 SWITCHES

3.11.1 CONDITION ASSESSMENT METHODOLOGY

3.11.1.1 Health Index Calculation

The Health Index formulation for distribution switches typically uses service age, visual inspections, and IR scan results as condition parameters. KWHI's preventative switch maintenance is scheduled to be performed on a 10-year cycle. Infrared (IR) thermography of overhead plant is completed once per year on all overhead 3-phase feeders. During this process all equipment installed on the same structure is checked for hot spots and general deficiencies of the facilities. However, at the time of this ACA, KWHI has the record of only the service age and therefore the RHIF is based on age only.

Since the service age provides a reasonably good measure of the remaining life of disconnects, switches, and cut-outs, it is employed as an assessment parameter, with the following scores:

Table 3-44: Overhead Switches- Age Based Health Scoring

Grade	Disconnect Switch Age
A	0 to 10 years
B	10 to 20 years
C	20 to 30 years
D	30 to 40 years
E	40 years or older

3.11.2 Results Analysis

3.11.2.1 Assumptions

There are no assumptions made in the HI calculation of Switches.

3.11.2.2 Age and Demographics

KWHI's distribution system has a total of 4263 various types of overhead and underground switches including load break, load interrupters, fused load interrupters, etc. operating at voltages 8.32 kV, 13.8 kV, and 27.6 kV. The installation age data is available for 98% of the assets. Figure 3-30 presents the age demographics of KWHI's distribution switches. Approximately 12% of the population are in-service for more than 40 years which are mainly overhead switches. Switches with service age range of 30 to 40 years accounts for about 17% of the population of which 15% are overhead. The remaining 69% of the population are less than 30 years of age.

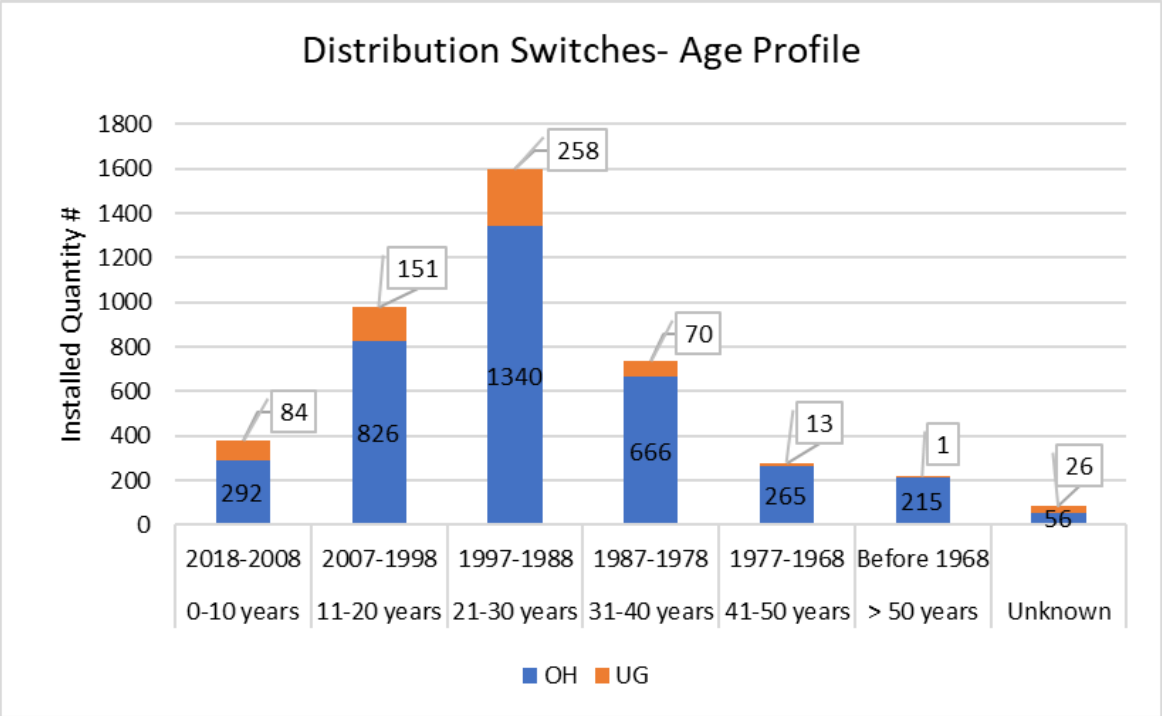


Figure 3-30: Distribution Switches Age Profile

3.11.2.3 DAI

Since only the age information is available DAI was not calculated. It is recommended to collect more degradation parameters to improve the HI accuracy. Section 4 provides more insights regarding the data collection recommendation.

3.11.2.4 Condition Assessment

Health Index for distribution switches is calculated using the age information and Figure 3-31 presents the HI Condition chart which aligns with the age profile.

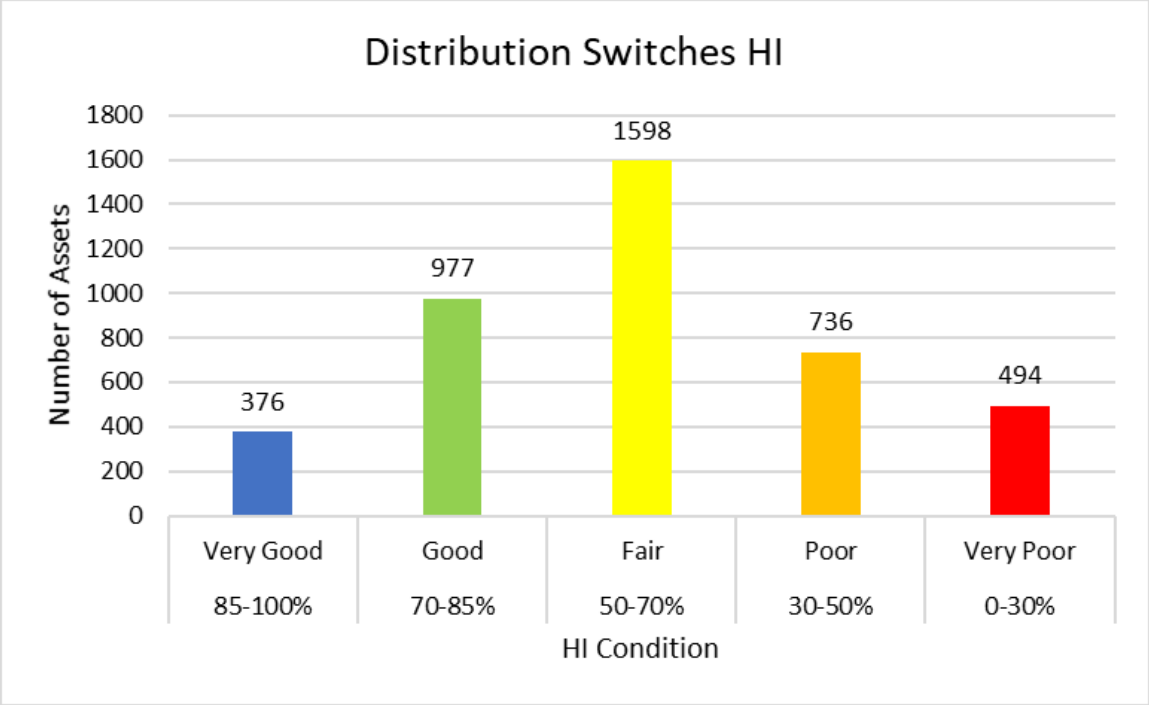


Figure 3-31: Distribution Switches HI Condition

4 RECOMMENDATIONS

4.1 RECOMMENDATION FOR DATA IMPROVEMENTS

This section identifies the data gaps present in KWHI's asset data. A data gap is an identified data point that can be used as part of the Health Index Formulation. We recommend for KWHI to investigate the possibility of collecting this data point moving forward to improve the accuracy of the Heath Index. A priority is given in relation to other criteria recommended to be collected for the asset.

A general recommendation for all the assets includes to move from paper format data entry to electronic format data entry.

4.1.1 SUBSTATION TRANSFORMERS

Table 4-1 identifies the data gaps present in KWHI's station transformers data.

Table 4-1: Data collection recommendations for substation power transformers

Criteria	Reasoning	Priority
IR scan	Infrared thermography is used to find areas of excess heat (caused by increased resistance) so that problems can be corrected before a component fails, causing damage to the component, safety hazards and productivity loss.	**High**
Furan Test	Economical test -provides good indication of asset aging	**High**
Transformer Insulation Power Factor	This should also be recorded during doble tests	**High**
Bushing Condition	Economical visual inspection on the bushing condition	**High**
DFR Test	While oil test gives only indirect moisture of solid insulation measurement, DFR test results provide most accurate moisture measurement for bulk of insulation including oil and paper. DFR is a recently developed advanced test.	**Medium**
Main tank corrosion	Economical visual inspection on the main tank	**Medium**
Oil tank corrosion	Economical visual inspection on the oil tank	**Medium**
Gaskets/Seals	Economical visual inspection on the seal condition	**Medium**
Connectors	Economical visual inspection on connector condition	**Medium**

Additional recommendations include:

- To record moisture content in the oil quality report
- To continue with DGA analysis

- Move from paper format to electronic format

4.1.2 SUBSTATION CIRCUIT BREAKERS

Table 4-2 identifies the data gaps present in KWHI's circuit breakers data.

Table 4-2: Data collection recommendations for substation circuit breakers and reclosers

Criteria	Reasoning	Priority
IR scan	Infrared electrical inspections provide key details regarding the hot spots, system overloads and loose defective equipment. Infrared thermography is used to find areas of excess heat (caused by increased resistance) so that problems can be corrected before a component fails, causing damage to the component, safety hazards and productivity loss.	**High**

4.1.3 STATION PROTECTION RELAYS

The current available data for protection relays is only the installation date. Table 4-3 identifies the data gaps present in KWHI's protection relays data. KWHI does test their protection relays on a regular basis and re-verify transformer station protection systems on a four-year cycle. Current practice has not adopted condition grading method and therefore there are no condition data for visual inspection and defect and test report. Moving forward, we recommend KWHI to record and collect five condition grading levels.

Table 4-3: Data collection recommendations for substation protection relays

Criteria	Reasoning	Priority
Visual Inspection	Visual inspection can provide better understanding of the physical condition of relays	**High**
Defect and Test Reports	This would note any damages on the equipment	**High**

4.1.4 Capacitor Banks

Table 4-4 identifies the data gaps present in KWHI's capacitor banks data.

Table 4-4: Data collection recommendations for capacitor banks

Criteria	Reasoning	Priority
Condition of Capacitor Units	Visual inspection to note any failures, deteriorations, and corrosions.	**High**
IR test	To identify any unusual hotspots	**High**
Capacitor Unit Fuses	Economical visual inspection	**Medium**
Connectors and Conductors	Economical visual inspection	**Low**
Steel Mounting Structure	Economical visual inspection	**Low**

4.1.5 Station Batteries

Table 4-5 identifies the data gaps present in KWHI's station batteries data.

Table 4-5: Data collection recommendations for substation batteries

Criteria	Reasoning	Priority
Testing	The end of life is reached when the battery is no longer able to retain adequate charge for required functions. Testing can provide information on batteries capability to retain full charge.	**High**

4.1.6 Wood Poles

The KWHI's current inspection practice for wood poles does include the high priority degradation parameters such as pole strength and visual inspection. It is recommended to collect these data for all the inspected poles.

Other recommendation is to standardize the grading system for visual inspection to include five levels of condition grading as shown in the Table below.

Table 4-6: Visual inspection condition grading -Wood poles

Condition Rating	Component Condition
A (Very Good)	Component is in "as new" condition
B (Good)	Component has normal wear expected with age
C (Fair)	Component has many minor problems or a major problem that requires close attention and monitoring
D (Poor)	Component has many problems and the potential for its failure would rapidly escalate unless preventative maintenance is performed
E (Very Poor)	Component requires immediate replacement

4.1.7 Concrete Poles

Table 4-7 identifies the data gaps present in KWHI's concrete poles data. A data gap is identified as a recommendation moving forward for the utility to adopt Best Practice Health Index Formulation for the entire population of assets which is expected to increase the accuracy of ACA results. A priority is given in relation to other criteria recommended to be collected for the asset.

Table 4-7: Data collection recommendations for concrete poles

Criteria	Reasoning	Priority
Visual Inspection	Visual inspection can provide better understanding of the actual condition of poles at any time of their life	**High**
Defects	This would find any defects on the concrete pole due to vandalism, vehicular accidents, electrical burns, or cracking	**Medium**
Out of Plumb	This would find any displacement of footings from the original installed condition	**Low**

The current available data for concrete poles is only the installation date. Visual inspection is used the HI formulation by assuming Good condition for all poles.

4.1.8 Overhead Conductors

KWHI has successfully collected the installation date information for majority of the population. It is recommended to continue recording the age data.

4.1.9 Underground Cables

Table 4-8 identifies the data gaps present in KWHI's underground cables data.

Table 4-8: Data collection recommendations for underground cables

Criteria	Reasoning	Priority
Cable Failure	Collecting cable failure results and identifying water tree samples throughout the service territory and varying age, the utility would be able to have an improved view on cable condition.	**High**
Field Testing	Field test would find any partial discharge	**High**
Condition of Concentric Neutral	This inspection provides the status of neutral corrosion	**High**
Outage Records	Collecting outage records with their known location would identify which feeder section are in poorer condition that will require replacement as it may be more cost effective to replace rather than maintain.	**Medium**
Loading History	Overloading cables results in temperature increases overtime causing accelerated degradation of the cable.	**Low**
Visual Inspections of Splices	A visual inspection would identify if the splice is in good or bad condition; with it being in a bad condition could result in moisture ingress that will further pose problems for the asset and utility.	**Low**

4.1.10 DISTRIBUTION TRANSFORMERS

Table 4-9 identifies the data gaps present in KWHI's distribution transformers data.

Table 4-9: Data collection recommendations for distribution transformers

Criteria	Reasoning	Priority
Visual Inspection	Visual inspection can provide better understanding of the physical condition of the transformer	**High**
IR Scan	Infrared electrical inspections provide key details regarding the hot spots, system overloads and loose defective equipment.	**High**

4.1.11 SWITCHES

Table 4-10 identifies the data gaps present in KWHI's distribution switches data.

Table 4-10: Data collection recommendations for switches

Criteria	Reasoning	Priority
IR Scan	Infrared electrical inspections provide key details regarding the hot spots, system overloads and loose defective equipment.	**High**
Condition of Insulator	Economical visual inspection on the insulator condition	**Medium**
Condition of Blades	Economical visual inspection on the blades condition	**Medium**
Condition of operating mechanism	Economical visual inspection on the condition of operating mechanism	**Medium**

4.2 RECOMMENDATION ON ASSETS REQUIRING ATTENTION

4.2.1 SUBSTATION TRANSFORMER

Based on the ACA, there are no substation transformers with HI condition of Very Poor. Three of the transformers are categorized to be in Poor condition which are recommended for action over the next five years. Table 4-11 shows the recommendation on substation TXs requiring attention and Table 4-12 provides the recommended replacement plan.

Table 4-11: Substation Transformers- Recommendation on assets requiring attention

Number of Assets	HI Condition	Recommendation
0	Very Poor	NA
3	Poor	Require attention over the next five years
11	Fair	Some of the assets in Fair may fall into Poor condition over the next five years window and recommended to monitor these assets.

*NA- Not applicable since there are no assets in the respective HI condition category.

Table 4-12: Substation Transformers- Recommended replacement plan

Number of Substation Transformers Recommended for Replacement						
Year	2018	2019	2020	2021	2022	2023
Quantity	0	0-1	0-1	0-1	0-1	0

4.2.2 SUBSTATION CIRCUIT BREAKERS

Based on the ACA, three circuit breakers are in Very Poor condition which are recommended for immediate action. Note that, age is the driving factor for these three assets. Table 4-13 shows the recommendation on substation CBs requiring attention and Table 4-14 provides the recommended replacement plan.

Table 4-13: Substation CBs- Recommendation on assets requiring attention

Number of Assets	HI Condition	Recommendation
3	Very Poor	Require immediate attention
0	Poor	NA
22	Fair	Some of the assets in Fair may fall into Poor condition over the next five years window and recommended to monitor these assets.

Table 4-14: Substation CBs- Recommended replacement plan

Number of Substation CBs Recommended for Replacement						
Year	2018	2019	2020	2021	2022	2023
Quantity	0-1	1-2	0-1	0	0-1	0-1

4.2.3 *Substation Protection Relays*

Based on the ACA, 86 protection relays are in Very Poor condition which are recommended for immediate action. Non-Discretionary Obsolescence parameter is the driving factor for these Very Poor assets. Table 4-15 shows the recommendation on substation protection relays requiring attention and Table 4-16 provides the recommended replacement plan.

Table 4-15: Substation Protection Relays- Recommendation on assets requiring attention

Number of Assets	HI Condition	Recommendation
86	Very Poor	Require immediate attention
71	Poor	Require attention over the next five years
2	Fair	These assets are on the verge of Fair to Poor condition and may fall into Poor condition over the next five years window and recommended to monitor these assets.

Table 4-16: Substation Protection Relays- Recommended replacement plan

Number of Substation Protection Relays Recommended for Replacement						
Year	2018	2019	2020	2021	2022	2023
Quantity	0-2	5-7	30-35	0-9	25-29	20-25

4.2.4 *Capacitor Banks*

Based on the ACA, all the capacitors are in either Good or Very Good condition. Therefore, no recommendations made in this section.

4.2.5 *Substation Batteries*

Based on the ACA, there are no batteries in Poor or Very Poor HI condition. There are seven batteries in Fair Condition which may fall into Poor condition over the next five years window and recommended to monitor these batteries. Table 4-17 shows the recommendation on substation batteries requiring attention. At the time of this ACA, there are no recommendations made on the replacement of batteries since there are no Very Poor or Poor condition batteries in the system.

Table 4-17: Substation Batteries- Recommendation on assets requiring attention

Number of Assets	HI Condition	Recommendation
0	Very Poor	NA
0	Poor	NA
7	Fair	Some of the assets in Fair may fall into Poor condition over the next five years window and recommended to monitor these assets.

4.2.6 WOOD POLES

Based on the ACA, 617 wood poles are in Very Poor condition which are recommended for immediate action. Of these 617 poles, 320 poles are in Very Poor condition based on the condition and age information. The remaining 297 poles are in service for more than 40 years and they are determined to be in Very Poor HI condition based on the age. Table 4-18 shows the recommendation on wood poles requiring attention and Table 4-19 provides recommended replacement plan.

Table 4-18: Wood Poles- Recommendation on assets requiring attention

Number of Assets	HI Condition	Recommendation
320	Very Poor based on condition and age	Require immediate attention
297	Very Poor based on age only	Require immediate attention- Of 297, 89 poles are 45 years and above. Need to be inspected to study the actual physical and mechanical condition to plan replacement
2874	Poor	Require attention over the next five to eight years
3806 of which 1770 >=45 years old	Fair	These assets are in Fair HI condition. 1770 poles are 45 years and above. Some of these assets may fall into Poor condition over the next five to eight years window and recommended to monitor these assets.

Table 4-19: Wood Poles- Recommended replacement plan

Number of Wood Poles Recommended for Replacement						
Year	2018	2019	2020	2021	2022	2023
Quantity	425-450	425-450	425-450	425-450	425-450	425-450

4.2.7 Concrete Poles

The HI analysis for concrete poles is based on the assumptions stated in section 3.7.2.1 and therefore is not very accurate. KWHI is currently collecting visual inspection data for concrete poles. It is recommended to continue inspection process for all poles to study accurate HI of the poles and to recommend optimal replacement plan.

4.2.8 Overhead Conductors

Overhead conductors typically outlive the poles which support them and are replaced when the poles are replaced. Therefore, no recommendations on overhead conductors are provided.

4.2.9 Underground Cables

Based on the ACA, nearly 42 km of underground primary cables are in Very Poor Condition and about 159.2 km in Poor Condition. Table 4-20 shows the recommendation on underground cables requiring attention and Table 4-21 provides recommended replacement plan. However, performing visual inspection would give better conclusions towards optimal replacement plan.

Table 4-20: Underground Cables- Recommendation on assets requiring attention

Cable Length	HI Condition	Recommendation
42 km	Very Poor	Require immediate attention. Need condition data to plan for replacement.
159.2 km	Poor	Require attention over the next five years. Need condition data to plan for replacement.
282.1 km	Fair	Some of these assets may fall into Poor condition over the next five years window and recommended to monitor these assets.

Table 4-21: Underground Cables- Recommended replacement plan

Length of Underground Cables Recommended for Replacement						
Year	2018	2019	2020	2021	2022	2023
Length (km)	10-12	10-12	10-12	10-12	15-17	15-17

4.2.10 Distribution Transformers

Based on the ACA, 24 submersible transformers, 14 network transformers, and 240 other distribution transformers are in Very Poor HI condition. Table 4-22 provides further

recommendations on assets requiring attention and Table 4-23 presents the recommended replacement plan. However, performing visual inspection would give better conclusions towards optimal replacement plan.

Table 4-22: Distribution Transformers- Recommendation on assets requiring attention

Type	# of Assets	HI Condition	Recommendation
Submersible TXs	24	Very Poor	Require immediate attention. Visual examination is recommended to plan for replacement.
Network TXs	14		Require immediate attention. These numbers are driven by age and the oil quality visual examination result. Recommendations include visual examination of the transformer and/or oil replacement. It is also recommended to consult the oil testers to obtain their recommendation for the transformers showing visual examination result as 'Fail'.
Other Distribution TXs	240		Require immediate attention. Visual examination is recommended to plan for replacement.
Submersible TXs	85	Poor	Require attention over the next five years. Need condition data to plan for replacement.
Network TXs	0		NA
Other Distribution TXs	166		Require attention over the next five years. Need condition data to plan for replacement.
Submersible TXs	1563	Fair	Some of these assets may fall into Poor condition over the next five years window and recommended to monitor these assets.
Network TXs	12		
Other Distribution TXs	2370		

Table 4-23: Distribution Transformers- Recommended replacement plan

Number of Distribution Transformers Recommended for Replacement						
Year	2018	2019	2020	2021	2022	2023
Submersible TXs	10-20	4-14	20-22	20-22	20-22	20-22
Network TXs	4-6	8-10	0	0	0	1-2
Other Distribution TXs	80-85	80-85	80-85	40-45	40-45	40-45

4.2.11 SWITCHES

Based on the ACA, there are 494 switches in Very Poor HI condition and 736 switches in Poor condition. The HI was calculated using only the age data.Table 4-24 provides further recommendations on assets requiring attention and Table 4-25 provides the recommended replacement plan. However, performing visual inspection would give better conclusions towards optimal replacement plan.

Table 4-24: Switches- Recommendation on assets requiring attention

Number of Assets	HI Condition	Recommendation
494	Very Poor	Require immediate attention. These switches are above 40 years age. Of 494 switches, 216 are greater than 50 years old. Perform visual inspection to study the actual physical condition.
736	Poor	Require attention over the next five years. Perform visual inspection to study the actual physical condition.
1598	Fair	Some of these assets may fall into Poor condition over the next five years window and recommended to monitor these assets.

Table 4-25: Switches- Recommended replacement plan

Number of Switches Recommended for Replacement						
Year	2018	2019	2020	2021	2022	2023
Quantity	100-108	100-108	130-140	130-140	150-160	150-160



Appendix M:
Pole Testing & Inspection Procedure 2017

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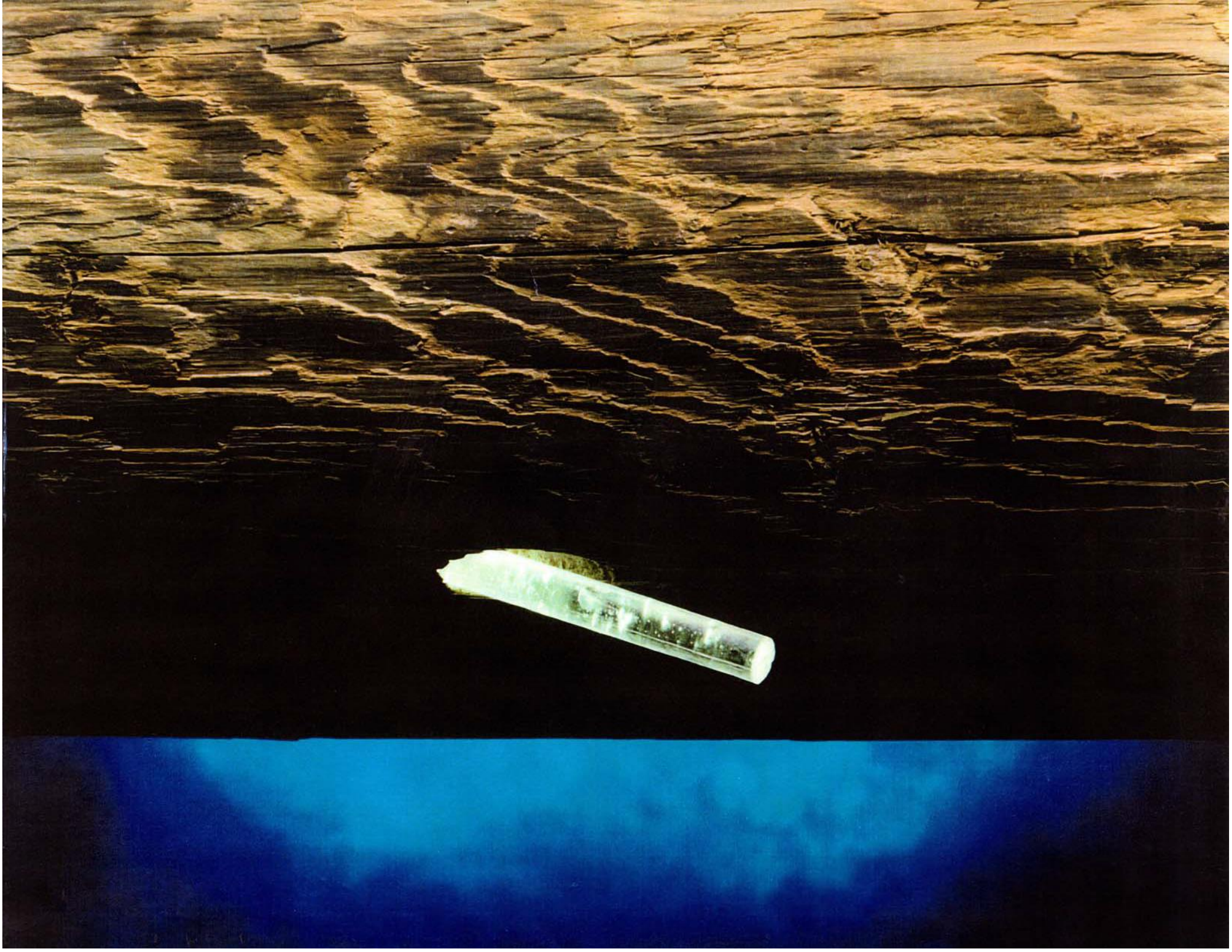


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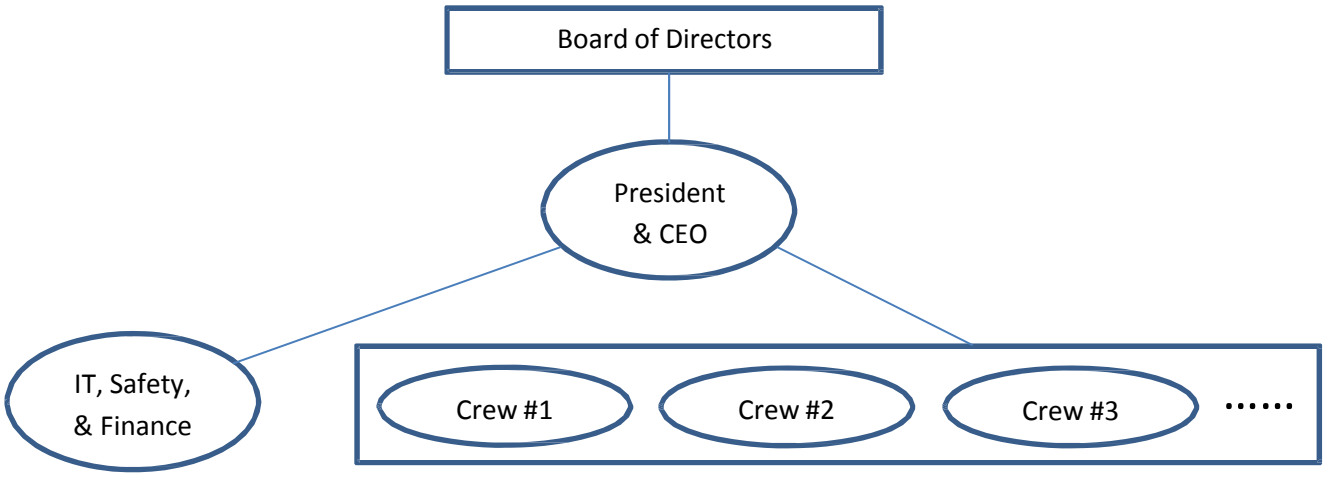
Due to the escalating cost of pole replacement, property management, safety and environmental responsibilities and possible liability cases, a well-planned pole maintenance and life extension program is increasingly important for today's utilities. PoleCare International is one of the most recognized utility pole inspection and remedial wood preservative treatment service providers across Canada. Within the last 17 plus years, PoleCare has tested over 750,000 poles for Canadian utilities, including Nova Scotia Power, PUC Services Inc, Toronto Hydro, Guelph Hydro, Algoma Power, Power Stream, Innisfil Hydro, Epcor, Fortis Alberta, to name a few. Services provided by PoleCare include both traditional and non-destructive inspections, Resistograph testing, remedial wood preservative treatment, sub-meter GPS, digital photography, client training, job auditing, pole tagging, probable remaining pole strength and life estimates, overhead attachment and inventory recording. With a long history of high quality service and a management team understanding the importance of honesty and dual diligence in this industrial sector, PoleCare has built up strong relationships with utility clients nationwide who are ready to provide supporting references.

Founded in 1998 by Dr. Samy Krishnasamy – a former head of the Transmission, Distribution and Structures Unit of Ontario Hydro, carrying out R & D work on weather related conductor loads, probability based design methods, management and life extension of wood pole lines, testing of fiber optic ground wires, conductors, line hardware, and large scale civil structures. Dr. Krishnasamy has over 30 years of extensive education and professional experience with utility pole testing and life extension, and he also holds memberships with most pole maintenance associations, and conducts scientific seminars throughout Canada, Norway, and Iceland.

In 2001 the company was bought by the late Ms. Lissi M. Jeppesen, who was a chemical engineer with over 30 years of extensive education and professional experience in wood preservation and protection, especially in the area of remedial wood preservative treatment against dry and wet rot, internal and external decay, wood boring insect and fungus attacks. Ms. Jeppesen was also a member of the Canadian Wood Preservation Association, and had served many positions in the CWPA including treasurer and president. After taking over, Ms. Jeppesen had introduced a full line of remedial wood preservative pole treatment products and services, and subsequently grew PoleCare from a small company of less than 5 people to a full pole inspection and treatment service provider that often runs more than 5 crews throughout Canada.

Today, PoleCare is headed by Mr. Darren Fournier, who has served as General Manager from day one, worked alongside both former presidents Dr. Krishnasamy and Ms. Jeppesen for over 15 years, and naturally took over after Ms. Jeppesen. In addition to the training and knowledge gained from working closely with the two former leaders, Darren has over 25 years of hands-on pole inspection and treatment experience with know-how in right-of-way clearing and industrial vegetation management from working with many utilities throughout Canada and USA. Darren keeps himself current with multiple provincially and federally essential accreditations and certificates including pesticide applications and workplace health and safety regulations.

Company Structure & Key Personnel



Darren Fournier, President & CEO, Certified Pesticide Applicator

Darren's experience with utility pole inspection and remedial treatment goes way back to 1987. Darren has ever since worked extensively in this industry, with four different companies across USA and Canada, including PoleCare International which he joined as General Manager and Chief Pole Inspector. Darren's contribution in the fast growth of PoleCare over the past 15 years was greatly recognized by former president Ms. Lissi M. Jeppesen, and naturally Darren became the new Owner – Operator of PoleCare.

Roger Zhang, IT, Safety, & Finance, Certified Pesticide Applicator

Roger obtained his computer science and business administration degree from Saint Mary's University in Halifax, and first joined PoleCare in 2008 as IT Manager. During the first three years with PoleCare, Roger has gone through extensive training in construction safety and industrial pesticide applications. Roger's current responsibilities include pole inspection data processing, reporting and billing, wood preservative material inventory control, as well as all safety related tasks.

Timothy Savard, Crew Foreman & Senior Pole Inspector, Certified Pesticide Applicator

Timmy started his career in the utility pole service industry in 1990, and worked together with Darren across USA and Canada for over 20 years. Timmy is an expert in both traditional and non-destructive inspection technologies, and has extensive experience in steel reinforcement, ground rod testing, right-of-way clearing, to name a few. Timmy is famous for his extraordinary ATV skills and rough terrain conquering capabilities in transmission line projects. Timmy's loyalty with PoleCare started in 2001.

Gerald Fournier, Crew Foreman & Senior Pole Inspector, Certified Pesticide Applicator

Gerald has worked side by side with his elder brother Darren since 1990, and became one of PoleCare's most experienced pole inspectors. In addition to his expertise in both sound & bore and non-destructive methods, Gerald also has extensive experience in ground rod testing, right-of-way clearing, workplace safety regulations, digital photography and GPS. Gerald has worked with most utilities in Ontario, where he is greatly recognized for his client communication skills, fast learning ability, and accurate reports.

Craig Brown, Crew Foreman & Pole Inspector, Certified Pesticide Applicator

Craig joined PoleCare in 2009, and has since enjoyed a very fast growth in his career mostly due to his ability and willingness to learn and adapt. Craig has been a team leader in PoleCare's major western Canada project for the last 3 years, where he demonstrated excellent interpersonal skills and built up great client relationships. Craig is very good with computers and electronic testing devices and widely recognized for his ability in studying and taking pesticide exams.

Assistant Pole Inspectors, Treatment Applicators, and General Labourers

Operating in a family like environment, PoleCare has long enjoyed the advantage of very high employee loyalty and morale. Regardless of the highly seasonal nature of our industrial sector, over 90% of our workers return every year when job starts. This gives PoleCare the advantage of highly experienced crews, not just foremen and supervisors. In fact, most members of the entire PoleCare team have been on board for over 5 years, with some over a decade long.

Inspection & Treatment Technologies

Visual, Sound, and Divot Tests

Visual inspection from ground line identifies damaged hardware such as broken insulators, wires or wire guards, pole surface rot at and above ground, mechanical damage from vehicles or equipment, wood loss, severe checks and cracks, woodpecker damage, fire damage, leaning poles, pole top rot or feathering, etc.

Sounding with a 29 ounce hammer from ground line up to 8' above identifies internal decay caused by insects or fungi, as well as wood softness due to shell rot.

Divot test (partial excavation of 6" below ground, usually 3 divots at 120° apart) identifies shell rot below ground. Additional sounding on the pole at excavated areas detects hollowness from internal decay and/or pockets below.

Visual, Sound, and Divot Tests are usually applied to every wood pole being inspected.

Traditional Bore Test with Internal Treatment

3 holes are drilled, 120° apart, from ground line down towards the centre of the pole at 45° angle using an auger drill bit. If internal decay is detected, a metal shell gauge is used to determine existing shell thickness and approximate size of internal voids. According to the circumference of the pole, 3, 6, or 9 Impel (Boron) Rods are inserted into the drill holes which are then tightly sealed with either pre-treated wood or plastic plugs. Poles with a circumference of 36" or less are usually treated with 3 rods; 37" to 54" – 6 rods; 55" and above – 9 rods; in the very rare case of 72" or bigger poles, we put 12 rods.

Traditional Bore Test is only recommended when Internal Treatment is to be applied.

Non-destructive Resistograph Test

A special battery powered drill with a 2 mm diameter bit is used to drill the pole at ground line, both horizontally straight through and 45° down to the centre. The instrument provides a graph representation of relative density of the wood by measuring its resistance to the drillings, and therefore assesses qualitatively the amount of degradation in the pole. Sudden drops of resistance are reflected by saddled sections in the graph, which can be further interpreted to evaluate the remaining shell thickness, sizes of internal voids and decay pockets. The 2 mm drilling needle is too small to cause any damage to the pole, and the mechanism measures below ground wood condition without excavation.

Resistograph Test is usually applied to poles older than 10 years, suspected poles, as well as rejects.

Non-destructive EDM Test

The EDM technique applies the principles of sonic spectral wave analysis. The sonic probe signals from the EDM non-destructive application to a wood pole are correlated with a stored database to obtain a measurement of the pole strength.

Internal Insecticide Treatment

Poles infested by termite, carpenter ants or other insects are drilled using the same drill bit for traditional bore test, usually from beside the main check which provides insect entrance, at 45° angle down to the nest. Tim-Bor Professional solution is pumped into the drill holes, till the point the insect nest and all its connected channels are flooded. The drill holes are sealed with same plugs as for bore test. Notice that this treatment is also applied to reject poles, in order to prevent further infestation of adjacent poles or future replacement poles.

External Preservative Bandage Treatment

The Pole is fully excavated to 18" below ground line, coated all around with a brush-on compound paste of copper naphthenate and diffusible borate, and then protected with a special type of wrapping paper. The paper wrap is stapled to the pole before backfilling. A 1 to 2 inch visible edge is left above ground line for easy identification of the treatment. A seamed plastic pouch containing Cu-Bor Paste is also available for easier and cleaner application.

This application may be restricted by undiggable pole settings and / or dips.

Additional Services – Additional visual identification and recording of pole attachments, digital photography, sub-meter GPS logging, pole height measurement with laser, EDM pole strength measurement, etc. can be conducted according to client requirements.

Plugging and Tagging

- All treatment holes drilled are plugged using either a pre-treated wood plug or a plastic screw type re-plug, whichever is preferred by client.
- All poles that have past the tests are tagged *PCI 2016* using aluminum tags – round shape for poles also treated with bandage, oval shape for the rest.
- Poles treated with Impel (Boron) Rods are tagged with a teardrop aluminum tag with the words *BORON RODS*.
- Poles treated with liquid are tagged with a narrow rectangular aluminum tag with the letters *INT TR*.
- Rejects are normally tagged with a wide rectangular plastic tag in red color, or adapted to a different tag according to client's preference.

Data Collection and Reporting – Data collection is done using hand-held devices with paper side notes for unusual conditions. Final reports are provided in Microsoft Excel or Access database format, whichever is preferred. Resistograph measurements can be provided in PDF format upon request. Additional information such as estimated remaining pole strength and life expectancy can be provided using computer data mining methods based on over 15 years of real world collected data.

Modern Inspection Equipment

Digital Resistograph

The IML PD Resistograph system uses a drilling needle to create a small 2 mm channel to measure and record the wood condition above and below ground level, providing the inspected pole's exact density measurements on a scale of 1:1, which are stored in the PD's large internal memory for review or download through the integrated Bluetooth or a USB adapter. Graphs can be further converted to PDF format and hyperlinked to the remaining data of respective poles during PoleCare's standard data post processing stage.

























Ruggedized Handheld & Sub-meter GPS

The Yuma handheld & Geo 7 sub-meter GPS units are the 2 types of data logging systems we typically use. They both have GPS logging and high resolution digital picture capabilities, with the Geo 7's system having sub-meter accuracy. The Geo 7's integrated laser eye can also be used to measure pole heights, and log position of poles surrounded by fence, water or other barricades. With the TerraSync frontend data collection interface on the handhelds and the Pathfinder Office backend software on the PC, we can customize our pole inspection programs effortlessly to satisfy different needs and requirements of our clients throughout Canada.







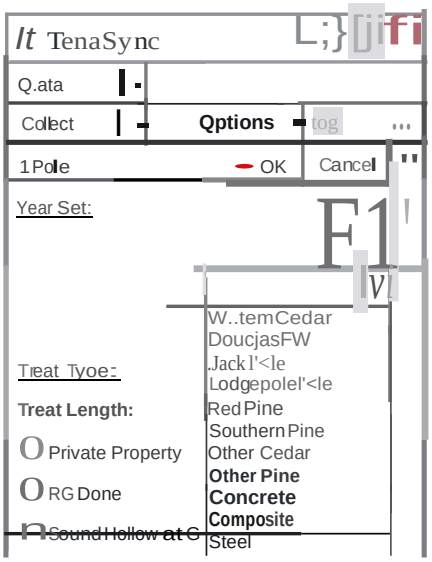
Trimble

Geo7X





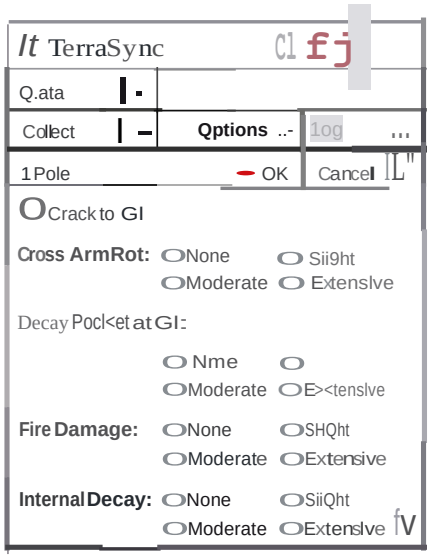




TerraSync Software

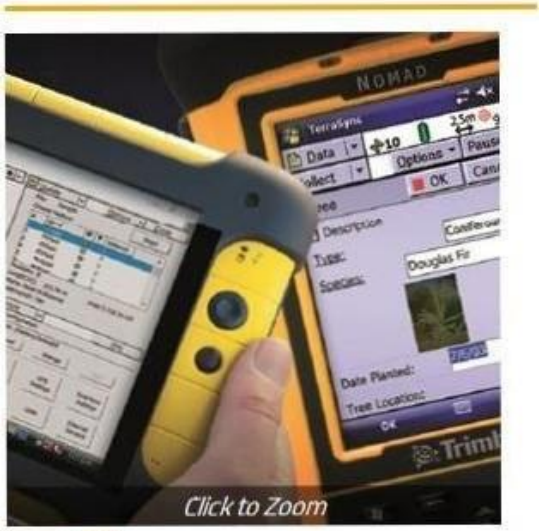
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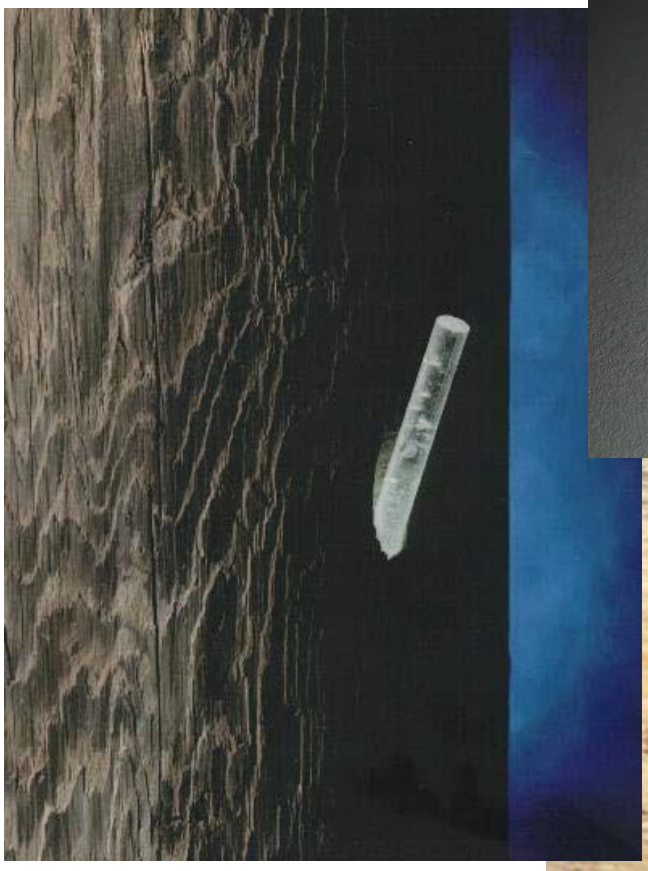


Pathfinder Office data dictionary creator interface

Remedial Treatment Products & Accessories

Impel (Boron) Rods II – PMRA Registration No. 23398

The Impel® Boron Rods are highly concentrated, water diffusible borate glass rods. The placement of the rods into the heartwood of utility wood poles offers superior internal protection against fungal decay and insect attack. With as little as 25% moisture content in the wood, a long term supply of wood preservative is drawn into the wood fibers, preventing and eradicating fungus, bacterial and insect attacks. The boron rods diffuse into the wood (both heartwood and sapwood) over a few months and transform into the active ingredient – boric acid. Studies have shown re-treatment is typically required every five to eight years. However, historical field experience has shown that utilities will often re-inspect and re-treat, if necessary, at intervals of eight to ten years with no problems. Boric acid and its sodium borate salts are pesticides that we can find in nature. Research has shown that boric acid, while highly toxic to insects and fungi, is practically non-toxic to human, mammals and birds, slightly toxic to practically non-toxic to freshwater fish, and practically non-toxic to frogs and toads and aquatic life.







Tim-Bor Professional – PMRA Registration No. 24091

Tim-Bor is widely used by Canadian and US utilities to kill and control wood destroying organisms, such as termites and carpenter ants. When internal decay and / or insect infestation are detected during pole inspection, Tim-Bor is usually applied by drilling and injecting into galleries and internal voids. While combining a broad spectrum of efficacy against wood boring beetles, termites, and carpenter ants, Tim-Bor has a very low acute mammalian toxicity; neither does it contain any organic or heavy metal components, nor uses any organic solvent when applied as an aqueous solution.

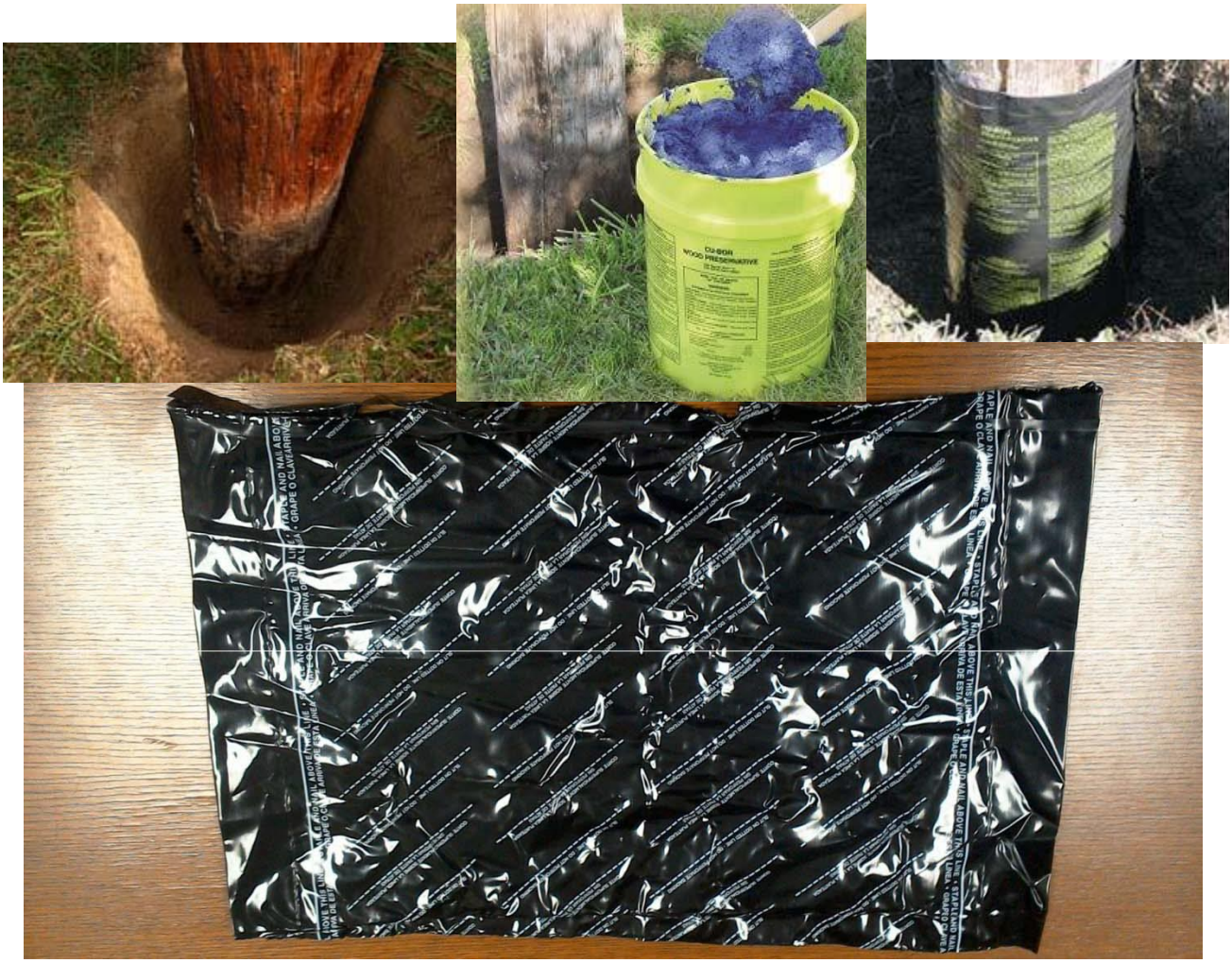




Cu-Bor Wraps and Paste – PMRA Registration No. 27621

Cu-Bor wood preservative paste can be applied by brush to the surface of wood utility poles from ground-line to about 18” below, and helps extending pole service-life for up to 15 years. Produced by one of North Americas leading preservative manufacturers, the two component paste contains both diffusible borates and copper as active ingredients. Nearly 80% of a wood poles strength is derived from the outer shell of wood at the ground-line, therefore protect this area against external decay is of great

economic and safety importance. A seamed plastic pouch containing Cu-Bor Paste is also available for easier and cleaner application.



Accessories



Safety is No. 1

PoleCare International greatly values workplace health and safety. It is our company policy to promote occupational health and safety, and to take every reasonable precaution to ensure our workplaces are safe and healthy for our employees, clients, as well as the general public as they may come into contact with our work sites.

The Occupational Health & Safety Act and accompanying regulations, along with generally accepted industry health and safety practices, shall describe the minimum standards expected for health and safety in our workplaces. All work related activities shall be performed in compliance with the Act and accompanying regulations.

We recognize and value the knowledge and skills of employees with regard to perform their jobs safely, and will work in a spirit of consultation and cooperation with our crew supervisors and workers of all levels. All employees are supported and encouraged to participate and contribute to our health and safety programs and initiatives. We commit to the development and implementation of rules and measures, through our training and internal responsibility system, in order to prevent and minimize occupational injury and illness.

We hold all levels of company management responsible for the implementation of this policy, as well as the continuous maintenance and improvement of our health and safety programs. All employees are requested to comply with our OH&S policy, to follow our health and safety programs, and to cooperate with our health and safety representative as well as personnel from any authorities performing health and safety related duties on our work sites. We shall make sure that company management, supervisors, and workers all share the responsibility of health and safety in our workplaces.

At the very minimum, we make the following mandatory to all PoleCare employees.

- All workers must have WHMIS training
- Proper PPE must be used at all workplaces
- Company vehicle drivers must have clean abstract
- Each crew must have at least two First Aid providers
- All client specific OH&S requirements must be followed
- All federally and provincially required trainings must be up to date
- Pesticide applications must be in compliance with respective provincial regulations
- Jobsite hazard assessment, tailboard meeting, safety inspections must be conducted

Started in 2009, we have implemented and kept up to date a comprehensive OH&S program which is both recognized locally by NSCSA and interprovincial compliant with ISNetworld.

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Appendix N:
Cable Testing & Inspection Procedure 2018

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Assessement of Medium Voltage Cables in Kitchener Wilmot Hydro's Distribution Network

November 23, 2018

Courtney Lawton, EIT
Testing & Instrumentation Engineering Intern

Phil Malone, M.Eng, P.Eng
Testing & Instrumentation Engineer

CABLE NON-DESTRUCTIVE TESTING Proprietary and Confidential Information

Cable Asset Management

The uncertainty of which cables require replacement or rejuvenation and which cables can be left untouched are million dollar decisions asset managers are consistently seeking to make. Early replacement of aged cable assets results in unnecessary capital spending and loss of service years. Diagnostic testing can eliminate the guessing game as to what action must be taken and when, saving valuable dollars and mitigating the risk of unexpected failures.

The recently published report by National Electric Energy Testing, Research and Applications Center (NEETRAC) reports that approximately 65% of North American electrical utilities do not use any form of diagnostics for their medium voltage underground distribution cables [1]. In order to optimize capital spending and meet customer and regulator demands for improved reliability, utilities must move towards developing a diagnostic approach to better understand the condition of their cable assets.

To protect capital investment, an asset management program must address the following issues:

1. Replacement of cables after they reach their end-of-life (wear-out) stage
   Although this option seems logical, the premature replacement of cables without knowing their true condition can result in unnecessary capital loss and loss of service-years.

2. Rejuvenation of cables
   Depending of the health index of the cable, rejuvenation with a dielectric liquid could help to preserve or improve the dielectric strength of the cable.

3. Maintaining cables in service until failure
   Simply replacing a cable as it fails causes unplanned outages that result in substantial operational and financial costs and poorer reliability.

Cross Linked Polyethylene (XLPE) insulated cable is the most widely used medium voltage (MV) cable for utilities across North America today. XLPE was invented in 1963 and the first use of this plastic in MV cables was in the late 1960s until a tree resistant form (TR-XLPE) was introduced and thoroughly adopted in North America by 1990. This shift was because a vast majority of XLPE failures were due to water trees found within the polymeric insulation [1].

Water-treeing is one of the most prevalent aging mechanisms of MV XLPE cables. A water tree begins due to moisture ingress and ionic impurities found within a cable's insulation. Once a water tree reaches a certain size and length, an increase in voltage stress can cause an electrical tree to form. If an electrical tree is found within the insulation, it is only a matter of time before failure occurs. Due to the increasing risk of failure with increasing tree length, it is important to have a diagnostic test that can determine to what extent water trees have deteriorated the insulation so that appropriate steps can be taken to remedy the situation before failure occurs.

Figure 1 depicts the appearance of water trees from National Research Council (NRC) laboratory studies.

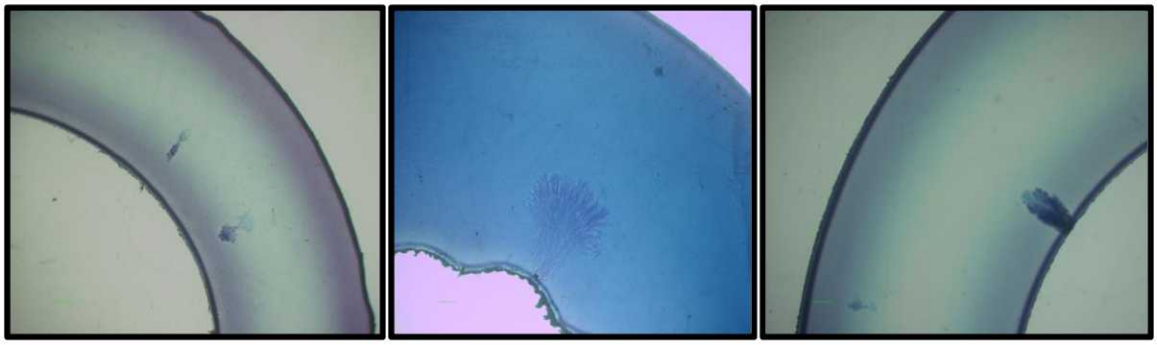


Figure 1- Vented and Bow-tie Water Trees in Miniature Aged Cables from NRC Laboratory

DC Polarization/Depolarization Measurement System

National Research Council Canada (NRC) developed a non-destructive method to detect the effect that water trees have on XLPE cables. The NRC's DC Polarization/Depolarization Current Measurement system uses three modules to complete the cable testing; the Depolarization Current Measurement Module (DCM), the Instrumentation Module (IM), and the Software Module (SM). A voltage of either 1kV or 3kV, depending on the rating of the tested cable, is applied through the bushing mounted on the DCM during the polarization stage of the testing. The voltage is then switched off and the depolarization current is measured. An oscilloscope, found in the IM, is used to capture the High Frequency (HF) component of the depolarization current waveform. A Keithley electrometer can be used to capture the Low Frequency (LF) component of the waveform but for the purpose of analysis, only the HF data is used. All of the captured data is sent to the SM through a USB hub for analysis.

The novelty of the NRC on-site cable testing system is in the integration of the fast digitizer and the noise-free solid state switch. This switching technology allows a measurement to be conducted with high signal-to-noise (SNR) ratio, thereby facilitating the detection of the depolarization current components that appear when water trees exist within the cable's insulation. Figure 2 depicts the principle of the Polarization/Depolarization Current Measurement concept.

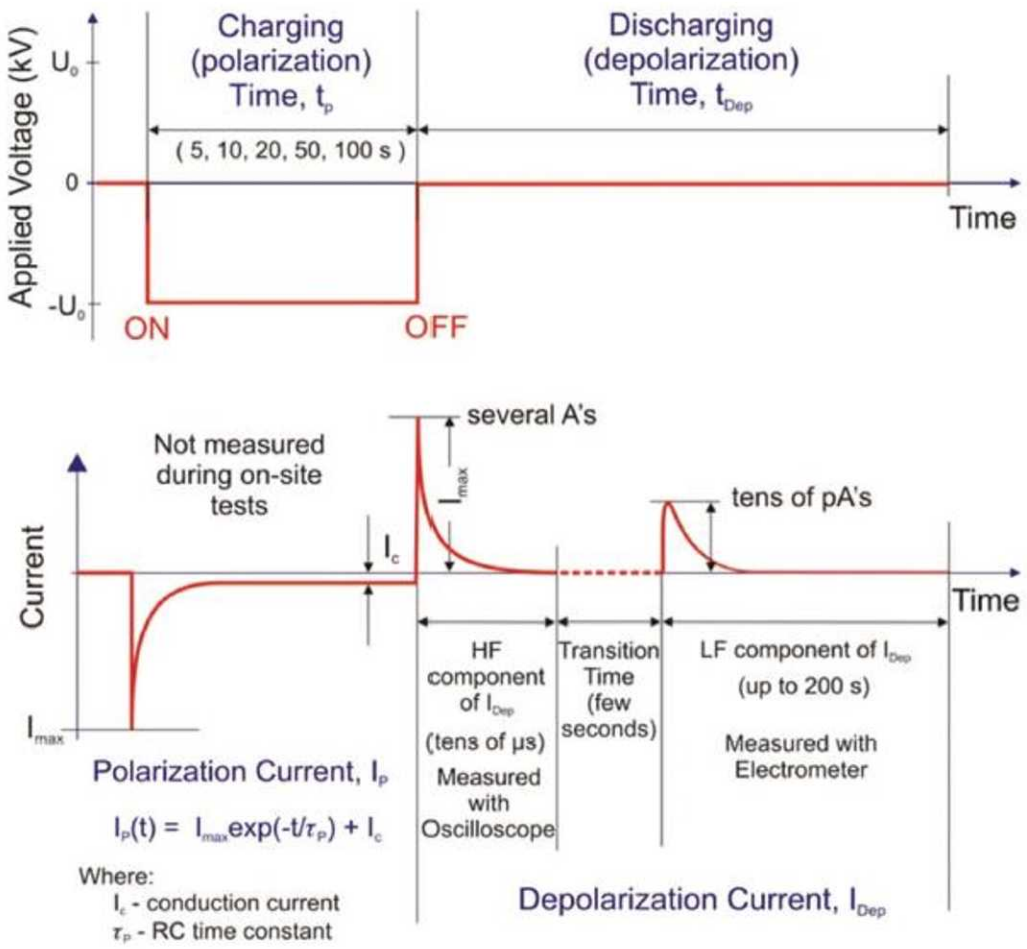


Figure 2 – Principle of the Polarization/Depolarization Current Measurement [2]

Development of a Diagnostic Indicator Q_{Dep}

The Measurement Science and Standards group at National Research Council Canada (NRC) developed a non-destructive method to detect the effect that water trees have on XLPE cables, and the resulting diagnostic criteria for obtaining the insulation condition. This Q_{Dep} parameter is based on the change in the depolarization current waveform of the aged cable under test relative to that of an unaged cable and can be used determine the health of the cable. Based on laboratory research, Q_{Dep} values are linked to length and density of water trees found within the cable's insulation (see Figure 3) [2].

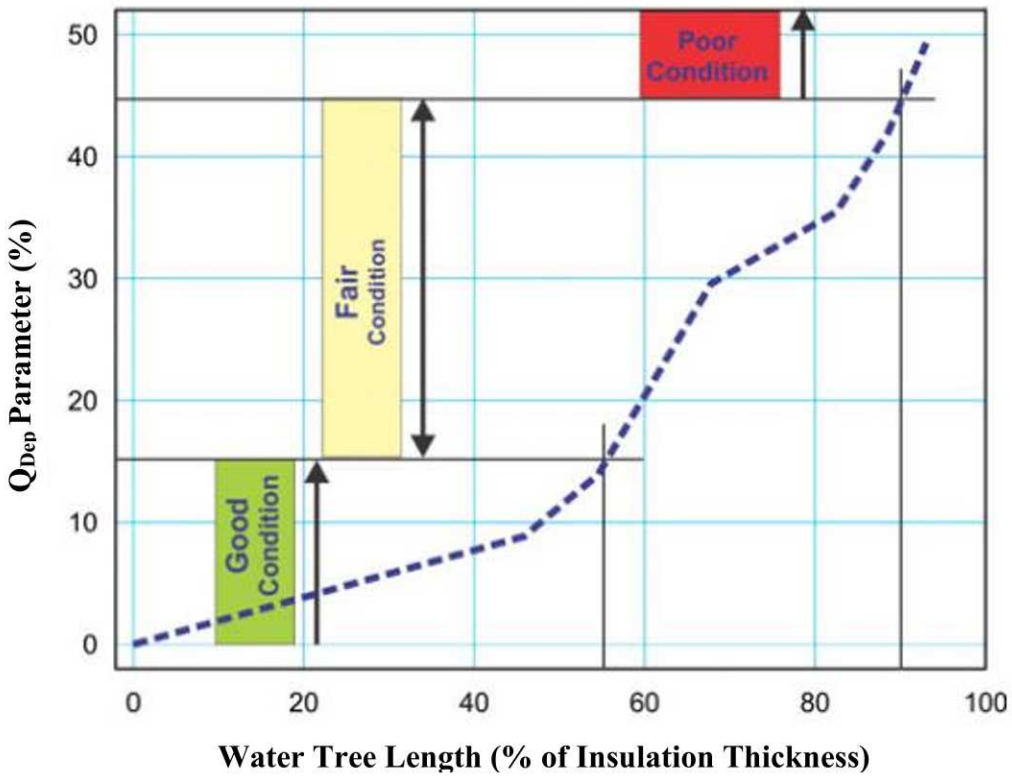


Figure 3 - The Length of Water Tree in XLPE Material as it Correlates to %Q_{Dep} [2]

Figure 4 shows the results of an accelerated aging experiment performed on three laboratory aged XLPE cables by NRC to determine the change in Q_{Dep} with aging time. Three miniature cables were aged in a 0.1 M NaCl solution at a 6 kV, 60 Hz voltage. Previous laboratory studies determined that higher values of Q_{Dep} indicate a larger amount of water treeing within the insulation. In this case, one of the miniature cables failed after 30,500 hours however after further investigation, the failure was found to be due to a faulty termination and Q_{Dep} was only 20%. It was found that high probability of insulation breakdown takes place when Q_{Dep} reaches approximately 40%, indicating that failures are likely to not occur due to insulation breakdown until the Q_{Dep} >40% [2].

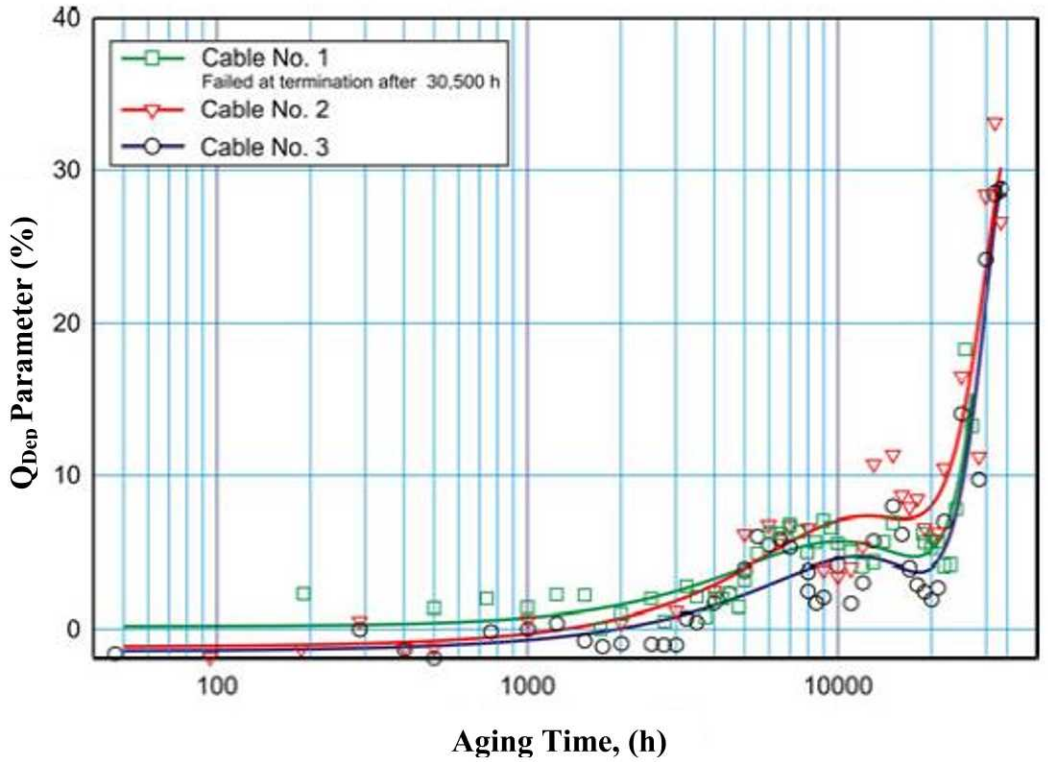


Figure 4 – Parameter Q_{Dep} Vs Time of Aging for the Miniature Cables [2]

The diagnostic criteria developed by the NRC based on their extensive research and development of this testing method can be found in Table 1. NRC proposed limits for $\%Q_{Dep}$ parameters are for XLPE and TR-XLPE insulation materials. It is observed in Table 1 that $\%Q_{Dep}$ for TR-XLPE is 4-5% higher than for XLPE material, since TR-XLPE contains tree retardants that can delay the growth of water trees.

Table 1 – Limits of the $\%Q_{Dep}$ Parameter for Various Cable Insulation Conditions

Cable Insulation Condition	Diagnostic Parameter Value	
	XLPE Insulation	TR-XLPE Insulation
Good	$\%Q_{Dep} < 15$	$\%Q_{Dep} < 20$
Fair	$15 \leq \%Q_{Dep} < 43$	$20 \leq \%Q_{Dep} < 47$
Poor	$\%Q_{Dep} \geq 43$	$\%Q_{Dep} \geq 47$

Asset management decisions can be taken with respect to the diagnosis determined as the following:

Good Condition: Failure probability due to water treeing is low but could increase and result in insulation failure if voltage transients due to switching operation or lightening surges are not properly controlled. Cable could be repaired and returned to service after failure. If cable failure occurs, it could be due to other causes such as local defects, mechanical damage or termination failure. Cable should be repaired and returned to service.

Fair Condition: Failure probability due to water treeing is moderate and could increase and result in insulation failure if voltage transients due to switching operation or lightening surges are not properly controlled. Cable could be repaired and returned to service after failure. However, the cable should be re-tested every 3 to 5 years to keep track of the on-going water tree deterioration.

Poor Condition: Failure probability due to water treeing is high and any repair to the cable would be short lived. The cables in this category should be scheduled for early replacement.

Condition Assessment of the Tested Cables

Fifty aged cables in Kitchener Wilmot Hydro's distribution network were tested with the NRC Polarization/Depolarization Current Measurement method. The cables have an estimated installation year ranging from the 1971 to 1997. All of the cables that were tested are XLPE insulated. The cables that were tested are all jacketed and direct buried except for the station cables which are in-duct. The determined value of $\%Q_{Dep}$ can be compared to the diagnostic criteria found in Table 1 that have been developed by the NRC based on their extensive research and development of this testing method. The tested cables were assessed accordingly as shown in Table 2 and illustrated in Figures 5 through 8.

Table 2 – Summary of Calculated 2018 Cable Testing Results for Kitchener Wilmot Hydro

Cable No.	Device 1	Device 2	Area	Phase	System Voltage (kV)	Record Cable Length (m)	TDR Length (m)	Cable Voltage Rating (kV)	Cond. Size	Cond. Material	Insulation Type (XLPE or TR-XLPE)	Insulation Thickness (100% or 133%)	Jacket (Y/N)	Estimated Year of Install	Civil Install.	$\%Q_{Dep}$	Diagnostic Test Result
1	LBEM6992	LBD939	Country Hills	R	13.8	70	61	15	#1	Cu	XLPE	100%	Y	1978	Direct buried	24	Fair
2	LBEM 8543	LBEM1084	Country Hills	R	13.8	75	77	15	#1	Cu	XLPE	100%	Y	1978	Direct buried	23	Fair
3	LBEM1051	LBEM1059	Country Hills	R	13.8	103	105	15	#1	Cu	XLPE	100%	Y	1978	Direct buried	19	Fair
4	LBEM1024	LBEM1063	Country Hills	R	13.8	N/A	110	15	#1	Cu	XLPE	100%	Y	1978	Direct buried	19	Fair
5	LBEM1021	LBEM1050	Country Hills	R	13.8	150	147	15	#1	Cu	XLPE	100%	Y	1978	Direct buried	19	Fair
6	LBEM1070	LBEM1027	Country Hills	R	13.8	128	130	15	#1	Cu	XLPE	100%	Y	1978	Direct buried	19	Fair
7	LBEM1058	LBEM1042	Country Hills	R	13.8	115	111	15	#1	Cu	XLPE	100%	Y	1978	Direct buried	18	Fair
8	LBEM799	LBEM1066	Country Hills	R	13.8	172	169	15	#1	Cu	XLPE	100%	Y	1978	Direct buried	16	Fair
9	LBEM1062	LBEM1023	Country Hills	R	13.8	63	73	15	#1	Cu	XLPE	100%	Y	1978	Direct buried	19	Fair
10	LBEM1023	LBEM750	Country Hills	R	13.8	103	105	15	#1	Cu	XLPE	100%	Y	1978	Direct buried	22	Fair
11	LBEM772	LBEM767	Country Hills	R	13.8	147	149	15	#1	Cu	XLPE	100%	Y	1978	Direct buried	21	Fair
12	LBEM761	LBEM757	Country Hills	R	13.8	115	120	15	#1	Cu	XLPE	100%	Y	1978	Direct buried	22	Fair
13	LBEM724	LBEM811	Country Hills	R	13.8	140	144	15	#1	Cu	XLPE	100%	Y	1978	Direct buried	20	Fair
14	LBEM713	LBD2880	Country Hills	R	13.8	90	49	15	#1	Cu	XLPE	100%	Y	1978	Direct buried	19	Fair
15	LBEM92	LBD2076	Westheights	Y	13.8	620	537	15	#1	Cu	XLPE	100%	Y	1987	Direct buried	21	Fair
16	LBEM97	LBEM99	Westheights	Y	13.8	80	196	15	#1	Cu	XLPE	100%	Y	1987	Direct buried	20	Fair
17	LBEM98	LBEM40	Westheights	Y	13.8	197	140	15	#1	Cu	XLPE	100%	Y	1987	Direct buried	19	Fair

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18	LBEM107	LBEM93	Westheights	Y	13.8	138	85	15	#1	Cu	XLPE	100%	Y	1987	Direct buried	19	Fair
19	LBEM96	LBEM125	Westheights	Y	13.8	312	295	15	#1	Cu	XLPE	100%	Y	1987	Direct buried	21	Fair
20	LBEM112	LBEM57	Westheights	Y	13.8	186	181	15	#1	Cu	XLPE	100%	Y	1987	Direct buried	18	Fair
21	5M13 - B - R	LBD2059-R	5 TS - Graber Place	R	13.8	430	440	15	600MCM	Cu	XLPE	100%	Y	1997	In duct	5	Good
22	5M13 - B - W	LBD2059-W	5 TS - Graber Place	W	13.8	430	440	15	600MCM	Cu	XLPE	100%	Y	1997	In duct	7	Good
23	5M13 - B - B	LBD2059-B	5 TS - Graber Place	B	13.8	430	440	15	600MCM	Cu	XLPE	100%	Y	1997	In duct	8	Good
24	5M11 - B - R	LBD317-R	5 TS - Graber Place	R	13.8	260	260	15	600MCM	Cu	XLPE	100%	Y	1984	In duct	6	Good
25	5M11 - B - W	LBD317-W	5 TS - Graber Place	W	13.8	260	260	15	600MCM	Cu	XLPE	100%	Y	1984	In duct	9	Good
26	5M11 - B - B	LBD317-B	5 TS - Graber Place	B	13.8	260	260	15	600MCM	Cu	XLPE	100%	Y	1984	In duct	8	Good
27	5M14 - R	LBD575 - R	5 TS - Graber Place	R	13.8	*1700	260	15	600MCM	Cu	XLPE	100%	Y	1984	In duct	10	Good
28	5M14 - W	LBD575 - W	5 TS - Graber Place	W	13.8	*1700	260	15	600MCM	Cu	XLPE	100%	Y	1984	In duct	9	Good
29	5M14 - B	LBD575 - B	5 TS - Graber Place	B	13.8	*1700	260	15	600MCM	Cu	XLPE	100%	Y	1984	In duct	9	Good
30	4M13-R	LBD54-R	4TS - Victoria Street	R	13.8	525	**450	15	600MCM	Cu	XLPE	100%	Y	1971	In duct	3	Good
31	4M13-W	LBD54-W	4TS - Victoria Street	W	13.8	525	**450	15	600MCM	Cu	XLPE	100%	Y	1971	In duct	3	Good
32	4M13-B	LBD54-B	4TS - Victoria Street	B	13.8	525	**450	15	600MCM	Cu	XLPE	100%	Y	1971	In duct	4	Good
33	4M16-R	LBD1151-R	4TS - Victoria Street	R	13.8	550	**470	15	600MCM	Cu	XLPE	100%	Y	1971	In duct	2	Good
34	4M16-W	LBD1151-W	4TS - Victoria Street	W	13.8	550	**470	15	600MCM	Cu	XLPE	100%	Y	1971	In duct	4	Good

CABLEQ NON-DESTRUCTIVE TESTING Proprietary and Confidential Information

35	4M16-B	LBD1151-B	4TS - Victoria Street	B	13.8	550	**470	15	600MCM	Cu	XLPE	100%	Y	1971	In duct	4	Good
36	4M14-R	LBD55-R	4TS - Victoria Street	R	13.8	320	270	15	600MCM	Cu	XLPE	100%	Y	1971	In duct	9	Good
37	4M14-W	LBD55-W	4TS - Victoria Street	W	13.8	320	270	15	600MCM	Cu	XLPE	100%	Y	1971	In duct	8	Good
38	4M14-B	LBD55-B	4TS - Victoria Street	B	13.8	320	270	15	600MCM	Cu	XLPE	100%	Y	1971	In duct	9	Good
39	4M11-R	LBD3422-R	4TS - Victoria Street	R	13.8	220	210	15	600MCM	Cu	XLPE	100%	Y	1971	In duct	16	Fair
40	4M11-W	LBD3422-W	4TS - Victoria Street	W	13.8	220	210	15	600MCM	Cu	XLPE	100%	Y	1971	In duct	13	Good
41	4M11-B	LBD3422-B	4TS - Victoria Street	B	13.8	220	210	15	600MCM	Cu	XLPE	100%	Y	1971	In duct	13	Good
42	4M21-R	LBD2153-R	4TS - Victoria Street	R	13.8	725	640	15	600MCM	Cu	XLPE	100%	Y	1971	In duct	10	Good
43	4M21-W	LBD2153-W	4TS - Victoria Street	W	13.8	725	640	15	600MCM	Cu	XLPE	100%	Y	1971	In duct	8	Good
44	4M21-B	LBD2153-B	4TS - Victoria Street	B	13.8	725	640	15	600MCM	Cu	XLPE	100%	Y	1971	In duct	12	Good
45	4M12-R	LBD3025-R	4TS - Victoria Street	R	13.8	305	230	15	600MCM	Cu	XLPE	100%	Y	1971	In duct	11	Good
46	4M12-W	LBD3025-W	4TS - Victoria Street	W	13.8	305	230	15	600MCM	Cu	XLPE	100%	Y	1971	In duct	11	Good
47	4M12-B	LBD3025-B	4TS - Victoria Street	B	13.8	305	230	15	600MCM	Cu	XLPE	100%	Y	1971	In duct	11	Good
48	4M24-R	LBD3297-R	4TS - Victoria Street	R	13.8	***730	730	15	600MCM	Cu	XLPE	100%	Y	1971	In duct	4	Good
49	4M24-W	LBD3297-W	4TS - Victoria Street	W	13.8	***730	730	15	600MCM	Cu	XLPE	100%	Y	1971	In duct	4	Good
50	4M24-B	LBD3297-B	4TS - Victoria Street	B	13.8	***730	730	15	600MCM	Cu	XLPE	100%	Y	1971	In duct	5	Good

**The length of this cable was determined during the 2017 testing. The induction on the cable would not permit the use of the TDR to verify the length in 2018.*

***The length of the cable was determined through verification with physical maps as the induction on the cable would not permit the use of the TDR to verify the length.*

**** The induction on the cable would not permit the use of the TDR to verify the length of the cable therefore the record length was used to determine the condition.*

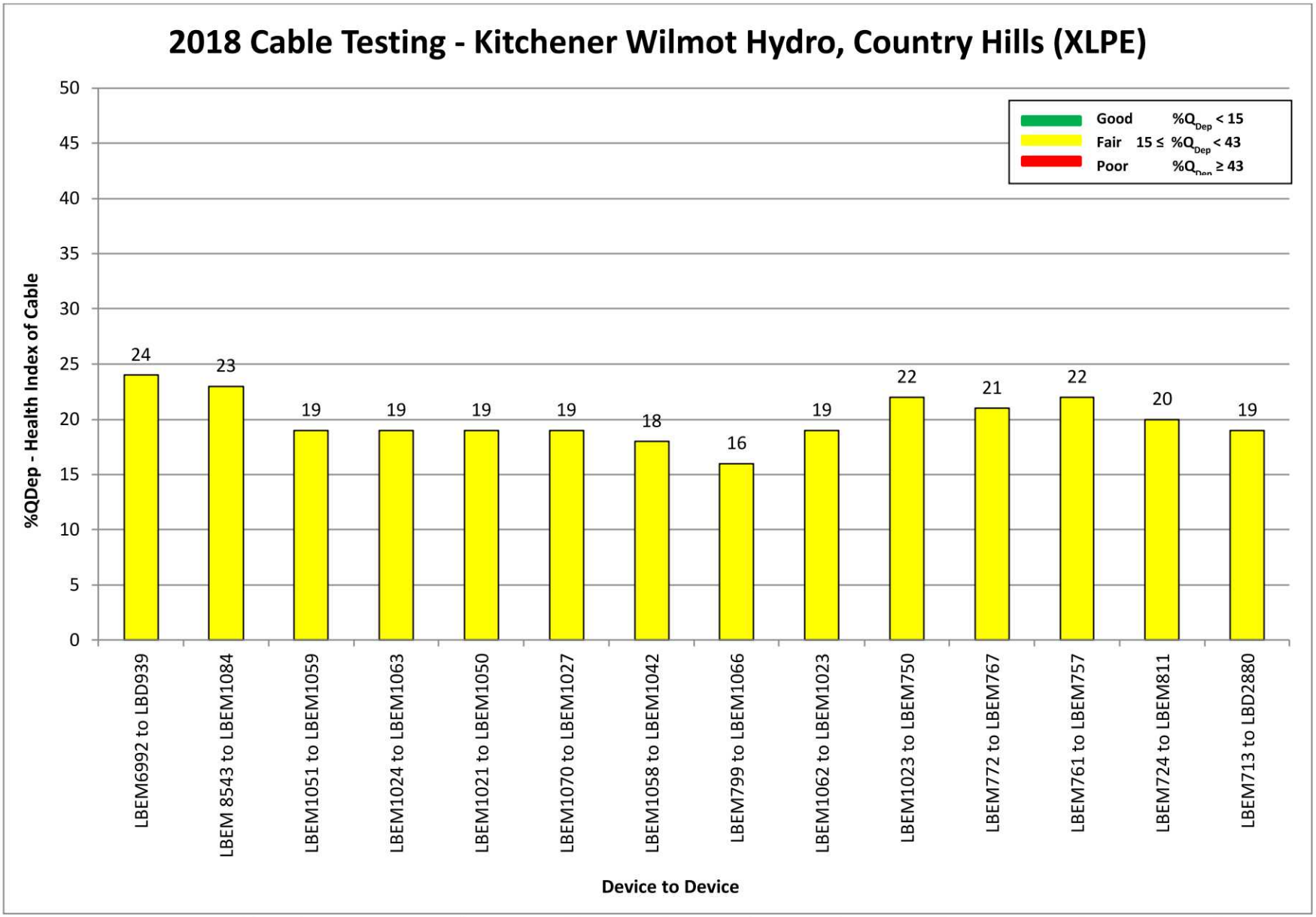


Figure 5 – Health Index Assessment of XLPE Cable in Kitchener Wilmot Hydro's Distribution Network, Country Hills

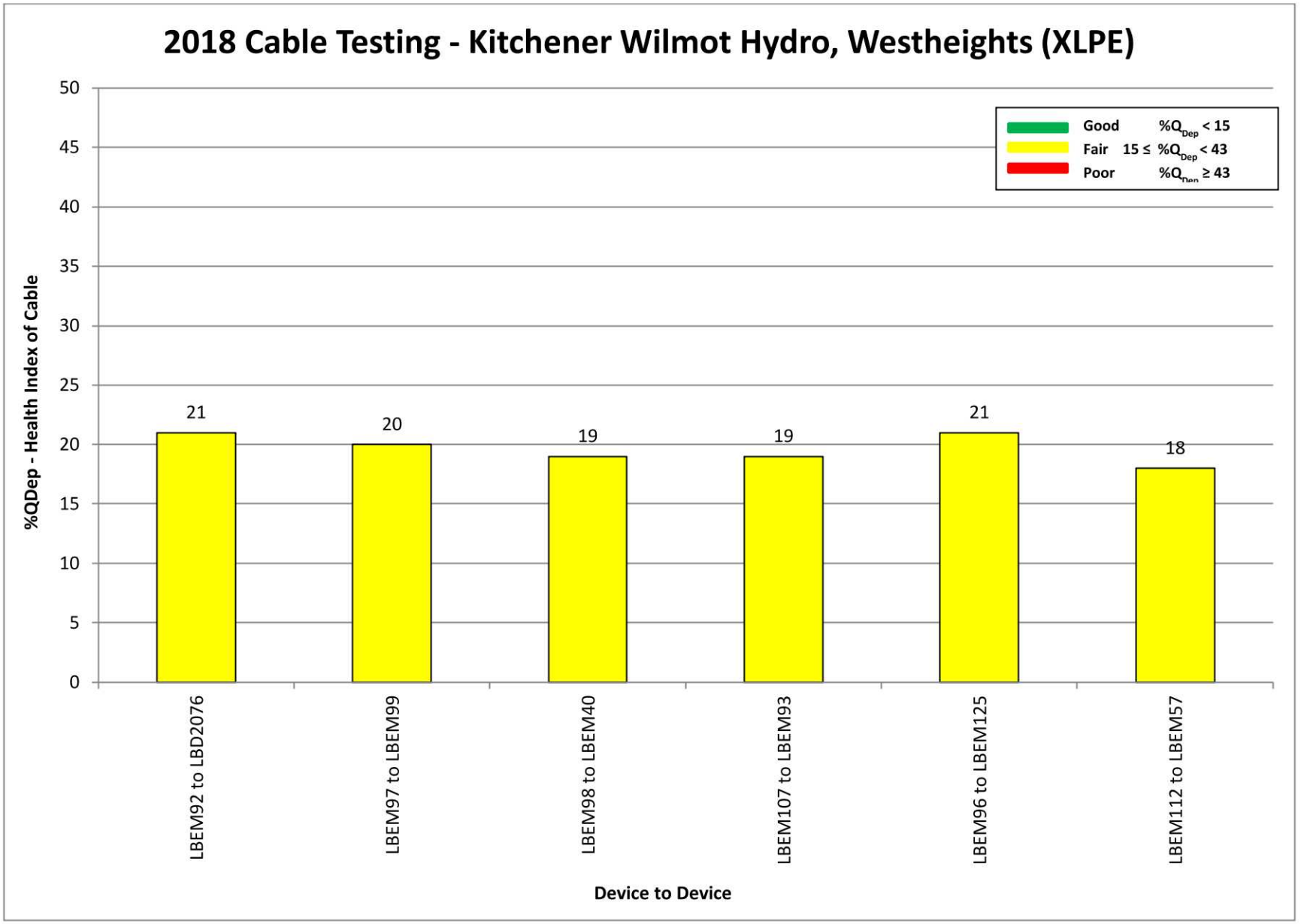


Figure 6 – Health Index Assessment of XLPE Cable in Kitchener Wilmot Hydro's Distribution Network, Westheights

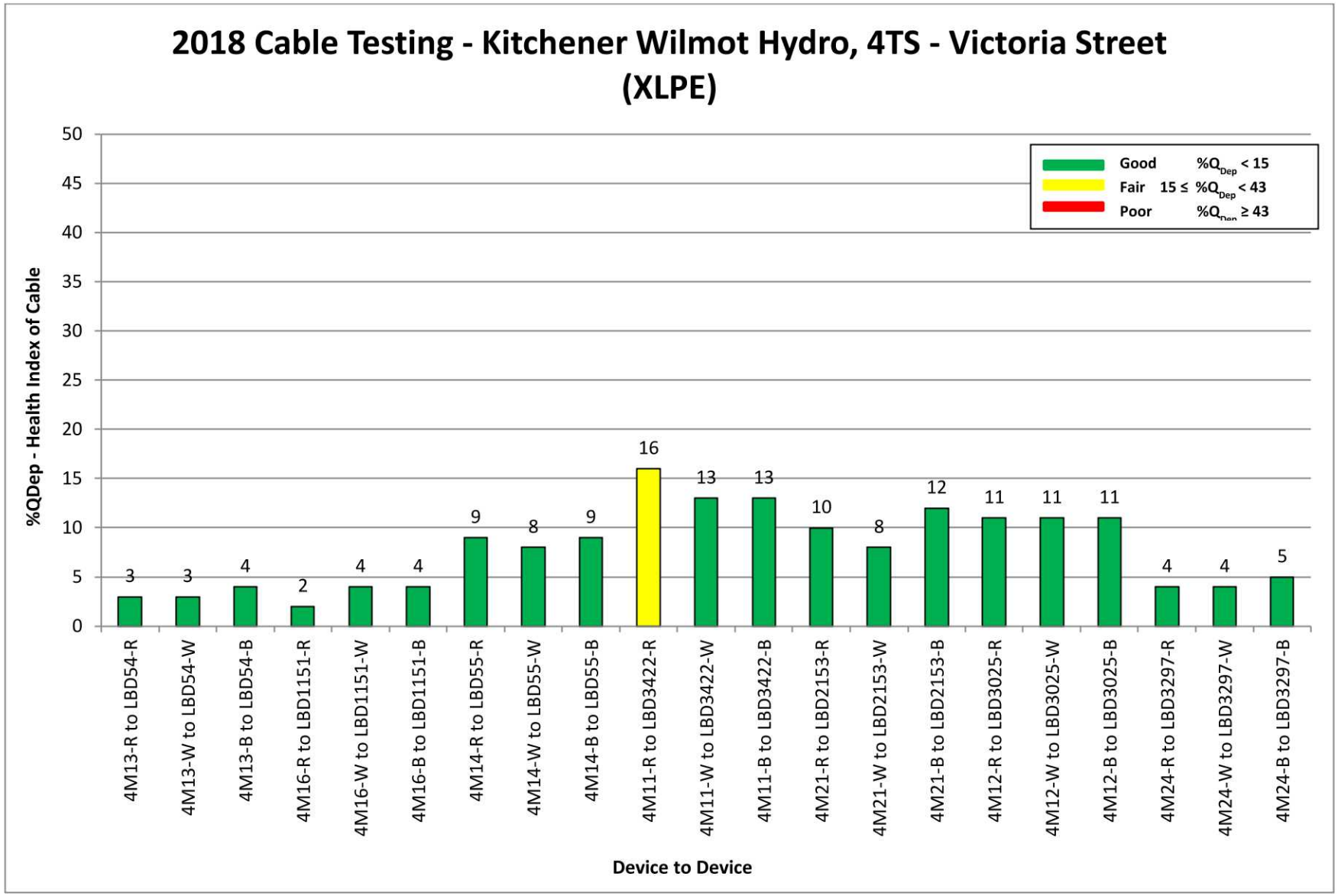


Figure 7 – Health Index Assessment of XLPE Cable in Kitchener Wilmot Hydro's Distribution Network, 4TS – Victoria Street

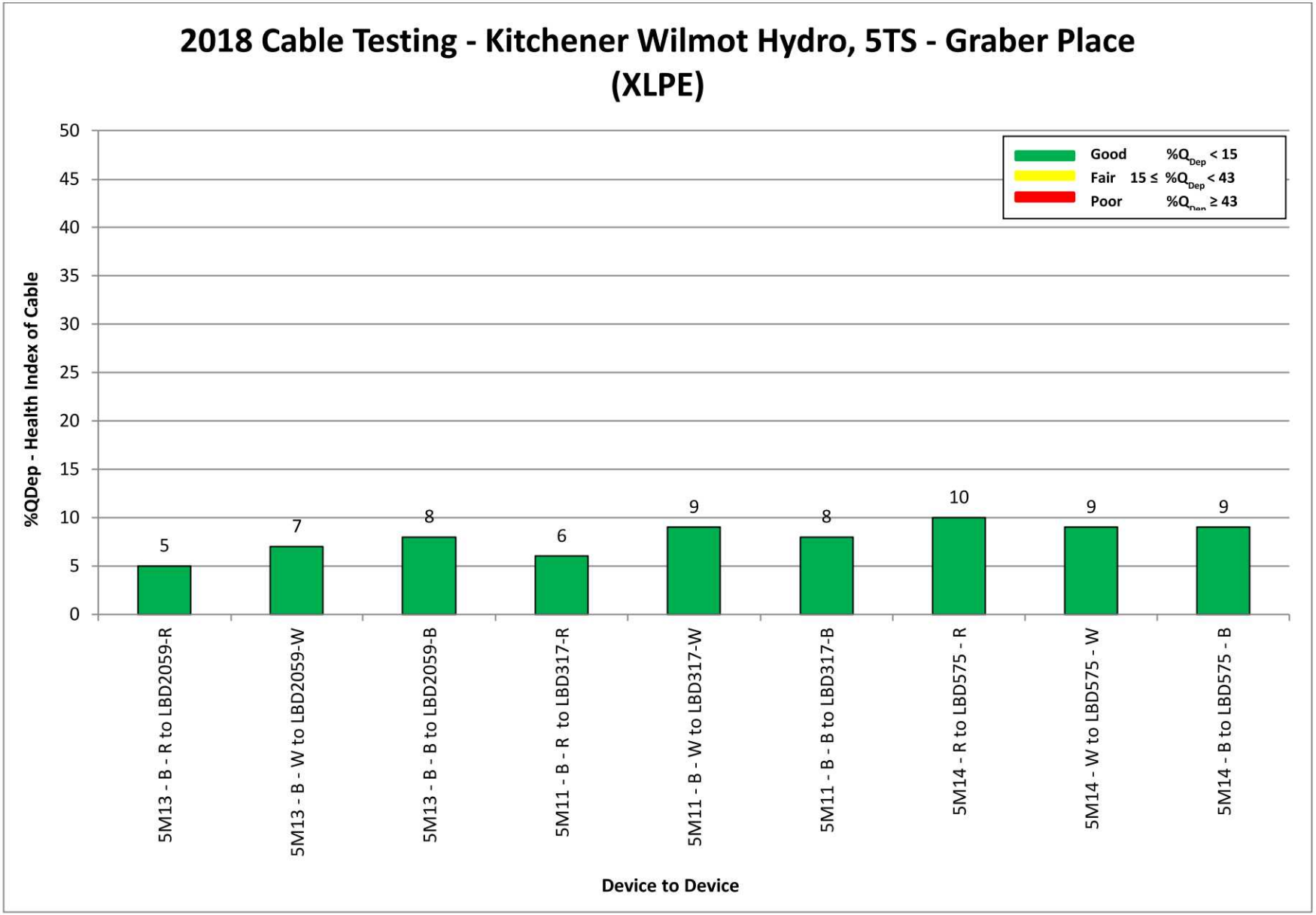


Figure 8 – Health Index Assessment of XLPE Cable in Kitchener Wilmot Hydro's Distribution Network, 5TS – Graber Place

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The results in Table 2 show that twenty-nine (29) cable segments were found to be in Good condition, and twenty-one (21) in Fair condition based on NRC's Polarization/Depolarization Current Measurement method, giving 58% of the cables tested in Good condition and 42% in Fair condition.

The testing results indicate that there is not always a direct correlation between cable age and its insulation condition as the tested cables have a range of estimated age from 21 to 47 years. The assessed cable conditions will allow the asset manager to prioritize wisely and use capital and operational budgets on cable replacement or rejuvenation activities, rather than just solely depending on the nominal age of the cable.

Conclusions and Recommendations

Twenty-nine cables tested in Kitchener Wilmot Hydro's distribution network were found in Good condition and twenty-one in Fair condition. Accordingly, the following general recommendations can be made;

Good Condition: Failure probability due to water treeing is low but could increase and result in insulation failure if voltage transients due to switching operation or lightening surges are not properly controlled. Cable could be repaired and returned to service after failure. If cable failure occurs, it could be due to other causes such as local defects, mechanical damage or termination failure. Cable should be repaired and returned to service.

Fair Condition: Failure probability due to water treeing is moderate and could increase and result in insulation failure if voltage transients due to switching operation or lightening surges are not properly controlled. Cable could be repaired and returned to service after failure. However, the cable should be re-tested every 3 to 5 years to keep track of the on-going water tree deterioration.

References

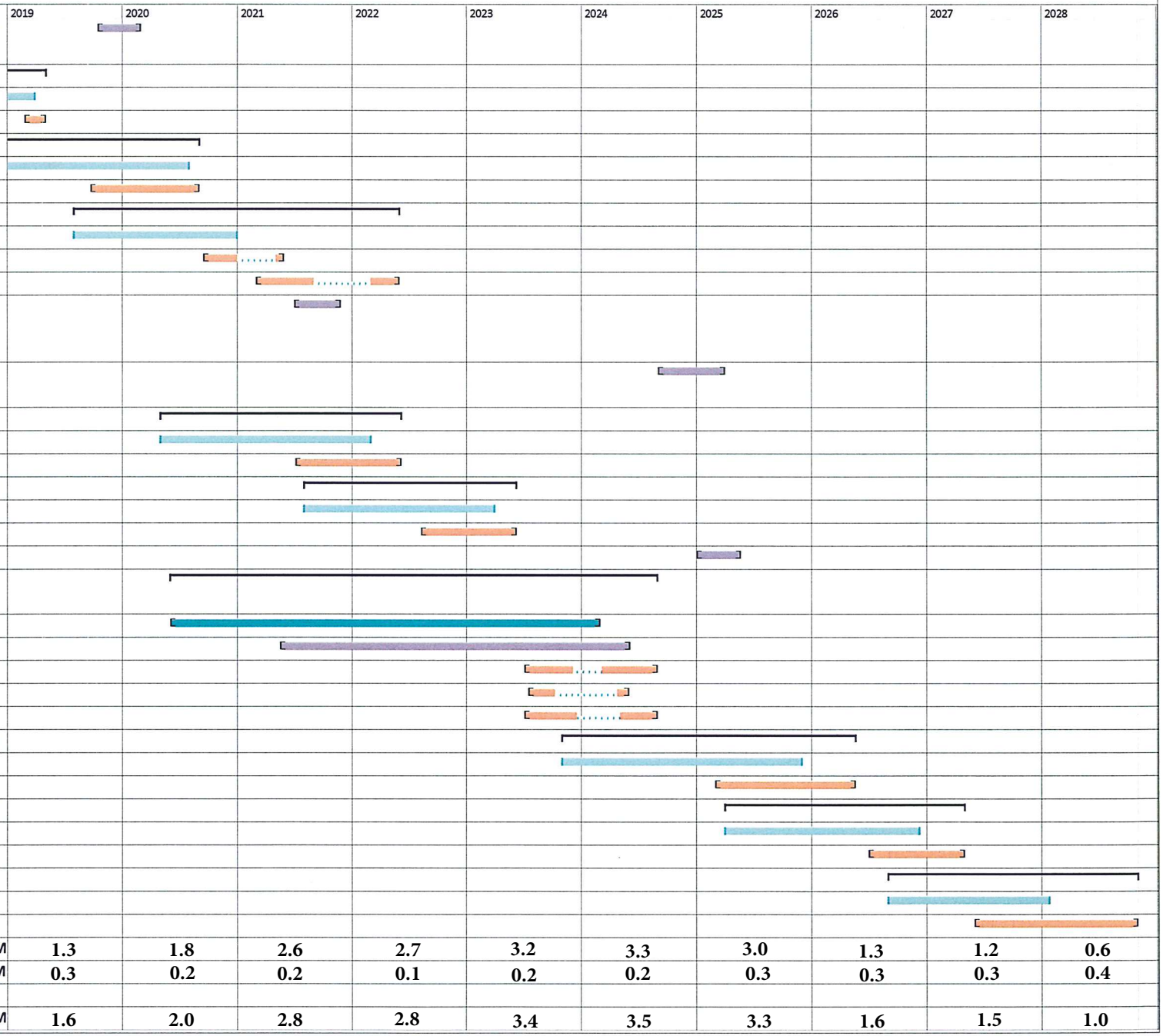
[1] N. Hampton, “Chapter 2: Medium Voltage Cable System Issues,” National Electric Energy Testing, Research and Applications Centre (NEETRAC), Georgia Tech Research Corporation, Atlanta, GA, February 2016, pp. 5-6.

[2] M. Abou-Dakka, A. Bulinsky and S.S. Bamji, “On-Site Diagnostics of Medium-Voltage Underground Cross-Linked Polyethylene Cables,” IEEE Electrical Insulation Magazine, vol. 27, No. 4, July/August 2011, pp. 35-38.

Appendix O:
10-Year Transformer & Distribution Station Renewal Plan

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Transformation Facilities' Major Equipment 10 Year Plan
2019-2028



ID	Task Name	Est Cost	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
1	#5TS - Install Arc Resistance on Switchgear & Replace 3 SF6	$1.4M										
2	**#3TS - No.1 Bus P&C Replacement**	$0.3M										
3	Engineering											
4	Rewire & Test P&C Panels											
5	**#6TS - P&C Replacement**	$1.2M										
6	Engineering											
7	Rewire & Test P&C Panels											
8	**#4TS - HV Equipment Replacemen**	$1.3M										
9	Engineering											
10	Install Circuit Switchers & founda											
11	Install Acoustic Enclosures											
12	#3TS - Install Switchgear Arc Resistance and Replace 14 SF6 Breakers at 3TS & 6TS	$1.2M										
13	#6TS - Install Switchgear Arc Resistance	$1.2M										
14	**#7TS - P&C Replacement**	$1.2M										
15	Engineering											
16	Rewire & Test P&C Panels											
17	**#1TS - P&C Replacement**	$1.2M										
18	Engineering											
19	Rewire & Test P&C Panels											
20	#7TS - Replace 13 SF6 Breakers	$0.7M										
21	**#5TS - Replace Power Transformers & Oil Retention Pits**	$6.4M										
22	Engineering											
23	Manufacture Transformers											
24	Install P&C Changes											
25	Install Oil Retention Pits											
26	Install Transformers											
27	**#3TS - P&C Replacement**	$2.0M										
28	Engineering											
29	Rewire & Test P&C Panels											
30	**#8TS - P&C Replacement**	$1.2M										
31	Engineering											
32	Rewire & Test P&C Panels											
33	**#4TS - P&C Replacement**											
34	Engineering	$1.6M										
35	Rewire & Test P&C Panels											
36	**TOTALS FOR MAJOR EQUIPMENT**	$21.0M	1.3	1.8	2.6	2.7	3.2	3.3	3.0	1.3	1.2	0.6
37	**Miscellaneous Small Projects**	$2.5M	0.3	0.2	0.2	0.1	0.2	0.2	0.3	0.3	0.3	0.4
38												
39	TOTALS	$23.5M	1.6	2.0	2.8	2.8	3.4	3.5	3.3	1.6	1.5	1.0

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Appendix P:
CIS Replacement Business Case

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CUSTOMER INFORMATION SYSTEM REPLACEMENT

Business Case Update

Confidential – for internal use only

April 2019

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Background on Existing CIS

For additional information covering all the details on the need for a new Customer Information System (CIS), see the full business case issued in late 2016, *CIS Replacement Business Case – KWHI_Final.docx.* Relevant quotes from that document are included in this section.

The CIS at Kitchener-Wilmot Hydro Inc. (KWHI) is the key enabler of its customer service capabilities. This strategic asset collects and stores its customer account information. It supports the integrated delivery of its customer care and revenue cycle processes, including meter reading, producing customers' bills and collecting revenues. It also supports consumer program development and delivery processes. KWHI's current system was built in-house, is highly customized, is 30+ years old and has become obsolete with regards to meeting current demands and requirements. Current industry trends and one of KWHI's Information Technology strategies support buying technology solutions as opposed to building internal systems. This is especially true in the case of enterprise applications such as CIS.

It is recommended that the current legacy CIS be replaced as soon as possible. The two main reasons for this change are operational necessity and strategic positioning to serve the growing demands of KWHI's customer base.

Current Situation

KWHI's existing CIS has served the organization well. Its origins date back over 30+ years and the technology platform has not changed. Over one million lines of code exist, most of which are written in COBOL, a programming language designed and standardized in the 1960s. Its use today is typically only one of maintenance of existing applications. Given the migration away from this language, the problem of KWHI's aging IT workforce is highlighted. KWHI has already experienced two significant retirements and it will continue to be challenged to recruit technology talent that not only has COBOL expertise but wants to continue to work with such an outdated tool set.

From a timing perspective, it is becoming more urgent that KWHI seek a replacement as the existing IT staff hold a tremendous collective knowledge of the business logic contained in the system. To move to a new solution, KWHI needs to have this staff involved before it sees further retirements.

The current system has adapted and expanded over the years to accommodate new requirements, including the challenge of the opening of a competitive electricity market in 2002. However the design of the system coupled with the verbosity of the underlying technology combine to limit the flexibility it has to enhance the system to KWHI's changing business needs. KWHI's customers' expectations are becoming increasingly demanding as cost pressures force them to focus attention on their consumption. The current CIS requires a number of manual workarounds to provide basic information to customers and lacks the capability of providing reports to support proactive real time decision making. Technology is readily available in KWHI's customers' hands and if it cannot supply them the desired information in a timely manner the opportunity exists for a third party to fill this role at the expense of KWHI. KWHI requires a system that can support the dynamics of an increasingly tech savvy consumer population.

The other major opportunity that exists in evaluating alternatives against the current CIS is in the area of reporting and data analytics. Both internal and external customers suffer today because the existing data

is difficult to access for use in analytics. A new system would supply understandable and flexible data with complete integrity and a high rate of availability due to a more integrated solution.

Risk of not undertaking the project

Legacy CIS systems were not built to handle the significant market and business disruptions that have transformed utility operations and customer engagements throughout the last few years; and at a very high level, lack of flexibility is to blame. If KWHI decided not to undertake a CIS replacement project, it would be subjecting itself to the following risks:

- Loss of knowledge and business logic, due to retiring workforce supporting legacy systems;
- Difficulty in hiring IT personnel, higher user/IT training costs and escalating support costs;
- Growing backlog of system change requests and an inability to extend systems without significant effort and/or redesign;
- Difficulty accommodating new rate structures;
- Difficulty integrating newer, packaged systems for other corporate applications and OEB/Ministry reporting with the existing CIS;
- Limited analytics for management decisions;
- Limited real-time access to data;
- Dated and inefficient business processes due to technology limitations;
- No customer portal, no online chat and limited self-service thereby increasing LDC workload.

Additionally, older systems are particularly deficient when it comes to easily extracting data for the purposes of web-portals, mobility extensions, business intelligence (BI) and more sophisticated financial reporting associated with billing and credit and collections.

Situational Update

In late 2016, the business case referenced and quoted above outlines the urgent need for a CIS and was accepted by senior management. The 2016 business case made the recommendation to move ahead with replacing its current CIS as part of a consortium which included two other LDCs. All three LDCs were members of the GridSmartCity co-operative and all were committed to working together to issue a Request for Proposals (RFP) with the expressed purpose of getting the best CIS possible in an affordable manner. It was believed that the pooling of resources would help each member LDC get a better CIS while saving money on both capital and operating costs.

The CIS RFP was issued November 23, 2016 jointly by KWHI, Utilities Kingston and Burlington Hydro and sent to 15 vendors. Significant resources were expended by all three member LDCs to issue the RFP. The RFP included requirements for electricity and for natural gas and water as one of the LDCs had that requirement.

Sharing of costs was initially to be based on number of customers. KWHI's share was 44% with an estimated 91,000 customers.

Following the issuance of the RFP, a pre-proposal conference was held at KWHI's offices where vendors could ask questions of the CIS Implementation team. The proposal deadline date was set for February 17, 2017.

Eight (8) CIS proposals were received by the Consortium with a mix of Tier 1 and Tier 2 vendors. The CIS Implementation team, with the assistance of third party experts, evaluated each of the proposals using the methodology recommended by the third party. Following the proposal evaluations, the list of potential vendors was short-listed to four (4) vendors – three (3) Tier 1 vendors and one (1) Tier 2 vendor. Onsite demonstrations with each of the vendors were scheduled and held at KWHI's offices with the full CIS Implementation team and many other Consortium employees in attendance.

Following the demonstrations, the CIS Implementation team went on site visits and completed referencing. Best and final offers were received from each of the short-listed vendors. The implementation costs, excluding KWHI's internal labour costs, were in the range of $5.6M to $14.9M, while the annual operating costs range between $0.5M and $2.36M.

Based on the rating criteria, a Tier 1 vendor was selected by the CIS Implementation team. It was recognized at that time that the costs were particularly high for all of the Tier 1 vendors and Burlington Hydro exited the consortium in August 2017, leaving KWHI and Utilities Kingston in the consortium.

With the exit of Burlington Hydro from the consortium, the estimated costs for the remaining consortium members increased significantly compared to when the consortium members were three.

The consortium actively sought a new consortium member and was approached by another LDC in Ontario. Unfortunately, this fourth LDC was unable to establish a strong enough business case to satisfy its Board of Directors as a Tier 2 system had been installed within the past five years. Although the installed solution did not meet all of their business needs, the LDC could not justify a full implementation of a new CIS and so did not join the consortium.

The CIS consortium disbanded very shortly thereafter (April 2018) when there was a realization that the options were unaffordable to the remaining two consortium members.

The fact remained that KWHI still needed a new CIS with some urgency as one year had already passed since the RFP had been issued and a solution had not yet been selected. KWHI resumed its search for a new CIS on its own.

Alternatives

There were a few options available to KWHI for acquiring a CIS in an affordable manner. Possibilities explored were:

- Restart a consortium (try again)

  Restarting a consortium with different partners would have helped KWHI realize the benefits that led it to start the previous consortium in the first place, assuming the outcome was successful. KWHI did briefly look for new partners but since the CIS project was already delayed by a full year, it could not lose any more time looking for a new partner. Another retirement within its IT department had occurred during the past year (leaving only one employee with the requisite knowledge and skills

required to maintain the existing CIS) and the risk of continuing to rely on its aged CIS was continuing to grow. KWHI finally made the decision that waiting for more consortium partners was too big of a risk to its business.

- Use another utility's billing platform
  Similar to the objectives of the consortium, one option was to explore using another LDC's billing platform through an instance of their application and a shared multi-tenant database. This alternative was explored. While the capital costs were deemed to be competitive, operating fees of $1.7M annually were considered by KWHI to be too high to be borne by its customers. In addition, the capital costs were, in effect, costs for software that it would not even own. Additionally, should the LDC hosting the CIS solution decide to move to another billing system, KWHI would again be looking for a new CIS solution. KWHI's traditional business approach is to look for a long-term, stable solution rather than incurring additional costs to implement something new every few years and negatively impact customer bills.

- Reissue RFP on a go-alone basis

  KWHI contemplated reissuing the RFP; however, it was decided that reissuing the RFP itself would lead to additional delays and vendors would essentially be asked to respond to the same requirements as the original RFP.

- Ask vendors to resubmit proposals based on a go-alone basis

  Instead of fully reissuing the RFP, KWHI could simply ask selected vendors to resubmit proposals assuming that KWHI was now the sole customer and that the RFP requirements included electricity only (no natural gas or water). KWHI did so, scaling its requirements to a phased approach, emphasizing the need for cost control.

Phased Approach

KWHI recognized that its costs would increase since it was no longer a part of a consortium that could share the costs of the new CIS so in order to control costs and reduce bill impacts, the decision was made to scale back the base requirements of the RFP and build the core CIS first. This core CIS would be built upon later, adding the additional features that customers expect out of a good functional CIS such as the customer portal. Workforce management would also be added later.

Proposal Resubmissions

Over the year 2018, vendors resubmitted their proposals to KWHI. Due to affordability issues, some submitted both informal and formal bids over an extended period of time. KWHI continued to stress affordability of the CIS and reducing customer bill impacts. KWHI recognized that, since its existing CIS was a home grown option with very little cost, that all of the costs of its new CIS would be fully incremental to its customers.

Additionally, one new vendor approached KWHI expressing interest in submitting a proposal although they had not been included in the initial invitation for RFP responses. KWHI, having had a long working relationship with this vendor, included them as a possibility and accepted their proposal.

Note the numbers presented below are updated figures from the budgets included in the 2020 Cost of Service Application and were presented to our Board on March 22, 2019.

The following bids, inclusive of hardware and business travel expenses including internal labour were received:

KWHI CIS Options (On Prem)

Vendor	$$$ Millions			Monthly Impact (All Customers	Monthly Residential Impact
	Total One-Time Costs	Total Operating Cost	Incremental Revenue Requirement		
Vendor 1			0.79	0.80	0.45
Vendor 2			1.20	1.21	0.67
Vendor 3			1.39	1.40	0.78
Vendor 4			0.22	0.22	0.13
Vendor 5			0.91	0.92	0.51

Note that there is no correlation between the Vendor numbers in the above table and the original consortium CIS proposals.

Vendor 1 was the vendor with whom KWHI has had a long standing relationship related to other software. This vendor offered to help KWHI after hearing of the loss of the consortium and the risks that KWHI was facing with its current CIS. This offer included a Tier 1 solution. This vendor had never installed this particular software which brought significant risk to the project; however, it had a lot of project experience from leading other ERP software implementations over many years. This vendor has also recruited a number of experienced consultants who had experience with the exact same Tier 1 software being offered by the vendor.

Vendor 2 was the same software package being offered by Vendor 1 with only a different vendor making the offer. Vendor 2 had a lot of previous experience with implementing this software which Vendor 1 lacked. Vendor 2 also had its own team of experienced consultants to help with the implementation. The cost was significantly higher than Vendor 1. In fact, it was out of KWHI's price range. This same vendor also offered a cloud option. Although the initial capital cost was competitive, the annual operating cost (which impacts customer bills one for one) was much higher than the on premises option and was deemed unaffordable.

Vendor 3 was a well-known and reputable system integrator with many successes in its history. The capital cost was lower than both Vendor 2 and Vendor 3; however, the estimated operating costs were significantly higher than all of the other options. The software being offered was a different software than what was being offered by Vendors 1 through 3 and was not being widely used in the Ontario

electricity distribution space. This option would leave KWHI with few peers to share future costs with when the software was updated for regulatory and legal requirements. Further investigation showed that this software would require significant internal resources to maintain, increasing the annual operating costs to an unaffordable level.

Vendor 4 was a Tier 2 solution with one instance of its software successfully running in the LDC space in Ontario. The capital and operating costs were lower than all the other vendors. This was a software solution that the consortium did not short-list during the first go around because of its availability and maturity at the time. KWHI spent significant time investigating this solution having numerous meeting and two software demonstrations. One demonstration was held with some senior team members and the leads of the CIS Implementation team at the offices of the host LDC running the software. The second was held at KWHI's office with a team of fourteen (14) KWHI staff in attendance. The first demonstration went well but the second showed that the software was still essentially in development and it still had some shortcomings. In addition, KWHI had learned that this vendor had recently signed to implement the software at another LDC in Ontario. This created concerns that the vendor would not have sufficient resources to implement this solution at two LDCs concurrently.

Vendor 5 was a solution presented to KWHI after all of the initial proposals were complete. KWHI recognized that Vendor 1 was lacking in experience in the CIS implementation space but was an affordable Tier 1 solution. This created some significant risk for KWHI. Vendor 2 had the experience but was not an affordable solution. Both vendors also recognized this issue and worked together to propose a solution that was still affordable to KWHI but also removed a lot of the risk of Vendor 1 alone.

KWHI had scaled back some of its RFP requirements in order to make the proposed solutions affordable. The original consortium solution included requirements for a customer portal, and workforce management. KWHI recognized that, while these items will likely be required in the future for its operations, they could be re-evaluated and added later once the core CIS was operational.

Tier 1 versus Tier 2 Solution

From the beginning of the CIS selection process, inclusive of when the consortium was working together, decisions had to be made as to whether a Tier 1 or a Tier 2 solution should be implemented.

A Tier 1 solution would allow for greater integration of KWHI's operations as the system was developed and its modules expanded. Tier 1 solutions are also highly configurable and flexible. They are also more expensive.

A Tier 2 solution would be an effective billing system and less pricey than a Tier 1 solution but it has limited capabilities to meet future customer and business needs.

A Tier 1 solution was the preferred option for KWHI for a number of reasons:

- The electricity distribution industry continues to evolve, introducing complexities into billing customers that a Tier 2 solution is not designed to do. The regulatory requirements imposed on LDCs continue to grow. Examples of current and future complexities are but are not limited to:
    - Regulatory asset and liability rate riders
    - Virtual net metering

    - Future changes related to the Rate Design for C&I customers creating more rate classes and changes to billing determinants
    - Future changes related to the Staff Research Paper on the Examination of Alternative Price Designs for the Recovery of Global Adjustment Costs from Class B Consumers in Ontario which, in time, may create a menu of billing options for RPP customers
    - Changes resulting from Phase I and Phase II of the Customer Services Rules Review ongoing at the OEB
- Customer expectations for the level of service they require from their LDC continues to grow. The Tier 2 billing system cannot provide all that the customers expects. In order to provide these expanded expectations, KWHI would have to install and implement numerous applications from outside third parties, creating a patch quilt of software solutions. Not only would this require some significant maintenance from KWHI staff, it would open KWHI to issues with cyber security as it relied on more and more vendors for outside software.
- Customer Relationship Management (CRM) is built in allowing the utility to have a 360 degree real-time view of its customers at any time and be able to provide timely and updated information.
- Built-in analytics tool allows for accurate and timely decision making
- Flexibility, scalability, and ongoing investments in R&D keep the product current and allows for quick response to changing customer and regulatory needs.
- A successful Tier 1 install at KWHI would allow it to possibly host a Tier 1 solution for other smaller LDCs. KWHI is the biggest of the medium size LDC's at just under 100,000 customers. Smaller LDCs struggle with the same issues of complex billing requirements as the larger LDCs; however, Tier 1 systems are likely out of reach for them at this point. This reality makes it more difficult for the smaller LDCs to meet customer expectations as well. KWHI could help the smaller LDCs meet this challenge.
- KWHI has other Tier 1 solutions in house. For example; JD Edwards an Oracle ERP product and Intergraph GIS.

KWHI did spend significant time in its decision as to whether to implement a Tier 1 or Tier 2 solution. Essentially in the Ontario market space, there are two (2) Tier 2 solution options available to an LDC.

The first is used by many small LDCs in the province. It is; however, a very basic billing system and rather dated. The software vendor has not expended significant effort in updating the software, likely because there is no need to as its customers include a significant majority of Ontario LDCs. KWHI did consider this option but because of the growing complexities of the electricity industry and regulatory requirements, KWHI felt that it could not best service its customers with this Tier 2 solution. Additionally, KWHI was aware that there was another implementation being completed at another LDC in the province that would run concurrent with its own CIS install. This could create resourcing issues with the software vendor.

The second Tier 2 vendor in the province has only one instance of its software running at an LDC. This was Vendor 5 that submitted a proposal during KWHI's second software selection phase (going alone). During that phase of software selection, KWHI seriously considered using this software as a solution but concerns regarding the maturity of the software and the limited knowledge of the vendor made this solution unacceptable to KWHI.

Some pros and cons of Tier 2 Solutions:

- Less expensive basic billing system
- Lack of customer portal would require addition of third-party solution
- Lack of analytics and only basic reporting
    - Many LDCs with Tier 2 solutions have to subcontract with a third-party provider to get mandatory reporting requirements as the system does not have them built in
- Electricity billing is becoming more and more complex making it difficult for a basic billing system to accommodate. Examples of current complexities and future are but are not limited to:
    - Regulatory asset and liability rate riders
    - Virtual net metering
    - Future changes related to the Rate Design for C&I customers creating more rate classes and changes to billing determinants
    - Future changes related to the Staff Research Paper on the Examination of Alternative Price Designs for the Recovery of Global Adjustment Costs from Class B Consumers in Ontario which, in time, may create a menu of billing options for RPP customers
    - Changes resulting from Phase I and Phase II of the Customer Services Rules Review ongoing at the OEB

The Tier 2 solution may be an acceptable option in the short term but unlikely to suffice into the future as the electricity industry continues to evolve.

Finally, through its Customer Engagement process, KWHI learned that its residential customers would support a new core CIS installation at an estimated cost of $0.78 per customer per month. There was less support from residential customers for the enhanced version which would add an additional $0.46 per customer per month. The results of the Customer Engagement process reinforced the phased approach KWHI had decided on already – pacing and prioritizing. In considering the elements of a core CIS, it quickly became apparent that, in this day of high technology, that residential customers expect a basic system to include options such as customer portals and IVR (interactive voice response) capability. The inclusion of these items are now considered to be a minimum requirement. Since they are invisible, customers often don't recognize that these items do cost additional money to implement and are not inexpensive. In considering this, KWHI maintained its earlier decision that, although these "extras" do incur additional cost, they are within the minimum expectations of its customers. In order to make these options affordable, KWHI will move forward, adding the additional options in phases – Phase One would deliver the core CIS billing, settlement and customer relationship management system and Phase Two would add the additional items that it believes fall within the minimum requirements of its customers.

In addition, KWHI also learned that its business customers wanted more of a business/partnership-type relationship with KWHI. Their expectations of a CIS included advance knowledge of outages and business analytics. Tier 2 systems have limited analytics built in while Tier 1 systems had this as a built-in feature.

Given that that the Tier 2 software solutions were so limited in the Ontario market space and they did not provide solutions that would meet the expectations of KWHI's customers, KWHI made the decision that a Tier 1 solution was the right option for it going forward.

Recommendation

The recommended solution is Vendor 5 with an estimated labour and material capital cost of $6.8M, inclusive of all business expenses and a 15% contingency. Internal labour would add another estimated $1.0M to bring the final implementation cost to $7.8M. A next to firm cost estimate will be available, following the initial blueprinting phase of the project.

AITO Solutions Ltd. (AITO) and Oracle Consulting Services (OCS) have created a partnership to assist KWHI in the implementation of an Oracle Customer Care & Billing (CC&B) solution. This solution is an on-premises solution using the most up-to-date CC&B application in the Ontario electricity sector which will help KWHI in meeting the requirements of this ever-evolving distribution sector while meeting customer expectations.

Through numerous negotiations with AITO and OCS, KWHI was able to negotiate an affordable solution while also mitigating its project risks.

It is further recommended that this project begin in Q2 2019 with an expected completion date of Q4 2020. In order to keep bill impacts as low as possible, additional functionality such as the customer portal and workforce management will be added after the initial billing system is live.

The high level project scope below outlines the requirements areas that will be defined in order to implement a new CIS, and the interfaces required to other legacy systems. The CIS replacement project will focus on the areas listed below for Phase 1 of the project. A separate needs analysis, business case and budget will be prepared, for board approval, before proceeding with Phase 2 at a later date (post 2020).

The following items will be in scope for Phase I of the project:

Customer Information	Credit History
Account Information/Maintenance	Security Deposits
Customer Correspondence	Payment Functions
Account Balance	Payment Extensions
Account Adjustments	Collections Functions
Accounts Payable	Disconnection Functions
Moves / Transfers	Write-off Functions
Accounting	Premise Related Functions
Taxes, Rebates	Device Testing
Financial Balancing	Field Work Orders
Consumption Review/Display	Meter Inventory
Customer Consumption Analytics	Equipment Inventory
Meter Reading	Master Data Synchronization
Bill Management and Scheduling	Reporting – including OEB regulatory requirements
Contracts and Rates	Retailers EBT Spoke
Billing Periods	AMI - Interface
Calculating Charges	MDM/R (integration or replacement)
Programs and Billing Options	Finance Interface
Billing Adjustments	GIS Interface
Bill controls and Reporting	OMS Interface
Bill Production	My Account (integration)
Retail Settlement	Bill Presentment
Retail Electronic Business Transaction (EBT)	Billing for multiple business lines
OESP Interface	

Following the implementation of the Oracle CC&B CIS, KWHI will enter into a managed services agreement with AITO to support the application at an annual cost of $175k. This amount is included in the operating cost estimate in the tables above. KWHI will monitor these costs on an on-going basis to determine the most cost effective solution over the long term. No additional internal IT resources are planned in the short term.

Following go-live of the new CIS, KWHI expects to see the following benefits:

- Much lower risk of CIS failure as obsolete technology will be removed
- Improved business continuity - retirement of aging staff will no longer be a factor
- Better analytics through improved access to data and reporting
- Easier input of regulatory changes to billing and customer service rules
- Integration with other systems (such as JDE) will reduce redundant input and other duplications of effort
- Much improved user interface/ease of use for CSRs
- Improved ability for CSRs to provide meaningful information to customers
- Better tracking of customers in collections/bad debts
- Ability to contact customers through telephone calls/texts to inform/update outage data and ETRs (Phase Two)
- Customer portal allowing customer more self-service options (Phase Two)
- Field work order integration (Phase Two)

Risk Mitigation

The following table shows areas of risk that KWHI recognizes it is currently encountering with its current CIS situation as well as other risks that it will face during the CIS implementation and mitigations associated with those risks.

Risk	Mitigation
• One remaining programmer close to retirement	• Must maintain strict timelines to complete CIS project on time • Contract retired programmers to assist, if needed
• Significant customer service/CIS changes required from OEB regulation changes	• Contact OEB for leave of non-compliance until CIS project complete
• Limited resource pool for CIS implementation	• Backfill where needed (temporary employees)
• Project not moving/implementation issues	• Work with AITO/OCS to address - scheduled meetings
• End User Acceptance	• Implement a change management program and provide adequate training
• SI does not meet the program delivery obligations	• Establish a steering committee • Ensure SI has appropriate subject matter experts • Negotiate fix price contracts where possible • Have a well-defined project scope

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Appendix Q:
OEB Appendix 5-A
Unit cost metrics for capital expenditures and O&M per customer

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Appendix 5-A
Metrics

Metric Category	Metric	Measures	
		1 Year (2018)	5 Year Average
Cost	**Total Cost per Customer[1]**	**$ 331.65**	**$ 339.36**
	Total Cost per km of Line[2]	**$ 16,317.55**	**$ 16,501.95**
	Total Cost per MW[3]	**$ 86.63**	**$ 93.67**
CAPEX	**Total CAPEX per Customer**	**$ 209.68**	**$ 230.54**
	Total CAPEX per km of Line	**$ 10,316.24**	**$ 11,206.27**
O&M	**Total O&M per Customer**	**$ 121.98**	**$ 108.82**
	Total O&M per km of Line	**$ 6,001.31**	**$ 5,295.68**

Notes to the Table:

1 The Total Cost per Customer is the sum of a distributor's capital and O&M costs divided by the total number of customers that the distributor serves.
2 The Total Cost per km of Line is the sum of a distributor's capital and O&M costs divided by the total number of kilometers of line that the distributor
3 The Total Cost per MW is the sum of the distributor's capital and O&M costs divided by the total peak MW that the distributor serves.
4 The metrics cover the period 2014 - 2018.

Explanatory Notes on Adverse Deviations (complete only if applicable)

Metric Name: ***Total O&M per Customer***

2018 value exceeds the 5 year average by more than 10% because of the ramp in O&M cost following LRT relocations completion

Metric Name: ***Total O&M per km of Line***

2018 value exceeds the 5 year average by more than 10% because of the ramp in O&M cost following LRT relocations completion

Metric Name: