RATE BASE

RATE BASE OVERVIEW

The rate base underlying the revenue requirement sought in this Application has been determined on a basis consistent with the definition in the 2006 Electricity Distribution Rate ("EDR") Handbook as an average of the balances at the beginning and the end of each Test Year plus a Working Capital Allowance. The Working Capital Allowance is 12.7% of the sum of the cost of power and controllable expenses, which is based on Horizon Utilities' Lead/Lag Study (Tab 4, Appendix 2-3 of this Exhibit).

Horizon Utilities includes in net fixed assets those distribution assets that are associated with activities that enable the conveyance of electricity for distribution purposes. Smart Meter assets recorded in deferral account 1555 represent installations between 2012 and 2014, consistent with Horizon Utilities' Smart Meter Prudence Application (EB-2011-0417), and are included in fixed asset additions in 2015. Horizon Utilities' Smart Meter deployment continued into 2014 with a principal focus on the conversion of 'hard to reach' residential meters and commercial installations. Despite its efforts to install Smart Meters at all Time-of-Use ("TOU")-eligible locations, access restrictions and metering constraints have resulted in the necessity of a hard-to-reach Smart Meter strategy (Exhibit 9, Tab 7, Schedule 1). This Application includes a request for a prudence review of the remainder of Horizon Utilities' Smart Meter costs incurred from 2012-2014 (Exhibit 9, Tab 7, Schedule 1) in order to transfer such assets into rate base as of 2015. The treatment of Stranded Meters is discussed in detail in Tab 5, Schedule 1 of this Exhibit.

Horizon Utilities adopted International Financial Reporting Standards ("IFRS") effective January 1, 2012 and has prepared this Application in accordance with the requirements of the OEB for regulatory accounting, reporting, and filing. Such requirements include certain modified accounting treatments for regulated utilities reporting under IFRS as specified by the OEB in its *Report of the Board: Transition to International Financial Reporting Standards* dated July 28, 2009 ("IFRS Report"). Specifically, the OEB requires modified IFRS ("MIFRS") filings and reporting requirements for utilities that have adopted IFRS. Horizon Utilities has incorporated the MIFRS requirements specified in the IFRS Report within the accounting and reporting components of the Application.

For financial reporting purposes, the OEB requires distributors adopting IFRS to present one year of comparative information in its first IFRS financial statements. The comparative year for Horizon Utilities is 2011.

Horizon Utilities has provided its rate base calculations in Tables 2-1 and 2-2 below as follows: 2011 Board-Approved reported under Canadian Generally Accepted Accounting Principles ("CGAAP"); 2011 Actual (CGAAP); 2011 Actual restated to Modified International Financial Reporting Standards ("MIFRS"); 2012 Actual (MIFRS); 2013 Actual (MIFRS); 2014 Bridge Year (MIFRS); and 2015 – 2019 Test Years (MIFRS). Horizon Utilities has provided a comparison of 2011 CGAAP to 2011 MIFRS for Rate Base in Tab 1, Schedule 2, page 3 of this Exhibit.

Table 2-1 – Summary of Rate Base

Description	$	2011 Board-Approved	2011 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Bridge Year
Reporting Basis		*CGAAP*	*CGAAP*	*MIFRS*	*MIFRS*	*MIFRS*	*MIFRS*
Opening Gross Fixed Assets	A	631,970,385	631,965,112	304,878,268	333,816,770	402,046,695	438,161,122
Closing Gross Fixed Assets	B	670,970,385	642,704,976	333,816,772	402,046,695	438,161,122	476,179,683
Average Gross Fixed Assets	C = (A+B)/2	651,470,385	637,335,044	319,347,520	367,931,732	420,103,908	457,170,402
Opening Accumulated Depreciation	D	327,078,967	327,086,844	-	16,079,487	35,946,311	55,089,359
Closing Accumulated Depreciation	E	355,485,201	325,707,010	16,079,487	35,946,310	55,089,359	75,980,036
Average Accumulated Depreciation	F = (D+E)/2	341,282,084	326,396,927	8,039,744	26,012,899	45,517,835	65,534,698
Average Net Fixed Assets	G = C-F	310,188,301	310,938,117	311,307,777	341,918,834	374,586,073	391,635,705
Working Capital Allowance	H	58,864,336	62,570,417	63,645,753	67,995,896	73,108,152	77,599,411
Total Rate Base	I = G+H	369,052,637	373,508,534	374,953,530	409,914,730	447,694,225	469,235,115

Description	$	2015 Test Year [1]	2016 Test Year	2017 Test Year	2018 Test Year	2019 Test Year
Reporting Basis		*MIFRS*	*MIFRS*	*MIFRS*	*MIFRS*	*MIFRS*
Opening Gross Fixed Assets	A	478,411,147	516,436,174	555,558,640	599,967,280	645,591,775
Closing Gross Fixed Assets	B	516,436,174	555,558,640	599,967,280	645,591,775	692,266,434
Average Gross Fixed Assets	C = (A+B)/2	497,423,660	535,997,407	577,762,960	622,779,528	668,929,104
Opening Accumulated Depreciation	D	76,231,029	99,427,151	122,542,713	146,359,811	169,366,490
Closing Accumulated Depreciation	E	99,427,151	122,542,713	146,359,811	169,366,490	191,816,803
Average Accumulated Depreciation	F = (D+E)/2	87,829,090	110,984,932	134,451,262	157,863,151	180,591,646
Average Net Fixed Assets	G = C-F	409,594,570	425,012,475	443,311,698	464,916,377	488,337,458
Working Capital Allowance	H	74,015,044	76,935,221	79,713,275	82,496,897	85,009,160
Total Rate Base	I = G+H	483,609,614	501,947,697	523,024,973	547,413,274	573,346,618

[1] 2015 includes 2012-2014 smart meter additions in opening balance

1 **Table 2-2 – Rate Base Variances**

Description	$	2011 Actual vs 2011 Board-Approved	2011 Actual (MIFRS) vs 2011 Actual (CGAAP)	2012 Actual vs 2011 Actual	2013 Actual vs 2012 Actual	2014 Bridge Year vs 2013 Actual
Reporting Basis		*CGAAP*		*MIFRS*	*MIFRS*	*MIFRS*
Opening Gross Fixed Assets	A	(5,273)	(327,086,844)	28,938,502	68,229,925	36,114,427
Closing Gross Fixed Assets	B	(28,265,409)	(308,888,203)	68,229,922	36,114,427	38,018,561
Average Gross Fixed Assets	C = (A+B)/2	(14,135,341)	(317,987,524)	48,584,212	52,172,176	37,066,494
Opening Accumulated Depreciation	D	7,877	(327,086,844)	16,079,487	19,866,824	19,143,048
Closing Accumulated Depreciation	E	(29,778,191)	(309,627,523)	19,866,823	19,143,049	20,890,677
Average Accumulated Depreciation	F = (D+E)/2	(14,885,157)	(318,357,183)	17,973,155	19,504,936	20,016,863
Average Net Fixed Assets	G = C-F	749,816	369,660	30,611,057	32,667,240	17,049,631
Working Capital Allowance	H	3,706,081	1,075,336	4,350,143	5,112,255	4,491,259
Total Rate Base	I = G+H	4,455,897	1,444,996	34,961,200	37,779,495	21,540,890

Description	$	2015 Test Year vs 2014 Bridge Year	2016 Test Year vs 2015 Test Year	2017 Test Year vs 2016 Test Year	2018 Test Year vs 2017 Test Year	2019 Test Year vs 2018 Test Year
Reporting Basis		*MIFRS*	*MIFRS*	*MIFRS*	*MIFRS*	*MIFRS*
Opening Gross Fixed Assets	A	40,250,025	38,025,028	39,122,466	44,408,640	45,624,494
Closing Gross Fixed Assets	B	40,256,491	39,122,466	44,408,640	45,624,494	46,674,659
Average Gross Fixed Assets	C = (A+B)/2	40,253,258	38,573,747	41,765,553	45,016,567	46,149,577
Opening Accumulated Depreciation	D	21,141,670	23,196,122	23,115,562	23,817,098	23,006,679
Closing Accumulated Depreciation	E	23,447,115	23,115,562	23,817,098	23,006,679	22,450,313
Average Accumulated Depreciation	F = (D+E)/2	22,294,393	23,155,842	23,466,330	23,411,888	22,728,496
Average Net Fixed Assets	G = C-F	17,958,865	15,417,905	18,299,223	21,604,679	23,421,081
Working Capital Allowance	H	(3,584,367)	2,920,177	2,778,053	2,783,623	2,512,263
Total Rate Base	I = G+H	14,374,499	18,338,082	21,077,276	24,388,302	25,933,344

Horizon Utilities has calculated its 2015 Test Year rate base as $483,609,614, which represents a 31.0% increase over the 2011 Board-Approved. Horizon Utilities has calculated its rate base for the 2016 to 2019 Test Years as follows:

- The 2016 Test Year rate base is calculated as $501,947,697, a 3.8% increase over the 2015 Test Year rate base.
- The 2017 Test Year rate base is calculated as $523,024,973, a 4.2% increase over the 2016 Test Year rate base.
- The 2018 Test Year rate base is calculated as $547,413,274, a 4.7% increase over the 2017 Test Year rate base.
- The 2019 Test Year rate base is calculated as $573,346,618, a 4.7% increase over the 2018 Test Year rate base.

The drivers of the increase for the 2015 Test Year rate base are provided in Table 2-3 below.

Table 2-3 - Drivers of the Rate Base Increases – 2015 Test Year vs. 2011 Board-Approved

Description	$
2011 Board-Approved Rate Base	**$369,052,637**
Transition to IFRS (including WCA impact)	$1,814,656
Smart Meter Implementation (including WCA impact)	$23,591,210
Capital Additions Net of Depreciation [1]	$82,291,688
Net Asset Disposals	($7,056,607)
WCA - Increase due to COP/OM&A [2]	$18,578,396
WCA - Decrease due to WCA % change from 13.5% to 12.7% in 2015	($4,662,365)
2011 to 2015 Net Additions to Rate Base	**$114,556,978**
2015 Board-Approved Rate Base	**$483,609,614**
[1] Includes impact of Averaging Net Fixed Assets	
[2] Excludes Working Capital impact of IFRS and Smart Meters	

The increases in rate base from the 2011 Board-Approved to the 2015 Test Year result from: i) necessary net capital additions of $82,291,688 principally in support of necessary renewal based investments in the distribution system and buildings; ii) the Smart Meter implementation of $23,591,210; iii) the net impact of the transition to IFRS on January 1, 2012 of $1,814,656; iv) a net increase in the Working Capital Allowance of $13,916,031; partly offset by v) the recognition of losses on asset disposals of $7,056,607 as required under IFRS.

Transition to IFRS

Horizon Utilities adopted IFRS effective January 1, 2012. The impact to rate base as a result of the transition to IFRS is discussed in further detail in Exhibit 6, Tab 2, Schedule 1 and the rate base variance analysis section of this Exhibit.

Smart Meter Implementation

Horizon Utilities had substantially completed its mass deployment of Smart Meters in 2009. As at the end of 2011, Horizon Utilities had installed 229,322 Smart Meters representing 98.0% of all metering points. The recovery of Smart Meter-related capital costs was the subject of Horizon Utilities' 2011 Smart Meter Prudence Application ("SMPA") (EB-2011-0417). The Board determined that Horizon Utilities' Smart Meter capital expenditures of $27,440,059 were prudently incurred and, as such, approved a Smart Meter Incremental Revenue Requirement Rate Rider ("SMIRR") for Smart Meters installed through to December 31, 2011. The Smart Meter implementation is discussed in further detail in Exhibit 9, Tab 7, Schedule 1. Horizon Utilities expects that the cumulative capital costs for the installation of Smart Meters will be $25,509,051 ($23,431,869 net of accumulated depreciation). This includes capital costs for installations expected to be incurred up until December 31, 2014. Horizon Utilities has incurred $1,800,894 of cumulative Smart Meter capital costs as of December 31, 2013.

Horizon Utilities' proposed 2015 Test Year Rate Base is $483,609,614, an increase of $114,556,978 over the reported 2011 Board-Approved Rate Base. 2015 Test Year Rate Base is $89,151,112 or 24.2% in excess of the 2011 Board-Approved Rate Base restated on a MIFRS basis (and including Smart Meter capital costs). The transition to IFRS and the Smart Meter Implementation comprise $25,405,866 or 6.9% of the increase in rate base from 2011 Board-Approved to the 2015 Test Year as illustrated in Table 2-4 below. Table 2-5 reconciles the reported Board-Approved amount for Rate Base to the “normalized” amount, including these two items for comparative purposes going forward:

Table 2-4 - Impact of Transition to IFRS and Smart Meter Implementation on Rate Base

Description	Rate Base $	% Increase vs Board-Approved Reported Rate Base
2011 Board-Approved Reported Rate Base	$369,052,637	
2011 Board-Approved Normalized (MIFRS basis including Smart Meters)	$394,458,502	6.9%
2015 Test Year	$483,609,614	31.0%
Increase from 2011 Board-Approved Reported to 2015 Test Year		
Due to Transition to IFRS and Smart Meter Implementation	$25,405,866	6.9%
Due to Capital Additions and Changes in Working Capital	$89,151,112	24.2%
Total Increase 2011 Board-Approved to 2015 Test Year	**$114,556,978**	**31.0%**

Table 2-5 – Normalized Rate Base Increases 2011-2019

Description	2011 Board-Approved	2011 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Bridge Year	2015 Test Year
Reporting Basis	*CGAAP*	*CGAAP*	*MIFRS*	*MIFRS*	*MIFRS*	*MIFRS*	*MIFRS*
Rate Base ($) - Reported	**369,052,637**	**373,508,534**	**374,953,530**	**409,914,730**	**447,694,225**	**469,235,115**	**$483,609,614**
Transition to IFRS[1]	1,814,656	1,814,656					
Smart Meter Implementation - 2011 and prior additions [1]	21,610,739	21,610,739	21,610,739				
Smart Meter Implementation - 2012 - 2014 additions [1]	1,980,471	1,980,471	1,980,471				
Rate Base ($) - Normalized	**394,458,502**	**398,914,399**	**398,544,739**	**409,914,730**	**447,694,225**	**469,235,115**	**$483,609,614**
Increase (%) vs Prior Year				2.9%	9.2%	4.8%	3.1%
Increase (%) relative to 2011 Board-Approved		1.1%	1.0%	3.9%	13.5%	19.0%	22.6%

Description	2016 Test Year	2017 Test Year	2018 Test Year	2019 Test Year
Reporting Basis	*MIFRS*	*MIFRS*	*MIFRS*	*MIFRS*
Rate Base ($) - Reported	**$501,947,697**	**$523,024,973**	**$547,413,274**	**$573,346,618**
Transition to IFRS[1]				
Smart Meter Implementation - 2011 and prior additions 1				
Smart Meter Implementation - 2012 - 2014 additions 1				
Rate Base ($) - Normalized	**$501,947,697**	**$523,024,973**	**$547,413,274**	**$573,346,618**
Increase (%) vs Prior Year	3.8%	4.2%	4.7%	4.7%

[1] Rate Base incorporates OM&A and corresponding WCA impact of IFRS Transition and Smart Meter Implementation

Net Capital Additions – 2011 to 2019

The increase in net capital additions from Horizon Utilities' 2011 Board-Approved to the 2019 Test Year is principally the result of necessary rising investment in the renewal of distribution assets at or near end-of-life and, to a lesser extent, buildings infrastructure. Horizon Utilities identified the need for careful planning, review, and prioritization of the increased asset investment in its 2008 and 2011 CoS Applications (EB-2007-0697 and EB-2010-0131 respectively). Horizon Utilities began increasing its distribution capital expenditures at a graduated rate from $17,841,422 (CGAAP) in 2008 to $31,380,634 (CGAAP) by 2011, to ensure the continued operational viability of the distribution system.

Renewal of Distribution Assets

In 2012, Horizon Utilities performed a comprehensive condition assessment of its key distribution assets. Prior to 2012, asset health was primarily determined by the age of the assets and assets were categorized as "end-of-life" ("EOL"), "near end-of-life" or "optimal". Horizon Utilities engaged an engineering firm, Kinectrics Inc. ("Kinectrics"), at the end of 2012, to conduct an Asset Condition Assessment ("ACA") of its key distribution assets. Kinectrics is an independent consulting engineering company with over 100 years of expertise gained as part of one of North America's largest integrated electric power companies. Kinectrics has a depth of experience in the area of transmission and distribution systems and has become a prime source of asset management and asset condition services to some of the largest power utilities in North America.

Kinectrics provided a quantifiable evaluation of the asset condition; aided in prioritizing and allocating sustainment resources; and facilitated the continued development of Horizon Utilities' asset management planning as documented in Section 2.1.2 of the Distribution System Plan ("DSP"). Kinectrics' ACA was based on a Health Index methodology, which incorporates many inputs including maintenance history, inspection records, failure history and other condition parameters. This approach provided more specific information on the status of the assets than could be gained through an evaluation of asset age alone.

Kinectrics' Asset Condition Assessment Report ("ACA Report"), included as Appendix B of the DSP, summarizes the methodology and approaches used in performing the ACA, and presents the resulting findings and recommendations.

Kinectrics gathered relevant condition data for twenty-two significant distribution asset groups, calculated related health indices for each group, and developed a condition-based 20 year renewal investment profile. The asset groups, ACA process, and Health Index information are identified in Tab 6, Schedule 1 of this Exhibit.

Horizon Utilities developed its DSP and, more specifically, its long-term plan for annual distribution system capital investments, based on the results identified in the ACA Report. The DSP is included in this Exhibit as Appendix 2-4.

Kinectrics identified that 30% of the assets within six of the 22 asset groups have a Health Index of "poor" or "very poor". This level of Health Index distribution is unacceptable. An unacceptable Health Index distribution occurs when:

- at least 20% of the assets within the group have a health index of either "very poor" or "poor"; or
- the assets within the group identified as having a "very poor" or "poor" Health Index require a significant five year investment (greater than $5,000,000).

Failure to address the risk presented by asset categories with an unacceptable Health Index distribution will result in increased service interruptions and reactive replacement, and higher costs for repair. The consequent asset failure rate will increase to a point that may affect Horizon Utilities' ability to repair and replace the asset in a reasonable time frame as expected by customers.

Cross-linked Polyethylene ("XLPE") cable, as an example, currently has 29% of assets with a Health Index of "poor" or "very poor". The volume of assets with a Health Index of "poor" or "very poor" increases to 45% in five years, 55% in ten years, 64% in 15 years and 70% in 20 years if annual renewal investment was to continue at 2013 levels. The Health Index distribution forecast for XLPE cable is identified in Figure 4 in Section 1.3.2 of the DSP, which is included as Appendix 2-4 of this Exhibit. The XLPE Cable Renewal Program is the primary vehicle for renewal of the underground distribution system, and is discussed in further detail in Tab 6, Schedule 1 of this Exhibit.

The 4kV and 8kV distribution system, constructed in the 1950s, represents the majority of Horizon Utilities' oldest distribution assets, which are at or near end-of-life. Conversion to a higher voltage level will provide greater security as the higher voltage system is designed with more redundancy, better interoperability, and requires no intermediary substation assets; eliminating both an unnecessary continued cost to maintain and an aging asset with a high impact to customer reliability. For these reasons, Horizon Utilities has prioritized renewal of these voltage systems in the capital expenditure plan and designated these projects as the primary vehicle for renewal of the overhead distribution system and the decommissioning of substation assets. The 4kV and 8kV Renewal Program is discussed in further detail in Tab 6, Schedule 1 of this Exhibit.

Section 1.3.2 of the DSP elaborates on the inherent risks with respect to these asset classes if the 2013 level of expenditure is not increased. It is imperative that Horizon Utilities increases investment in system renewal now to mitigate this trend and related reliability risks, and to allow a graduated management of the cost implications for its customers. The risk of failures will increase (in such asset categories as underground cables, substation breakers and overhead conductors) with longer outages in the absence of such investment. The greater investment in the renewal of distribution system assets is the principal driver of the increase in capital additions in each of the Test Years as compared to the 2011 Board-Approved Year.

Buildings Renewal

Horizon Utilities' buildings and infrastructure systems are at or nearing end of life; resulting in poor equipment performance, increased risk of system failure, poor work environments for employees, and increased health and safety risks. The majority of the office space is as and does not meet the needs of the current workforce. Horizon Utilities' buildings were constructed between 1914 and the early 1980s as identified in Table 2-48 in Tab 6, Schedule 1 of this Exhibit. Expenditures for the maintenance and operations of Horizon Utilities' buildings are increasing year-over-year due to required structural repairs, additional expenses to procure replacement parts for obsolete systems, and due to end-of-life systems.

Horizon Utilities identified that a long-term building asset renewal plan was necessary and commenced a series of studies in 2010 to:

- understand building and operational requirements;
- determine the level of required investment; and,
- prioritize the prospective building renewal projects.

Several issues and gaps were identified in the studies. Necessary renovations are required to address operational deficiencies, building accessibility, the removal of hazardous materials, security, and air quality. Horizon Utilities needs to replace assets which have reached end-of-life and ensure compliance with Ontario Building and Fire Codes. These issues and gaps are discussed in further detail in Tab 6, Schedule 1 of this Exhibit.

Renovations subsequent to the aforementioned studies began in 2012 and are scheduled to continue through to 2019 at a total investment of $22,057,000 over the eight years as identified in Table 2-6 below.

Table 2-6 Material Building Capital Expenditures

Buildings - Capital Expenditures $	2012 Actual	2013 Actual	2014 Bridge Year	2015 Test Year	2016 Test Year	2017 Test Year	2018 Test Year	2019 Test Year
Reporting Basis	*MIFRS*	*MIFRS*	*MIFRS*	*MIFRS*	*MIFRS*	*MIFRS*	*MIFRS*	*MIFRS*
Building Renovations - Vansickle Road	$ 460,000	$ 2,060,000	$ 1,300,000	$ -	$ -	$ -	$ -	$ -
Building Renovations - John and Hughson Streets	$ 1,307,000	$ 1,900,000	$ -	$ 2,000,000	$ 1,600,000	$ 2,200,000	$ 1,200,000	$ -
Building Renovations - Nebo Road	$ -	$ 1,530,000	$ 2,400,000	$ -	$ -	$ -	$ -	$ -
Building Renovations - Stoney Creek	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,200,000
Building Security Replacement	$ -	$ -	$ 400,000	$ 300,000	$ 200,000	$ -	$ -	$ -
John Street Roof Replacement	$ -	$ -	$ -	$ 900,000	$ -	$ -	$ -	$ -
John Street Window Replacement	$ -	$ -	$ -	$ 300,000	$ 300,000	$ 200,000	$ -	$ -
Nebo Road Emergency Backup Generator	$ -	$ -	$ -	$ 300,000	$ -	$ -	$ -	$ -
Total Material Buildings Capital Expenditures	**$ 1,767,000**	**$ 5,490,000**	**$ 4,100,000**	**$ 3,800,000**	**$ 2,100,000**	**$ 2,400,000**	**$ 1,200,000**	**$ 1,200,000**

The justification for Horizon Utilities' building renovation plan is discussed in further detail in Tab 6, Schedule 1 of this Exhibit.

Information System Technology ("IST") and the Renewal of Enterprise Class Systems

The capital investment strategy for IST is focused on the delivery and maintenance of enterprise class systems and technologies that provide the necessary tools and services to support Horizon Utilities' business, customers, and employees in an efficient, effective, and secure manner.

Enterprise class systems interoperate and interface with other key business databases and tools, are secure, and have the ability to be customized for the needs of specific departments.

This Application proposes necessary investments for the renewal of enterprise class systems with an aggregate value of $3,212,876 across the 2015 and 2019 Test Years, as identified in Table 2-7 below.

Table 2-7 - Investments for the Renewal of Enterprise Class Systems

Description	IFS ERP Upgrade [1]	Enterprise Phone System Upgrade	GIS Renewal (OMS) [2]	Total
2012 Actuals	$ -	$ -	$ 807,000	$ 807,000
2013 Actuals	$ 1,225,762	$ -	$ 1,103,442	$ 2,329,204
2014 Bridge Year	$ 980,260	$ -	$ 1,869,308	$ 2,849,568
2015 Test Year	$ 1,382,600	$ 400,000	$ 205,276	$ 1,987,876
2016 Test Year	$ -	$ -	$ -	$ -
2017 Test Year	$ -	$ -	$ -	$ -
2018 Test Year	$ 1,225,000	$ -	$ -	$ 1,225,000
2019 Test Year	$ -	$ -	$ -	$ -
Total 2015-2019	**$ 2,607,600**	**$ 400,000**	**$ 205,276**	**$ 3,212,876**
Project Total	**$ 4,813,622**	**$ 400,000**	**$ 3,985,026**	**$ 9,198,648**

IFS = Industrial and Financial Systems; ERP = Enterprise Resource Planning
GIS = Geospatial Information System; OMS = Outage Management System

Such investments are principally comprised of necessary replacements and upgrades of end-of-life systems that are no longer supported by vendors; necessary systems to sustain operations; and systems required to advance efficiency, effectiveness, and security objectives.

The major projects through the 2015 to 2019 Test Years include the following:

- upgrade key operational systems such as the Industrial and Financial Systems ("IFS") Enterprise Resource Planning ("ERP") system; and
- implementation of new enterprise operational systems including Geospatial Information System ("GIS"), Supervisory Control and Data Acquisition ("SCADA"), and Outage Management System ("OMS"). The GIS implementation is discussed in further detail in Tab 6, Schedule 1 of this Exhibit.

The scope of and justification for IST projects is included in Tab 6, Schedule 1 of this Exhibit.

Working Capital Allowance

Horizon Utilities engaged a leading consulting firm, Navigant Consulting ("Navigant"), to undertake Horizon Utilities' Lead/Lag study; which is the principal basis for its proposal for Working Capital Allowance. In this Application, based on the work completed by Navigant, Horizon Utilities submits that 12.7% is the appropriate statistic applied to Operating, Maintenance and Administrative ("OM&A") and power costs for the purpose of calculating the Working Capital Allowance commencing in 2015. This represents a decrease of 0.8% from the 13.5% rate for Working Capital Allowance that the OEB approved in its Decision in Horizon Utilities' 2011 CoS Application. This change is discussed in further detail in Tab 4, Schedule 1 of this Exhibit.

Horizon Utilities' proposed Working Capital Allowance for each of the Test Years is: $74,015,044 for 2015; $76,935,221 for 2016; $79,713,275 for 2017; $82,496,897 for 2018 and $85,009,160 for 2019.

RATE BASE VARIANCE ANALYSIS

Chapter 2 of the Board's the Chapter 2 Filing Requirements states that "*The applicant must provide justification for changes from year to year to its rate base, capital expenditures, OM&A and other items above a materiality threshold. The materiality thresholds differ for each applicant, depending on the magnitude of the revenue requirement*." Horizon Utilities' materiality threshold is computed based on 0.5% of distribution revenue requirement for distributors with a revenue requirement greater than $10,000,000 and less than or equal to $200,000,000. The materiality threshold as per the Filing Requirements is $563,930 (0.5% of Horizon Utilities' distribution revenue of $112,785,966). The Materiality Threshold that Horizon Utilities will be using for the purpose of its variance analysis in this Exhibit is $300,000.

Horizon Utilities provides the following comments in respect of the relevant variances identified above. Horizon Utilities also provides explanations for certain variances below the materiality threshold, where relevant.

2011 Actual vs. 2011 Board-Approved (CGAAP):

The rate base of $373,508,534 for 2011 CGAAP Actual was higher than 2011 CGAAP Board-Approved by $4,455,897. This is due to an increase in average net fixed assets of $749,816 and an increase in Working Capital Allowance of $3,706,081 as identified in Table 2-8 below.

Table 2-8 - 2011 Actual Rate Base vs. 2011 Board-Approved Rate Base

Description ($)	2011 Board-Approved (CGAAP)	2011 Actual (CGAAP)	Variance
NET BOOK VALUE			
Gross Fixed Assets - Closing	670,970,385	642,704,976	(28,265,409)
Accumulated Depreciation - Closing	355,485,201	325,707,010	(29,778,191)
Net Fixed Assets - Closing	315,485,183	316,997,965	1,512,782
Average Net Fixed Assets	310,188,301	310,938,117	749,816
WORKING CAPITAL ALLOWANCE			
Cost of Power	53,092,213	56,948,389	3,856,176
OM&A	5,772,123	5,622,028	(150,095)
13.5% Working Capital	58,864,336	62,570,417	3,706,081
Total Rate Base	369,052,637	373,508,534	4,455,897

The primary driver for the Working Capital Allowance variance in the 2011 Actual (CGAAP) compared to the 2011 Board-Approved is higher than expected kWh purchases (6.56%) as identified in Exhibit 3, Tab 2, Schedule 1, Table 3-35. This resulted in a higher than expected Cost of Power and related Working Capital Allowance in 2011.

Higher than planned additions for Poles, Towers and Fixtures and Meters were partially offset by lower than planned additions for general plant; specifically, Building and Fixtures, Office Equipment, and Computer Hardware and Software. Horizon Utilities disposed of fully depreciated assets with an original cost of $29,100,768 in 2011. This disposal was not included in the 2011 Board-Approved. There was a decrease in gross fixed assets of $29,100,768 and a corresponding decrease in accumulated depreciation relative to the 2011 Board-Approved, as identified in Table 2-8 above.

2011 Actual (MIFRS) vs. 2011 Actual (CGAAP)

Horizon Utilities has reported its 2011 information under CGAAP and MIFRS. The impact to rate base as a result of the transition to IFRS is identified below and discussed in further detail in Exhibit 6, Tab 2, Schedule 1.

The rate base of $374,953,530 for 2011 MIFRS was $1,444,996 higher than 2011 CGAAP. This is due to an increase in average net fixed assets of $369,660 and an increase in Working Capital Allowance of $1,075,336 as identified in Table 2-9 below.

Table 2-9 - 2011 Actual (MIFRS) Rate Base vs. 2011 Actual (CGAAP) Rate Base

Description ($)	2011 Actual (CGAAP)	2011 Actual (MIFRS)	Variance
NET BOOK VALUE			
Gross Fixed Assets - Closing	642,704,976	333,816,772	(308,888,203)
Accumulated Depreciation - Closing	325,707,010	16,079,487	(309,627,523)
Net Fixed Assets - Closing	316,997,965	317,737,285	739,320
Average Net Fixed Assets	310,938,117	311,307,777	369,660
WORKING CAPITAL ALLOWANCE			
Cost of Power	56,948,389	56,948,389	0
OM&A	5,622,028	6,697,364	1,075,336
13.5% Working Capital	62,570,417	63,645,753	1,075,336
Total Rate Base	373,508,534	374,953,530	1,444,996

Horizon Utilities adopted IFRS effective January 1, 2012 with a transition date of January 1, 2011. Horizon Utilities elected to use accounting standard IFRS 1 deemed cost exemption, which allows rate-regulated entities to use the CGAAP net book value as the IFRS asset cost on the date of transition to IFRS. The deemed cost exemption is discussed in further detail in Exhibit 6, Tab 2, Schedule 1. The accumulated depreciation is set to $0 on the transition date. Table 2-10 below illustrates how the carrying value under CGAAP of $304,878,268 is used as the deemed cost and the accumulated depreciation is $0 under IFRS at the transition date of January 1, 2011. These amounts are also identified in the Fixed Asset Continuity Schedule – MIFRS for 2011 in Appendix 2-BA2.

Table 2-10 – Determination of Deemed Cost under IFRS

Description	Gross Fixed Assets Incr/(Decr)	Accumulated Depreciation Incr/(Decr)	Net Fixed Assets
Closing CGAAP, December 31st, 2010	**$631,965,112**	**$327,086,844**	**$304,878,268**
Deemed Cost Exemption	(327,086,844)	(327,086,844)	0
Opening MIFRS, January 1st, 2011	**$304,878,268**	**$0**	**$304,878,268**

Under MIFRS:

- Useful lives of distribution assets are longer than under CGAAP. The change in useful lives is discussed in further detail in Exhibit 6, Tab 2, Schedule 1.
- Only directly attributable costs are permitted to be capitalized; and
- An item of Property, Plant and Equipment ("PP&E") is derecognized when it is disposed of or when no future economic benefits are expected from its continued use or retention. Gains/ losses on disposals of assets are recorded as a charge against income.

Table 2-11 below summarizes these changes. Specific details regarding the impact on financial results and accounting policy changes arising from the transition to IFRS are provided in Exhibit 6, Tab 2, Schedule 1.

Table 2-11 - Summary of Changes in Net Fixed Assets due to the Transition to IFRS

Description	Gross Fixed Assets Incr/(Decr)	Accumulated Depreciation Incr/(Decr)	Net Fixed Assets
Closing CGAAP, December 31st, 2011	**$642,704,976**	**$325,707,010**	**$316,997,965**
CGAAP write-off of assets at end of life	29,100,768	29,100,768	0
Deemed Cost Exemption	(327,086,844)	(327,086,844)	0
Indirect Costs not Eligible for Capitalization	(9,339,658)	(127,897)	(9,211,761)
Change to Useful Lives	0	(11,463,261)	11,463,261
Derecognition of Assets	(1,562,469)	(50,288)	(1,512,181)
Total Change due to IFRS transition	**(308,888,203)**	**(309,627,523)**	**739,320**
Closing MIFRS, December 31st, 2011	**$333,816,772**	**$16,079,487**	**$317,737,285**

The increase of $739,320 in net fixed assets is a result of the following:

- A decrease in accumulated depreciation of $11,463,261 due to the extension of useful lives of assets under MIFRS, partly offset by:
    - A decrease in net fixed assets of $9,211,761 resulting from the removal of costs that are not directly attributable to capital activities and represent expenses under IFRS ($9,339,658 net of related depreciation of $127,897); and

- o The charge against income of $1,512,181 representing the net book value of specific asset components identified to have been removed from service. Unlike CGAAP, IFRS does not permit a pooled approach to fixed assets or general assumptions that assets removed from service are fully depreciated. Please refer to Exhibit 6, Tab 2, Schedule 1 for changes to accounting policies and related financial impacts regarding the treatment of derecognized assets under IFRS.

The increase in rate base also included an increase in the Working Capital Allowance. The transition to IFRS resulted in the removal of $9,339,658 (gross) from capital expenditures reported for 2011 under CGAAP, as identified above and for the reasons set out in Exhibit 6, Tab 2, Schedule 1 of this Application. Such costs, that are deemed not attributable to capital activity under IFRS, were reported for IFRS purposes in 2011 as follows:

- OM&A expenses - $8,008,453; and
- Depreciation - $1,331,205.

The transition to IFRS also resulted in the removal of $43,000 from OM&A expenses for post-employment losses. Such losses were reported as OM&A expense under CGAAP and as Other Comprehensive Income (“OCI”) under IFRS.

The resulting net OM&A increase under IFRS of $7,965,453 resulted in a corresponding increase to the Working Capital Allowance of $1,075,336 (at a percentage factor for Working Capital Allowance purposes of 13.5%).

2012 Actual (MIFRS) vs. 2011 Actual (MIFRS):

The 2012 actual rate base of $409,914,731 was $34,961,200 higher than 2011 actual results as a result of: an increase in average net fixed assets of $30,611,058; and an increase in Working Capital Allowance of $4,350,143, as identified in Table 2-12 below.

Table 2-12 – 2012 Actual (MIFRS) Rate Base vs. 2011 Actual (MIFRS) Rate Base

Description ($)	2011 Actual (MIFRS)	2012 Actual (MIFRS)	Variance
NET BOOK VALUE			
Gross Fixed Assets - Closing	333,816,772	402,046,695	68,229,922
Accumulated Depreciation - Closing	16,079,487	35,946,310	19,866,823
Net Fixed Assets - Closing	317,737,285	366,100,384	48,363,099
Average Net Fixed Assets	311,307,777	341,918,835	30,611,058
WORKING CAPITAL ALLOWANCE			
Cost of Power	56,948,389	61,046,317	4,097,929
OM&A	6,697,364	6,949,579	252,215
13.5% Working Capital	63,645,753	67,995,896	4,350,143
Total Rate Base	374,953,530	409,914,731	34,961,200

The 2012 net fixed assets increased by $48,363,099 as a result of capital additions of $46,980,043 and gross Smart Meter additions of $23,277,588, partly offset by asset disposals with an original cost of $2,027,707 ($1,876,942 net of depreciation) and depreciation of $19,866,823. A more detailed variance analysis is provided in Tab 6, Schedule 3 of this Exhibit.

The net Smart Meter additions in 2012 represented $23,277,588 in gross asset additions, partly offset by depreciation of $1,826,189. The Smart Meter implementation was discussed previously in Tab 1, Schedule 1 of this Exhibit, and Horizon Utilities has included a Smart Meter Prudence Review in Exhibit 9, Tab 7, Schedule 1 of this Application.

The increase in rate base from 2011 to 2012 is also partly due to an increase in Working Capital Allowance of $4,350,143 driven by the Cost of Power. The 2012 Cost of Power was $30,355,026 higher than the 2011 amount, resulting in an increase in rate base (at 13.5%) of $4,097,929. The increase in the Cost of Power was due to an increase in the Cost of Power rate of 10.0% from 2011 to 2012 and an increase in kWh purchases of 0.86% as identified in Exhibit 3, Tab 2, Schedule 1, Table 3-35.

2013 Actual vs. 2012 Actual:

The rate base of $447,694,225 for the 2013 Actual was $37,779,495 higher than the 2012 Actual. This is due to an increase in average net fixed assets of $32,667,239 and an increase in Working Capital Allowance of $5,112,255 as identified in Table 2-13 below.

Table 2-13 – 2013 Actual (MIFRS) Rate Base vs. 2012 Actual (MIFRS) Rate Base

Description ($)	2012 Actual (MIFRS)	2013 Actual (MIFRS)	Variance
NET BOOK VALUE			
Gross Fixed Assets - Closing	402,046,695	438,161,122	36,114,427
Accumulated Depreciation - Closing	35,946,310	55,089,359	19,143,049
Net Fixed Assets - Closing	366,100,384	383,071,763	16,971,379
Average Net Fixed Assets	341,918,835	374,586,074	32,667,239
WORKING CAPITAL ALLOWANCE			
Cost of Power	61,046,317	65,748,424	4,702,106
OM&A	6,949,579	7,359,728	410,149
13.5% Working Capital	67,995,896	73,108,152	5,112,255
Total Rate Base	409,914,731	447,694,225	37,779,495

The 2013 net fixed assets increased by $16,971,379 as a result of capital additions of $37,908,037, partly offset by disposals with an original cost of $1,793,609 ($1,637,146 net of depreciation) and depreciation of $19,143,049. A more detailed description of capital expenditures and variance analysis is provided in Tab 6, Schedule 3 of this Exhibit.

The increase in rate base from 2012 to 2013 is also partly due to an increase in Working Capital Allowance driven by the Cost of Power. The 2013 Cost of Power was $34,830,418 higher than the 2012 amount, resulting in an increase in rate base (at 13.5%) of $4,702,106. The increase in the Cost of Power was due to an increase in the Cost of Power rate of 6.2% from 2012 to 2013, partly offset by a decrease in kWh purchases of 0.54% as identified in Exhibit 3, Tab 2, Schedule 1, Table 3-35.

2014 Bridge Year vs. 2013 Actual:

The rate base of $469,235,115 for the 2014 Bridge Year is forecast to be $21,540,890 higher than the 2013 Actual. This is due to an increase in average net fixed assets of $17,049,631 and an increase in Working Capital Allowance of $4,491,259 as shown in Table 2-14 below.

Table 2-14 – 2014 Bridge Year (MIFRS) Rate Base vs. 2013 Actual (MIFRS) Rate Base

Description ($)	2013 Actual (MIFRS)	2014 Bridge Year (MIFRS)	Variance
NET BOOK VALUE			
Gross Fixed Assets - Closing	438,161,122	476,179,683	38,018,561
Accumulated Depreciation - Closing	55,089,359	75,980,036	20,890,677
Net Fixed Assets - Closing	383,071,763	400,199,647	17,127,884
Average Net Fixed Assets	374,586,074	391,635,705	17,049,631
WORKING CAPITAL ALLOWANCE			
Cost of Power	65,748,424	69,447,116	3,698,692
OM&A	7,359,728	8,152,295	792,567
13.5% Working Capital	73,108,152	77,599,411	4,491,259
Total Rate Base	447,694,225	469,235,115	21,540,890

The 2014 net fixed assets are forecast to increase by $17,127,884 due to capital additions of $39,792,050 partly offset by disposals of $1,773,488 ($1,640,446 net of depreciation) and depreciation of $20,890,677. Further details on forecast capital expenditures and project summaries for the 2014 Bridge Year are provided in Tab 6, Schedule 3 of this Exhibit.

The increase in rate base from 2013 to 2014 is also partly due to an increase in Working Capital Allowance driven by the Cost of Power. The 2013 Cost of Power was $27,397,720 higher than the 2012 amount, resulting in an increase in rate base (at 13.5%) of $3,698,692. The increase in the Cost of Power was primarily driven by an increase in the Cost of Power rate of 4.2% from 2013 to 2014.

2015 Test Year vs. 2014 Bridge Year:

The rate base of $483,609,614 for the 2015 Test Year is forecast to be $14,374,499 higher than the 2014 Bridge Year. This is due to an increase in average net fixed assets of $17,958,865 partly offset by a decrease in Working Capital Allowance of $3,584,367, as provided in Table 2-15 below.

Table 2-15 – 2015 Test Year Rate Base vs. 2014 Bridge Year Rate Base

Description ($)	2014 Bridge Year (MIFRS)	2015 Test Year (MIFRS)	Variance
NET BOOK VALUE			
Gross Fixed Assets - Closing	476,179,683	516,436,174	40,256,491
Accumulated Depreciation - Closing	75,980,036	99,427,151	23,447,115
Net Fixed Assets - Closing	400,199,647	417,009,023	16,809,377
Average Net Fixed Assets [1]	391,635,705	409,594,570	17,958,865
WORKING CAPITAL ALLOWANCE			
Cost of Power	69,447,116	66,060,694	(3,386,422)
OM&A	8,152,295	7,954,350	(197,945)
13.5%/12.7% Working Capital	77,599,411	74,015,044	(3,584,367)
Total Rate Base	469,235,115	483,609,614	14,374,499

[1] Average Net Fixed Assets for 2015 factors in net smart meter additions included in opening balance of $1,980,470

The 2015 net fixed assets are expected to increase by $16,809,377 due to capital additions of $40,114,524, gross Smart Meter additions of $2,231,464 transferred from deferral account 1555, partly offset by disposals with an original cost of $2,089,496 ($1,902,074 net of depreciation) and depreciation of $23,447,115. Horizon Utilities has provided further detail regarding related projects and expenditures in 2015 in Tab 6, Schedule 3 of this Exhibit.

Horizon Utilities completed the mass deployment of Smart Meters in 2009 and, as of the end of 2011, had installed Smart Meters for 229,322 customers or 98.0% of all metering points. Despite its efforts to install Smart Meters at all TOU-eligible locations, access restrictions and metering constraints have resulted in the necessity of a hard-to-reach Smart Meter program. In its Decision on Horizon Utilities' SMPA, the Board authorized Horizon Utilities to continue recording Smart Meter capital costs in deferral account 1555 for the remaining 297 Residential customers with hard-to-reach meters and GS < 50 kW customers with Smart Meters that were replaced upon repair or recertification from January 1, 2012 to December 31, 2014. A disposition of these costs is requested in this Application (Exhibit 9, Tab 7, Schedule 1) and these costs are included above as additions in the 2015 Test Year. The balance accumulated in this account of $2,231,464 was previously recorded in deferral account 1555 and is included in the opening balance of the Smart Meter capital account in 2015. The accumulated depreciation of $250,993 included in the determination of the Smart Meter Disposition Rider discussed in Exhibit 9, Tab 7, Schedule 1 is included in the opening balance of accumulated depreciation in 2015.

The decrease in Working Capital Allowance is driven by the change in the percentage factor used to calculate the Working Capital Allowance, which is partly offset by an increase in Cost of Power/OM&A expenses. Prior to 2015, Horizon Utilities used a percentage factor of 13.5% in the calculation of its Working Capital Allowance. In 2013, Horizon Utilities, in conjunction with Navigant, completed a Lead/Lag study to determine the appropriate percentage factor to be used in its Working Capital Allowance calculation. Horizon Utilities proposes to use 12.7% for the purposes of calculating the Working Capital Allowance effective 2015, based on this study. Although the Cost of Power and OM&A increased by $7,985,174 from 2014 to 2015, the decrease of 0.8% in the percentage used to calculate the Working Capital Allowance led to an overall decrease in the Working Capital Allowance as detailed in Table 2-16 below. The Lead/Lag Study is discussed in more detail in Tab 4 of this Exhibit.

Table 2-16 – Impact of Change in Working Capital Allowance %

Description	$
Cost of Power/OM&A 2014	574,810,449
Cost of Power/OM&A 2015	582,795,623
Increase in COP/OM&A	**7,985,174**
Increase in WCA at 13.5%	1,077,998
Decrease in WCA due to 0.8% reduction	(4,662,365)
Net Change in WCA	**(3,584,367)**

2016 Test Year vs. 2015 Test Year:

The rate base of $501,947,697 for the 2016 Test Year is forecast to be $18,338,082 higher than the 2015 Test Year. This is due to an increase in average net fixed assets of $15,417,905 and an increase in Working Capital Allowance of $2,920,177 as identified in Table 2-17 below.

Table 2-17 – 2016 Test Year Rate Base vs. 2015 Test Year Rate Base

Description ($)	2015 Test Year (MIFRS)	2016 Test Year (MIFRS)	Variance
NET BOOK VALUE			
Gross Fixed Assets - Closing	516,436,174	555,558,640	39,122,466
Accumulated Depreciation - Closing	99,427,151	122,542,713	23,115,562
Net Fixed Assets - Closing	417,009,023	433,015,927	16,006,903
Average Net Fixed Assets	409,594,570	425,012,475	15,417,905
WORKING CAPITAL ALLOWANCE			
Cost of Power	66,060,694	68,757,167	2,696,473
OM&A	7,954,350	8,178,055	223,704
12.7% Working Capital	74,015,044	76,935,221	2,920,177
Total Rate Base	483,609,614	501,947,697	18,338,082

The 2016 net fixed assets are expected to increase by $15,417,905 due to capital additions of $42,947,533, partly offset by disposals with an original cost of $3,825,068 ($2,739,310 net of depreciation) and depreciation of $23,115,562. Horizon Utilities has provided further detail related to 2016 projects in Tab 6, Schedule 3 of this Exhibit.

The increase in rate base from 2015 to 2016 is also partly due to an increase in Working Capital Allowance driven by the Cost of Power. The 2016 Cost of Power was $21,232,070 higher than the 2015 amount, resulting in an increase in rate base (at 12.7%) of $2,696,473. The increase in the Cost of Power was due to an increase in the Cost of Power rate of 4.5% from 2015 to 2016, partly offset by a decrease in kWh purchases of 0.08% as identified in Exhibit 3, Tab 2, Schedule 1, Table 3-36.

2017 Test Year vs. 2016 Test Year:

The rate base of $523,024,973 for the 2017 Test Year is forecast to be $21,077,276 higher than the 2016 Test Year. This is due to an increase in average net fixed assets of $18,299,223 and an increase in Working Capital Allowance of $2,778,053, as identified in Table 2-18 below.

Table 2-18 – 2017 Test Year Rate Base vs. 2016 Test Year Rate Base

Description ($)	2016 Test Year (MIFRS)	2017 Test Year (MIFRS)	Variance
NET BOOK VALUE			
Gross Fixed Assets - Closing	555,558,640	599,967,280	44,408,640
Accumulated Depreciation - Closing	122,542,713	146,359,811	23,817,098
Net Fixed Assets - Closing	433,015,927	453,607,469	20,591,542
Average Net Fixed Assets	425,012,475	443,311,698	18,299,223
WORKING CAPITAL ALLOWANCE			
Cost of Power	68,757,167	71,298,785	2,541,618
OM&A	8,178,055	8,414,490	236,435
12.7% Working Capital	76,935,221	79,713,275	2,778,053
Total Rate Base	501,947,697	523,024,973	21,077,276

The 2017 net fixed assets are expected to increase by $20,591,542 due to capital additions of $47,426,114, partly offset by disposals with an original cost of $3,017,473 ($2,673,315 net of depreciation) and depreciation of $23,817,098. Horizon Utilities has provided further detail related to 2017 projects in Tab 6, Schedule 3 of this Exhibit.

The increase in rate base from 2016 to 2017 is also partly due to an increase in Working Capital Allowance driven by the Cost of Power. The 2017 Cost of Power was $20,012,739 higher than the 2016 amount, resulting in an increase in rate base (at 12.7%) of $2,541,618. The increase in the Cost of Power was due to an increase in the Cost of Power rate of 4.3% from 2016 to 2017, partly offset by a decrease in kWh purchases of 0.20% as identified in Exhibit 3, Tab 2, Schedule 1, Table 3-36.

2018 Test Year vs. 2017 Test Year:

The rate base of $547,413,274 for the 2018 Test Year is forecast to be $24,388,302 higher than the 2017 Test Year. This is due to an increase in average net fixed assets of $21,604,679 and an increase in Working Capital Allowance of $2,783,623, as identified in Table 2-19 below.

Table 2-19 – 2018 Test Year Rate Base vs. 2017 Test Year Rate Base

Description ($)	2017 Test Year (MIFRS)	2018 Test Year (MIFRS)	Variance
NET BOOK VALUE			
Gross Fixed Assets - Closing	599,967,280	645,591,775	45,624,494
Accumulated Depreciation - Closing	146,359,811	169,366,490	23,006,679
Net Fixed Assets - Closing	453,607,469	476,225,285	22,617,816
Average Net Fixed Assets	443,311,698	464,916,377	21,604,679
WORKING CAPITAL ALLOWANCE			
Cost of Power	71,298,785	73,897,898	2,599,113
OM&A	8,414,490	8,599,000	184,510
12.7% Working Capital	79,713,275	82,496,897	2,783,623
Total Rate Base	523,024,973	547,413,274	24,388,302

The 2018 net fixed assets are expected to increase by $22,617,816 due to capital additions of $48,942,504, partly offset by disposals with an original cost of $3,318,009 ($2,887,498 net of depreciation) and depreciation of $23,006,679. Capital additions are driven primarily by investment in system renewal, as previously discussed. Horizon Utilities has provided further detail related to 2018 projects in Tab 6, Schedule 3 of this Exhibit.

The increase in rate base from 2017 to 2018 is also partly due to an increase in Working Capital Allowance driven by the Cost of Power. The 2018 Cost of Power was $20,465,458 higher than the 2017 amount, resulting in an increase in rate base (at 12.7%) of $2,599,113. The increase in the Cost of Power was due to an increase in the Cost of Power rate of 4.1% from 2017 to 2018, partly offset by a decrease in kWh purchases of 0.06% as identified in Exhibit 3, Tab 2, Schedule 1, Table 3-36.

2019 Test Year vs. 2018 Test Year:

The rate base of $573,346,618 for the 2019 Test Year is forecast to be $25,933,344 higher than the 2018 Test Year. This is due to an increase in average net fixed assets of $23,421,081 and an increase in Working Capital Allowance of $2,512,263 as identified in Table 2-20 below.

Table 2-20 – 2019 Test Year Rate Base vs. 2018 Test Year Rate Base

Description ($)	2018 Test Year (MIFRS)	2019 Test Year (MIFRS)	Variance
NET BOOK VALUE			
Gross Fixed Assets - Closing	645,591,775	692,266,434	46,674,659
Accumulated Depreciation - Closing	169,366,490	191,816,803	22,450,313
Net Fixed Assets - Closing	476,225,285	500,449,631	24,224,346
Average Net Fixed Assets	464,916,377	488,337,458	23,421,081
WORKING CAPITAL ALLOWANCE			
Cost of Power	73,897,898	76,228,318	2,330,420
OM&A	8,599,000	8,780,842	181,843
12.7% Working Capital	82,496,897	85,009,160	2,512,263
Total Rate Base	547,413,274	573,346,618	25,933,344

The 2019 net fixed assets are expected to increase by $24,224,346 due to capital additions of $51,272,477 partly offset by disposals with an original cost of $4,597,818 ($3,171,069 net of depreciation) and depreciation of $22,450,313. Horizon Utilities has provided further detail related to 2019 projects in Tab 6, Schedule 3 of this Exhibit.

The increase in rate base from 2018 to 2019 is also partly due to an increase in Working Capital Allowance driven by the Cost of Power. The 2019 Cost of Power was $18,349,767 higher than the 2018 amount, resulting in an increase in rate base (at 12.7%) of $2,330,420. The increase in the Cost of Power was due to an increase in the Cost of Power rate of 4.0% from 2018 to 2019, partly offset by a decrease in kWh purchases of 0.09% as identified in Exhibit 3, Tab 2, Schedule 1, Table 3-36.

Continuity Statement and Reconciliation

Horizon Utilities has provided its continuity statements in the following Appendix 2-1. The opening and closing balances of gross assets and accumulated depreciation that have been used to calculate the fixed asset component of rate base, correspond to the respective balances before Work in Progress ('WIP') in the fixed asset continuity statements. Additions of Smart Meters in 2015 have been included in the opening balance of rate base.

The differences in the 2011 CGAAP and 2011 MIFRS fixed asset continuities are discussed in the rate base variance analysis section of this Exhibit in Tab 1, Schedule 2, pages 3-4.

The following continuity statements have been provided:

- 2011 Board-Approved;
- 2011 Actual CGAAP;
- 2011 Actual MIFRS;
- 2012 Actual MIFRS;
- 2013 Actual MIFRS;
- Forecast for the 2014 Bridge Year MIFRS; and
- Forecast for the 2015-2019 Test Years MIFRS.

APPENDIX 2-1 CONTINUITY STATEMENTS

Table 1 - Chapter 2 Filing Requirements - Appendix 2-BA1 – 2011 Actual CGAAP

			Cost				Accumulated Depreciation				
CCA Class	**OEB**	**Description**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
N/A	1805	Land - Substations	$ 414,741	$ -	$ -	$ 414,741	$ -	$ -	$ -	$ -	$ 414,741
1	1808	Buildings - Substations	$ 2,153,482	$ 127,157	$ -	$ 2,280,640	$ (1,610,899)	$ (79,165)	$ -	$ (1,690,064)	$ 590,576
13	1810	Leasehold Improvements	$ 20,886	$ -	$ -	$ 20,886	$ (20,886)	$ -	$ -	$ (20,886)	$ -
47	1821	Substation transformers	$ 12,743,580	$ 119,324	$ -	$ 12,862,904	$ (9,411,962)	$ (317,128)	$ -	$ (9,729,091)	$ 3,133,813
47	1830	Poles, towers and fixtures	$ 75,428,553	$ 11,048,413	$ (1,218,087)	$ 85,258,879	$ (27,399,153)	$ (3,125,398)	$ 1,218,087	$ (29,306,464)	$ 55,952,415
47	1835	Overhead conductors and devices	$ 74,386,897	$ 4,832,502	$ (1,667,005)	$ 77,552,394	$ (33,104,555)	$ (2,964,648)	$ 1,667,005	$ (34,402,198)	$ 43,150,196
47	1840	Underground Conduit	$117,389,284	$ 5,017,549	$ (8,763,660)	$113,643,173	$ (64,823,095)	$ (4,621,313)	$ 8,763,660	$ (60,680,748)	$ 52,962,426
47	1845	Underground Conductors and Devices	$122,806,078	$ 7,151,416	$ (9,885,790)	$120,071,703	$ (59,145,642)	$ (4,945,035)	$ 9,885,790	$ (54,204,887)	$ 65,866,816
47	1850	Line Transformers	$ 99,670,106	$ 6,071,958	$ (5,412,675)	$100,329,389	$ (47,236,077)	$ (3,985,852)	$ 5,412,675	$ (45,809,255)	$ 54,520,134
47	1855	Services	$ 25,989,562	$ 1,304,732	$ (436,507)	$ 26,857,787	$ (9,555,261)	$ (1,128,715)	$ 436,507	$ (10,247,469)	$ 16,610,318
47	1860	Meters	$ 39,317,446	$ 3,467,413	$ (963,393)	$ 41,821,467	$ (17,875,151)	$ (1,550,833)	$ 963,393	$ (18,462,591)	$ 23,358,875
N/A	1905	Land	$ 1,067,629	$ -	$ -	$ 1,067,629	$ -	$ -	$ -	$ -	$ 1,067,629
CEC	1906	Land Rights	$ 162,636	$ -	$ -	$ 162,636	$ (72,149)	$ (3,338)	$ -	$ (75,487)	$ 87,149
1	1908	Buildings and Fixtures	$ 28,577,205	$ 753,646	$ -	$ 29,330,851	$ (18,289,863)	$ (1,280,965)	$ -	$ (19,570,829)	$ 9,760,023
13	1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture and Equipment	$ 5,299,584	$ 24,344	$ -	$ 5,323,928	$ (3,760,285)	$ (220,495)	$ -	$ (3,980,780)	$ 1,343,148
45	1920	Computer Equipment - Hardware	$ 10,058,430	$ 615,786	$ -	$ 10,674,216	$ (7,494,226)	$ (858,723)	$ -	$ (8,352,949)	$ 2,321,268
45	1925	Computer Software	$ 11,874,074	$ 859,782	$ -	$ 12,733,856	$ (7,608,958)	$ (1,879,268)	$ -	$ (9,488,225)	$ 3,245,631
10	1930	Transportation Equipment	$ 18,062,964	$ 1,033,975	$ (753,652)	$ 18,343,287	$ (11,773,329)	$ (1,277,937)	$ 753,652	$ (12,297,614)	$ 6,045,673
8	1935	Stores Equipment	$ 968,061	$ -	$ -	$ 968,061	$ (550,197)	$ (53,586)	$ -	$ (603,783)	$ 364,278
8	1940	Tools, Shop and Garage Equipment	$ 7,847,983	$ 493,820	$ -	$ 8,341,804	$ (6,041,880)	$ (330,730)	$ -	$ (6,372,610)	$ 1,969,194
8	1945	Measurement and Testing Equipment	$ 1,512,751	$ 180,845	$ -	$ 1,693,596	$ (1,038,404)	$ (98,496)	$ -	$ (1,136,900)	$ 556,696
8	1950	Power Operated Equipment	$ 144,035	$ -	$ -	$ 144,035	$ (108,675)	$ (11,436)	$ -	$ (120,111)	$ 23,924
8	1955	Communication Equipment	$ 1,445,074	$ 903,229	$ -	$ 2,348,303	$ (634,836)	$ (143,865)	$ -	$ (778,700)	$ 1,569,602
47	1970	Load Management Controls - Customer Premises	$ 515,330	$ -	$ -	$ 515,330	$ (202,992)	$ (51,533)	$ -	$ (254,525)	$ 260,805
47	1980	System Supervisory Equipment	$ 3,777,542	$ -	$ -	$ 3,777,542	$ (3,106,631)	$ (68,753)	$ -	$ (3,175,384)	$ 602,158
47	1996	Hydro One SS Contributions	$ 10,330,150	$ -	$ -	$ 10,330,150	$ (1,121,114)	$ (413,206)	$ -	$ (1,534,320)	$ 8,795,830
47	1995	Contributions and Grants	$ (39,998,953)	$ (4,165,260)	$ -	$ (44,164,213)	$ 4,899,376	$ 1,689,483	$ -	$ 6,588,859	$ (37,575,353)
		Sub-Total	**$631,965,112**	**$ 39,840,632**	**$(29,100,768)**	**$642,704,976**	**$ (327,086,844)**	**$ (27,720,934)**	**$ 29,100,768**	**$(325,707,010)**	**$316,997,965**
		Less Socialized Renewable Energy Generation Investments **(input as negative)**				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets ***(input as negative)***				$ -				$ -	$ -
		Total PP&E	**$631,965,112**	**$ 39,840,632**	**$(29,100,768)**	**$642,704,976**	**$ (327,086,844)**	**$ (27,720,934)**	**$ 29,100,768**	**$(325,707,010)**	**$316,997,965**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets)									
		Total						**(27,720,934)**			
		Work in Process	$ 9,157,146	$ (742,791)	$ -	$ 8,414,355	$ -	$ -	$ -	$ -	$ 8,414,355
		Total PP&E Including WIP	**$641,122,258**	**$ 39,097,841**	**$(29,100,768)**	**$651,119,331**	**$ (327,086,844)**	**$ (27,720,934)**	**$ 29,100,768**	**$(325,707,010)**	**$325,412,320**

Table 2 - Chapter 2 Filing Requirements - Appendix 2-BA2 – 2011 Actual MIFRS

			Cost					Accumulated Depreciation					
CCA Class	**OEB**	**Description**	**Opening Balance**	**Additions (Less Capital Contributions)**	**Disposals**	**Burden Adjustment**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Burden Adjustment**	**Closing Balance**	**Net Book Value**
N/A	1805	Land - Substations	$ 414,741	$ -		$ -	$ 414,741	$ -	$ -		$ -	$ -	$ 414,741
1	1808	Buildings - Substations	$ 542,583	$ 127,157		$ -	$ 669,741	$ -	$ (76,563)		$ -	$ (76,563)	$ 593,178
13	1810	Leasehold Improvements	$ -	$ -		$ -	$ -	$ -			$ -	$ -	$ -
47	1821	Substation transformers	$ 3,140,058	$ 119,324		$ -	$ 3,259,383	$ -	$ (89,296)		$ -	$ (89,296)	$ 3,170,087
47	1830	Poles, towers and fixtures	$ 48,029,400	$ 11,048,413	$ (333,952)	$ (2,564,755)	$ 56,179,106	$ -	$ (1,454,226)	$ 9,225	$ 31,508	$ (1,413,493)	$ 54,765,613
47	1835	Overhead conductors and devices	$ 41,282,342	$ 4,832,502	$ (535,358)	$ (1,165,546)	$ 44,413,941	$ -	$ (1,117,556)	$ 11,292	$ 12,647	$ (1,093,617)	$ 43,320,324
47	1840	Underground Conduit	$ 52,566,190	$ 5,017,549	$ (35,574)	$ (1,169,697)	$ 56,378,468	$ -	$ (1,886,807)	$ 902	$ 15,127	$ (1,870,778)	$ 54,507,689
47	1845	Underground Conductors and Devices	$ 63,660,436	$ 7,151,416	$ (169,469)	$ (1,686,169)	$ 68,956,213	$ -	$ (2,849,308)	$ 5,102	$ 21,688	$ (2,822,518)	$ 66,133,695
47	1850	Line Transformers	$ 52,434,029	$ 6,071,958	$ (577,027)	$ (1,464,489)	$ 56,464,471	$ -	$ (2,124,620)	$ 19,635	$ 21,802	$ (2,083,183)	$ 54,381,287
47	1855	Services	$ 16,434,301	$ 1,304,732		$ (314,687)	$ 17,424,346	$ -	$ (388,421)		$ 3,147	$ (385,274)	$ 17,039,072
47	1860	Meters	$ 21,442,295	$ 3,467,413	$ (59,498)	$ (974,315)	$ 23,875,896	$ -	$ (1,531,870)	$ 4,132	$ 21,979	$ (1,505,760)	$ 22,370,136
N/A	1905	Land	$ 1,067,629	$ -		$ -	$ 1,067,629	$ -	$ -		$ -	$ -	$ 1,067,629
CEC	1906	Land Rights	$ 90,487	$ -		$ -	$ 90,487	$ -	$ (3,337)		$ -	$ (3,337)	$ 87,150
1	1908	Buildings and Fixtures	$ 10,287,342	$ 753,646		$ -	$ 11,040,988	$ -	$ (1,276,104)		$ -	$ (1,276,104)	$ 9,764,885
13	1910	Leasehold Improvements	$ -	$ -		$ -	$ -	$ -			$ -	$ -	$ -
8	1915	Office Furniture and Equipment	$ 1,539,298	$ 24,344		$ -	$ 1,563,642	$ -	$ (217,369)		$ -	$ (217,369)	$ 1,346,273
45	1920	Computer Equipment - Hardware	$ 2,564,204	$ 615,786		$ -	$ 3,179,990	$ -	$ (831,679)		$ -	$ (831,679)	$ 2,348,311
45	1925	Computer Software	$ 4,265,117	$ 859,782		$ -	$ 5,124,898	$ -	$ (1,654,300)		$ -	$ (1,654,300)	$ 3,470,598
10	1930	Transportation Equipment	$ 6,289,635	$ 1,033,975		$ -	$ 7,323,610	$ -	$ (1,288,410)		$ -	$ (1,288,410)	$ 6,035,200
8	1935	Stores Equipment	$ 417,864	$ -		$ -	$ 417,864	$ -	$ (54,989)		$ -	$ (54,989)	$ 362,875
8	1940	Tools, Shop and Garage Equipment	$ 1,806,103	$ 493,820		$ -	$ 2,299,923	$ -	$ (339,618)		$ -	$ (339,618)	$ 1,960,306
8	1945	Measurement and Testing Equipment	$ 474,347	$ 180,845		$ -	$ 655,192	$ -	$ (99,237)		$ -	$ (99,237)	$ 555,955
8	1950	Power Operated Equipment	$ 35,360	$ -		$ -	$ 35,360	$ -	$ (11,365)		$ -	$ (11,365)	$ 23,995
8	1955	Communication Equipment	$ 810,238	$ 903,229		$ -	$ 1,713,467	$ -	$ (141,295)		$ -	$ (141,295)	$ 1,572,172
47	1970	Load Management Controls - Customer Premises	$ 312,338	$ -		$ -	$ 312,338	$ -	$ (51,603)		$ -	$ (51,603)	$ 260,736
47	1980	System Supervisory Equipment	$ 862,471	$ -		$ -	$ 862,471	$ -	$ (107,817)		$ -	$ (107,817)	$ 754,653
47	1996	Hydro One SS Contributions	$ 9,209,036	$ -		$ -	$ 9,209,036	$ -	$ (407,843)		$ -	$ (407,843)	$ 8,801,192
47	1995	Contributions and Grants	$ (35,099,577)	$ -	$ 148,408	$ -	$ (34,951,169)	$ -	$ 1,689,483		$ -	$ 1,689,483	$ (33,261,686)
		Sub-Total	**$ 304,878,268**	**$ 44,005,892**	**$ (1,562,469)**	**$ (9,339,658)**	**$ 337,982,032**	**$ -**	**$ (16,314,151)**	**$ 50,288**	**$ 127,897**	**$ (16,135,965)**	**$ 321,846,067**
		Less Socialized Renewable Energy Generation Investments (input as negative)											
		Less Capital Contributions 2011 and future years	$ -	$ 4,165,260	$ -	$ -	**$ 4,165,260**		$ (56,478)			$ (56,478)	$ 4,108,782
		Total PP&E	**$ 304,878,268**	**$ 39,840,632**	**$ (1,562,469)**	**$ (9,339,658)**	**$ 333,816,772**	**$ -**	**$ (16,257,673)**	**$ 50,288**	**$ 127,897**	**$ (16,079,487)**	**$ 317,737,285**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets)											
		Total											
		Work in Process	$ 9,157,146	$ (742,791)	$ -	$ -	$ 8,414,355						$ 8,414,355
		Total PP&E Including WIP	**$ 314,035,414**	**$ 39,097,841**	**$ (1,562,469)**	**$ (9,339,658)**	**$ 342,231,127**	**$ -**	**$ (16,257,673)**	**$ 50,288**	**$ 127,897**	**$ (16,079,487)**	**$ 326,151,640**

Table 3 - Chapter 2 Filing Requirements - Appendix 2-BA2 – 2012 Actual MIFRS

				Cost					Accumulated Depreciation					
CCA Class	**OEB**	**OEB**	**Description**	**Opening Balance**	**Add Back SM 1555**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Add Back SM 1555**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
47	1675		Standby Generators	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
47	1609		Capital Contributions Hydro One	$ -	$ -	$ 10,000,000	$ -	$ 10,000,000	$ -	$ -	$ -	$ -	$ -	$ 10,000,000
N/A	1805		Land - Substations	$ 414,741		$ -	$ -	$ 414,741	$ -		$ -	$ -	$ -	$ 414,741
1	1808		Buildings - Substations	$ 669,741		$ 57,965	$ -	$ 727,705	$ (76,563)		$ (76,599)	$ -	$ (153,162)	$ 574,543
13	1810		Leasehold Improvements	$ 0		$ -	$ -	$ 0	$ (0)		$ -	$ -	$ (0)	$ -
47	1820		Substation transformers	$ 3,259,383		$ 5,524,644	$ -	$ 8,784,026	$ (89,296)		$ (141,829)	$ -	$ (231,125)	$ 8,552,902
47	1830		Poles, towers and fixtures - concrete	$ 56,179,106		$ 7,971,931	$ (581,164)	$ 63,569,872	$ (1,413,493)		$ (1,613,588)	$ 31,393	$ (2,995,688)	$ 60,574,184
47	1835		Overhead conductors and devices - secondary service	$ 44,413,941		$ 5,290,359	$ (393,761)	$ 49,310,539	$ (1,093,817)		$ (1,199,468)	$ 15,204	$ (2,278,082)	$ 47,032,456
47	1840		Underground conduit chambers and other elements	$ 56,378,468		$ 5,768,050	$ (69,069)	$ 62,077,449	$ (1,870,778)		$ (1,974,758)	$ 6,872	$ (3,838,664)	$ 58,238,785
47	1845		Underground conductors and devices primary XLPE	$ 68,956,213		$ 7,754,629	$ (208,910)	$ 76,501,932	$ (2,822,518)		$ (2,275,890)	$ 8,243	$ (5,090,164)	$ 71,411,768
47	1850		Line transformers - Overhead	$ 56,464,471		$ 5,536,332	$ (508,913)	$ 61,491,889	$ (2,083,183)		$ (2,208,300)	$ 28,301	$ (4,263,182)	$ 57,228,707
47	1855		Services	$ 17,424,346		$ 813,293	$ -	$ 18,237,639	$ (385,274)		$ (406,920)	$ -	$ (792,194)	$ 17,445,446
47	1860		Meters	$ 23,875,896	$ 22,275,055	$ 1,890,455	$ (26,064)	$ 48,015,342	$ (1,505,760)	$ (1,725,075)	$ (3,359,735)	$ 3,278	$ (6,587,291)	$ 41,428,051
N/A	1905		Land	$ 1,067,629	$ -	$ -	$ -	$ 1,067,629	$ -		$ -	$ -	$ -	$ 1,067,629
CEC	1906		Land Rights	$ 90,487	$ -	$ -	$ -	$ 90,487	$ (3,337)		$ (3,337)	$ -	$ (6,674)	$ 83,813
1	1908		Buildings & Fixtures	$ 11,040,988	$ -	$ 2,746,734	$ -	$ 13,787,723	$ (1,276,104)		$ (1,021,603)	$ -	$ (2,297,707)	$ 11,490,016
13	1910		Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
8	1915		Office Furniture & Equipment	$ 1,563,643	$ 295,717	$ 336,611	$ -	$ 2,195,971	$ (217,169)	$ (5,258)	$ (247,650)	$ -	$ (470,078)	$ 1,725,894
10	1920		Computer - Hardware	$ 3,179,990	$ 313,837	$ 1,486,093	$ -	$ 4,979,920	$ (831,679)	$ (71,021)	$ (1,047,852)	$ -	$ (1,950,552)	$ 3,029,368
12	1611		Computer - Software	$ 5,124,899	$ 325,589	$ 528,140	$ -	$ 5,978,627	$ (1,654,300)	$ (19,167)	$ (1,840,326)	$ -	$ (3,513,792)	$ 2,464,835
10	1930		Transportation Equipment	$ 7,323,610	$ -	$ 1,057,410	$ (308,385)	$ 8,072,635	$ (1,288,410)	$ (2,045)	$ (1,243,876)	$ 72,491	$ (2,461,839)	$ 5,610,796
8	1935		Stores Equipment	$ 417,864	$ -	$ -	$ -	$ 417,864	$ (54,989)		$ (54,349)	$ -	$ (109,337)	$ 308,526
8	1940		Tools, Shop & Garage Equipment	$ 2,299,923	$ 43,453	$ 279,587	$ -	$ 2,622,963	$ (339,618)	$ (3,624)	$ (352,561)	$ -	$ (695,803)	$ 1,927,161
8	1945		Measurement & Testing Equipment	$ 655,192	$ 1,080	$ 143,900	$ -	$ 800,173	$ (99,237)		$ (106,666)	$ -	$ (205,903)	$ 594,270
8	1950		Power operated Equipment	$ 35,360	$ -	$ -	$ -	$ 35,360	$ (11,365)		$ (11,041)	$ -	$ (22,406)	$ 12,954
8	1955		Communications Equipment	$ 1,713,467	$ 13,753	$ 17,661	$ -	$ 1,744,881	$ (141,295)		$ (222,948)	$ -	$ (364,243)	$ 1,380,638
47	1970		Load Management controls	$ 312,338	$ -	$ -	$ -	$ 312,338	$ (51,603)		$ (51,603)	$ -	$ (103,205)	$ 209,133
47	1980		System Supervisory Protection and Control	$ 862,471	$ -	$ 28,413	$ -	$ 890,883	$ (107,817)		$ (108,004)	$ -	$ (215,821)	$ 675,062
47	1996		Hydro One S/S Contribution	$ 9,209,036	$ 9,103	$ (1,261,409)	$ -	$ 7,956,730	$ (407,843)		$ (407,843)	$ -	$ (815,686)	$ 7,141,043
47	1995		Contributions & Grants	$ (34,951,171)	$ -	$ -	$ 68,559	$ (34,882,612)	$ 1,689,483		$ 1,607,580	$ (15,016)	$ 3,282,047	$ (31,600,564)
10	2005		Capital Leases	$ -	$ -	$ 820,130	$ -	$ 820,130	$ -		$ -	$ -	$ -	$ 820,130
			Sub-Total	**$ 337,982,031**	**$ 23,277,588**	**$ 56,790,927**	**$ (2,027,707)**	**$ 416,022,839**	**$ (16,135,965)**	**$ (1,826,189)**	**$ (18,369,163)**	**$ 150,765**	**$ (36,180,552)**	**$ 379,842,287**
			Less Socialized Renewable Energy Generation Investments (input as negative)					$ -					$ -	$ -
			Less Other Non Rate-Regulated Utility Assets *(input as negative)*					$ -					$ -	$ -
	2440		***Less Capital Contributions 2011 and future years***	$ 4,165,260	$ -	$ 9,810,885	$ -	$ 13,976,144	$ (56,478)	$ -	$ (177,764)	$ -	$ (234,242)	$ 13,741,903
			Total PP&E	**$ 333,816,771**	**$ 23,277,588**	**$ 46,980,043**	**$ (2,027,707)**	**$ 402,046,695**	**$ (16,079,487)**	**$ (1,826,189)**	**$ (18,191,399)**	**$ 150,765**	**$ (35,946,310)**	**$ 366,100,384**
			Work in Process	$ 8,414,355		$ (4,653,663)		$ 3,760,692	$ -		$ -	$ -	$ -	$ 3,760,692
			Total PP&E Including WIP	**$ 342,231,126**	**$ 23,277,588**	**$ 42,326,380**	**$ (2,027,707)**	**$ 405,807,387**	**$ (16,079,487)**	**$ (1,826,189)**	**$ (18,191,399)**	**$ 150,765**	**$ (35,946,310)**	**$ 369,861,076**

Table 4 - Chapter 2 Filing Requirements - Appendix 2-BA2 – 2013 Actual MIFRS

			Cost				**Accumulated Depreciation**				
CCA Class	**OEB**	**Description**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
43.1	1675	Standby Generators	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1609	Capital Contributions	$ 10,000,000	$ 2,419,847	$ -	$ 12,419,847	$ -	$ (733,127)	$ -	$ (733,127)	$ 11,686,720
N/A	1805	Land - Substations	$ 414,741	$ -	$ -	$ 414,741	$ -	$ -	$ -	$ -	$ 414,741
1	1808	Buildings - Substations	$ 727,705	$ 1,300	$ -	$ 729,005	$ (153,162)	$ (71,752)	$ -	$ (224,914)	$ 504,091
13	1810	Leasehold Improvements	$ 0	$ -	$ -	$ 0	$ (0)	$ -	$ -	$ (0)	$ -
47	1820	Substation transformers	$ 8,784,026	$ 3,141,285	$ -	$ 11,925,312	$ (231,125)	$ (222,631)	$ -	$ (453,756)	$ 11,471,556
47	1830	Poles, towers and fixtures - concrete	$ 63,569,872	$ 5,755,888	$ (324,357)	$ 69,001,403	$ (2,995,688)	$ (1,754,955)	$ 26,595	$ (4,724,048)	$ 64,277,355
47	1835	Overhead conductors and devices - secondary service	$ 49,310,539	$ 4,291,044	$ (507,021)	$ 53,094,562	$ (2,278,082)	$ (1,268,480)	$ 30,923	$ (3,515,638)	$ 49,578,923
47	1840	Underground conduit chambers and other elements	$ 62,077,449	$ 3,276,432	$ (20,356)	$ 65,333,526	$ (3,838,664)	$ (2,065,600)	$ 1,309	$ (5,902,955)	$ 59,430,571
47	1845	Underground conductors and devises primary PILC	$ 76,501,932	$ 6,135,152	$ (253,208)	$ 82,383,876	$ (5,090,164)	$ (2,346,031)	$ 20,176	$ (7,416,019)	$ 74,967,857
47	1850	Line transformers - Overhead	$ 61,491,889	$ 5,339,559	$ (533,942)	$ 66,297,507	$ (4,263,182)	$ (2,347,714)	$ 55,273	$ (6,555,624)	$ 59,741,883
47	1855	Services	$ 18,237,639	$ 770,424	$ -	$ 19,008,063	$ (792,194)	$ (417,506)	$ -	$ (1,209,700)	$ 17,798,364
47	1860	Meters	$ 48,015,342	$ 1,658,707	$ (52,266)	$ 49,621,783	$ (6,587,292)	$ (3,348,346)	$ 9,583	$ (9,926,055)	$ 39,695,728
N/A	1905	Land	$ 1,067,629	$ -	$ -	$ 1,067,629	$ -	$ -	$ -	$ -	$ 1,067,629
CEC	1906	Land Rights	$ 90,487	$ -	$ -	$ 90,487	$ (6,674)	$ (3,337)	$ -	$ (10,011)	$ 80,477
1	1908	Buildings & Fixtures	$ 13,787,723	$ 6,398,686	$ (102,460)	$ 20,083,948	$ (2,297,707)	$ (1,177,158)	$ 12,604	$ (3,462,261)	$ 16,621,688
13	1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment	$ 2,195,971	$ 873,925	$ -	$ 3,069,896	$ (470,078)	$ (281,851)	$ -	$ (751,928)	$ 2,317,968
52	1920	Computer - Hardware	$ 4,979,920	$ 1,390,098	$ -	$ 6,370,018	$ (1,950,552)	$ (976,013)	$ -	$ (2,926,565)	$ 3,443,453
12	1611	Computer - Software	$ 5,978,627	$ 2,317,602	$ -	$ 8,296,229	$ (3,513,792)	$ (1,573,377)	$ -	$ (5,087,169)	$ 3,209,061
10	1930	Transportation Equipment	$ 8,072,635	$ 36,365	$ (0)	$ 8,109,000	$ (2,461,839)	$ (1,250,110)	$ 0	$ (3,711,950)	$ 4,397,051
8	1935	Stores Equipment	$ 417,864	$ -	$ -	$ 417,864	$ (109,337)	$ (53,519)	$ -	$ (162,856)	$ 255,008
8	1940	Tools, Shop & Garage Equipment	$ 2,622,963	$ 417,572	$ -	$ 3,040,535	$ (695,803)	$ (352,668)	$ -	$ (1,048,471)	$ 1,992,064
8	1945	Measurement & Testing Equipment	$ 800,173	$ 197,176	$ -	$ 997,348	$ (205,903)	$ (113,745)	$ -	$ (319,648)	$ 677,700
8	1950	Power operated Equipment	$ 35,360	$ -	$ -	$ 35,360	$ (22,406)	$ (6,770)	$ -	$ (29,176)	$ 6,184
10	1955	Communications Equipment	$ 1,744,881	$ 975	$ -	$ 1,745,855	$ (364,243)	$ (220,700)	$ -	$ (584,943)	$ 1,160,912
8	1970	Load Management controls	$ 312,338	$ -	$ -	$ 312,338	$ (103,205)	$ (51,603)	$ -	$ (154,808)	$ 157,531
8	1980	System Supervisory Protection and Control	$ 890,883	$ 91,934	$ -	$ 982,817	$ (215,821)	$ (92,702)	$ -	$ (308,524)	$ 674,293
47	1996	Hydro One S/S Contribution	$ 7,956,730	$ -	$ -	$ 7,956,730	$ (815,686)	$ (332,159)	$ -	$ (1,147,845)	$ 6,808,884
47	1995	Contributions & Grants	$ (34,882,612)	$ -	$ -	$ (34,882,612)	$ 3,282,047	$ 1,607,580	$ -	$ 4,889,627	$ (29,992,984)
10	2005	Capital Lease	$ 820,130	$ -	$ -	$ 820,130	$ -	$ (273,377)	$ -	$ (273,377)	$ 546,753
		Sub-Total	**$ 416,022,839**	**$ 44,513,971**	**$ (1,793,609)**	**$ 458,743,200**	**$ (36,180,552)**	**$ (19,727,648)**	**$ 156,463**	**$ (55,751,738)**	**$ 402,991,462**
		Less Socialized Renewable Energy Generation Investments **(input as negative)**				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets ***(input as negative)***				$ -				$ -	$ -
	2440	***Less Capital Contributions 2011 and future years***	$ 13,976,144	$ 6,605,934	$ -	$ 20,582,078	$ (234,242)	$ (428,137)	$ -	$ (662,379)	$ 19,919,700
		Total PP&E	**$ 402,046,695**	**$ 37,908,037**	**$ (1,793,609)**	**$ 438,161,122**	**$ (35,946,311)**	**$ (19,299,511)**	**$ 156,463**	**$ (55,089,359)**	**$ 383,071,763**
		Work in Process	$ 3,760,692	$ 1,596,607		$ 5,357,299	$ -	$ -	$ -	$ -	$ 5,357,299
		Total PP&E Including WIP	**$ 405,807,387**	**$ 39,504,643**	**$ (1,793,609)**	**$ 443,518,421**	**$ (35,946,311)**	**$ (19,299,511)**	**$ 156,463**	**$ (55,089,359)**	**$ 388,429,062**

Table 5 - Chapter 2 Filing Requirements - Appendix 2-BA2 – 2014 Bridge Year Forecast MIFRS

			Cost				Accumulated Depreciation				
CCA Class	**OEB**	**Description**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
43.1	1675	Standby Generators	$0	$0	$0	$0	$0	$0	$0	$0	$0
47	1609	Capital Contributions	$12,419,847	$0	$0	$12,419,847	($733,127)	($818,588)	$0	($1,551,715)	$10,868,132
N/A	1805	Land - Substations	$414,741	$0	$0	$414,741	$0	$0	$0	$0	$414,741
1	1808	Buildings - Substations	$729,005	$150,000	$0	$879,005	($224,914)	($76,859)	$0	($301,773)	$577,232
13	1810	Leasehold Improvements	$0	$0	$0	$0	($0)	$0	$0	($0)	$0
47	1820	Substation transformers	$11,925,312	$846,790	$0	$12,772,102	($453,756)	($304,600)	$0	($758,356)	$12,013,746
47	1830	Poles, towers and fixtures - concrete	$69,001,403	$6,599,420	($273,450)	$75,327,373	($4,724,048)	($1,962,036)	$18,539	($6,667,545)	$68,659,828
47	1835	Overhead conductors and devices - secondary service	$53,094,562	$4,974,138	($540,581)	$57,528,119	($3,515,638)	($1,415,106)	$30,885	($4,899,860)	$52,628,259
47	1840	Underground conduit chambers and other elements	$65,333,526	$3,959,555	($40,711)	$69,252,369	($5,902,955)	($2,182,396)	$2,618	($8,082,733)	$61,169,636
47	1845	Underground conductors and devises primary PILC	$82,383,876	$2,140,598	($461,450)	$84,063,024	($7,416,019)	($2,458,674)	$34,746	($9,839,947)	$74,223,077
47	1850	Line transformers - Overhead	$66,297,507	$7,029,249	($389,524)	$72,937,233	($6,555,624)	($2,580,932)	$34,294	($9,102,262)	$63,834,971
47	1855	Services	$19,008,063	$3,436,995	$0	$22,445,058	($1,209,700)	($474,131)	$0	($1,683,831)	$20,761,227
47	1860	Meters	$49,621,783	$2,499,104	($67,772)	$52,053,114	($9,926,055)	($3,532,531)	$11,961	($13,446,625)	$38,606,489
N/A	1905	Land	$1,067,629	$0	$0	$1,067,629	$0	$0	$0	$0	$1,067,629
CEC	1906	Land Rights	$90,487	$0	$0	$90,487	($10,011)	($3,337)	$0	($13,347)	$77,140
1	1908	Buildings & Fixtures	$20,083,948	$3,700,000	$0	$23,783,949	($3,462,261)	($1,166,631)	$0	($4,628,892)	$19,155,057
13	1910	Leasehold Improvements	$0	$0	$0	$0	$0	$0	$0	$0	$0
8	1915	Office Furniture & Equipment	$3,069,896	$618,000	$0	$3,687,896	($751,928)	($404,152)	$0	($1,156,080)	$2,531,816
52	1920	Computer - Hardware	$6,370,018	$1,132,756	$0	$7,502,774	($2,926,565)	($1,298,024)	$0	($4,224,589)	$3,278,185
12	1611	Computer - Software	$8,296,229	$5,321,945	$0	$13,618,174	($5,087,169)	($1,653,638)	$0	($6,740,807)	$6,877,368
10	1930	Transportation Equipment	$8,109,000	$785,000	$0	$8,894,000	($3,711,950)	($1,330,571)	$0	($5,042,521)	$3,851,480
8	1935	Stores Equipment	$417,864	$0	$0	$417,864	($162,856)	($49,367)	$0	($212,223)	$205,641
8	1940	Tools, Shop & Garage Equipment	$3,040,535	$511,300	$0	$3,551,835	($1,048,471)	($391,239)	$0	($1,439,710)	$2,112,125
8	1945	Measurement & Testing Equipment	$997,348	$154,000	$0	$1,151,348	($319,648)	($144,768)	$0	($464,416)	$686,932
8	1950	Power operated Equipment	$35,360	$0	$0	$35,360	($29,176)	($6,178)	$0	($35,354)	$6
10	1955	Communications Equipment	$1,745,855	$6,200	$0	$1,752,055	($584,943)	($220,673)	$0	($805,616)	$946,440
8	1970	Load Management controls	$312,338	$0	$0	$312,338	($154,808)	($51,615)	$0	($206,423)	$105,915
8	1980	System Supervisory Protection and Control	$982,817	$400,000	$0	$1,382,817	($308,524)	($97,492)	$0	($406,016)	$976,801
47	1996	Hydro One S/S Contribution	$7,956,730	$0	$0	$7,956,730	($1,147,845)	($357,384)	$0	($1,505,229)	$6,451,501
47	1995	Contributions & Grants	($34,882,612)	$0	$0	($34,882,612)	$4,889,627	$1,607,580	$0	$6,497,207	($28,385,405)
10	2005	Capital Lease	$820,130	$0	$0	$820,130	($273,377)	($273,377)	$0	($546,753)	$273,377
		Sub-Total	**$458,743,200**	**$44,265,050**	**($1,773,488)**	**$501,234,761**	**($55,751,738)**	**($21,646,719.87)**	**$133,043**	**($77,265,415)**	**$423,969,347**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$0				$0	$0
		***Less Other Non Rate-Regulated Utility Assets** (input as negative)*				$0				$0	$0
	2440	***Less Capital Contributions 2011 and future years***	$20,582,078	$4,473,000	$0	$25,055,078	($662,379)	($623,000)	$0	($1,285,379)	$23,769,700
		Total PP&E	**$438,161,122**	**$39,792,050**	**($1,773,488)**	**$476,179,683**	**($55,089,359)**	**($21,023,720)**	**$133,043**	**($75,980,036)**	**$400,199,647**
		Work in Process	$5,357,299	($2,018,736)		$3,338,563	$0	$0	$0	$0	$3,338,563
		Total PP&E Including WIP	**$443,518,421**	**$37,773,313**	**($1,773,488)**	**$479,518,246**	**($55,089,359)**	**($21,023,720)**	**$133,043**	**($75,980,036)**	**$403,538,209**

Table 6 - Chapter 2 Filing Requirements - Appendix 2-BA2 – 2015 Test Year Forecast MIFRS

			Cost					Accumulated Depreciation					
CCA Class	OEB	Description	Opening Balance	Add Back SM From 1555	Additions	Disposals	Closing Balance	Opening Balance	Add Back SM From 1555	Additions	Disposals	Closing Balance	Net Book Value
43.1	1675	Standby Generators	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
47	1609	Capital Contributions	$ 12,419,847	$ -	$ -	$ -	$ 12,419,847	$ (1,551,715)	$ -	$ (818,588)	$ -	$ (2,370,303)	$ 10,049,545
N/A	1805	Land - Substations	$ 414,741		$ -	$ -	$ 414,741	$ -		$ -	$ -	$ -	$ 414,741
1	1808	Buildings - Substations	$ 879,005		$ -	$ -	$ 879,005	$ (301,773)		$ (70,955)	$ -	$ (372,728)	$ 506,277
13	1810	Leasehold Improvements	$ 0		$ -	$ -	$ 0	$ (0)		$ -	$ -	$ (0)	$ -
47	1820	Substation transformers	$ 12,772,102		$ 754,301	$ -	$ 13,526,403	$ (758,356)		$ (323,909)	$ -	$ (1,082,264)	$ 12,444,139
47	1830	Poles, towers and fixtures - concrete	$ 75,327,373		$ 9,106,322	$ (322,175)	$ 84,111,520	$ (6,667,545)		$ (2,128,997)	$ 26,331	$ (8,770,210)	$ 75,341,310
47	1835	Overhead conductors and devices - secondary service	$ 57,528,119		$ 5,755,400	$ (636,904)	$ 62,646,615	$ (4,899,860)		$ (1,521,250)	$ 44,245	$ (6,376,865)	$ 56,269,751
47	1840	Underground conduit chambers and other elements	$ 69,252,369		$ 6,132,251	$ (47,965)	$ 75,336,655	$ (8,082,733)		$ (2,318,353)	$ 3,817	$ (10,397,269)	$ 64,939,386
47	1845	Underground conductors and devises primary PILC	$ 84,063,024		$ 2,264,209	$ (543,673)	$ 85,783,560	$ (9,839,947)		$ (2,487,230)	$ 49,099	$ (12,278,077)	$ 73,505,482
47	1850	Line transformers - Overhead	$ 72,937,233		$ 7,352,388	$ (458,931)	$ 79,830,690	$ (9,102,262)		$ (2,762,069)	$ 46,646	$ (11,817,685)	$ 68,013,005
47	1855	Services	$ 22,445,058		$ 1,250,214	$ -	$ 23,695,272	$ (1,683,831)		$ (520,373)	$ -	$ (2,204,204)	$ 21,491,068
47	1860	Meters	$ 52,053,114	$ 2,231,464	$ 2,470,674	$ (79,848)	$ 56,675,403	$ (13,446,625)	$ (250,993)	$ (3,738,273)	$ 17,284	$ (17,418,607)	$ 39,256,796
N/A	1905	Land	$ 1,067,629		$ -	$ -	$ 1,067,629	$ -		$ -	$ -	$ -	$ 1,067,629
CEC	1906	Land Rights	$ 90,487		$ -	$ -	$ 90,487	$ (13,347)		$ (3,337)	$ -	$ (16,684)	$ 73,803
1	1908	Buildings & Fixtures	$ 23,783,949		$ 3,700,000	$ -	$ 27,483,949	$ (4,628,892)		$ (1,244,241)	$ -	$ (5,873,133)	$ 21,610,816
13	1910	Leasehold Improvements	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment	$ 3,687,896		$ 69,000	$ -	$ 3,756,896	$ (1,156,080)		$ (447,293)	$ -	$ (1,603,373)	$ 2,153,523
52	1920	Computer - Hardware	$ 7,502,774		$ 1,491,500	$ -	$ 8,994,274	$ (4,224,589)		$ (1,380,938)	$ -	$ (5,605,527)	$ 3,388,748
12	1611	Computer - Software	$ 13,618,174		$ 2,390,404	$ -	$ 16,008,579	$ (6,740,807)		$ (3,056,428)	$ -	$ (9,797,234)	$ 6,211,344
10	1930	Transportation Equipment	$ 8,894,000		$ 778,000	$ -	$ 9,672,000	$ (5,042,521)		$ (1,273,018)	$ -	$ (6,315,539)	$ 3,356,462
8	1935	Stores Equipment	$ 417,864		$ -	$ -	$ 417,864	$ (212,223)		$ (48,108)	$ -	$ (260,331)	$ 157,533
8	1940	Tools, Shop & Garage Equipment	$ 3,551,835		$ 555,560	$ -	$ 4,107,395	$ (1,439,710)		$ (419,351)	$ -	$ (1,859,061)	$ 2,248,334
8	1945	Measurement & Testing Equipment	$ 1,151,348		$ 132,300	$ -	$ 1,283,648	$ (464,416)		$ (149,991)	$ -	$ (614,408)	$ 669,241
8	1950	Power operated Equipment	$ 35,360		$ -	$ -	$ 35,360	$ (35,354)		$ -	$ -	$ (35,354)	$ 6
10	1955	Communications Equipment	$ 1,752,055		$ 245,000	$ -	$ 1,997,055	$ (805,616)		$ (233,880)	$ -	$ (1,039,496)	$ 957,559
8	1970	Load Management controls	$ 312,338		$ -	$ -	$ 312,338	$ (206,423)		$ (51,615)	$ -	$ (258,038)	$ 54,300
8	1980	System Supervisory Protection and Control	$ 1,382,817		$ 300,000	$ -	$ 1,682,817	$ (406,016)		$ (114,168)	$ -	$ (520,184)	$ 1,162,633
47	1996	Hydro One S/S Contribution	$ 7,956,730		$ -	$ -	$ 7,956,730	$ (1,505,229)		$ (357,384)	$ -	$ (1,862,612)	$ 6,094,117
47	1995	Contributions & Grants	$ (34,882,612)		$ -	$ -	$ (34,882,612)	$ 6,497,207		$ 1,607,580	$ -	$ 8,104,787	$ (26,777,825)
10	2005	Capital Lease	$ 820,130		$ -	$ -	$ 820,130	$ (546,753)		$ (273,377)	$ -	$ (820,130)	$ -
		Sub-Total	**$ 501,234,761**	**$ 2,231,464**	**$ 44,747,524**	**$ (2,089,496)**	**$ 546,124,253**	**$ (77,265,415)**	**$ (250,993)**	**$ (24,135,544)**	**$ 187,423**	**$ (101,464,530)**	**$ 444,659,723**
		Less Socialized Renewable Energy Generation Investments (input as negative)					$ -					$ -	$ -
		Less Other Non Rate-Regulated Utility Assets *(input as negative)*					$ -					$ -	$ -
	2440	***Less Capital Contributions 2011 and future years***	$ 25,055,078	$ -	$ 4,633,000	$ -	$ 29,688,078	$ (1,285,379)	$ -	$ (752,000)	$ -	$ (2,037,379)	$ 27,650,700
		Total PP&E	**$ 476,179,683**	**$ 2,231,464**	**$ 40,114,524**	**$ (2,089,496)**	**$ 516,436,174**	**$ (75,980,036)**	**$ (250,993)**	**$ (23,383,544)**	**$ 187,423**	**$ (99,427,151)**	**$ 417,009,023**
		Work in Process	$ 3,338,563		$ (174,557)		$ 3,164,006	$ -		$ -	$ -	$ -	$ 3,164,006
		Total PP&E Including WIP	**$ 479,518,246**	**$ 2,231,464**	**$ 39,939,967**	**$ (2,089,496)**	**$ 519,600,180**	**$ (75,980,036)**	**$ (250,993)**	**$ (23,383,544)**	**$ 187,423**	**$ (99,427,151)**	**$ 420,173,029**

Table 7 - Chapter 2 Filing Requirements - Appendix 2-BA2 – 2016 Test Year Forecast MIFRS

			Cost				**Accumulated Depreciation**				
CCA Class	**OEB**	**Description**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
43.1	1675	Standby Generators	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1609	Capital Contributions	$ 12,419,847	$ -	$ -	$ 12,419,847	$ (2,370,303)	$ (818,588)	$ -	$ (3,188,891)	$ 9,230,957
N/A	1805	Land - Substations	$ 414,741	$ -	$ -	$ 414,741	$ -	$ -	$ -	$ -	$ 414,741
1	1808	Buildings - Substations	$ 879,005	$ -	$ -	$ 879,005	$ (372,728)	$ (55,897)	$ -	$ (428,625)	$ 450,381
13	1810	Leasehold Improvements	$ 0	$ -	$ -	$ 0	$ (0)	$ -	$ -	$ (0)	$ -
47	1820	Substation transformers	$ 13,526,403	$ 902,070	$ -	$ 14,428,473	$ (1,082,264)	$ (344,767)	$ -	$ (1,427,032)	$ 13,001,442
47	1830	Poles, towers and fixtures - concrete	$ 84,111,520	$ 10,123,690	$ (463,325)	$ 93,771,885	$ (8,770,210)	$ (2,336,742)	$ 37,537	$ (11,069,415)	$ 82,702,470
47	1835	Overhead conductors and devices - secondary service	$ 62,646,615	$ 5,878,255	$ (915,942)	$ 67,608,928	$ (6,376,865)	$ (1,633,251)	$ 63,459	$ (7,946,657)	$ 59,662,271
47	1840	Underground conduit chambers and other elements	$ 75,336,655	$ 5,146,835	$ (68,980)	$ 80,414,511	$ (10,397,269)	$ (2,456,831)	$ 5,541	$ (12,848,559)	$ 67,565,952
47	1845	Underground conductors and devises primary PILC	$ 85,783,560	$ 5,121,047	$ (781,865)	$ 90,122,742	$ (12,278,077)	$ (2,557,013)	$ 69,740	$ (14,765,351)	$ 75,357,391
47	1850	Line transformers - Overhead	$ 79,830,690	$ 8,537,311	$ (659,995)	$ 87,708,005	$ (11,817,685)	$ (2,966,019)	$ 64,410	$ (14,719,294)	$ 72,988,711
47	1855	Services	$ 23,695,272	$ 3,904,951	$ -	$ 27,600,224	$ (2,204,204)	$ (574,137)	$ -	$ (2,778,342)	$ 24,821,882
47	1860	Meters	$ 56,675,403	$ 2,101,174	$ (114,831)	$ 58,661,745	$ (17,418,607)	$ (3,790,838)	$ 24,940	$ (21,184,505)	$ 37,477,240
N/A	1905	Land	$ 1,067,629	$ -	$ -	$ 1,067,629	$ -	$ -	$ -	$ -	$ 1,067,629
CEC	1906	Land Rights	$ 90,487	$ -	$ -	$ 90,487	$ (16,684)	$ (3,337)	$ -	$ (20,021)	$ 70,466
1	1908	Buildings & Fixtures	$ 27,483,949	$ 1,995,000	$ -	$ 29,478,949	$ (5,873,133)	$ (1,154,568)	$ -	$ (7,027,701)	$ 22,451,248
13	1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment	$ 3,756,896	$ 69,000	$ -	$ 3,825,896	$ (1,603,373)	$ (442,132)	$ -	$ (2,045,505)	$ 1,780,391
52	1920	Computer - Hardware	$ 8,994,274	$ 825,500	$ -	$ 9,819,774	$ (5,605,527)	$ (1,595,149)	$ -	$ (7,200,676)	$ 2,619,098
12	1611	Computer - Software	$ 16,008,579	$ 455,500	$ -	$ 16,464,079	$ (9,797,234)	$ (3,157,219)	$ -	$ (12,954,453)	$ 3,509,626
10	1930	Transportation Equipment	$ 9,672,000	$ 780,000	$ -	$ 10,452,000	$ (6,315,539)	$ (1,106,815)	$ -	$ (7,422,353)	$ 3,029,647
8	1935	Stores Equipment	$ 417,864	$ -	$ -	$ 417,864	$ (260,331)	$ (47,431)	$ -	$ (307,762)	$ 110,102
8	1940	Tools, Shop & Garage Equipment	$ 4,107,395	$ 567,600	$ -	$ 4,674,995	$ (1,859,061)	$ (447,470)	$ -	$ (2,306,530)	$ 2,368,465
8	1945	Measurement & Testing Equipment	$ 1,283,648	$ 89,600	$ -	$ 1,373,248	$ (614,408)	$ (141,131)	$ -	$ (755,538)	$ 617,710
8	1950	Power operated Equipment	$ 35,360	$ -	$ -	$ 35,360	$ (35,354)	$ -	$ -	$ (35,354)	$ 6
10	1955	Communications Equipment	$ 1,997,055	$ 5,000	$ -	$ 2,002,055	$ (1,039,496)	$ (230,472)	$ -	$ (1,269,968)	$ 732,087
8	1970	Load Management controls	$ 312,338	$ -	$ -	$ 312,338	$ (258,038)	$ (48,856)	$ -	$ (306,894)	$ 5,444
8	1980	System Supervisory Protection and Control	$ 1,682,817	$ 200,000	$ -	$ 1,882,817	$ (520,184)	$ (126,853)	$ -	$ (647,037)	$ 1,235,780
47	1996	Hydro One S/S Contribution	$ 7,956,730	$ -	$ -	$ 7,956,730	$ (1,862,612)	$ (357,384)	$ -	$ (2,219,996)	$ 5,736,733
47	1995	Contributions & Grants	$ (34,882,612)	$ -	$ -	$ (34,882,612)	$ 8,104,787	$ 1,607,580	$ -	$ 9,712,367	$ (25,170,245)
10	2005	Capital Lease	$ 820,130	$ 900,000	$ (820,130)	$ 900,000	$ (820,130)	$ (300,000)	$ 820,130	$ (300,000)	$ 600,000
		Sub-Total	**$ 546,124,253**	**$ 47,602,533**	**$ (3,825,068)**	**$ 589,901,718**	**$ (101,464,530)**	**$ (25,085,320)**	**$ 1,085,758**	**$ (125,464,092)**	**$ 464,437,626**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
	2440	***Less Capital Contributions 2011 and future years***	$ 29,688,078	$ 4,655,000	$ -	$ 34,343,078	$ (2,037,379)	$ (884,000)	$ -	$ (2,921,379)	$ 31,421,700
		Total PP&E	**$ 516,436,174**	**$ 42,947,533**	**$ (3,825,068)**	**$ 555,558,640**	**$ (99,427,151)**	**$ (24,201,320)**	**$ 1,085,758**	**$ (122,542,713)**	**$ 433,015,927**

		Work in Process	$ 3,164,006	$ -		$ 3,164,006	$ -	$ -	$ -	$ -	$ 3,164,006
		Total PP&E Including WIP	**$ 519,600,180**	**$ 42,947,533**	**$ (3,825,068)**	**$ 558,722,646**	**$ (99,427,151)**	**$ (24,201,320)**	**$ 1,085,758**	**$ (122,542,713)**	**$ 436,179,933**

Table 8 - Chapter 2 Filing Requirements - Appendix 2-BA2 – 2017 Test Year Forecast MIFRS

			Cost				Accumulated Depreciation				
CCA Class	**OEB**	**Description**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
43.1	1675	Standby Generators	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1609	Capital Contributions	$ 12,419,847	$ -	$ -	$ 12,419,847	$ (3,188,891)	$ (818,588)	$ -	$ (4,007,478)	$ 8,412,369
N/A	1805	Land - Substations	$ 414,741	$ -	$ -	$ 414,741	$ -	$ -	$ -	$ -	$ 414,741
1	1808	Buildings - Substations	$ 879,005	$ -	$ -	$ 879,005	$ (428,625)	$ (51,715)	$ -	$ (480,339)	$ 398,666
13	1810	Leasehold Improvements	$ 0	$ -	$ -	$ 0	$ (0)	$ -	$ -	$ (0)	$ -
47	1820	Substation transformers	$ 14,428,473	$ 911,190	$ -	$ 15,339,664	$ (1,427,032)	$ (367,442)	$ -	$ (1,794,474)	$ 13,545,190
47	1830	Poles, towers and fixtures - concrete	$ 93,771,885	$ 10,176,507	$ (465,258)	$ 103,483,135	$ (11,069,415)	$ (2,543,828)	$ 48,790	$ (13,564,454)	$ 89,918,681
47	1835	Overhead conductors and devices - secondary service	$ 67,608,928	$ 5,941,145	$ (919,763)	$ 72,630,310	$ (7,946,657)	$ (1,744,121)	$ 82,753	$ (9,608,025)	$ 63,022,285
47	1840	Underground conduit chambers and other elements	$ 80,414,511	$ 5,034,920	$ (69,267)	$ 85,380,163	$ (12,848,559)	$ (2,582,258)	$ 7,273	$ (15,423,544)	$ 69,956,619
47	1845	Underground conductors and devises primary PILC	$ 90,122,742	$ 9,777,635	$ (785,127)	$ 99,115,250	$ (14,765,351)	$ (2,741,773)	$ 90,467	$ (17,416,656)	$ 81,698,594
47	1850	Line transformers - Overhead	$ 87,708,005	$ 8,478,595	$ (662,749)	$ 95,523,852	$ (14,719,294)	$ (3,189,703)	$ 82,248	$ (17,826,749)	$ 77,697,103
47	1855	Services	$ 27,600,224	$ 3,910,048	$ -	$ 31,510,272	$ (2,778,342)	$ (652,291)	$ -	$ (3,430,633)	$ 28,079,638
47	1860	Meters	$ 58,661,745	$ 2,046,174	$ (115,310)	$ 60,592,609	$ (21,184,505)	$ (3,844,312)	$ 32,627	$ (24,996,190)	$ 35,596,418
N/A	1905	Land	$ 1,067,629	$ -	$ -	$ 1,067,629	$ -	$ -	$ -	$ -	$ 1,067,629
CEC	1906	Land Rights	$ 90,487	$ -	$ -	$ 90,487	$ (20,021)	$ (3,337)	$ -	$ (23,358)	$ 67,129
1	1908	Buildings & Fixtures	$ 29,478,949	$ 2,495,000	$ -	$ 31,973,949	$ (7,027,701)	$ (1,189,448)	$ -	$ (8,217,149)	$ 23,756,800
13	1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment	$ 3,825,896	$ 69,000	$ -	$ 3,894,896	$ (2,045,505)	$ (416,999)	$ -	$ (2,462,504)	$ 1,432,393
52	1920	Computer - Hardware	$ 9,819,774	$ 1,447,200	$ -	$ 11,266,974	$ (7,200,676)	$ (1,605,174)	$ -	$ (8,805,850)	$ 2,461,124
12	1611	Computer - Software	$ 16,464,079	$ 439,500	$ -	$ 16,903,579	$ (12,954,453)	$ (2,354,594)	$ -	$ (15,309,047)	$ 1,594,532
10	1930	Transportation Equipment	$ 10,452,000	$ 775,000	$ -	$ 11,227,000	$ (7,422,353)	$ (1,095,601)	$ -	$ (8,517,955)	$ 2,709,046
8	1935	Stores Equipment	$ 417,864	$ -	$ -	$ 417,864	$ (307,762)	$ (47,085)	$ -	$ (354,847)	$ 63,017
8	1940	Tools, Shop & Garage Equipment	$ 4,674,995	$ 508,600	$ -	$ 5,183,595	$ (2,306,530)	$ (459,895)	$ -	$ (2,766,425)	$ 2,417,170
8	1945	Measurement & Testing Equipment	$ 1,373,248	$ 87,600	$ -	$ 1,460,848	$ (755,538)	$ (135,069)	$ -	$ (890,607)	$ 570,241
8	1950	Power operated Equipment	$ 35,360	$ -	$ -	$ 35,360	$ (35,354)	$ -	$ -	$ (35,354)	$ 6
10	1955	Communications Equipment	$ 2,002,055	$ 5,000	$ -	$ 2,007,055	$ (1,269,968)	$ (148,682)	$ -	$ (1,418,650)	$ 588,406
8	1970	Load Management controls	$ 312,338	$ -	$ -	$ 312,338	$ (306,894)	$ (5,431)	$ -	$ (312,325)	$ 13
8	1980	System Supervisory Protection and Control	$ 1,882,817	$ -	$ -	$ 1,882,817	$ (647,037)	$ (130,106)	$ -	$ (777,143)	$ 1,105,674
47	1996	Hydro One S/S Contribution	$ 7,956,730	$ -	$ -	$ 7,956,730	$ (2,219,996)	$ (357,384)	$ -	$ (2,577,380)	$ 5,379,350
47	1995	Contributions & Grants	$ (34,882,612)	$ -	$ -	$ (34,882,612)	$ 9,712,367	$ 1,607,580	$ -	$ 11,319,947	$ (23,562,665)
10	2005	Capital Lease	$ 900,000	$ -	$ -	$ 900,000	$ (300,000)	$ (300,000)	$ -	$ (600,000)	$ 300,000
		Sub-Total	**$ 589,901,718**	**$ 52,103,114**	**$ (3,017,473)**	**$ 638,987,359**	**$ (125,464,092)**	**$ (25,177,257)**	**$ 344,159**	**$ (150,297,190)**	**$ 488,690,169**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets *(input as negative)*				$ -				$ -	$ -
	2440	***Less Capital Contributions 2011 and future years***	$ 34,343,078	$ 4,677,000	$ -	$ 39,020,078	$ (2,921,379)	$ (1,016,000)	$ -	$ (3,937,379)	$ 35,082,700
		Total PP&E	**$ 555,558,640**	**$ 47,426,114**	**$ (3,017,473)**	**$ 599,967,280**	**$ (122,542,713)**	**$ (24,161,257)**	**$ 344,159**	**$ (146,359,811)**	**$ 453,607,469**
		Work in Process	$ 3,164,006	$ -		$ 3,164,006	$ -	$ -	$ -	$ -	$ 3,164,006
		Total PP&E Including WIP	**$ 558,722,646**	**$ 47,426,114**	**$ (3,017,473)**	**$ 603,131,286**	**$ (122,542,713)**	**$ (24,161,257)**	**$ 344,159**	**$ (146,359,811)**	**$ 456,771,475**

Table 9 - Chapter 2 Filing Requirements - Appendix 2-BA2 – 2018 Test Year Forecast MIFRS

			Cost				Accumulated Depreciation				
CCA Class	**OEB**	**Description**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
43.1	1675	Standby Generators	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1609	Capital Contributions	$ 12,419,847	$ -	$ -	$ 12,419,847	$ (4,007,478)	$ (818,588)	$ -	$ (4,826,066)	$ 7,593,781
N/A	1805	Land - Substations	$ 414,741	$ -	$ -	$ 414,741	$ -	$ -	$ -	$ -	$ 414,741
1	1808	Buildings - Substations	$ 879,005	$ -	$ -	$ 879,005	$ (480,339)	$ (41,888)	$ -	$ (522,227)	$ 356,778
13	1810	Leasehold Improvements	$ 0	$ -	$ -	$ 0	$ (0)	$ -	$ -	$ (0)	$ -
47	1820	Substation transformers	$ 15,339,664	$ 929,783	$ -	$ 16,269,447	$ (1,794,474)	$ (390,474)	$ -	$ (2,184,948)	$ 14,084,499
47	1830	Poles, towers and fixtures - concrete	$ 103,483,135	$ 11,905,369	$ (511,597)	$ 114,876,907	$ (13,564,454)	$ (2,773,958)	$ 61,163	$ (16,277,248)	$ 98,599,659
47	1835	Overhead conductors and devices - secondary service	$ 72,630,310	$ 6,977,528	$ (1,011,370)	$ 78,596,468	$ (9,608,025)	$ (1,865,990)	$ 103,969	$ (11,370,046)	$ 67,226,421
47	1840	Underground conduit chambers and other elements	$ 85,380,163	$ 5,333,288	$ (76,166)	$ 90,637,284	$ (15,423,544)	$ (2,710,346)	$ 9,177	$ (18,124,713)	$ 72,512,571
47	1845	Underground conductors and devises primary PILC	$ 99,115,250	$ 7,784,123	$ (863,324)	$ 106,036,050	$ (17,416,656)	$ (2,958,837)	$ 113,259	$ (20,262,234)	$ 85,773,815
47	1850	Line transformers - Overhead	$ 95,523,852	$ 9,007,105	$ (728,757)	$ 103,802,199	$ (17,826,749)	$ (3,407,386)	$ 101,863	$ (21,132,272)	$ 82,669,927
47	1855	Services	$ 31,510,272	$ 4,032,234	$ -	$ 35,542,505	$ (3,430,633)	$ (731,816)	$ -	$ (4,162,449)	$ 31,380,056
47	1860	Meters	$ 60,592,609	$ 2,063,174	$ (126,795)	$ 62,528,988	$ (24,996,190)	$ (3,860,605)	$ 41,080	$ (28,815,715)	$ 33,713,273
N/A	1905	Land	$ 1,067,629	$ -	$ -	$ 1,067,629	$ -	$ -	$ -	$ -	$ 1,067,629
CEC	1906	Land Rights	$ 90,487	$ -	$ -	$ 90,487	$ (23,358)	$ (3,337)	$ -	$ (26,695)	$ 63,793
1	1908	Buildings & Fixtures	$ 31,973,949	$ 1,595,000	$ -	$ 33,568,949	$ (8,217,149)	$ (1,070,801)	$ -	$ (9,287,950)	$ 24,280,999
13	1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment	$ 3,894,896	$ 73,000	$ -	$ 3,967,896	$ (2,462,504)	$ (377,449)	$ -	$ (2,839,953)	$ 1,127,944
52	1920	Computer - Hardware	$ 11,266,974	$ 868,200	$ -	$ 12,135,174	$ (8,805,850)	$ (1,514,620)	$ -	$ (10,320,470)	$ 1,814,704
12	1611	Computer - Software	$ 16,903,579	$ 1,664,500	$ -	$ 18,568,079	$ (15,309,047)	$ (1,044,342)	$ -	$ (16,353,389)	$ 2,214,690
10	1930	Transportation Equipment	$ 11,227,000	$ 785,000	$ -	$ 12,012,000	$ (8,517,955)	$ (1,046,634)	$ -	$ (9,564,588)	$ 2,447,412
8	1935	Stores Equipment	$ 417,864	$ -	$ -	$ 417,864	$ (354,847)	$ (45,278)	$ -	$ (400,125)	$ 17,739
8	1940	Tools, Shop & Garage Equipment	$ 5,183,595	$ 530,600	$ -	$ 5,714,195	$ (2,766,425)	$ (478,845)	$ -	$ (3,245,270)	$ 2,468,925
8	1945	Measurement & Testing Equipment	$ 1,460,848	$ 89,600	$ -	$ 1,550,448	$ (890,607)	$ (136,919)	$ -	$ (1,027,526)	$ 522,923
8	1950	Power operated Equipment	$ 35,360	$ -	$ -	$ 35,360	$ (35,354)	$ -	$ -	$ (35,354)	$ 6
10	1955	Communications Equipment	$ 2,007,055	$ 5,000	$ -	$ 2,012,055	$ (1,418,650)	$ (136,552)	$ -	$ (1,555,202)	$ 456,854
8	1970	Load Management controls	$ 312,338	$ -	$ -	$ 312,338	$ (312,325)	$ -	$ -	$ (312,325)	$ 13
8	1980	System Supervisory Protection and Control	$ 1,882,817	$ -	$ -	$ 1,882,817	$ (777,143)	$ (120,722)	$ -	$ (897,865)	$ 984,952
47	1996	Hydro One S/S Contribution	$ 7,956,730	$ -	$ -	$ 7,956,730	$ (2,577,380)	$ (357,384)	$ -	$ (2,934,763)	$ 5,021,966
47	1995	Contributions & Grants	$ (34,882,612)	$ -	$ -	$ (34,882,612)	$ 11,319,947	$ 1,607,580	$ -	$ 12,927,527	$ (21,955,085)
10	2005	Capital Lease	$ 900,000	$ -	$ -	$ 900,000	$ (600,000)	$ (300,000)	$ -	$ (900,000)	$ -
		Sub-Total	**$ 638,987,359**	**$ 53,643,504**	**$ (3,318,009)**	**$ 689,312,853**	**$ (150,297,190)**	**$ (24,585,190)**	**$ 430,511**	**$ (174,451,869)**	**$ 514,860,985**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets *(input as negative)*				$ -				$ -	$ -
	2440	***Less Capital Contributions 2011 and future years***	$ 39,020,078	$ 4,701,000	$ -	$ 43,721,078	$ (3,937,379)	$ (1,148,000)	$ -	$ (5,085,379)	$ 38,635,700
		Total PP&E	**$ 599,967,280**	**$ 48,942,504**	**$ (3,318,009)**	**$ 645,591,775**	**$ (146,359,811)**	**$ (23,437,190)**	**$ 430,511**	**$ (169,366,490)**	**$ 476,225,285**
		Work in Process	$ 3,164,006	$ -		$ 3,164,006	$ -	$ -	$ -	$ -	$ 3,164,006
		Total PP&E Including WIP	**$ 603,131,286**	**$ 48,942,504**	**$ (3,318,009)**	**$ 648,755,781**	**$ (146,359,811)**	**$ (23,437,190)**	**$ 430,511**	**$ (169,366,490)**	**$ 479,389,291**

Table 10 - Chapter 2 Filing Requirements - Appendix 2-BA2 – 2019 Test Year Forecast MIFRS

			Cost				Accumulated Depreciation				
CCA Class	**OEB**	**Description**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
43.1	1675	Standby Generators	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1609	Capital Contributions	$ 12,419,847	$ -	$ -	$ 12,419,847	$ (4,826,066)	$ (818,588)	$ -	$ (5,644,654)	$ 6,775,193
N/A	1805	Land - Substations	$ 414,741	$ -	$ -	$ 414,741	$ -	$ -	$ -	$ -	$ 414,741
1	1808	Buildings - Substations	$ 879,005	$ -	$ -	$ 879,005	$ (522,227)	$ (34,745)	$ -	$ (556,972)	$ 322,034
13	1810	Leasehold Improvements	$ 0	$ -	$ -	$ 0	$ (0)	$ -	$ -	$ (0)	$ -
47	1820	Substation transformers	$ 16,269,447	$ 950,986	$ -	$ 17,220,433	$ (2,184,948)	$ (414,006)	$ -	$ (2,598,953)	$ 14,621,480
47	1830	Poles, towers and fixtures - concrete	$ 114,876,907	$ 12,581,297	$ (570,158)	$ 126,888,045	$ (16,277,248)	$ (3,091,335)	$ 74,953	$ (19,293,630)	$ 107,594,415
47	1835	Overhead conductors and devices - secondary service	$ 78,596,468	$ 7,091,513	$ (1,127,140)	$ 84,560,841	$ (11,370,046)	$ (2,022,337)	$ 127,613	$ (13,264,771)	$ 71,296,070
47	1840	Underground conduit chambers and other elements	$ 90,637,284	$ 5,699,675	$ (84,885)	$ 96,252,074	$ (18,124,713)	$ (2,624,544)	$ 11,299	$ (20,737,958)	$ 75,514,117
47	1845	Underground conductors and devises primary PILC	$ 106,036,050	$ 7,569,832	$ (962,148)	$ 112,643,733	$ (20,262,234)	$ (3,175,946)	$ 138,659	$ (23,299,521)	$ 89,344,213
47	1850	Line transformers - Overhead	$ 103,802,199	$ 9,623,452	$ (812,177)	$ 112,613,474	$ (21,132,272)	$ (3,680,119)	$ 123,723	$ (24,688,668)	$ 87,924,806
47	1855	Services	$ 35,542,505	$ 4,186,649	$ -	$ 39,729,154	$ (4,162,449)	$ (820,427)	$ -	$ (4,982,877)	$ 34,746,278
47	1860	Meters	$ 62,528,988	$ 2,063,174	$ (141,309)	$ 64,450,852	$ (28,815,715)	$ (3,940,280)	$ 50,501	$ (32,705,494)	$ 31,745,358
N/A	1905	Land	$ 1,067,629	$ -	$ -	$ 1,067,629	$ -	$ -	$ -	$ -	$ 1,067,629
CEC	1906	Land Rights	$ 90,487	$ -	$ -	$ 90,487	$ (26,695)	$ (3,337)	$ -	$ (30,031)	$ 60,456
1	1908	Buildings & Fixtures	$ 33,568,949	$ 1,595,000	$ -	$ 35,163,949	$ (9,287,950)	$ (1,123,968)	$ -	$ (10,411,918)	$ 24,752,031
13	1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment	$ 3,967,896	$ 73,000	$ -	$ 4,040,896	$ (2,839,953)	$ (365,378)	$ -	$ (3,205,331)	$ 835,566
52	1920	Computer - Hardware	$ 12,135,174	$ 1,518,200	$ -	$ 13,653,374	$ (10,320,470)	$ (1,177,170)	$ -	$ (11,497,640)	$ 2,155,734
12	1611	Computer - Software	$ 18,568,079	$ 689,500	$ -	$ 19,257,579	$ (16,353,389)	$ (972,973)	$ -	$ (17,326,362)	$ 1,931,217
10	1930	Transportation Equipment	$ 12,012,000	$ 785,000	$ -	$ 12,797,000	$ (9,564,588)	$ (934,791)	$ -	$ (10,499,379)	$ 2,297,621
8	1935	Stores Equipment	$ 417,864	$ -	$ -	$ 417,864	$ (400,125)	$ (17,738)	$ -	$ (417,863)	$ 1
8	1940	Tools, Shop & Garage Equipment	$ 5,714,195	$ 580,600	$ -	$ 6,294,795	$ (3,245,270)	$ (506,399)	$ -	$ (3,751,669)	$ 2,543,126
8	1945	Measurement & Testing Equipment	$ 1,550,448	$ 89,600	$ -	$ 1,640,048	$ (1,027,526)	$ (137,911)	$ -	$ (1,165,436)	$ 474,612
8	1950	Power operated Equipment	$ 35,360	$ -	$ -	$ 35,360	$ (35,354)	$ -	$ -	$ (35,354)	$ 6
10	1955	Communications Equipment	$ 2,012,055	$ 5,000	$ -	$ 2,017,055	$ (1,555,202)	$ (135,046)	$ -	$ (1,690,248)	$ 326,807
8	1970	Load Management controls	$ 312,338	$ -	$ -	$ 312,338	$ (312,325)	$ -	$ -	$ (312,325)	$ 13
8	1980	System Supervisory Protection and Control	$ 1,882,817	$ -	$ -	$ 1,882,817	$ (897,865)	$ (111,222)	$ -	$ (1,009,087)	$ 873,730
47	1996	Hydro One S/S Contribution	$ 7,956,730	$ -	$ -	$ 7,956,730	$ (2,934,763)	$ (357,384)	$ -	$ (3,292,147)	$ 4,664,582
47	1995	Contributions & Grants	$ (34,882,612)	$ -	$ -	$ (34,882,612)	$ 12,927,527	$ 1,607,580	$ -	$ 14,535,107	$ (20,347,505)
10	2005	Capital Lease	$ 900,000	$ 900,000	$ (900,000)	$ 900,000	$ (900,000)	$ (300,000)	$ 900,000	$ (300,000)	$ 600,000
		Sub-Total	**$ 689,312,853**	**$ 56,002,477**	**$ (4,597,818)**	**$ 740,717,512**	**$ (174,451,869)**	**$ (25,158,061)**	**$ 1,426,748**	**$ (198,183,181)**	**$ 542,534,331**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
	2440	***Less Capital Contributions 2011 and future years***	$ 43,721,078	$ 4,730,000	$ -	$ 48,451,078	$ (5,085,379)	$ (1,281,000)	$ -	$ (6,366,379)	$ 42,084,700
		Total PP&E	**$ 645,591,775**	**$ 51,272,477**	**$ (4,597,818)**	**$ 692,266,434**	**$ (169,366,490)**	**$ (23,877,061)**	**$ 1,426,748**	**$ (191,816,803)**	**$ 500,449,631**
		Work in Process	$ 3,164,006	$ -		$ 3,164,006	$ -	$ -	$ -	$ -	$ 3,164,006
		Total PP&E Including WIP	**$ 648,755,781**	**$ 51,272,477**	**$ (4,597,818)**	**$ 695,430,440**	**$ (169,366,490)**	**$ (23,877,061)**	**$ 1,426,748**	**$ (191,816,803)**	**$ 503,613,637**

COST OF POWER

COST OF POWER OVERVIEW

Horizon Utilities has calculated the Cost of Power for the 2014 Bridge Year and 2015-2019 Test Years in support of its rate base calculation, using the 2014-2019 load forecasts, adjusted for the impact of Conservation and Demand Management ("CDM") programs and proposed loss factors of 0.60% for Large Use customers and 3.79% for all remaining customers. Horizon Utilities' wholesale market participant ("WMP") customers have been excluded from the calculation of electricity and global adjustment costs, as they transact directly with the Independent Electricity System Operator ("IESO") for the purchase of electricity. WMP customers are included in the calculation of the retail transmission costs.

For 2014 to 2019, energy revenue is assumed to equal the Cost of Power, with no impact to net income, notwithstanding known timing variances associated with the Smart Meter Entity ("SME") Charge.

The Filing Requirements state that "*The commodity price estimate used to calculate the Cost of Power must be determined by the split between RPP and non-RPP customers based on actual data and using the most current RPP (TOU) price. The calculation must also reflect the most recent Uniform Transmission Rates approved by the Board…*" Horizon Utilities has estimated Cost of Power in the Bridge Year using the most current RPP (TOU) price, with forecasted rates for the 2015-2019 Test Years based on the relevant historical trends in cost of power rates. Horizon Utilities proposes that this approach to estimating the Cost of Power is appropriate given that this Application covers five Test Years. Horizon Utilities submits that forecasting the commodity price of electricity for the 2015 – 2019 Test Years provides a more realistic assessment of the Working Capital needs of the utility over this term than utilizing a static rate over the five year term.

Horizon Utilities requests that the rates used to calculate the Cost of Power be updated on an annual basis to include the most current RPP rates and Uniform Transmission Rates ("UTR") at the time to comply with the Filing Requirements. The Cost of Power for 2014-2019 is summarized in Table 2-21 below. Detailed calculations are provided in Appendix 2-2 Cost of Power.

Table 2-21 - Summary of Cost of Power by Year

Year	Cost of Power $ (before SME charge)	SME Charge $	Total Cost of Power [1] $
2014 Bridge Year	512,200,920	2,222,161	514,423,081
2015 Test Year	517,939,156	2,223,788	520,162,944
2016 Test Year	539,143,650	2,251,365	541,395,015
2017 Test Year	559,140,364	2,267,389	561,407,753
2018 Test Year	579,968,713	1,904,499	581,873,212
2019 Test Year	600,222,979	0	600,222,979

1. #s include SME charge; Appendix 2-2 does not

Regulated Price Plan ("RPP") Pricing

In its RPP Report dated October 17, 2013, the Board estimated the RPP price for the period from November 1, 2013 through October 31, 2014 at $0.08900 per kWh. Horizon Utilities has provided estimates for future adjustments to the RPP price in November 2014 and for 2015 to 2019. These estimates were based on a linear trend of the changes in RPP prices from May 2006 to November 2013.

Non-RPP pricing

The ratio of the Non-RPP price to the RPP Price, based on historical data, was applied to the RPP price to determine the non-RPP estimate. The ratio of the Non-RPP price to the RPP Price was calculated using data from May 2009 to November 2013.

Commodity Price Estimate

Horizon Utilities has calculated the Cost of Power determining the split between RPP and Non-RPP customers based on actual 2013 data, consistent with the Chapter 2 Filing Requirements. Horizon Utilities has used the most recent RPP (TOU) price for January through April of 2014 as identified above. Beyond this point, Horizon Utilities has forecast the RPP price using the average of the four most recent price reports. Horizon Utilities proposes that this methodology is appropriate for calculating working capital for the 2015 – 2019 Test Years. As part of the annual adjustments outlined in Exhibit 1, Horizon Utilities proposes to update the working capital calculation with actual rates as published by the Board.

Uniform Transmission Rates

UTR are the rates charged for the provision of transmission service and are established on a uniform basis for all transmitters in Ontario. As summarized in the rationale for the RPP estimate, Horizon Utilities' UTR for the 2014 Bridge Year are set at those amounts approved by the Board in Horizon Utilities' 2014 Incentive Rate Mechanism ("IRM") application (EB-2013-0137). Horizon Utilities has forecast line connection and transformer connection rates for the 2015 to 2019 Test Years based on a linear trend of historical rates. Horizon Utilities proposes to update the Cost of Power and Working Capital calculations to reflect actual rates in the 2015 to 2019 Test Years.

Low Voltage ("LV")

The LV costs vary by rate class and are based on current rates and forecasted purchases for each of the Bridge Year and Test Years. The Low Voltage Rates are identified in Table 2-22 below. Horizon Utilities proposes to update the Cost of Power and Working Capital calculations to reflect actual rates in the 2015 to 2019 Test Years.

Table 2-22 - Low Voltage Rates

Rate Class	$/kWh
Residential	0.00006
GS < 50kW	0.00006
GS > 50kW	0.02169
Large Use	0.02492
USL	0.00006
Sentinel Lighting	0.01745
Street Lighting	0.01702

IESO Rates

The Wholesale Market Service ("WMS") and Rural or Remote Electricity Rate Protection ("RRRP") costs are based on current rates as issued by the Board on December 19, 2013 and the forecasted purchases for each of the Bridge Year and Test Years. The IESO rates are identified in Table 2-23 below. Horizon Utilities proposes to update the Cost of Power and Working Capital calculations to reflect actual rates in the 2015 to 2019 Test Years.

Table 2-23 – IESO Rates

Rate Class	$/kWh
WMS Rate	0.0044
RRRP Rate	0.0013

Smart Metering Entity ("SME") Charge

Horizon Utilities' Cost of Power Calculation includes the impacts arising from the new SME charge approved by the Board on March 28, 2013 (EB-2012-0100). SME costs are calculated using the rate of $0.788 per month for each Residential and General Service <50kW customer multiplied by the previous year-end customer count. There is an expected cost versus revenue variance since revenue is recognized based on customer count at the time of billing and is tracked in account 1551. Horizon Utilities' proposal for the disposition of this account is addressed in Exhibit 9, Tab 6, Schedule 3. Horizon Utilities proposes to update the Cost of Power and Working Capital calculations to reflect actual rates in the 2015 to 2019 Test Years.

APPENDIX 2-2 COST OF POWER

Electricity - Commodity		2014 Forecasted	2014 Loss	2014 Bridge Year		
Class Per Load Forecast		**Metered kWhs**	**Factor**	**Uplifed**	**Cost of Energy**	**Total Cost**
Residential		1,630,039,291	1.0407			
	- RPP			1,428,183,913	$0.09433	$134,726,963
	- Non RPP			268,197,977	$0.04769	$12,791,537
GS<50kW		589,101,097	1.0407			
	- RPP			517,498,728	$0.08836	$45,724,080
	- Non RPP			95,578,784	$0.07883	$7,534,545
GS>50kW		1,862,301,069	1.0407			
	- RPP			219,004,930	$0.08919	$19,532,234
	- Non RPP			1,719,091,793	$0.08480	$145,785,733
Large Use (1)		264,367,942	1.0078			
	- RPP			0	$0.00000	$0
	- Non RPP			266,430,012	$0.08508	$22,669,067
Large Use (2)		322,581,816	1.0078			
	- RPP			0	$0.00000	
	- Non RPP			325,097,954	$0.08518	$27,690,584
Unmetered Scattered Load		11,620,990	1.0407			
	- RPP			11,301,810	$0.07492	$846,755
	- Non RPP			792,155	$0.25532	$202,252
Sentinel Lighting		455,814	1.0407			
	- RPP			461,178	$0.08881	$40,957
	- Non RPP			13,187	$0.02813	$371
Street Lighting		39,744,804	1.0407			
	- RPP			219,221	$0.09551	$20,937
	- Non RPP			41,143,197	$0.08513	$3,502,634
Total		**4,720,212,823**		**4,893,014,838**		**$ 421,068,649**

Transmission - Network		Volume Metric	2014 Bridge Year				
Class per Load Forecast							
Residential		kWh	1,696,381,890	$	0.0072	$	12,213,950
GS<50kW		kWh	613,077,512	$	0.0063	$	3,862,388
GS>50kW		kW	5,126,645	$	2.5071	$	12,853,013
Large Use (1)		kW	613,675	$	2.8640	$	1,757,566
Large Use (2)		kW	1,846,057	$	2.8640	$	5,287,108
Unmetered Scattered Load		kWh	12,093,964	$	0.0064	$	77,401
Sentinel Lighting		kW	1,294	$	2.0833	$	2,695
Street Lighting		kW	110,065	$	1.9737	$	217,235
Total			**2,329,251,103**			**$**	**36,271,356**

Transmission - Connection		Volume Metric	2014 Bridge Year				
Class per Load Forecast							
Residential		kWh	1,696,381,890	$	0.0052	$	8,821,186
GS<50kW		kWh	613,077,512	$	0.0047	$	2,881,464
GS>50kW		kW	5,126,645	$	1.8734	$	9,604,258
Large Use (1)		kW	613,675	$	2.1528	$	1,321,120
Large Use (2)		kW	1,846,057	$	2.1528	$	3,974,192
Unmetered Scattered Load		kWh	12,093,964	$	0.0048	$	58,051
Sentinel Lighting		kW	1,294	$	1.5075	$	1,950
Street Lighting		kW	110,065	$	1.4698	$	161,773
Total			**2,329,251,103**			**$**	**26,823,994**

Wholesale Market Service		Volume Metric	2014 Bridge Year				
Class per Load Forecast							
Residential		kWh	1,696,381,890	$	0.0044	$	7,464,080
GS<50kW		kWh	613,077,512	$	0.0044	$	2,697,541
GS>50kW		kWh	1,938,096,723	$	0.0044	$	8,527,626
Large Use (1)		kWh	266,430,012	$	0.0044	$	1,172,292
Large Use (2)		kWh	325,097,954	$	0.0044	$	1,430,431
Unmetered Scattered Load		kWh	12,093,964	$	0.0044	$	53,213
Sentinel Lighting		kWh	474,365	$	0.0044	$	2,087
Street Lighting		kWh	41,362,418	$	0.0044	$	181,995
Total			**4,893,014,838**			**$**	**21,529,265**

Rural Rate Assistance Class per Load Forecast		**Volume Metric**	**2014 Bridge Year**				
Residential		kWh	1,696,381,890	$	0.0013	$	2,150,962
GS<50kW		kWh	613,077,512	$	0.0013	$	776,766
GS>50kW		kWh	1,938,096,723	$	0.0013	$	2,455,299
Large Use (1)		kWh	266,430,012	$	0.0013	$	337,322
Large Use (2)		kWh	325,097,954	$	0.0013	$	410,846
Unmetered Scattered Load		kWh	12,093,964	$	0.0013	$	15,334
Sentinel Lighting		kWh	474,365	$	0.0013	$	602
Street Lighting		kWh	41,362,418	$	0.0013	$	52,289
Total			**4,893,014,838**	.		**$**	**6,199,421**

	2014 Bridge Year	
4705 - Power Purchased	$	421,068,649
4708 - Charges - WMS	$	21,529,265
4710 - Cost of Power Adjustments		
4714 - Charges - NW	$	36,271,356
4716 - Charges - CN	$	26,823,994
4730 - Rural Rate Assistance	$	6,199,421
4750 - Low Voltage	$	308,235
Total	$	512,200,920

Electricity - Commodity Class Per Load Forecast		**2015 Forecasted Metered kWhs**	**2015 Loss Factor**	**2015 Test Year Uplifed**	**Cost of Energy**	**Total Cost**
Residential		1,617,715,605	1.0379			
	- RPP			1,430,363,124	$0.09440	$135,029,958
	- Non RPP			248,663,903	$0.05133	$12,763,032
GS<50kW		586,002,830	1.0379			
	- RPP			513,392,034	$0.08942	$45,909,225
	- Non RPP			94,820,303	$0.07942	$7,530,250
GS>50kW		1,857,864,416	1.0379			
	- RPP			217,895,355	$0.09025	$19,664,689
	- Non RPP			1,710,382,122	$0.08542	$146,096,458
Large Use (1)		269,877,849	1.0060			
	- RPP			0	$0.00000	$0
	- Non RPP			271,497,116	$0.08566	$23,255,934
Large Use (2)		329,305,006	1.0060			
	- RPP			0	$0.00000	$0
	- Non RPP			331,280,836	$0.08562	$28,363,384
Unmetered Scattered Load		11,397,660	1.0379			
	- RPP			11,054,791	$0.07589	$838,964
	- Non RPP			774,841	$0.25747	$199,495
Sentinel Lighting		437,397	1.0379			
	- RPP			441,354	$0.08999	$39,718
	- Non RPP			12,620	$0.02838	$358
Street Lighting		39,694,810	1.0379			
	- RPP			218,356	$0.09658	$21,089
	- Non RPP			40,980,887	$0.08566	$3,510,453
Total		**4,712,295,573**		**4,871,777,642**		**$ 423,223,007**

Transmission - Network Class per Load Forecast		**Volume Metric**	**2015 Test Year**				
Residential		kWh	1,679,027,027	$	0.0076	$	12,760,605
GS<50kW		kWh	608,212,337	$	0.0065	$	3,953,380
GS>50kW		kW	5,114,245	$	2.6038	$	13,316,470
Large Use (1)		kW	626,465	$	2.9745	$	1,863,421
Large Use (2)		kW	1,884,533	$	2.9745	$	5,605,542
Unmetered Scattered Load		kWh	11,829,632	$	0.0066	$	78,076
Sentinel Lighting		kW	1,241	$	2.1637	$	2,685
Street Lighting		kW	110,006	$	2.0498	$	225,491
Total			**2,306,805,485**			**$**	**37,805,670**

Transmission - Connection					
Class per Load Forecast	**Volume Metric**	**2015 Test Year**			
Residential	kWh	1,679,027,027	$ 0.0056	$	9,402,551
GS<50kW	kWh	608,212,337	$ 0.0051	$	3,101,883
GS>50kW	kW	5,114,245	$ 2.0115	$	10,287,303
Large Use (1)	kW	626,465	$ 2.3115	$	1,448,074
Large Use (2)	kW	1,884,533	$ 2.3115	$	4,356,097
Unmetered Scattered Load	kWh	11,829,632	$ 0.0052	$	61,514
Sentinel Lighting	kW	1,241	$ 1.6186	$	2,008
Street Lighting	kW	110,006	$ 1.5782	$	173,612
Total		**2,306,805,485**		**$**	**28,833,043**

Wholesale Market Service					
Class per Load Forecast	**Volume Metric**	**2015 Test Year**			
Residential	kWh	1,679,027,027	$ 0.0044	$	7,387,719
GS<50kW	kWh	608,212,337	$ 0.0044	$	2,676,134
GS>50kW	kWh	1,928,277,477	$ 0.0044	$	8,484,421
Large Use (1)	kWh	271,497,116	$ 0.0044	$	1,194,587
Large Use (2)	kWh	331,280,836	$ 0.0044	$	1,457,636
Unmetered Scattered Load	kWh	11,829,632	$ 0.0044	$	52,050
Sentinel Lighting	kWh	453,974	$ 0.0044	$	1,997
Street Lighting	kWh	41,199,243	$ 0.0044	$	181,277
Total		**4,871,777,642**		**$**	**21,435,822**

Rural Rate Assistance					
Class per Load Forecast	**Volume Metric**	**2015 Test Year**			
Residential	kWh	1,679,027,027	$ 0.0013	$	2,182,735
GS<50kW	kWh	608,212,337	$ 0.0013	$	790,676
GS>50kW	kWh	1,928,277,477	$ 0.0013	$	2,506,761
Large Use (1)	kWh	271,497,116	$ 0.0013	$	352,946
Large Use (2)	kWh	331,280,836	$ 0.0013	$	430,665
Unmetered Scattered Load	kWh	11,829,632	$ 0.0013	$	15,379
Sentinel Lighting	kWh	453,974	$ 0.0013	$	590
Street Lighting	kWh	41,199,243	$ 0.0013	$	53,559
Total		**4,871,777,642**		**$**	**6,333,311**

	2015 Test Year	
4705 - Power Purchased	$	423,223,007
4708 - Charges - WMS	$	21,435,822
4710 - Cost of Power Adjustments		
4714 - Charges - NW	$	37,805,670
4716 - Charges - CN	$	28,833,043
4730 - Rural Rate Assistance	$	6,333,311
4750 - Low Voltage	$	308,303
Total	$	517,939,156

Electricity - Commodity				**2016 Test Year**		
Class Per Load Forecast		**2016 Forecasted Metered kWhs**	**2016 Loss Factor**	**Uplifed**	**Cost of Energy**	**Total Cost**
Residential		1,615,569,770	1.0379			
	- RPP			1,411,697,805	$0.09982	$140,919,756
	- Non RPP			265,102,058	$0.05024	$13,319,981
GS<50kW		585,648,636	1.0379			
	- RPP			513,081,727	$0.09345	$47,946,231
	- Non RPP			94,762,992	$0.08299	$7,864,505
GS>50kW		1,852,830,462	1.0379			
	- RPP			217,304,959	$0.09431	$20,493,985
	- Non RPP			1,705,747,777	$0.08926	$152,260,210
Large Use (1)		275,125,662	1.0060			
	- RPP			0	$0.00000	$0
	- Non RPP			276,776,416	$0.08952	$24,776,457
Large Use (2)		335,708,389	1.0060			
	- RPP			0	$0.00000	$0
	- Non RPP			337,722,639	$0.08948	$30,218,229
Unmetered Scattered Load		11,174,331	1.0379			
	- RPP			10,838,179	$0.07931	$859,558
	- Non RPP			759,658	$0.26906	$204,395
Sentinel Lighting		418,980	1.0379			
	- RPP			422,771	$0.09405	$39,760
	- Non RPP			12,089	$0.02966	$359
Street Lighting		39,602,538	1.0379			
	- RPP			217,848	$0.10093	$21,988
	- Non RPP			40,885,626	$0.08952	$3,660,193
Total		**4,716,078,768**		**4,875,332,547**		**$ 442,585,607**

Transmission - Network			**2016 Test Year**		
Class per Load Forecast		**Volume Metric**			
Residential		kWh	1,676,799,864	$ 0.0078	$ 13,079,039
GS<50kW		kWh	607,844,719	$ 0.0067	$ 4,072,560
GS>50kW		kW	5,085,745	$ 2.6913	$ 13,687,264
Large Use (1)		kW	638,647	$ 3.0744	$ 1,963,456
Large Use (2)		kW	1,921,178	$ 3.0744	$ 5,906,468
Unmetered Scattered Load		kWh	11,597,838	$ 0.0068	$ 78,865
Sentinel Lighting		kW	1,185	$ 2.2364	$ 2,651
Street Lighting		kW	109,948	$ 2.1187	$ 232,947
Total			**2,303,999,123**		**$ 39,023,250**

Transmission - Connection			**2016 Test Year**		
Class per Load Forecast		**Volume Metric**			
Residential		kWh	1,676,799,864	$ 0.0057	$ 9,557,759
GS<50kW		kWh	607,844,719	$ 0.0052	$ 3,160,793
GS>50kW		kW	5,085,745	$ 2.0527	$ 10,439,508
Large Use (1)		kW	638,647	$ 2.3588	$ 1,506,440
Large Use (2)		kW	1,921,178	$ 2.3588	$ 4,531,674
Unmetered Scattered Load		kWh	11,597,838	$ 0.0053	$ 61,469
Sentinel Lighting		kW	1,185	$ 1.6517	$ 1,958
Street Lighting		kW	109,948	$ 1.6104	$ 177,060
Total			**2,303,999,123**		**$ 29,436,660**

Wholesale Market Service			**2016 Test Year**		
Class per Load Forecast		**Volume Metric**			
Residential		kWh	1,676,799,864	$ 0.0044	$ 7,377,919
GS<50kW		kWh	607,844,719	$ 0.0044	$ 2,674,517
GS>50kW		kWh	1,923,052,736	$ 0.0044	$ 8,461,432
Large Use (1)		kWh	276,776,416	$ 0.0044	$ 1,217,816
Large Use (2)		kWh	337,722,639	$ 0.0044	$ 1,485,980
Unmetered Scattered Load		kWh	11,597,838	$ 0.0044	$ 51,030
Sentinel Lighting		kWh	434,860	$ 0.0044	$ 1,913
Street Lighting		kWh	41,103,475	$ 0.0044	$ 180,855
Total			**4,875,332,547**		**$ 21,451,463**

Rural Rate Assistance **Class per Load Forecast**		**Volume Metric**	**2016 Test Year**		
Residential		kWh	1,676,799,864	$ 0.0013	$ 2,179,840
GS<50kW		kWh	607,844,719	$ 0.0013	$ 790,198
GS>50kW		kWh	1,923,052,736	$ 0.0013	$ 2,499,969
Large Use (1)		kWh	276,776,416	$ 0.0013	$ 359,809
Large Use (2)		kWh	337,722,639	$ 0.0013	$ 439,039
Unmetered Scattered Load		kWh	11,597,838	$ 0.0013	$ 15,077
Sentinel Lighting		kWh	434,860	$ 0.0013	$ 565
Street Lighting		kWh	41,103,475	$ 0.0013	$ 53,435
Total			**4,875,332,547**		**$ 6,337,932**

	2016 Test Year
4705 - Power Purchased	$ 442,585,607
4708 - Charges - WMS	$ 21,451,463
4710 - Cost of Power Adjustments	
4714 - Charges - NW	$ 39,023,250
4716 - Charges - CN	$ 29,436,660
4730 - Rural Rate Assistance	$ 6,337,932
4750 - Low Voltage	$ 308,736
Total	$ 539,143,650

Electricity - Commodity **Class Per Load Forecast**		**2017 Forecasted Metered kWhs**	**2017 Loss Factor**	**2017 Test Year** **Uplifed**	**Cost of Energy**	**Total Cost**
Residential		1,608,117,860	1.0379			
	- RPP			1,405,186,267	$0.10413	$146,318,206
	- Non RPP			263,879,260	$0.05241	$13,830,203
GS<50kW		583,142,939	1.0379			
	- RPP			510,886,508	$0.09748	$49,800,117
	- Non RPP			94,357,548	$0.08657	$8,168,575
GS>50kW		1,841,172,846	1.0379			
	- RPP			215,937,722	$0.09838	$21,243,435
	- Non RPP			1,695,015,574	$0.09311	$157,827,837
Large Use (1)		280,664,097	1.0060			
	- RPP			0	$0.00000	$0
	- Non RPP			282,348,082	$0.09338	$26,364,646
Large Use (2)		342,466,388	1.0060			
	- RPP			0	$0.00000	$0
	- Non RPP			344,521,186	$0.09334	$32,156,021
Unmetered Scattered Load		10,951,001	1.0379			
	- RPP			10,621,568	$0.08272	$878,668
	- Non RPP			744,476	$0.28065	$208,939
Sentinel Lighting		400,564	1.0379			
	- RPP			404,187	$0.09810	$39,650
	- Non RPP			11,558	$0.03093	$358
Street Lighting		39,651,553	1.0379			
	- RPP			218,118	$0.10528	$22,963
	- Non RPP			40,936,229	$0.09338	$3,822,483
Total		**4,706,567,248**		**4,865,068,284**		**$ 460,682,101**

Transmission - Network **Class per Load Forecast**		**Volume Metric**	**2017 Test Year**		
Residential		kWh	1,669,065,527	$ 0.0081	$ 13,519,431
GS<50kW		kWh	605,244,056	$ 0.0069	$ 4,176,184
GS>50kW		kW	5,068,149	$ 2.7789	$ 14,083,879
Large Use (1)		kW	651,503	$ 3.1744	$ 2,068,132
Large Use (2)		kW	1,959,852	$ 3.1744	$ 6,221,354
Unmetered Scattered Load		kWh	11,366,044	$ 0.0070	$ 79,562
Sentinel Lighting		kW	1,135	$ 2.3091	$ 2,622
Street Lighting		kW	109,890	$ 2.1876	$ 240,394
Total			**2,293,466,156**		**$ 40,391,558**

Transmission - Connection Class per Load Forecast		Volume Metric	2017 Test Year				
Residential		kWh	1,669,065,527	$	0.0058	$	9,680,580
GS<50kW		kWh	605,244,056	$	0.0053	$	3,207,793
GS>50kW		kW	5,068,149	$	2.0938	$	10,611,690
Large Use (1)		kW	651,503	$	2.4060	$	1,567,517
Large Use (2)		kW	1,959,852	$	2.4060	$	4,715,404
Unmetered Scattered Load		kWh	11,366,044	$	0.0054	$	61,377
Sentinel Lighting		kW	1,135	$	1.6848	$	1,913
Street Lighting		kW	109,890	$	1.6427	$	180,516
Total			**2,293,466,156**			**$**	**30,026,789**

Wholesale Market Service Class per Load Forecast		Volume Metric	2017 Test Year				
Residential		kWh	1,669,065,527	$	0.0044	$	7,343,888
GS<50kW		kWh	605,244,056	$	0.0044	$	2,663,074
GS>50kW		kWh	1,910,953,296	$	0.0044	$	8,408,195
Large Use (1)		kWh	282,348,082	$	0.0044	$	1,242,332
Large Use (2)		kWh	344,521,186	$	0.0044	$	1,515,893
Unmetered Scattered Load		kWh	11,366,044	$	0.0044	$	50,011
Sentinel Lighting		kWh	415,745	$	0.0044	$	1,829
Street Lighting		kWh	41,154,347	$	0.0044	$	181,079
Total			**4,865,068,284**			**$**	**21,406,300**

Rural Rate Assistance Class per Load Forecast		Volume Metric	2017 Test Year				
Residential		kWh	1,669,065,527	$	0.0013	$	2,169,785
GS<50kW		kWh	605,244,056	$	0.0013	$	786,817
GS>50kW		kWh	1,910,953,296	$	0.0013	$	2,484,239
Large Use (1)		kWh	282,348,082	$	0.0013	$	367,053
Large Use (2)		kWh	344,521,186	$	0.0013	$	447,878
Unmetered Scattered Load		kWh	11,366,044	$	0.0013	$	14,776
Sentinel Lighting		kWh	415,745	$	0.0013	$	540
Street Lighting		kWh	41,154,347	$	0.0013	$	53,501
Total			**4,865,068,284**			**$**	**6,324,589**

	2017 Test Year	
4705 - Power Purchased	$	460,682,101
4708 - Charges - WMS	$	21,406,300
4710 - Cost of Power Adjustments		
4714 - Charges - NW	$	40,391,558
4716 - Charges - CN	$	30,026,789
4730 - Rural Rate Assistance	$	6,324,589
4750 - Low Voltage	$	309,026
Total	$	559,140,364

Electricity - Commodity				**2018 Test Year**		
Class Per Load Forecast		**2018 Forecasted Metered kWhs**	**2018 Loss Factor**	**Uplifed**	**Cost of Energy**	**Total Cost**
Residential		1,604,991,612	1.0379			
	- RPP			1,402,454,527	$0.10842	$152,050,063
	- Non RPP			263,366,268	$0.05457	$14,372,402
GS<50kW		581,558,617	1.0379			
	- RPP			509,498,497	$0.10149	$51,711,296
	- Non RPP			94,101,191	$0.09014	$8,482,306
GS>50kW		1,831,925,238	1.0379			
	- RPP			214,853,138	$0.10243	$22,007,815
	- Non RPP			1,686,502,067	$0.09695	$163,511,599
Large Use (1)		285,758,686	1.0060			
	- RPP			0	$0.00000	$0
	- Non RPP			287,473,238	$0.09723	$27,950,484
Large Use (2)		348,682,806	1.0060			
	- RPP			0	$0.00000	$0
	- Non RPP			350,774,903	$0.09719	$34,090,880
Unmetered Scattered Load		10,727,671	1.0379			
	- RPP			10,404,957	$0.08613	$896,210
	- Non RPP			729,293	$0.29222	$213,116
Sentinel Lighting		382,147	1.0379			
	- RPP			385,604	$0.10214	$39,386
	- Non RPP			11,026	$0.03221	$355
Street Lighting		39,629,670	1.0379			
	- RPP			217,998	$0.10962	$23,896
	- Non RPP			40,913,637	$0.09723	$3,977,849
Total		**4,703,656,447**		**4,861,686,343**		**$ 479,327,656**

Transmission - Network		**Volume Metric**	**2018 Test Year**		
Class per Load Forecast					
Residential		kWh	1,665,820,794	$ 0.0084	$ 13,992,895
GS<50kW		kWh	603,599,688	$ 0.0072	$ 4,345,918
GS>50kW		kW	5,042,608	$ 2.8664	$ 14,454,133
Large Use (1)		kW	663,329	$ 3.2744	$ 2,172,005
Large Use (2)		kW	1,995,427	$ 3.2744	$ 6,533,826
Unmetered Scattered Load		kWh	11,134,250	$ 0.0073	$ 81,280
Sentinel Lighting		kW	1,083	$ 2.3819	$ 2,579
Street Lighting		kW	109,831	$ 2.2565	$ 247,834
Total			**2,288,367,011**		**$ 41,830,469**

Transmission - Connection		**Volume Metric**	**2018 Test Year**		
Class per Load Forecast					
Residential		kWh	1,665,820,794	$ 0.0060	$ 9,994,925
GS<50kW		kWh	603,599,688	$ 0.0054	$ 3,259,438
GS>50kW		kW	5,042,608	$ 2.1349	$ 10,765,465
Large Use (1)		kW	663,329	$ 2.4533	$ 1,627,346
Large Use (2)		kW	1,995,427	$ 2.4533	$ 4,895,381
Unmetered Scattered Load		kWh	11,134,250	$ 0.0055	$ 61,238
Sentinel Lighting		kW	1,083	$ 1.7179	$ 1,860
Street Lighting		kW	109,831	$ 1.6750	$ 183,967
Total			**2,288,367,011**		**$ 30,789,620**

Wholesale Market Service		**Volume Metric**	**2018 Test Year**		
Class per Load Forecast					
Residential		kWh	1,665,820,794	$ 0.0044	$ 7,329,611
GS<50kW		kWh	603,599,688	$ 0.0044	$ 2,655,839
GS>50kW		kWh	1,901,355,205	$ 0.0044	$ 8,365,963
Large Use (1)		kWh	287,473,238	$ 0.0044	$ 1,264,882
Large Use (2)		kWh	350,774,903	$ 0.0044	$ 1,543,410
Unmetered Scattered Load		kWh	11,134,250	$ 0.0044	$ 48,991
Sentinel Lighting		kWh	396,631	$ 0.0044	$ 1,745
Street Lighting		kWh	41,131,634	$ 0.0044	$ 180,979
Total			**4,861,686,343**		**$ 21,391,420**

Rural Rate Assistance Class per Load Forecast	Volume Metric	2018 Test Year		
Residential	kWh	1,665,820,794	$ 0.0013	$ 2,165,567
GS<50kW	kWh	603,599,688	$ 0.0013	$ 784,680
GS>50kW	kWh	1,901,355,205	$ 0.0013	$ 2,471,762
Large Use (1)	kWh	287,473,238	$ 0.0013	$ 373,715
Large Use (2)	kWh	350,774,903	$ 0.0013	$ 456,007
Unmetered Scattered Load	kWh	11,134,250	$ 0.0013	$ 14,475
Sentinel Lighting	kWh	396,631	$ 0.0013	$ 516
Street Lighting	kWh	41,131,634	$ 0.0013	$ 53,471
Total		**4,861,686,343**		**$ 6,320,192**

2018 Test Year	
4705 - Power Purchased	$ 479,327,656
4708 - Charges - WMS	$ 21,391,420
4710 - Cost of Power Adjustments	
4714 - Charges - NW	$ 41,830,469
4716 - Charges - CN	$ 30,789,620
4730 - Rural Rate Assistance	$ 6,320,192
4750 - Low Voltage	$ 309,355
Total	$ 579,968,713

Electricity - Commodity Class Per Load Forecast		2019 Forecasted Metered kWhs	2019 Loss Factor	2019 Test Year Uplifed	Cost of Energy	Total Cost
Residential		1,600,739,130	1.0379			
	- RPP			1,398,738,674	$0.11271	$157,652,190
	- Non RPP			262,668,469	$0.05673	$14,901,375
GS<50kW		579,899,038	1.0379			
	- RPP			508,044,554	$0.10551	$53,606,217
	- Non RPP			93,832,657	$0.09371	$8,792,801
GS>50kW		1,822,597,172	1.0379			
	- RPP			213,759,117	$0.10649	$22,763,206
	- Non RPP			1,677,914,487	$0.10079	$169,117,459
Large Use (1)		290,887,091	1.0060			
	- RPP			0	$0.00000	$0
	- Non RPP			292,632,413	$0.10108	$29,578,229
Large Use (2)		354,940,487	1.0060			
	- RPP			0	$0.00000	$0
	- Non RPP			357,070,130	$0.10104	$36,076,722
Unmetered Scattered Load		10,504,342	1.0379			
	- RPP			10,188,345	$0.08954	$912,306
	- Non RPP			714,111	$0.30379	$216,936
Sentinel Lighting		363,731	1.0379			
	- RPP			367,021	$0.08609	$31,598
	- Non RPP			10,495	$0.71594	$7,514
Street Lighting		39,610,413	1.0379			
	- RPP			217,892	$0.11395	$24,830
	- Non RPP			40,893,756	$0.10107	$4,133,193
Total		**4,699,541,403**		**4,857,052,123**		**$ 497,814,578**

Transmission - Network Class per Load Forecast	Volume Metric	2019 Test Year		
Residential	kWh	1,661,407,144	$ 0.0086	$ 14,288,101
GS<50kW	kWh	601,877,211	$ 0.0074	$ 4,453,891
GS>50kW	kW	5,016,885	$ 2.9539	$ 14,819,378
Large Use (1)	kW	675,234	$ 3.3743	$ 2,278,441
Large Use (2)	kW	2,031,238	$ 3.3743	$ 6,854,007
Unmetered Scattered Load	kWh	10,902,456	$ 0.0075	$ 81,768
Sentinel Lighting	kW	1,030	$ 2.4546	$ 2,528
Street Lighting	kW	109,773	$ 2.3253	$ 255,254
Total		**2,282,020,971**		**$ 43,033,369**

Transmission - Connection **Class per Load Forecast**		**Volume Metric**	**2019 Test Year**				
Residential		kWh	1,661,407,144	$	0.0061	$	10,134,584
GS<50kW		kWh	601,877,211	$	0.0055	$	3,310,325
GS>50kW		kW	5,016,885	$	2.1761	$	10,917,244
Large Use (1)		kW	675,234	$	2.5006	$	1,688,490
Large Use (2)		kW	2,031,238	$	2.5006	$	5,079,314
Unmetered Scattered Load		kWh	10,902,456	$	0.0056	$	61,054
Sentinel Lighting		kW	1,030	$	1.7510	$	1,803
Street Lighting		kW	109,773	$	1.7072	$	187,404
Total			**2,282,020,971**			**$**	**31,380,217**

Wholesale Market Service **Class per Load Forecast**		**Volume Metric**	**2019 Test Year**				
Residential		kWh	1,661,407,144	$	0.0044	$	7,310,191
GS<50kW		kWh	601,877,211	$	0.0044	$	2,648,260
GS>50kW		kWh	1,891,673,605	$	0.0044	$	8,323,364
Large Use (1)		kWh	292,632,413	$	0.0044	$	1,287,583
Large Use (2)		kWh	357,070,130	$	0.0044	$	1,571,109
Unmetered Scattered Load		kWh	10,902,456	$	0.0044	$	47,971
Sentinel Lighting		kWh	377,516	$	0.0044	$	1,661
Street Lighting		kWh	41,111,648	$	0.0044	$	180,891
Total			**4,857,052,123**			**$**	**21,371,029**

Rural Rate Assistance **Class per Load Forecast**		**Volume Metric**	**2019 Test Year**				
Residential		kWh	1,661,407,144	$	0.0013	$	2,159,829
GS<50kW		kWh	601,877,211	$	0.0013	$	782,440
GS>50kW		kWh	1,891,673,605	$	0.0013	$	2,459,176
Large Use (1)		kWh	292,632,413	$	0.0013	$	380,422
Large Use (2)		kWh	357,070,130	$	0.0013	$	464,191
Unmetered Scattered Load		kWh	10,902,456	$	0.0013	$	14,173
Sentinel Lighting		kWh	377,516	$	0.0013	$	491
Street Lighting		kWh	41,111,648	$	0.0013	$	53,445
Total			**4,857,052,123**			**$**	**6,314,168**

	2019 Test Year	
4705 - Power Purchased	$	497,814,578
4708 - Charges - WMS	$	21,371,029
4710 - Cost of Power Adjustments		
4714 - Charges - NW	$	43,033,369
4716 - Charges - CN	$	31,380,217
4730 - Rural Rate Assistance	$	6,314,168
4750 - Low Voltage	$	309,616
Total	$	600,222,979

GROSS ASSETS – PROPERTY, PLANT, AND EQUIPMENT AND ACCUMULATED DEPRECIATION

OVERVIEW

In support of its rate base calculation, Horizon Utilities has attached the information required in the Chapter 2 Filing Requirements for Gross Assets (Tab 3, Schedule 1 of this Exhibit); Accumulated Depreciation (Tab 3, Schedule 1 of this Exhibit) and Working Capital (Tab 4, Schedule 1 of this Exhibit).

Gross Assets – By Function

Horizon Utilities' gross assets are divided into three categories (distribution plant, general plant, and other plant) as illustrated in Table 2-24. Horizon Utilities has included asset accounts 1805 to 1860, 1612, 1905 and 1906, in the category of distribution plant, accounts 1908 to 1990, and 1611 in the category of general plant and account 2005 in the category of other capital assets in accordance with the Uniform System of Accounts ('USoA"). Horizon Utilities does not have any transmission plant assets. Capital contributions have been listed separately.

Detailed amounts categorized by major plant account are provided Table 2-25 and 2-26 of this Exhibit.

Table 2-24 – Gross Assets Breakdown by Function

Description	2011 Board-Approved ($) (CGAAP)	2011 Actual ($) (CGAAP)	2011 Actual ($) (MIFRS)	2012 Actual ($) (MIFRS)	2013 Actual ($) (MIFRS)	2014 Bridge Year ($) (MIFRS)
Distribution Plant	605,378,274	582,344,229	329,194,422	390,289,252	418,967,894	448,830,254
General Plant	97,305,086	94,194,809	34,529,745	41,839,338	53,461,210	66,090,411
Capital Contributions	(31,712,975)	(33,834,063)	(29,907,394)	(30,902,025)	(35,088,112)	(39,561,112)
Other Plant	0	0	0	820,130	820,130	820,130
Gross Assets less Capital Contributions	670,970,385	642,704,976	333,816,773	402,046,695	438,161,122	476,179,683

Description	2015 Test Year ($) (MIFRS)	2016 Test Year ($) (MIFRS)	2017 Test Year ($) (MIFRS)	2018 Test Year ($) (MIFRS)	2019 Test Year ($) (MIFRS)
Distribution Plant	484,057,980	522,768,376	566,027,115	610,741,711	656,810,470
General Plant	75,752,176	80,739,376	86,566,276	92,177,176	97,513,076
Capital Contributions	(44,194,112)	(48,849,112)	(53,526,112)	(58,227,112)	(62,957,112)
Other Plant	820,130	900,000	900,000	900,000	900,000
Gross Assets less Capital Contributions	516,436,174	555,558,640	599,967,280	645,591,775	692,266,434

Gross Assets – Detailed Breakdown

Section 2.5.1.2 of the Board's Filing Requirements requires that Applicants provide a detailed breakdown by major plant account for each functionalized plant item: distribution plant, general plant and other plant. For the Test Year, each plant item must be accompanied by a description. Horizon Utilities has included a breakdown of each major plant account according to the Board's USofA in Tables 2-25 and 2-26 in compliance with this requirement. The table covers historical years and the 2014 Bridge Year, as well as each of the 2015-2019 Test Years.

Table 2-25 - Gross Assets – Detailed Breakdown

Description	OEB	2011 Board-Approved ($) (CGAAP)	2011 Actual ($) (CGAAP)	Variance 2011 (CGAAP) from 2011 Board-Approved ($)	2011 Actual ($) (MIFRS)	Variance 2011 Actual (MIFRS) from 2011 Actual (CGAAP) ($)	2012 Actual ($) (MIFRS)	Variance 2012 Actual (MIFRS) from 2011 Actual (MIFRS) ($)	2013 Actual ($) (MIFRS)	Variance 2013 Actual (MIFRS) from 2012 Actual (MIFRS) ($)	2014 Bridge Year ($) (MIFRS)	Variance 2014 Bridge Year (MIFRS) from 2013 Actual (MIFRS) ($)
Land and Buildings												
Land	1905	1,067,629	1,067,629	0	1,067,629	0	1,067,629	0	1,067,629	0	1,067,629	0
Land Rights	1612	162,636	162,636	0	90,487	(72,149)	90,487	0	90,487	0	90,487	0
Land	1805	414,741	414,741	0	414,741	0	414,741	0	414,741	0	414,741	0
Buildings and Fixtures	1808	2,153,482	2,280,640	127,158	669,741	(1,610,899)	727,705	57,965	729,005	1,300	879,005	150,000
Leasehold Improvements	1810	20,886	20,886	(0)	0	(20,886)	0	0	0	0	0	0
Sub total		3,819,375	3,946,532	127,158	2,242,599	(1,703,934)	2,300,563	57,965	2,301,863	1,300	2,451,863	150,000
DS												
Distribution Station Equipment	1820	12,743,580	12,862,904	119,324	3,259,384	(9,603,521)	8,784,027	5,524,644	11,925,313	3,141,285	12,772,103	846,790
Sub total		12,743,580	12,862,904	119,324	3,259,384	(9,603,521)	8,784,027	5,524,644	11,925,313	3,141,285	12,772,103	846,790
Poles and Wires												
Poles, Towers & Fixtures	1830	84,424,366	85,258,879	834,513	56,179,106	(29,079,773)	63,569,872	7,390,767	69,001,403	5,431,531	75,327,373	6,325,970
OH Conductors & Devices	1835	79,236,966	77,552,394	(1,684,572)	44,413,941	(33,138,454)	49,310,539	4,896,598	53,094,562	3,784,023	57,528,119	4,433,557
UG Conduit	1840	122,657,788	113,643,173	(9,014,615)	56,378,468	(57,264,706)	62,077,449	5,698,981	65,333,526	3,256,077	69,252,369	3,918,844
UG Conductors & Devices	1845	129,298,340	120,071,703	(9,226,637)	68,956,213	(51,115,490)	76,501,932	7,545,719	82,383,876	5,881,944	84,063,024	1,679,148
Sub total		415,617,460	396,526,150	(19,091,311)	225,927,727	(170,598,422)	251,459,792	25,532,065	269,813,366	18,353,575	286,170,885	16,357,518
Line Transformers												
Line Transformers	1850	106,122,859	100,329,389	(5,793,470)	56,464,471	(43,864,919)	61,491,889	5,027,419	66,297,507	4,805,618	72,937,233	6,639,725
Sub total		106,122,859	100,329,389	(5,793,470)	56,464,471	(43,864,919)	61,491,889	5,027,419	66,297,507	4,805,618	72,937,233	6,639,725
Services and Meters												
Services	1855	26,632,119	26,857,787	225,668	17,424,347	(9,433,441)	18,237,639	813,293	19,008,063	770,424	22,445,058	3,436,995
Meters	1860	40,442,880	41,821,467	1,378,587	23,875,896	(17,945,571)	24,697,843	821,947	25,778,720	1,080,877	27,292,394	1,513,674
Smart Meters	1860			0	0	0	23,317,499	23,317,499	23,843,063	525,564	24,760,720	917,658
Sub total		67,074,999	68,679,254	1,604,255	41,300,243	(27,379,011)	66,252,982	24,952,739	68,629,846	2,376,864	74,498,172	5,868,326
General Plant												
Buildings & Fixtures	1908	29,967,705	29,330,851	(636,854)	11,040,988	(18,289,863)	13,787,723	2,746,734	20,083,948	6,296,226	23,783,949	3,700,000
Sub total		29,967,705	29,330,851	(636,854)	11,040,988	(18,289,863)	13,787,723	2,746,734	20,083,948	6,296,226	23,783,949	3,700,000
IT Assets												
Computer Equipment- Hardware	1920	11,308,777	10,674,216	(634,561)	3,179,990	(7,494,226)	4,979,920	1,799,930	6,370,018	1,390,098	7,502,774	1,132,756
Computer Software	1611	12,732,652	12,733,856	1,204	5,124,899	(7,608,957)	5,978,627	853,729	8,296,229	2,317,602	13,618,174	5,321,945
Sub total		24,041,429	23,408,072	(633,357)	8,304,889	(15,103,184)	10,958,547	2,653,659	14,666,248	3,707,700	21,120,948	6,454,701
Equipment												
Office Furniture & Equipment	1915	5,684,084	5,323,928	(360,156)	1,563,642	(3,760,285)	2,195,971	632,328	3,069,896	873,925	3,687,896	618,000
Transportation Equipment	1930	19,108,464	18,343,287	(765,177)	7,323,610	(11,019,677)	8,072,635	749,025	8,109,000	36,365	8,894,000	785,000
Stores Equipment	1935	968,061	968,061	0	417,864	(550,197)	417,864	0	417,864	0	417,864	0
Tools, Shop & Garage Equipment	1940	8,397,333	8,341,804	(55,529)	2,299,923	(6,041,880)	2,622,964	323,040	3,040,535	417,572	3,551,835	511,300
Measurement & Testing Equipment	1945	1,721,251	1,693,596	(27,655)	655,192	(1,038,404)	800,173	144,980	997,348	197,176	1,151,348	154,000
Power operated Equipment	1950	144,035	144,035	(0)	35,360	(108,675)	35,360	0	35,360	0	35,360	0
Communications Equipment	1955	2,544,574	2,348,303	(196,271)	1,713,467	(634,836)	1,744,881	31,414	1,745,855	975	1,752,055	6,200
Load Management Controls	1970	515,330	515,330	(0)	312,338	(202,992)	312,338	0	312,338	0	312,338	0
System Supervisory Equipment	1980	4,212,820	3,777,542	(435,278)	862,471	(2,915,072)	890,883	28,413	982,817	91,934	1,382,817	400,000
Sub total		43,295,952	41,455,885	(1,840,067)	15,183,868	(26,272,018)	17,093,069	1,909,201	18,711,014	1,617,946	21,185,514	2,474,500
Other Distribution Assets												
Capital Contributions Paid	1609			0		0	10,000,000	10,000,000	12,419,847	2,419,847	12,419,847	0
Hydro One S/S Contribution	1996		10,330,150	10,330,150	9,209,036	(1,121,114)	7,956,730	(1,252,306)	7,956,730	0	7,956,730	0
Contributions & Grants	1995	(31,712,975)	(44,164,213)	(12,451,238)	(34,951,169)	9,213,043	(34,882,610)	68,559	(34,882,610)	0	(34,882,610)	0
Property Under Finance Leases	2005						820,130	820,130	820,130	0	820,130	0
Sub total		(31,712,975)	(33,834,063)	(2,121,088)	(25,742,134)	8,091,929	(16,105,751)	9,636,383	(13,685,903)	2,419,847	(13,685,903)	0
Gross Asset Total		670,970,385	642,704,976	(28,265,409)	337,982,033	(304,722,942)	416,022,841	78,040,808	458,743,203	42,720,361	501,234,764	42,491,561
Less Capital Contributions 2011 and future years	2240	0	0	0	(4,165,260)	(4,165,260)	(13,976,144)	(9,810,885)	(20,582,078)	(6,605,934)	(25,055,078)	(4,473,000)
Gross Asset Less Capital Contributi		670,970,385	642,704,976	(28,265,409)	333,816,772	(308,888,202)	402,046,695	68,229,924	438,161,122	36,114,427	476,179,683	38,018,561

Table 2-26 - Gross Assets – Detailed Breakdown

Description	OEB	Variance 2014 Bridge Year (MIFRS) from 2013 Actual (MIFRS) ($)	2015 Test Year ($) (MIFRS)	Variance 2015 Test Year (MIFRS) from 2014 Bridge Year (MIFRS) ($)	2016 Test Year ($) (MIFRS)	Variance 2016 Test Year (MIFRS) from 2015 Test Year (MIFRS) ($)	2017 Test Year ($) (MIFRS)	Variance 2017 Test Year (MIFRS) from 2016 Test Year (MIFRS) ($)	2018 Test Year ($) (MIFRS)	Variance 2018 Test Year (MIFRS) from 2017 Test Year (MIFRS) ($)	2019 Test Year ($) (MIFRS)	Variance 2019 Test Year (MIFRS) from 2018 Test Year (MIFRS) ($)
Land and Buildings												
Land	1905	0	1,067,629	0	1,067,629	0	1,067,629	0	1,067,629	0	1,067,629	0
Land Rights	1612	0	90,487	0	90,487	0	90,487	0	90,487	0	90,487	0
Land	1805	0	414,741	0	414,741	0	414,741	0	414,741	0	414,741	0
Buildings and Fixtures	1808	150,000	879,005	0	879,005	0	879,005	0	879,005	0	879,005	0
Leasehold Improvements	1810	0	0		0		0		0		0	
Sub total		150,000	2,451,863	0	2,451,863	0	2,451,863	0	2,451,863	0	2,451,863	0
DS												
Distribution Station Equipment	1820	846,790	13,526,404	754,301	14,428,475	902,070	15,339,665	911,190	16,269,448	929,783	17,220,434	950,986
Sub total		846,790	13,526,404	754,301	14,428,475	902,070	15,339,665	911,190	16,269,448	929,783	17,220,434	950,986
Poles and Wires												
Poles, Towers & Fixtures	1830	6,325,970	84,111,520	8,784,147	93,771,885	9,660,365	103,483,135	9,711,249	114,876,907	11,393,773	126,888,045	12,011,138
OH Conductors & Devices	1835	4,433,557	62,646,615	5,118,496	67,608,928	4,962,313	72,630,310	5,021,382	78,596,468	5,966,158	84,560,841	5,964,373
UG Conduit	1840	3,918,844	75,336,655	6,084,286	80,414,511	5,077,856	85,380,163	4,965,652	90,637,284	5,257,121	96,252,074	5,614,790
UG Conductors & Devices	1845	1,679,148	85,783,560	1,720,536	90,122,742	4,339,182	99,115,250	8,992,508	106,036,050	6,920,799	112,643,733	6,607,684
Sub total		16,357,518	307,878,350	21,707,465	331,918,066	24,039,716	360,608,858	28,690,792	390,146,709	29,537,851	420,344,694	30,197,985
Line Transformers												
Line Transformers	1850	6,639,725	79,830,690	6,893,457	87,708,005	7,877,316	95,523,852	7,815,846	103,802,199	8,278,347	112,613,474	8,811,275
Sub total		6,639,725	79,830,690	6,893,457	87,708,005	7,877,316	95,523,852	7,815,846	103,802,199	8,278,347	112,613,474	8,811,275
Services and Meters												
Services	1855	3,436,995	23,695,272	1,250,214	27,600,224	3,904,951	31,510,272	3,910,048	35,542,506	4,032,234	39,729,155	4,186,649
Meters	1860	1,513,674	28,756,067	1,463,674	30,142,241	1,386,174	31,498,414	1,356,174	32,854,588	1,356,174	34,210,762	1,356,174
Smart Meters	1860	917,658	27,919,336	3,158,615	28,519,505	600,169	29,094,195	574,690	29,674,400	580,205	30,240,091	565,691
Sub total		5,868,326	80,370,675	5,872,503	86,261,969	5,891,294	92,102,880	5,840,911	98,071,493	5,968,613	104,180,007	6,108,514
General Plant												
Buildings & Fixtures	1908	3,700,000	27,483,949	3,700,000	29,478,949	1,995,000	31,973,949	2,495,000	33,568,949	1,595,000	35,163,949	1,595,000
Sub total		3,700,000	27,483,949	3,700,000	29,478,949	1,995,000	31,973,949	2,495,000	33,568,949	1,595,000	35,163,949	1,595,000
IT Assets												
Computer Equipment- Hardware	1920	1,132,756	8,994,274	1,491,500	9,819,774	825,500	11,266,974	1,447,200	12,135,174	868,200	13,653,374	1,518,200
Computer Software	1611	5,321,945	16,008,579	2,390,404	16,464,079	455,500	16,903,579	439,500	18,568,079	1,664,500	19,257,579	689,500
Sub total		6,454,701	25,002,853	3,881,904	26,283,853	1,281,000	28,170,553	1,886,700	30,703,253	2,532,700	32,910,953	2,207,700
Equipment												
Office Furniture & Equipment	1915	618,000	3,756,896	69,000	3,825,896	69,000	3,894,896	69,000	3,967,896	73,000	4,040,896	73,000
Transportation Equipment	1930	785,000	9,672,000	778,000	10,452,000	780,000	11,227,000	775,000	12,012,000	785,000	12,797,000	785,000
Stores Equipment	1935	0	417,864	0	417,864	0	417,864	0	417,864	0	417,864	0
Tools, Shop & Garage Equipment	1940	511,300	4,107,395	555,560	4,674,995	567,600	5,183,595	508,600	5,714,195	530,600	6,294,795	580,600
Measurement & Testing Equipment	1945	154,000	1,283,648	132,300	1,373,248	89,600	1,460,848	87,600	1,550,448	89,600	1,640,048	89,600
Power operated Equipment	1950	0	35,360	0	35,360	0	35,360	0	35,360	0	35,360	0
Communications Equipment	1955	6,200	1,997,055	245,000	2,002,055	5,000	2,007,055	5,000	2,012,055	5,000	2,017,055	5,000
Load Management Controls	1970	0	312,338	0	312,338	0	312,338	0	312,338	0	312,338	0
System Supervisory Equipment	1980	400,000	1,682,817	300,000	1,882,817	200,000	1,882,817	0	1,882,817	0	1,882,817	0
Sub total		2,474,500	23,265,374	2,079,860	24,976,574	1,711,200	26,421,774	1,445,200	27,904,974	1,483,200	29,438,174	1,533,200
Other Distribution Assets												
Capital Contributions Paid	1609	0	12,419,847	0	12,419,847	0	12,419,847	0	12,419,847	0	12,419,847	0
Hydro One S/S Contribution	1996	0	7,956,730	0	7,956,730	0	7,956,730	0	7,956,730	0	7,956,730	0
Contributions & Grants	1995	0	(34,882,610)	0	(34,882,610)	0	(34,882,610)	0	(34,882,610)	0	(34,882,610)	0
Property Under Finance Leases	2005	0	820,130	0	900,000	79,870	900,000	0	900,000	0	900,000	0
Sub total		0	(13,685,903)	0	(13,606,033)	79,870	(13,606,033)	0	(13,606,033)	0	(13,606,033)	0
Gross Asset Total		42,491,561	546,124,255	44,889,491	589,901,721	43,777,466	638,987,361	49,085,640	689,312,856	50,325,494	740,717,515	51,404,659
Less Capital Contributions 2011 and and future years	2240	(4,473,000)	(29,688,078)	(4,633,000)	(34,343,078)	(4,655,000)	(39,020,078)	(4,677,000)	(43,721,078)	(4,701,000)	(48,451,078)	(4,730,000)
Gross Asset Less Capital Contributi		38,018,561	516,436,174	40,256,491	555,558,640	39,122,466	599,967,280	44,408,640	645,591,775	45,624,494	692,266,434	46,674,659

VARIANCE ANALYSIS ON GROSS ASSETS

The Gross Asset Variance analysis for the variances identified Table 2-25 and 2-26 is provided as follows:

2011 Actual (CGAAP) vs. 2011 Board-Approved (CGAAP):

The 2011 Board-Approved amounts for each account were calculated in accordance with the Board's findings at page 12 of its Decision and Order in Horizon Utilities' 2011 Cost of Service Application (EB-2010-0131). The Board found that Horizon Utilities' opening 2011 rate base should be the actual 2010 NBV excluding ending Work-in-Progress ("WIP").

Total Gross Assets for 2011 actual for were $642,704,976, which is $28,265,409 lower than the 2011 Board-Approved amount. Horizon Utilities disposed of fully depreciated assets with an original cost of $29,100,768 in 2011. The disposal was not included in the 2011 Board-Approved Test Year. There was a decrease in gross fixed assets of $29,100,768 and a corresponding decrease in accumulated depreciation relative to the 2011 Board-Approved Test Year. This was discussed previously in Tab 1, Schedule 2, page 2 of this Exhibit.

2011 Actual (Restated as MIFRS) vs. 2011 Actual (CGAAP):

Total Gross Assets for 2011 Actual (MIFRS) were $333,816,712, a decrease of $308,888,203 compared to 2011 Actual (CGAAP). Horizon Utilities adopted IFRS on January 1, 2012 with a transition date of January 1, 2011. Horizon Utilities elected to take the IFRS 1 deemed cost exemption which allowed rate-regulated entities to use the CGAAP net book value as the IFRS cost on the date of transition to IFRS. Accumulated depreciation as at January 1, 2011 is set to $0. The impact of this deemed cost exemption was a decrease in gross fixed assets of $327,086,844 and is discussed in further detail in Exhibit 6, Tab 2.

In addition, the change to IFRS accounting standards impacted gross fixed assets by:

- an increase of $29,100,768 for the amount of fully depreciated assets written off in 2011 under CGAAP;

- a decrease of $9,339,658 due to the non-directly attributable overhead costs capitalized under CGAAP and now expensed under IFRS; and
- a decrease of $1,562,469 for the derecognition of assets now recorded under IFRS.

Table 2-27 below summarizes these changes. Specific details regarding the impact on financial results and accounting policy arising from the transition to IFRS are provided in Exhibit 6, Tab 2, Schedule 1.

Table 2-27 - Impact of Transition to IFRS on Gross Assets

Description	Gross Fixed Assets Incr/(Decr)
Closing CGAAP, December 31st, 2011	**$642,704,976**
CGAAP write-off of assets at end of life	29,100,768
Deemed Cost Exemption	(327,086,844)
Indirect Costs not Eligible for Capitalization	(9,339,658)
Change to Useful Lives	0
Derecognition of Assets	(1,562,469)
Total Change due to IFRS transition	**(308,888,203)**
Closing MIFRS, December 31st, 2011	**$333,816,772**

2012 Actual (MIFRS) vs. 2011 Actual (MIFRS):

Total Gross Assets for 2012 Actual were $402,046,695, an increase of $68,229,924 compared to the 2011 Actual. This increase was due to capital additions of $46,980,043 and Smart Meter additions of $23,277,588, partly offset by disposals with an original cost of $2,027,707. The capital additions were driven by distribution system assets, general plant, and a one-time Hydro One contribution; as further described below.

The increase in distribution system additions was driven by increases in poles and wires, distribution station equipment, and line transformers; all of which were largely the result of capital replacements of aging infrastructure and to support Horizon Utilities' system access obligations. A more detailed variance analysis is provided in Tab 6, Schedule 3 of this Exhibit. General plant additions in 2012 were higher than 2011 primarily due to additions in computer equipment, buildings, and transportation equipment. A more detailed variance analysis is provided in Tab 6, Schedule 3 of this Exhibit.

One of the primary contributors to the increase in gross assets in 2012 was the Smart Meter implementation as discussed in Tab 1, Schedule 1, page 1 of this Exhibit. The cumulative gross Smart Meter additions in 2012 represented $23,277,588. Smart Meters are discussed in further detail in Exhibit 9, Tab 7, Schedule 1.

Another contributor to the increase in gross assets in 2012 was an addition for a one-time Hydro One contribution. Horizon Utilities is party to Connection and Cost Recovery Agreements ("CCRAs") with Hydro One. Such agreements provide for the construction by Hydro One of transformer stations ("TSs") for the purpose of serving Horizon Utilities' customers, including anticipated electricity load growth. The following discussion relates to Hydro One's Winona and Dundas TSs.

Horizon Utilities is required to provide Hydro One with an initial capital contribution ("Initial Capital Contribution") based on an economic evaluation that considers the difference between the net present value of the capital and ongoing maintenance cost of the TS and a projection of transformation revenue ("Hydro One Revenue") to be earned on the conveyance of electricity through the TS, under the CCRAs.

The CCRAs provide for periodic "True-Ups" commencing on the fifth anniversary of the "Ready for Service Date" in the agreements and every fifth year thereafter during the 25 year term of the CCRAs between Horizon Utilities and Hydro One, to address any significant variances between the projected and actual Hydro One Revenue. The amount of the True-Up is computed in a manner similar to the Initial Capital Contribution using discounted cash flows based on the difference between: a) the initial 25 year Load Forecast used in the determination of the initial Capital Contribution; and b) a revised 25 year Load Forecast comprising actual historical loads and forecast loads through the remainder of the 25 year term. The CCRA provides that if the difference between actual and projected Hydro One Revenue used in the Initial Capital Contribution calculations for the specified five twelve-month periods is greater than 20% of the projected Hydro One Revenue, the parties will determine the most equitable methodology for compensation for the variation.

The initial 5-year review of the CCRAs was completed and from that review it was clear that Hydro One Revenue at that time was substantially consistent with the projections used in the Initial Capital Contribution calculations. However, several factors resulted in a sharp drop in load, with expectations for persistence, following year 4:

- The Green Belt proposed by the Ontario Government in 2003 slowed development; by 2005 the Green Belt Act protected certain lands from development in Stoney Creek;
- Shut down of a GS>50kW customer in 2004-2005, with a resulting loss of 3 MVA;
- Significant load reduction (5MW) of a GS>50kW customer from 2005-2012;
- Shutdown of a Large Use customer in 2003 – Many spin off businesses in Stoney Creek also shut down after 2004; and
- General impact of recession forward from 2007.

The experienced and expected persistence of the sharp drop in load results in corresponding reductions in actual and forecast Hydro One Revenues. Hydro One has advised Horizon Utilities that it estimates that Horizon Utilities will be subject to a requirement to make a further capital contribution of $10,000,000 to recover the shortfall in Hydro One Revenues.

Horizon Utilities has recorded Obligations under Capital Cost Recovery Agreements and a corresponding intangible asset of $10,000,000 in 2012, as a result of such shortfalls and based on the terms of the CCRAs. This amount has been included in rate base as identified in the 2012 MIFRS Fixed Asset Continuity Schedule provided in Appendix 2-1 of this Exhibit. Horizon Utilities expects to be presented with a request for settlement from Hydro One in 2014; with the final calculation of the capital contribution and related payment terms to be arranged at that time.

2013 Actual (MIFRS) vs. 2012 Actual (MIFRS):

Total Gross Assets for 2013 were $438,161,122, an increase of $36,114,427 compared to the 2012 Actual. This increase is due to capital additions of $37,908,037 and partly offset by disposals with an original cost of $1,793,609. The total capital additions of $37,908,037 are comprised of additions to distribution plant of $26,183,705, and general plant additions of $11,724,332.

The increase in distribution plant additions was driven by increases in overhead and underground replacements; substation renewal investments; and distribution transformers due to capital replacements of aging infrastructure and to support Horizon Utilities' system access obligations. General plant additions in 2013 were higher than 2012 primarily due to general plant additions in computer equipment, buildings and office equipment. A more detailed variance analysis is provided in Tab 6, Schedule 3 of this Exhibit.

2014 Bridge Year (MIFRS) vs. 2013 Actual (MIFRS):

Total Gross Assets for the 2014 Bridge Year are forecast to be $476,179,683, an increase of $38,018,561 compared to the 2013 Actual. This increase is due to capital additions of $39,792,050 which were partly offset by disposals of $1,773,488. The total capital additions of $39,792,050 are comprised of additions to distribution plant of $27,162,848 and general plant additions of $12,629,201.

Distribution plant additions were driven by increases in overhead and underground replacements and distribution transformers. These were for necessary capital replacements for aging infrastructure and to support Horizon Utilities' system access obligations. General plant additions in 2014 are higher than 2013, primarily due to further additions in computer equipment and buildings.

A more detailed variance analysis is provided in Tab 6, Schedule 3 of this Exhibit.

2015 Test Year (MIFRS) vs. 2014 Bridge Year (MIFRS):

Total Gross Assets for the 2015 Test Year are forecast to be $516,436,174, an increase of $40,256,491 compared to the 2014 Bridge Year. This increase is due to ongoing capital additions of $40,114,524 and Smart Meter additions related to 2012 to 2014 installations of $2,231,464, partly offset by disposals of $2,089,496.

The total capital additions of $40,114,524 are comprised of additions to distribution plant of $30,452,758 and general plant additions of $9,661,765. A more detailed variance analysis is provided in Tab 6, Schedule 3 of this Exhibit and justification for specific projects is provided in Appendix G of the DSP.

The Smart Meter additions of $2,231,464 are associated with installations between 2012 and 2014. Horizon Utilities completed its Smart Meter deployment in 2011 with the exception of 'hard to reach' residential meters and commercial installations. Smart Meter deployment continued into 2014 with a principal focus on the conversion of the outstanding meters identified above which have been added to rate base in 2015.

2016 Test Year (MIFRS) vs. 2015 Test Year (MIFRS):

Total Gross Assets for the 2016 Test Year are forecast to be $555,558,640, an increase of $39,122,466 compared to the 2015 Test Year. This increase is due to capital additions of $42,947,533 partly offset by disposals of $3,825,068. The total capital additions of $42,947,533 are comprised of additions to distribution plant of $37,060,333, additions to general plant of $4,987,200 and additions to other plant of $900,000.

Horizon Utilities' investment requirements in the 2016 to 2019 Test Years are discussed in further detail in Tab 6, Schedule 3 of this Exhibit. Justification for specific projects is provided in Appendix A and Appendix G of the DSP.

2017 Test Year (MIFRS) vs. 2016 Test Year (MIFRS):

Total Gross Assets for the 2017 Test Year are forecast to be $599,967,280, an increase of $44,408,640 compared to the 2016 Test Year. This increase is due to capital additions of $47,426,114 partly offset by disposals of $3,017,473. The total capital additions of $47,426,114 are comprised of additions to distribution plant of $41,599,212 and additions to general plant of $5,826,900.

Further details on capital expenditures for the 2017 Test Year are provided in Tab 6, Schedule 3 of this Exhibit. Justification for specific projects is provided in Appendix A and Appendix G of the DSP.

2018 Test Year (MIFRS) vs. 2017 Test Year (MIFRS):

Total Gross Assets for the 2018 Test Year are forecast to be $645,591,775, an increase of $45,624,494 compared to the 2017 Test Year. This increase is due to capital additions of $48,942,504 partly offset by disposals of $3,318,009. The total capital additions of $48,942,504 are comprised of additions to distribution plant of $43,331,604 and additions to general plant of $5,610,900.

Further details on capital expenditures for the 2018 Test Year are provided in Tab 6, Schedule 3 of this Exhibit. Justification for specific projects is provided in Appendix A and Appendix G of the DSP.

2019 Test Year (MIFRS) vs. 2018 Test Year (MIFRS):

Total Gross Assets for the 2019 Test Year are forecast to be $692,266,434, an increase of $46,674,659 compared to the 2018 Test Year. This increase was due to capital additions of $51,272,477 partly offset by disposals of $4,597,818. The total capital additions of $51,272,477 are comprised of additions to distribution plant of $45,036,577, additions to general plant of $5,335,900 and additions to other plant of $900,000.

Further details on capital expenditures for the 2019 Test Year are provided in Tab 6, Schedule 3 of this Exhibit. Justification for specific projects is provided in Appendix A and Appendix G of the DSP.

The increase in general plant capital from 2011 to 2019 is primarily due to investments in information technology, communications equipment, and buildings upgrades for assets that have reached end-of-life. Horizon Utilities' strategy for building refurbishments and renewals, and the upgrading of computer equipment and software is provided in Tab 6, Schedule 3 of this Exhibit.

RECONCILIATION OF CONTINUITY STATEMENTS TO DEPRECIATION EXPENSE

Horizon Utilities has provided a reconciliation of the depreciation in the fixed continuity statements provided in Appendix 2-1 of this Exhibit (Appendices 2-BA1 and 2-BA2) to the calculated depreciation expenses presented in Exhibit 4, Tab 1, Schedule 1, in Table 2-28 below.

There are two reconciling items between the depreciation recorded on the fixed asset continuity statements and the depreciation expenses recorded on the income statement.

- **Fleet/Stores Depreciation Allocated to Capital** - The Logistics Department facilitates the receiving, storage (warehousing), and issuance of materials purchased by Horizon Utilities and used in the construction or maintenance of the distribution system. Such materials would include poles, electrical cable, transformers, switches, and other items.

  The depreciation recorded on the fixed asset continuities in 2011 reported under CGAAP is $1,331,522 higher than the depreciation expense recorded on the income statement, as identified in Table 2-28 below. Depreciation on fleet and stores equipment reported under CGAAP was allocated to capital and was not recorded as a charge or credit to income. This reconciling item only applies to financial statements prepared under CGAAP. Under MIFRS, fleet and stores depreciation is not directly attributable to an item of PP&E and, therefore, cannot be capitalized. Fleet and stores depreciation expense is recorded as a charge or credit to income as a result. (Refer to Exhibit 6, Tab 2, Schedule 1 for more information on the financial impact of accounting policy changes required under MIFRS).

- **Gain/(Loss) on Disposals** - The second reconciling item between the depreciation on the fixed asset continuity statements and the calculated depreciation expenses in 2012 to 2019 is due to the treatment of gains or losses on disposals under IFRS. Horizon Utilities has accounted for the amount of gain or loss on disposals as a charge or credit to income for financial reporting purposes under IFRS. Horizon Utilities has reclassified gains and losses on disposals as depreciation expense for regulatory reporting and filing purposes. Depreciation expense recorded as a charge or credit to income is higher than the depreciation recorded on the fixed asset continuities by the amount recorded for gains or losses on disposition.

Table 2-28 below identifies these reconciling amounts separately.

Table 2-28 - Reconciliation of Depreciation on Continuities to Depreciation Expense

Description	2011 Actual CGAAP	2012 Actual MIFRS	2013 Actual MIFRS	2014 Bridge Year MIFRS	2015 Test Year MIFRS	2016 Test Year MIFRS	2017 Test Year MIFRS	2018 Test Year MIFRS	2019 Test Year MIFRS
Total Depreciation on Continuties	**$ 27,720,934**	**$18,191,399**	**$19,299,511**	**$21,023,720**	**$23,383,544**	**$24,201,320**	**$24,161,257**	**$23,437,190**	**$23,877,061**
Deduct:									
Fleet/Stores Depreciation Allocated to Capital	$ (1,331,522)								
Add: (Gain)/Loss on Derecognition:									
Cost	$0	$2,027,707	$1,793,609	$1,773,488	$2,089,496	$3,825,068	$3,017,473	$3,318,009	$4,597,818
Accumulated Depreciation	$0	($150,765)	($156,463)	($133,043)	($187,423)	($1,085,758)	($344,159)	($430,511)	($1,426,748)
Proceeds	$0	($443,492)	($518,695)	($267,360)	($315,000)	($453,006)	($454,896)	($500,203)	($557,460)
(Gain)/Loss on Derecognition of PP&E	**$0**	**$1,433,449**	**$1,118,452**	**$1,373,086**	**$1,587,074**	**$2,286,304**	**$2,218,419**	**$2,387,296**	**$2,613,609**
Total Depreciation Expense	**$ 26,389,412**	**$ 19,624,849**	**$ 20,417,963**	**$ 22,396,806**	**$ 24,970,618**	**$ 26,487,624**	**$ 26,379,676**	**$ 25,824,486**	**$ 26,490,670**

Accumulated Depreciation – By Function

Accumulated depreciation is divided into three categories: distribution plant; general plant; and other plant. Horizon Utilities has included the accumulated depreciation associated with asset accounts 1805 to 1860, 1905 and 1906 in the category of distribution plant; 1908 to 1990 and 1611 in the category of general plant; and 2005 in the category of other capital assets, compliant with the Board's Uniform System of Accounts. Horizon Utilities does not have any transmission plant assets. Capital contributions have been listed separately.

Table 2-29 – Accumulated Depreciation Breakdown by Function

Description	2011 Board-Approved ($) (CGAAP)	2011 Actual ($) (CGAAP)	2011 Actual ($) (MIFRS)	2012 Actual ($) (MIFRS)	2013 Actual ($) (MIFRS)	2014 Bridge Year ($) (MIFRS)
Distribution Plant	293,010,035	264,629,140	11,343,819	26,236,226	39,938,718	54,796,278
General Plant	67,324,662	66,132,410	6,073,786	12,410,688	18,548,298	25,362,647
Capital Contributions	(4,849,496)	(5,054,539)	(1,338,118)	(2,700,603)	(3,671,034)	(4,725,642)
Other Plant	0	0	0	0	273,377	546,753
Accumulated Depreciation	355,485,201	325,707,010	16,079,487	35,946,311	55,089,359	75,980,036

Description	2015 Test Year ($) (MIFRS)	2016 Test Year ($) (MIFRS)	2017 Test Year ($) (MIFRS)	2018 Test Year ($) (MIFRS)	2019 Test Year ($) (MIFRS)
Distribution Plant	70,734,594	87,187,800	104,564,423	122,878,549	142,158,875
General Plant	33,781,677	42,279,772	49,867,856	55,840,017	61,322,613
Capital Contributions	(5,909,251)	(7,224,859)	(8,672,467)	(10,252,076)	(11,964,684)
Other Plant	820,130	300,000	600,000	900,000	300,000
Accumulated Depreciation	99,427,151	122,542,713	146,359,811	169,366,490	191,816,803

Detailed amounts categorized by major plant account are provided in Tables 2-30 and 2-31 of this Exhibit.

Accumulated Depreciation – Detailed Breakdown

Table 2-30 - Accumulated Depreciation – Detailed Breakdown

Description	OEB	2011 Board-Approved ($) (CGAAP)	2011 Actual ($) (CGAAP)	Variance 2011 (CGAAP) from 2011 Board-Approved ($)	2011 Actual ($) (MIFRS)	Variance 2011 Actual (MIFRS) from 2011 Actual (CGAAP)) ($)	2012 Actual ($) (MIFRS)	Variance 2012 (MIFRS) from 2011 (MIFRS) ($)	Variance 2012 (MIFRS) from 2011 Board-Approved ($)	2013 Actual ($) (MIFRS)	Variance 2013 (MIFRS) from 2012 (MIFRS) ($)	2014 Bridge Year ($) (MIFRS)	Variance 2014 (MIFRS) from 2013 (MIFRS) ($)
Land and Buildings													
Land	1905		0	0	0	0	0	0	0	0	0	0	0
Land Rights	1612	75,487	75,487	0	3,337	(72,150)	6,674	3,337	(68,813)	10,011	3,337	13,347	3,337
Land	1805		0	0	0	0	0	0	0	0	0	0	0
Buildings and Fixtures	1808	1,684,149	1,690,064	5,915	76,563	(1,613,501)	153,162	76,599	(1,530,987)	224,914	71,752	301,773	76,859
Leasehold Improvements	1810	20,886	20,886	(0)	0	(20,886)	0	0	(20,886)	0	0	0	0
Sub total		1,780,522	1,786,437	5,915	79,900	(1,706,537)	159,835	79,936	(1,620,687)	234,924	75,089	315,120	80,196
DS													
Distribution Station Equipment	1820	9,688,971	9,729,091	40,120	89,296	(9,639,795)	231,125	141,829	(9,457,846)	453,756	222,631	758,356	304,600
Sub total		9,688,971	9,729,091	40,120	89,296	(9,639,795)	231,125	141,829	(9,457,846)	453,756	222,631	758,356	304,600
Poles and Wires													
Poles, Towers & Fixtures	1830	30,637,539	29,306,464	(1,331,075)	1,413,493	(27,892,971)	2,995,688	1,582,195	(27,641,851)	4,724,048	1,728,360	6,667,545	1,943,497
OH Conductors & Devices	1835	36,173,654	34,402,198	(1,771,456)	1,093,617	(33,308,581)	2,278,082	1,184,465	(33,895,572)	3,515,638	1,237,556	4,899,860	1,384,222
UG Conduit	1840	69,494,754	60,680,748	(8,814,006)	1,870,778	(58,809,969)	3,838,664	1,967,886	(65,656,090)	5,902,955	2,064,291	8,082,733	2,179,778
UG Conductors & Devices	1845	64,103,240	54,204,887	(9,898,353)	2,822,518	(51,382,369)	5,090,164	2,267,646	(59,013,076)	7,416,019	2,325,855	9,839,947	2,423,928
Sub total		200,409,187	178,594,297	(21,814,890)	7,200,406	(171,393,891)	14,202,598	7,002,192	(186,206,589)	21,558,660	7,356,062	29,490,084	7,931,424
Line Transformers													
Line Transformers	1850	51,183,513	45,809,255	(5,374,258)	2,083,183	(43,726,072)	4,263,182	2,179,999	(46,920,331)	6,555,624	2,292,441	9,102,262	2,546,638
Sub total		51,183,513	45,809,255	(5,374,258)	2,083,183	(43,726,072)	4,263,182	2,179,999	(46,920,331)	6,555,624	2,292,441	9,102,262	2,546,638
Services and Meters													
Services	1855	10,567,110	10,247,469	(319,641)	385,274	(9,862,195)	792,194	406,920	(9,774,916)	1,209,700	417,506	1,683,831	474,131
Meters	1860	19,380,733	18,462,591	(918,141)	1,505,760	(16,956,831)	3,141,656	1,635,896	(16,239,077)	4,711,983	1,570,327	6,405,868	1,693,885
Smart Meters	1860			0	0	0	3,445,636	3,445,636	3,445,636	5,214,072	1,768,436	7,040,757	1,826,686
Sub total		29,947,842	28,710,060	(1,237,782)	1,891,034	(26,819,026)	7,379,485	5,488,451	(22,568,357)	11,135,754	3,756,269	15,130,456	3,994,702
General Plant													
Buildings & Fixtures	1908	19,587,153	19,570,829	(16,324)	1,276,104	(18,294,725)	2,297,707	1,021,603	(17,289,446)	3,462,261	1,164,554	4,628,892	1,166,631
Sub total		19,587,153	19,570,829	(16,324)	1,276,104	(18,294,725)	2,297,707	1,021,603	(17,289,446)	3,462,261	1,164,554	4,628,892	1,166,631
IT Assets													
Computer Equipment - Hardware	1920	18,096,764	8,352,949	(9,743,815)	831,679	(7,521,269)	1,950,552	1,118,873	(16,146,212)	2,926,565	976,013	4,224,589	1,298,024
Computer Software	1611		9,488,225	9,488,225	1,654,300	(7,833,925)	3,513,792	1,859,493	3,513,792	5,087,169	1,573,377	6,740,807	1,653,638
Sub total		18,096,764	17,841,174	(255,590)	2,485,979	(15,355,195)	5,464,345	2,978,366	(12,632,419)	8,013,734	2,549,389	10,965,396	2,951,662
Equipment													
Office Furniture & Equipment	1915	4,012,496	3,980,780	(31,716)	217,369	(3,763,411)	470,078	252,708	(3,542,418)	751,928	281,851	1,156,080	404,152
Transportation Equipment	1930	13,107,991	12,297,614	(810,377)	1,288,410	(11,009,204)	2,461,839	1,173,429	(10,646,152)	3,711,950	1,250,110	5,042,521	1,330,571
Stores Equipment	1935	596,231	603,783	7,552	54,989	(548,794)	109,337	54,349	(486,894)	162,856	53,519	212,223	49,367
Tools, Shop & Garage Equipment	1940	6,379,320	6,372,610	(6,710)	339,618	(6,032,992)	695,803	356,185	(5,683,517)	1,048,471	352,668	1,439,710	391,239
Measurement & Testing Equipment	1945	1,144,480	1,136,900	(7,580)	99,237	(1,037,663)	205,903	106,666	(938,577)	319,648	113,745	464,416	144,768
Power operated Equipment	1950	120,111	120,111	(0)	11,365	(108,746)	22,406	11,041	(97,705)	29,176	6,770	35,354	6,178
Communications Equipment	1955	841,501	778,700	(62,801)	141,295	(637,405)	364,243	222,948	(477,258)	584,943	220,700	805,616	220,673
Load Management Controls	1970	254,525	254,525	(0)	51,603	(202,922)	103,205	51,603	(151,320)	154,808	51,603	206,423	51,615
System Supervisory Equipment	1980	3,184,090	3,175,384	(8,706)	107,817	(3,067,567)	215,821	108,004	(2,968,269)	308,524	92,702	406,016	97,492
Sub total		29,640,745	28,720,407	(920,338)	2,311,703	(26,408,704)	4,648,636	2,336,933	(24,992,109)	7,072,303	2,423,667	9,768,359	2,696,056
Other Distribution Assets													
Capital Contributions Paid	1609			0		0	0	0	0	733,127	733,127	1,551,715	818,588
Hydro One S/S Contribution	1996		1,534,320	1,534,320	407,843	(1,126,477)	815,686	407,843	815,686	1,147,845	332,159	1,505,229	357,384
Contributions & Grants	1995	(4,849,496)	(6,588,859)	(1,739,363)	(1,689,483)	4,899,376	(3,282,047)	(1,592,564)	1,567,449	(4,889,627)	(1,607,580)	(6,497,207)	(1,607,580)
Property Under Finance Leases	2005			0		0		0	0	273,377	273,377	546,753	273,377
Sub total		(4,849,496)	(5,054,539)	(205,043)	(1,281,640)	3,772,899	(2,466,361)	(1,184,721)	2,383,135	(2,735,278)	(268,917)	(2,893,510)	(158,232)
Accumulated Depreciation Total		355,485,201	325,707,010	(29,778,191)	16,135,965	(309,571,045)	36,180,552	20,044,587	(319,304,649)	55,751,738	19,571,185	77,265,415	21,513,677
Less Capital Contributions 2011 and and future years				0	(56,478)	(56,478)	(234,242)	(177,764)	(234,242)	(662,379)	(428,137)	(1,285,379)	(623,000)
Acc Dep. Less Capital Contributions		355,485,201	325,707,010	(29,778,191)	16,079,487	(309,627,523)	35,946,311	19,866,823	(319,538,890)	55,089,359	19,143,048	75,980,036	20,890,677

Table 2-31 - Accumulated Depreciation – Detailed Breakdown

Description	OEB	2015 Test Year ($) (MIFRS)	Variance 2015 (MIFRS) from 2014 (MIFRS) ($)	2016 Test Year ($) (MIFRS)	Variance 2016 (MIFRS) from 2015 (MIFRS) ($)	2017 Test Year ($) (MIFRS)	Variance 2017 (MIFRS) from 2016 (MIFRS) ($)	2018 Test Year ($) (MIFRS)	Variance 2018 (MIFRS) from 2017 (MIFRS) ($)	2019 Test Year ($) (MIFRS)	Variance 2019 (MIFRS) from 2018 (MIFRS) ($)
Land and Buildings											
Land	1905	0	0	0	0	0	0	0	0	0	0
Land Rights	1612	16,684	3,337	20,021	3,337	23,358	3,337	26,695	3,337	30,032	3,337
Land	1805	0	0	0	0	0	0	0	0	0	0
Buildings and Fixtures	1808	372,728	70,955	428,625	55,897	480,339	51,715	522,227	41,888	556,972	34,745
Leasehold Improvements	1810	0	0	0	0	0	0	0	0	0	0
Sub total		389,412	74,292	448,646	59,234	503,697	55,052	548,922	45,225	587,004	38,082
DS											
Distribution Station Equipment	1820	1,082,264	323,909	1,427,032	344,767	1,794,474	367,442	2,184,948	390,474	2,598,953	414,006
Sub total		1,082,264	323,909	1,427,032	344,767	1,794,474	367,442	2,184,948	390,474	2,598,953	414,006
Poles and Wires											
Poles, Towers & Fixtures	1830	8,770,210	2,102,666	11,069,415	2,299,205	13,564,454	2,495,038	16,277,248	2,712,794	19,293,630	3,016,382
OH Conductors & Devices	1835	6,376,865	1,477,005	7,946,657	1,569,792	9,608,025	1,661,368	11,370,046	1,762,022	13,264,771	1,894,724
UG Conduit	1840	10,397,269	2,314,536	12,848,559	2,451,290	15,423,544	2,574,985	18,124,713	2,701,169	20,737,958	2,613,244
UG Conductors & Devices	1845	12,278,077	2,438,131	14,765,351	2,487,273	17,416,656	2,651,306	20,262,234	2,845,578	23,299,521	3,037,286
Sub total		37,822,421	8,332,337	46,629,982	8,807,561	56,012,679	9,382,697	66,034,242	10,021,563	76,595,879	10,561,637
Line Transformers											
Line Transformers	1850	11,817,685	2,715,423	14,719,294	2,901,609	17,826,749	3,107,455	21,132,272	3,305,523	24,688,668	3,556,396
Sub total		11,817,685	2,715,423	14,719,294	2,901,609	17,826,749	3,107,455	21,132,272	3,305,523	24,688,668	3,556,396
Services and Meters											
Services	1855	2,204,204	520,373	2,778,342	574,137	3,430,633	652,291	4,162,449	731,816	4,982,877	820,427
Meters	1860	8,109,454	1,703,586	9,815,602	1,706,149	11,536,134	1,720,532	13,234,447	1,698,312	14,961,816	1,727,369
Smart Meters	1860	9,309,153	2,268,396	11,368,903	2,059,750	13,460,056	2,091,153	15,581,268	2,121,212	17,743,678	2,162,410
Sub total		19,622,811	4,492,355	23,962,847	4,340,035	28,426,823	4,463,977	32,978,164	4,551,341	37,688,370	4,710,206
General Plant											
Buildings & Fixtures	1908	5,873,133	1,244,241	7,027,701	1,154,568	8,217,149	1,189,448	9,287,950	1,070,801	10,411,918	1,123,968
Sub total		5,873,133	1,244,241	7,027,701	1,154,568	8,217,149	1,189,448	9,287,950	1,070,801	10,411,918	1,123,968
IT Assets											
Computer Equipment - Hardware	1920	5,605,527	1,380,938	7,200,676	1,595,149	8,805,850	1,605,174	10,320,470	1,514,620	11,497,640	1,177,170
Computer Software	1611	9,797,234	3,056,428	12,954,453	3,157,219	15,309,047	2,354,594	16,353,389	1,044,342	17,326,362	972,973
Sub total		15,402,761	4,437,366	20,155,129	4,752,368	24,114,897	3,959,769	26,673,859	2,558,962	28,824,002	2,150,143
Equipment											
Office Furniture & Equipment	1915	1,603,373	447,293	2,045,505	442,132	2,462,504	416,999	2,839,953	377,449	3,205,331	365,378
Transportation Equipment	1930	6,315,539	1,273,018	7,422,353	1,106,815	8,517,955	1,095,601	9,564,588	1,046,634	10,499,379	934,791
Stores Equipment	1935	260,331	48,108	307,762	47,431	354,847	47,085	400,125	45,278	417,863	17,738
Tools, Shop & Garage Equipment	1940	1,859,061	419,351	2,306,530	447,470	2,766,425	459,895	3,245,270	478,845	3,751,669	506,399
Measurement & Testing Equipment	1945	614,408	149,991	755,538	141,131	890,607	135,069	1,027,526	136,919	1,165,436	137,911
Power operated Equipment	1950	35,354	0	35,354	0	35,354	0	35,354	0	35,354	0
Communications Equipment	1955	1,039,496	233,880	1,269,968	230,472	1,418,650	148,682	1,555,202	136,552	1,690,248	135,046
Load Management Controls	1970	258,038	51,615	306,894	48,856	312,325	5,431	312,325	0	312,325	0
System Supervisory Equipment	1980	520,184	114,168	647,037	126,853	777,143	130,106	897,865	120,722	1,009,087	111,222
Sub total		12,505,783	2,737,424	15,096,942	2,591,159	17,535,810	2,438,867	19,878,208	2,342,398	22,086,693	2,208,485
Other Distribution Assets											
Capital Contributions Paid	1609	2,370,303	818,588	3,188,891	818,588	4,007,478	818,588	4,826,066	818,588	5,644,654	818,588
Hydro One S/S Contribution	1996	1,862,612	357,384	2,219,996	357,384	2,577,380	357,384	2,934,763	357,384	3,292,147	357,384
Contributions & Grants	1995	(8,104,787)	(1,607,580)	(9,712,367)	(1,607,580)	(11,319,947)	(1,607,580)	(12,927,527)	(1,607,580)	(14,535,107)	(1,607,580)
Property Under Finance Leases	2005	820,130	273,377	300,000	(520,130)	600,000	300,000	900,000	300,000	300,000	(600,000)
Sub total		(3,051,742)	(158,232)	(4,003,480)	(951,738)	(4,135,089)	(131,608)	(4,266,697)	(131,608)	(5,298,306)	(1,031,608)
Accumulated Depreciation Total		101,464,529	24,199,115	125,464,092	23,999,562	150,297,190	24,833,098	174,451,869	24,154,679	198,183,182	23,731,313
Less Capital Contributions 2011 and and future years		(2,037,379)	(752,000)	(2,921,379)	(884,000)	(3,937,379)	(1,016,000)	(5,085,379)	(1,148,000)	(6,366,379)	(1,281,000)
Acc Dep. Less Capital Contributions		99,427,151	23,447,115	122,542,713	23,115,562	146,359,811	23,817,098	169,366,490	23,006,679	191,816,803	22,450,313

VARIANCE ANALYSIS ON ACCUMULATED DEPRECIATION

Table 2-30 and 2-31 identify the change in accumulated depreciation from 2011 Board-Approved to 2011 Actual (CGAAP), 2011 Actual (CGAAP) to 2011 Actual (MIFRS) and the annual changes in accumulated depreciation from 2011 (MIFRS) to 2019 (MIFRS).

2011 Actual vs. 2011 Board-Approved (CGAAP):

Total Accumulated Depreciation for 2011 Actual was $325,707,010, a decrease of $29,778,191 compared to 2011 Board-Approved. In 2011, Horizon Utilities disposed of fully depreciated assets with an original cost of $29,100,768. The disposal was not included in the 2011 Board-Approved Test Year since the value of fully depreciated assets was not known at the time of submission and there was no impact to rate base of the removal. There was a decrease in gross fixed assets of $29,100,768 and a corresponding decrease in accumulated depreciation relative to the 2011 Board-Approved. The remaining decrease of $677,423 in depreciation was due to lower gross asset additions of $28,265,409 versus 2011 Board-Approved.

2011 Actual (Restated as MIFRS) vs. 2011 Actual (CGAAP):

Total Accumulated Depreciation for the 2011 Actual (MIFRS) was $16,079,487, a decrease of $309,627,523 compared to the 2011 Actual (CGAAP). Horizon Utilities adopted IFRS on January 1, 2012 with a transition date of January 1, 2011. Horizon Utilities elected to take the IFRS 1 deemed cost exemption which allowed rate-regulated entities to use the CGAAP net book value as the IFRS cost on the date of transition to IFRS (which effectively preserves net book value as amortized original cost). Accumulated depreciation as at January 1, 2011 is set to $0. The impact of this exemption was a decrease in accumulated depreciation of $327,086,844 and is discussed in further detail in Exhibit 6, Tab 2, Schedule 1.

In addition, the change to IFRS accounting standards impacted depreciation by:

- an increase of $29,100,768, for the amount of fully depreciated assets written off in 2011 under CGAAP;

- a decrease of $127,897 for the amount of depreciation associated with $9,339,658 in non-directly attributable overhead costs capitalized under CGAAP and now expensed under IFRS;

- a decrease of $11,463,261 for the change in useful lives of distribution assets that are longer than under CGAAP. The change to useful lives is discussed in further detail in Exhibit 6, Tab 2, Schedule 1; and

- a decrease of $50,288 for the amount of depreciation associated with $1,562,469 for the derecognition of assets now recorded under IFRS.

Table 2-32 below summarizes these changes. Specific details regarding the impact on financial results and accounting policy arising from the transition to IFRS are provided in Exhibit 6, Tab 2.

Table 2-32 - Impact of Transition to IFRS on Accumulated Depreciation

Description	Accumulated Depreciation Incr/(Decr)
Closing CGAAP, December 31st, 2011	**$325,707,010**
CGAAP write-off of assets at end of life	29,100,768
Deemed Cost Exemption	(327,086,844)
Indirect Costs not Eligible for Capitalization	(127,897)
Change to Useful Lives	(11,463,261)
Derecognition of Assets	(50,288)
Total Change due to IFRS transition	**(309,627,523)**
Closing MIFRS, December 31st, 2011	**$16,079,487**

2011-2019 Actuals vs. Prior Year (MIFRS)

The change in accumulated depreciation year-over-year is a direct result of the increased depreciation from capital additions over the nine year period offset by decreased depreciation as assets are disposed of and/or reach the end of their useful lives. Net capital additions have increased from $30,500,974 in 2011 (MIFRS) to $46,980,043 in 2012 and are expected to increase from $37,908,037 in 2013 to $51,272,477 in 2019. Depreciation expense will increase over the nine year period at a rate similar to this overall increase in capital investments. A detailed analysis of the increase in capital investments has been provided in Tab 6, Schedule 3 of this Exhibit.

ALLOWANCE FOR WORKING CAPITAL

WORKING CAPITAL CALCULATION OVERVIEW

Horizon Utilities filed its first forward test year Cost of Service Application in 2007 (EB-2007-0697) for electricity distribution rates effective May 1, 2008. The Board approved a Working Capital Allowance of 15%, the Board's default at the time, in its decision on the 2008 Application. Horizon Utilities was directed by the Board in the 2008 Decision to file a Lead/Lag Study as part of its 2011 EDR CoS Application. Horizon Utilities engaged Navigant Consulting Inc. ("Navigant") to perform an analysis of Horizon Utilities' working capital requirements which determined a Working Capital Allowance of 14% that represented the filing position in such application. The Board approved a Working Capital Allowance of 13.5% in its decision on the 2011 Application.

Horizon Utilities engaged Navigant to perform an independent review of its Lead/Lag Study in 2013. The Lead/Lag Study was undertaken to provide Horizon Utilities with the basis for the determination of its Working Capital Allowance percentage. This Lead/Lag study was based on specific Lead inputs (lead times associated with payments for services) and Lag inputs (lag in the collection of revenues) as follows:

Lead Inputs: cost of power, payroll and benefits, OM&A expenses, payments in lieu of taxes, interest expenses, and debt retirement charge

Lag Inputs: service lag, billing lag, collections lag, and payment processing lag

Revenue weighting was used to determine the revenue lags and expense leads to compute the Working Capital Allowance percentage.

Horizon Utilities reviewed the 2012 OM&A expenses, which totalled $51,478,365, and determined that OM&A expense categories with a year-to-date total expenditure in excess of $500,000 should be included in the Lead/Lag Study. OM&A expense categories with a total expenditure of less than $500,000 aggregated to $4,200,000, and were deemed immaterial in the determination of the Working Capital Allowance percentage.

Payments for expenditures included in the Lead/Lag Study were extracted from Horizon Utilities' accounting system and reviewed to determine the lead time between the invoice/service date and the payment date of each expense. Navigant assisted in reviewing the data and provided confirmation of the weighting calculations used in the determination of the Working Capital Allowance percentage.

Horizon Utilities reviewed the meter reading, customer billing and payment cycles to calculate the revenue lag. This review included an evaluation of all customer classes and their related billing cycles and was used in the determination of the Working Capital Allowance percentage.

Horizon Utilities determined its Working Capital Allowance to be 12.7% based on the results of the Lead/Lag study. Horizon Utilities captured 100% of its revenue and 100% of its expenses over $500,000 in its calculation of the Working Capital Allowance percentage. The Lead/Lag study accompanies this Application at Tab 4, Schedule 1, Appendix 2-3 of this Exhibit.

Horizon Utilities proposes that 12.7% is appropriate for purposes of calculating the Working Capital Allowance effective January 1, 2015. Horizon Utilities has provided its calculations by account for each of 2011 Board Approved, 2011 Actual, 2012 Actual, 2013 Actual, 2014 Bridge Year, and the 2015 to 2019 Test Years in Tables 2-34 to 2-41 of this Exhibit. A summary of Horizon Utilities' working capital calculation is provided in Table 2-33 below and is based on 12.7% of specific OM&A and Cost of Power expenses.

Table 2-33 - Summary of Working Capital Calculation

Description	2011 Board-Approved	2011 Actual	2012 Actual	2013 Actual	2014 Bridge Year	2015 Test Year	2016 Test Year	2017 Test Year	2018 Test Year	2019 Test Year
Reporting Basis	*CGAAP*	*CGAAP*	*MIFRS*	*MIFRS*	*MIFRS*	*MIFRS*	*MIFRS*	*MIFRS*	*MIFRS*	*MIFRS*
Cost of Power	$53,092,213	$56,948,389	$61,046,317	$65,748,424	$69,447,116	$66,060,694	$68,757,167	$71,298,785	$73,897,898	$76,228,318
Operations	$2,061,435	$2,083,205	$3,287,767	$3,470,632	$4,107,200	$3,947,714	$4,050,070	$4,146,029	$4,258,184	$4,341,029
Maintenance	$632,289	$570,054	$459,128	$569,622	$452,530	$442,801	$458,977	$471,031	$483,633	$495,698
Billing & Collections	$1,029,200	$1,121,569	$1,218,063	$1,134,012	$1,306,783	$1,265,645	$1,295,084	$1,365,679	$1,360,072	$1,379,743
Community	$35,245	$0	$0	$0	$0	$0	$0	$0	$0	$0
Administration & General	$2,013,954	$1,847,199	$1,984,621	$2,185,462	$2,285,781	$2,298,190	$2,373,924	$2,431,751	$2,497,110	$2,564,372
Working Capital	**$58,864,336**	**$62,570,417**	**$67,995,896**	**$73,108,152**	**$77,599,411**	**$74,015,044**	**$76,935,221**	**$79,713,275**	**$82,496,897**	**$85,009,160**

Table 2-34 - Working Capital Calculation by Account 2011 – 2019

$	2011 Actual	Allowance for Working Capital	2012 Actual	Allowance for Working Capital	2013 Actual	Allowance for Working Capital	2014 Bridge Year
Rate Used for Working Capital Allowance		13.5%		13.5%		13.5%	
Operations							
5005-Operation Supervision and Engineering	1,901,779	256,740	3,158,766	426,433	3,167,163	427,567	4,454,100
5010-Load Dispatching	2,188,202	295,407	2,381,866	321,552	2,337,585	315,574	2,168,057
5012-Station Buildings and Fixtures Expense	459,523	62,036	520,520	70,270	690,082	93,161	615,317
5014-Transformer Station Equipment - Operation Labour	0	0	0	0	0	0	0
5015-Transformer Station Equipment - Operation Supplies and Expenses	0	0	0	0	0	0	0
5016-Distribution Station Equipment - Operation Labour	13,272	1,792	3,505	473	12,492	1,686	218,188
5017-Distribution Station Equipment - Operation Supplies and Expenses	143,977	19,437	79,349	10,712	144,141	19,459	182,607
5020-Overhead Distribution Lines and Feeders - Operation Labour	1,458,676	196,921	393,014	53,057	201,384	27,187	222,412
5025-Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	335,708	45,321	364,193	49,166	348,516	47,050	487,444
5030-Overhead Sub transmission Feeders - Operation	0	0	0	0	0	0	0
5035-Overhead Distribution Transformers- Operation	0	0	0	0	0	0	646
5040-Underground Distribution Lines and Feeders - Operation Labour	481,933	65,061	162,186	21,895	44,159	5,961	261,093
5045-Underground Distribution Lines & Feeders - Operation Supplies & Expenses	795,598	107,406	881,425	118,992	880,755	118,902	838,669
5050-Underground Sub transmission Feeders - Operation	0	0	0	0	0	0	0
5055-Underground Distribution Transformers - Operation	9,009	1,216	5,565	751	3,284	443	4,634
5060-Street Lighting and Signal System Expense	0	0	0	0	0	0	0
5065-Meter Expense	4,311,295	582,025	4,110,262	554,885	4,122,160	556,492	4,589,705
5070-Customer Premises - Operation Labour	1,266,361	170,959	880,481	118,865	797,211	107,624	574,880
5075-Customer Premises - Materials and Expenses	429,481	57,980	85,825	11,586	68,245	9,213	42,662
5085-Miscellaneous Distribution Expense	1,391,874	187,903	11,116,390	1,500,713	12,666,142	1,709,929	15,508,294
5090-Underground Distribution Lines and Feeders - Rental Paid	0	0	0	0	0	0	0
5095-Overhead Distribution Lines and Feeders - Rental Paid	0	0	0	0	0	0	0
5096-Other Rent	244,461	33,002	210,482	28,415	225,065	30,384	255,000
Sub-Total	15,431,149	2,083,205	24,353,827	3,287,767	25,708,382	3,470,632	30,423,707

Table 2-35 - Working Capital Calculation by Account 2011 – 2019

$	2011 Actual	Allowance for Working Capital	2012 Actual	Allowance for Working Capital	2013 Actual	Allowance for Working Capital	2014 Bridge Year
Rate Used for Working Capital Allowance		13.5%		13.5%		13.5%	
Maintenance							
5105-Maintenance Supervision and Engineering	184,296	24,880	19,880	2,684	111,518	15,055	36,181
5110-Maintenance of Buildings and Fixtures - Distribution Stations	235,658	31,814	98,013	13,232	239,287	32,304	345,815
5112-Maintenance of Transformer Station Equipment	0	0	0	0	0	0	0
5114-Maintenance of Distribution Station Equipment	393,033	53,059	323,581	43,683	238,249	32,164	346,594
5120-Maintenance of Poles, Towers and Fixtures	152,308	20,562	68,798	9,288	86,486	11,676	45,560
5125-Maintenance of Overhead Conductors and Devices	1,591,820	214,896	1,177,108	158,910	1,587,606	214,327	746,376
5130-Maintenance of Overhead Services	136,875	18,478	161,542	21,808	160,890	21,720	89,104
5135-Overhead Distribution Lines and Feeders - Right of Way	748,038	100,985	824,330	111,285	1,094,305	147,731	932,771
5145-Maintenance of Underground Conduit	86,827	11,722	31,161	4,207	110,428	14,908	112,851
5150-Maintenance of Underground Conductors and Devices	540,407	72,955	551,245	74,418	437,406	59,050	458,783
5155-Maintenance of Underground Services	4,645	627	8,083	1,091	2,498	337	20,682
5160-Maintenance of Line Transformers	76,503	10,328	95,898	12,946	90,868	12,267	146,096
5165-Maintenance of Street Lighting and Signal Systems	0	0	0	0	0	0	0
5170-Sentinel Lights - Labour	0	0	0	0	0	0	0
5172-Sentinel Lights - Materials and Expenses	0	0	0	0	0	0	0
5175-Maintenance of Meters	72,215	9,749	41,308	5,577	59,884	8,084	71,263
5178-Customer Installations Expenses- Leased Property	0	0	0	0	0	0	0
5185-Water Heater Rentals - Labour	0	0	0	0	0	0	0
5186-Water Heater Rentals - Materials and Expenses	0	0	0	0	0	0	0
5190-Water Heater Controls - Labour	0	0	0	0	0	0	0
5192-Water Heater Controls - Materials and Expenses	0	0	0	0	0	0	0
5195-Maintenance of Other Installations on Customer Premises	0	0	0	0	0	0	0
Sub-Total	4,222,626	570,054	3,400,949	459,128	4,219,425	569,622	3,352,076

Table 2-36 - Working Capital Calculation by Account - 2011 – 2019 (continued)

$	2011 Actual	Allowance for Working Capital	2012 Actual	Allowance for Working Capital	2013 Actual	Allowance for Working Capital	2014 Bridge Year	Allowance for Working Capital
Rate Used for Working Capital Allowance		13.5%		13.5%		13.5%		13.5%
Billing and Collections								
5305-Supervision	0	0	0	0	0	0	0	0
5310-Meter Reading Expense	0	0	0	0	0	0	0	0
5315-Customer Billing	0	0	0	0	0	0	0	0
5320-Collecting	158,892	21,450	173,510	23,424	177,704	23,990	173,288	23,394
5325-Collecting- Cash Over and Short	0	0	0	0	0	0	0	0
5330-Collection Charges	0	0	0	0	(94)	(13)	0	0
5335-Bad Debt Expense	1,536,562	207,436	1,549,348	209,162	865,616	116,858	1,435,000	193,725
5340-Miscellaneous Customer Accounts Expenses	6,612,467	892,683	7,299,834	985,478	7,356,864	993,177	8,071,587	1,089,664
Sub-Total	8,307,921	1,121,569	9,022,692	1,218,063	8,400,090	1,134,012	9,679,875	1,306,783
Administrative and General Expenses								
5605-Executive Salaries and Expenses	2,007,963	271,075	2,155,069	290,934	2,116,029	285,664	2,053,235	277,187
5610-Management Salaries and Expenses	2,241,112	302,550	2,746,133	370,728	2,911,716	393,082	3,366,851	454,525
5615-General Administrative Salaries and Expenses	2,769,434	373,874	2,846,383	384,262	2,615,742	353,125	2,382,401	321,624
5620-Office Supplies and Expenses	1,919,949	259,193	1,926,695	260,104	1,801,801	243,243	2,650,224	357,780
5625-Administrative Expense Transferred Credit	(1,080,210)	(145,828)	(1,166,169)	(157,433)	(1,140,022)	(153,903)	(1,625,421)	(219,432)
5630-Outside Services Employed	2,434,103	328,604	1,614,988	218,023	1,964,935	265,266	2,218,965	299,560
5635-Property Insurance	54,561	7,366	30,657	4,139	130,054	17,557	122,514	16,539
5640-Injuries and Damages	525,532	70,947	439,742	59,365	587,590	79,325	571,607	77,167
5645-Employee Pensions and Benefits	763,085	103,016	1,150,414	155,306	1,414,886	191,010	1,354,288	182,829
5650-Franchise Requirements	0	0	0	0	0	0	0	0
5655-Regulatory Expenses	847,420	114,402	807,933	109,071	810,612	109,433	700,000	94,500
5660-General Advertising Expenses	2,888	390	360	49	252,039	34,025	13,800	1,863
5665-Miscellaneous General Expenses	756,938	102,187	624,524	84,311	847,585	114,424	1,027,700	138,740
5670-Rent	0	0	0	0	0	0	0	0
5675-Maintenance of General Plant	1,086,079	146,621	1,289,843	174,129	1,456,000	196,560	1,670,791	225,557
5680-Electrical Safety Authority Fees	0	0	0	0	0	0	0	0
5685-Independent Market Operator Fees and Penalties	0	0	0	0	0	0	0	0
5695-OM&A Contra	(1,180,303)	(159,341)	0	0	0	0	0	0
6105 -Property Taxes	396,097	53,473	50,574	6,827	294,779	39,795	295,754	39,927
6205 -Donations	138,308	18,672	183,752	24,806	124,863	16,857	129,000	17,415
Sub-Total	13,682,957	1,847,199	14,700,897	1,984,621	16,188,608	2,185,462	16,931,711	2,285,781

Table 2-37 - Working Capital Calculation by Account - 2011 – 2019 (continued)

$	2011 Actual	Allowance for Working Capital	2012 Actual	Allowance for Working Capital	2013 Actual	Allowance for Working Capital	2014 Bridge Year	Allowance for Working Capital
Rate Used for Working Capital Allowance		13.5%		13.5%		13.5%		13.5%
Cost of Power								
4705-Power Purchased	243,463,670	32,867,595	245,846,765	33,189,313	259,428,934	35,022,906	253,365,409	34,204,330
4708-Charges-WMS	26,046,341	3,516,256	24,922,057	3,364,478	138,834,663	18,742,680	27,728,686	3,743,373
4710-Cost of Power Adjustments	93,993,285	12,689,094	116,557,288	15,735,234	25,084,300	3,386,380	167,703,239	22,639,937
4712-Charges-One-Time	0	0	0	0	0	0	0	0
4714-Charges-NW	31,582,393	4,263,623	36,182,227	4,884,601	34,600,123	4,671,017	36,271,356	4,896,633
4716-Charges-CN	26,573,434	3,587,414	28,374,855	3,830,605	27,300,283	3,685,538	26,823,994	3,621,239
4730-Rural Rate Assistance Expense	0	0	0	0	0	0	0	0
4750-LV Charge	180,792	24,407	311,750	42,086	307,287	41,484	308,235	41,612
4751-Charges-Smart Metering Entity Charge	0	0	0	0	1,469,771	198,419	2,222,161	299,992
Sub-Total	421,839,916	56,948,389	452,194,942	61,046,317	487,025,361	65,748,424	514,423,081	69,447,116
WORKING CAPITAL ALLOWANCE TOTAL	**463,484,570**	**62,570,417**	**503,673,307**	**67,995,896**	**541,541,866**	**73,108,152**	**574,810,450**	**77,599,411**

Table 2-38 - Working Capital Calculation by Account - 2011 – 2019 (continued)

$	2015 Test Year	Allowance for Working Capital	2016 Test Year	Allowance for Working Capital	2017 Test Year	Allowance for Working Capital	2018 Test Year	Allowance for Working Capital	2019 Test Year	Allowance for Working Capital
Rate Used for Working Capital Allowance		**12.7%**		**12.7%**		**12.7%**		**12.7%**		**12.7%**
Operations										
5005-Operation Supervision and Engineering	4,690,916	595,746	4,911,403	623,748	5,058,218	642,394	5,205,787	661,135	5,312,654	674,707
5010-Load Dispatching	2,220,659	282,024	2,300,647	292,182	2,366,298	300,520	2,436,626	309,451	2,495,626	316,944
5012-Station Buildings and Fixtures Expense	624,546	79,317	633,915	80,507	643,423	81,715	653,074	82,940	662,870	84,185
5014-Transformer Station Equipment - Operation Labour	0	0	0	0	0	0	0	0	0	0
5015-Transformer Station Equipment - Operation Supplies and Expenses	0	0	0	0	0	0	0	0	0	0
5016-Distribution Station Equipment - Operation Labour	130,751	16,605	134,693	17,106	139,733	17,746	143,920	18,278	147,949	18,790
5017-Distribution Station Equipment - Operation Supplies and Expenses	93,085	11,822	298,596	37,922	302,768	38,452	308,585	39,190	312,421	39,678
5020-Overhead Distribution Lines and Feeders - Operation Labour	228,627	29,036	235,485	29,907	242,551	30,804	249,826	31,728	256,820	32,616
5025-Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	600,284	76,236	715,454	90,863	725,187	92,099	741,393	94,157	749,613	95,201
5030-Overhead Sub transmission Feeders - Operation	0	0	0	0	0	0	0	0	0	0
5035-Overhead Distribution Transformers- Operation	665	84	685	87	705	89	727	92	747	95
5040-Underground Distribution Lines and Feeders - Operation Labour	268,387	34,085	276,439	35,108	284,731	36,161	293,274	37,246	301,485	38,289
5045-Underground Distribution Lines & Feeders - Operation Supplies & Expenses	842,868	107,044	860,125	109,236	874,701	111,087	892,888	113,397	907,061	115,197
5050-Underground Sub transmission Feeders - Operation	0	0	0	0	0	0	0	0	0	0
5055-Underground Distribution Transformers - Operation	4,797	609	4,978	632	5,168	656	5,366	681	5,565	707
5060-Street Lighting and Signal System Expense	0	0	0	0	0	0	0	0	0	0
5065-Meter Expense	4,896,314	621,832	5,068,053	643,643	5,197,679	660,105	5,341,233	678,337	5,455,484	692,846
5070-Customer Premises - Operation Labour	590,943	75,050	608,671	77,301	626,926	79,620	645,737	82,009	663,815	84,305
5075-Customer Premises - Materials and Expenses	46,930	5,960	51,622	6,556	56,783	7,211	62,462	7,933	68,708	8,726
5085-Miscellaneous Distribution Expense	15,573,081	1,977,781	15,500,644	1,968,582	15,813,802	2,008,353	16,221,587	2,060,142	16,509,088	2,096,654
5090-Underground Distribution Lines and Feeders - Rental Paid	0	0	0	0	0	0	0	0	0	0
5095-Overhead Distribution Lines and Feeders - Rental Paid	0	0	0	0	0	0	0	0	0	0
5096-Other Rent	271,512	34,482	288,907	36,691	307,228	39,018	326,525	41,469	331,423	42,091
Sub-Total	31,084,364	3,947,714	31,890,317	4,050,070	32,645,901	4,146,029	33,529,011	4,258,184	34,181,330	4,341,029

Table 2-39 - Working Capital Calculation by Account - 2011 – 2019 (continued)

$	2015 Test Year	Allowance for Working Capital	2016 Test Year	Allowance for Working Capital	2017 Test Year	Allowance for Working Capital	2018 Test Year	Allowance for Working Capital	2019 Test Year	Allowance for Working Capital
Rate Used for Working Capital Allowance		12.7%		12.7%		12.7%		12.7%		12.7%
Maintenance										
5105-Maintenance Supervision and Engineering	36,727	4,664	37,982	4,824	38,550	4,896	39,925	5,070	39,939	5,072
5110-Maintenance of Buildings and Fixtures - Distribution Stations	351,504	44,641	357,376	45,387	363,352	46,146	369,437	46,918	375,545	47,694
5112-Maintenance of Transformer Station Equipment	0	0	0	0	0	0	0	0	0	0
5114-Maintenance of Distribution Station Equipment	354,577	45,031	363,162	46,122	372,011	47,245	381,133	48,404	390,137	49,547
5120-Maintenance of Poles, Towers and Fixtures	47,170	5,991	48,937	6,215	50,798	6,451	52,745	6,699	54,708	6,948
5125-Maintenance of Overhead Conductors and Devices	775,371	98,472	838,666	106,511	868,114	110,250	898,928	114,164	928,467	117,915
5130-Maintenance of Overhead Services	92,129	11,700	95,459	12,123	98,952	12,567	102,610	13,031	106,268	13,496
5135-Overhead Distribution Lines and Feeders - Right of Way	948,247	120,427	964,196	122,453	980,473	124,520	997,095	126,631	1,013,892	128,764
5145-Maintenance of Underground Conduit	115,747	14,700	118,882	15,098	122,139	15,512	125,520	15,941	128,887	16,369
5150-Maintenance of Underground Conductors and Devices	471,820	59,921	485,997	61,722	500,788	63,600	516,222	65,560	531,688	67,524
5155-Maintenance of Underground Services	21,091	2,679	21,520	2,733	21,961	2,789	22,415	2,847	22,870	2,904
5160-Maintenance of Line Transformers	150,089	19,061	154,442	19,614	158,956	20,187	163,637	20,782	168,257	21,369
5165-Maintenance of Street Lighting and Signal Systems	0	0	0	0	0	0	0	0	0	0
5170-Sentinel Lights - Labour	0	0	0	0	0	0	0	0	0	0
5172-Sentinel Lights - Materials and Expenses	0	0	0	0	0	0	0	0	0	0
5175-Maintenance of Meters	122,148	15,513	127,372	16,176	132,809	16,867	138,467	17,585	142,478	18,095
5178-Customer Installations Expenses- Leased Property	0	0	0	0	0	0	0	0	0	0
5185-Water Heater Rentals - Labour	0	0	0	0	0	0	0	0	0	0
5186-Water Heater Rentals - Materials and Expenses	0	0	0	0	0	0	0	0	0	0
5190-Water Heater Controls - Labour	0	0	0	0	0	0	0	0	0	0
5192-Water Heater Controls - Materials and Expenses	0	0	0	0	0	0	0	0	0	0
5195-Maintenance of Other Installations on Customer Premises	0	0	0	0	0	0	0	0	0	0
Sub-Total	3,486,620	442,801	3,613,989	458,977	3,708,903	471,031	3,808,133	483,633	3,903,135	495,698

Table 2-40 - Working Capital Calculation by Account - 2011 – 2019 (continued)

$	2015 Test Year	Allowance for Working Capital	2016 Test Year	Allowance for Working Capital	2017 Test Year	Allowance for Working Capital	2018 Test Year	Allowance for Working Capital	2019 Test Year	Allowance for Working Capital
Rate Used for Working Capital Allowance		12.7%		12.7%		12.7%		12.7%		12.7%
Billing and Collections										
5305-Supervision	0	0	0	0	0	0	0	0	0	0
5310-Meter Reading Expense	0	0	0	0	0	0	0	0	0	0
5315-Customer Billing	0	0	0	0	0	0	0	0	0	0
5320-Collecting	175,984	22,350	178,736	22,699	181,535	23,055	184,381	23,416	187,267	23,783
5325-Collecting- Cash Over and Short	0	0	0	0	0	0	0	0	0	0
5330-Collection Charges	0	0	0	0	0	0	0	0	0	0
5335-Bad Debt Expense	1,451,913	184,393	1,468,918	186,553	1,489,350	189,147	1,511,268	191,931	1,531,413	194,489
5340-Miscellaneous Customer Accounts Expenses	8,337,813	1,058,902	8,549,854	1,085,831	9,082,495	1,153,477	9,013,584	1,144,725	9,145,439	1,161,471
Sub-Total	9,965,710	1,265,645	10,197,508	1,295,084	10,753,379	1,365,679	10,709,232	1,360,072	10,864,119	1,379,743
Administrative and General Expenses										
5605-Executive Salaries and Expenses	2,072,770	263,242	2,122,486	269,556	2,175,166	276,246	2,227,915	282,945	2,289,812	290,806
5610-Management Salaries and Expenses	3,464,597	440,004	3,590,367	455,977	3,679,379	467,281	3,804,424	483,162	3,902,106	495,567
5615-General Administrative Salaries and Expenses	2,501,963	317,749	2,654,879	337,170	2,736,786	347,572	2,815,079	357,515	2,893,526	367,478
5620-Office Supplies and Expenses	2,634,378	334,566	2,971,834	377,423	3,031,323	384,978	3,114,251	395,510	3,124,421	396,801
5625-Administrative Expense Transferred Credit	(1,652,703)	(209,893)	(1,706,219)	(216,690)	(1,749,723)	(222,215)	(1,803,673)	(229,066)	(1,824,854)	(231,756)
5630-Outside Services Employed	2,500,927	317,618	2,365,893	300,468	2,452,130	311,421	2,590,409	328,982	2,524,650	320,631
5635-Property Insurance	147,486	18,731	149,272	18,958	151,085	19,188	152,926	19,422	155,220	19,713
5640-Injuries and Damages	571,367	72,564	571,124	72,533	570,877	72,501	570,626	72,469	579,185	73,557
5645-Employee Pensions and Benefits	1,393,120	176,926	1,435,091	182,257	1,480,649	188,042	1,529,345	194,227	1,529,345	194,227
5650-Franchise Requirements	0	0	0	0	0	0	0	0	0	0
5655-Regulatory Expenses	1,262,441	160,330	1,273,098	161,683	1,283,916	163,057	1,258,691	159,854	1,306,039	165,867
5660-General Advertising Expenses	14,007	1,779	14,217	1,806	14,430	1,833	14,647	1,860	14,867	1,888
5665-Miscellaneous General Expenses	1,049,438	133,279	1,065,398	135,306	1,083,731	137,634	1,102,431	140,009	1,122,075	142,504
5670-Rent	0	0	0	0	0	0	0	0	0	0
5675-Maintenance of General Plant	1,700,456	215,958	1,737,830	220,704	1,782,540	226,383	1,822,606	231,471	2,103,442	267,137
5680-Electrical Safety Authority Fees	0	0	0	0	0	0	0	0	0	0
5685-Independent Market Operator Fees and Penalties	0	0	0	0	0	0	0	0	0	0
5695-OM&A Contra	0	0	0	0	0	0	0	0	0	0
6105 -Property Taxes	300,190	38,124	304,693	38,696	309,263	39,276	313,902	39,866	318,611	40,464
6205 -Donations	135,547	17,214	142,354	18,079	146,092	18,554	148,704	18,885	153,459	19,489
Sub-Total	18,095,985	2,298,190	18,692,317	2,373,924	19,147,644	2,431,751	19,662,283	2,497,110	20,191,905	2,564,372

Table 2-41 - Working Capital Calculation by Account - 2011 – 2019 (continued)

$	2015 Test Year	Allowance for Working Capital	2016 Test Year	Allowance for Working Capital	2017 Test Year	Allowance for Working Capital	2018 Test Year	Allowance for Working Capital	2019 Test Year	Allowance for Working Capital
Rate Used for Working Capital Allowance		**12.7%**		**12.7%**		**12.7%**		**12.7%**		**12.7%**
Cost of Power										
4705-Power Purchased	257,047,755	32,645,065	268,480,655	34,097,043	279,013,502	35,434,715	290,008,273	36,831,051	300,825,305	38,204,814
4708-Charges-WMS	27,769,133	3,526,680	27,789,396	3,529,253	27,730,889	3,521,823	27,711,612	3,519,375	27,685,197	3,516,020
4710-Cost of Power Adjustments	166,175,251	21,104,257	174,104,952	22,111,329	181,668,599	23,071,912	189,319,383	24,043,562	196,989,274	25,017,638
4712-Charges-One-Time	0	0	0	0	0	0	0	0	0	0
4714-Charges-NW	37,805,670	4,801,320	39,023,250	4,955,953	40,391,558	5,129,728	41,830,469	5,312,470	43,033,369	5,465,238
4716-Charges-CN	28,833,043	3,661,797	29,436,660	3,738,456	30,026,789	3,813,402	30,789,620	3,910,282	31,380,217	3,985,288
4730-Rural Rate Assistance Expense	0	0	0	0	0	0	0	0	0	0
4750-LV Charge	308,303	39,154	308,736	39,209	309,026	39,246	309,355	39,288	309,616	39,321
4751-Charges-Smart Metering Entity Charge	2,223,788	282,421	2,251,365	285,923	2,267,389	287,958	1,904,499	241,871	0	0
Sub-Total	520,162,944	66,060,694	541,395,015	68,757,167	561,407,753	71,298,785	581,873,212	73,897,898	600,222,979	76,228,318
WORKING CAPITAL ALLOWANCE TOTAL	**582,795,623**	**74,015,044**	**605,789,145**	**76,935,221**	**627,663,580**	**79,713,275**	**649,387,749**	**82,496,897**	**669,168,170**	**85,009,160**

APPENDIX 2-3 HORIZON UTILITIES' LEAD/LAG STUDY

NAVIGANT

A Determination of the Working Capital Requirements of Horizon Utilities' Distribution Business

Prepared for:
Horizon Utilities Corporation

horizon UTILITIES Looking beyond...

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March 31, 2014

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NAVIGANT

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Section I: Executive Summary

Summary

In preparation for HUC's 2014 Distribution Cost of Service Rate Application before the Ontario Energy Board ("OEB" or "Board"), Horizon Utilities Corporation ("HUC") retained Navigant Consulting Ltd. ("Navigant") to perform a lead-lag study using the most recent data available, and to derive HUC's WCA using historical 2012 data with known and measurable forward looking changes applied. This report provides the results of the study and the WCA of HUC's distribution business.

Results from the lead-lag study applied to HUC's 2012 distribution expenses identify that an average working capital percentage of 12.7% of the Cost of Power and OM&A Expenses for the 2014-2019 test years. This represents an average of 12.7% of HUC's distribution OM&A expenses for the 2014-2019 time periods. Inasmuch as slight variation exists from year-to-year in our analysis Navigant believes application of the 12.7% provides an accurate recovery of the cost of working capital for the time period 2014 through 2019. Based upon the working capital dollar amounts for each of the test years, the weighted average working capital was calculated to be 12.7%. Table 1 below provides the estimated working capital dollars and percentages for the test years 2014-2019.

Table 1 – Estimated Working Capital Requirements

	2014	2015	2016	2017	2018	2019	2014 to 2019
Estimated Working Capital Requirements ($)	$73,386,661	$74,271,709	$76,895,589	$79,721,717	$82,565,878	$85,320,939	$458,010,166
Estimated Working Capital Requirements (%)	12.7%	12.7%	12.6%	12.7%	12.6%	12.7%	12.7%

Organization of the Report

Section I of this report is the Executive Summary and discusses the key findings and conclusions from this study.

Section II presents the methods and assumptions used in determining the lead-lag approach. Included in this section is a description of two key concepts; the mid-point method and the statutory approach for services and materials provided and expensed.

Section III of this report discusses the lags associated with HUC's collections of revenues. This includes a description of the sources of such revenues, how they were treated for the purposes of deriving an overall revenue lag, and how it affects HUC's distribution operations.

Section IV presents a description of the various expenses and their attendant lead times. Included in this discussion are the lead times on Payroll and Benefits, OM&A, Taxes, Interest, Debt Retirement Charges and the Harmonized Sales Tax ("HST"). The methods used to calculate the expense lead times associated with each of the items as well as the results from the application of the methods are described.

Section V presents the cash WCA of HUC's distribution business including the WCA associated with the HST.

Section II: Methodology Used to Estimate Cash Working Capital

Working capital is the amount of funds that are required to finance the day-to-day operations of a utility and are included as part of a rate base for ratemaking purposes. A lead-lag study is the most accurate basis for determination of working capital and was used by Navigant for this purpose.

A lead-lag study analyzes the time between the date customers receive service and the date customers' payments are available to HUC (or "lag") together with the time between which HUC receives goods and services from its vendors and pays for them at a later date (or "lead")[1]. "Leads" and "Lags" are both measured in days and are generally where appropriate, dollar-weighted.[2] The dollar-weighted net lag (i.e., lag minus lead) days is divided by 365 (or 366 if a leap year is selected) and then multiplied by the annual test year cash expenses to determine the amount of working capital required for operations. The resulting amount of working capital is then included as part of HUC's rate base for the purpose of deriving revenue requirement.

Key Concepts

Two key concepts need to be defined up-front as they appear throughout the lead-lag study described in this report:

Mid-Point Method: When a service is provided to (or by) HUC over a period of time, the service is deemed to have been provided (or received) evenly over the midpoint of the period, unless specific information regarding the provision (or receipt) of that service is available indicating otherwise. If both the service end date ("Y") and the service start date ("X") are known, the mid-point of a service period can be calculated using the formula:

$$\text{Mid-Point} = \frac{\left([\text{Y-X}]+1\right)}{2}$$

When specific start and end dates are unknown but it is known that a service is evenly distributed over the mid-point of a period, an alternative formula that is typically used is shown below. The formula uses the number of days in a year ("A") and the number of periods in a year ("B"):

$$\text{Mid-Point} = \frac{A/B}{2}$$

Statutory Approach: In conjunction with the use of the mid-point method, it is important to note that not all areas of this study may utilize dates on which actual payments were made by HUC. In some instances, particularly for the HST, the due dates for payments are established by statute or by regulation with significant penalties in place for late payments. In these instances, the due date established by statute has been used in lieu of when payments were actually made.

1 A positive lag (or lead) indicates that payments are received (or paid for) after the provision of a good or service.

2 The notion of dollar-weighting is pursued further in the sub-section titled "Key Concepts".

Expense Lead Components: As used in this study, Expense Leads are defined to consist of two components:

1. A Service Lead component (i.e., services are assumed to be provided to HUC evenly around the mid-point of the service period); and
2. A Payment Lead component (i.e., the time period from the end of the service period to the time payment was made and the funds left HUC's possession).

Dollar-Weighting: Both "Leads" and "Lags" should be dollar-weighted where appropriate and where data is available to more accurately reflect the flow of dollars. As an example, suppose that a transaction has a Cash Outflow Lead time of 100 days and its dollar value was $100. Suppose further that another transaction has a Cash Outflow Lead time of 30 days with a dollar value of $1M. A simple un-weighted average of the two transactions would give us a Cash Outflow Lead time of 65 days ([100+30]/2). On the other hand, dollar-weighting the two transactions gives us a Cash Outflow Lead time closer to 30 days; an answer which is more representative of how the dollars actually flowed in this example.

Methodology

Performing a lead-lag study requires two key undertakings:

1. Developing an understanding of how the regulated business works, (i.e., in terms of products and services sold to customers or purchased from vendors and the collections and payment policies and procedures that govern such transactions); and
2. Modeling such operations using data from a relevant period of time and a representative data set. It is important to ascertain and factor into the study whether (or not) there are known changes to existing business policies and procedures going forward. Where such changes are known and material, they should be factored into the study.

To develop an understanding of HUC's operations, interviews with HUC personnel were conducted. Key questions that were addressed during the interviews included:

1. What is being sold (or bought)? If a service is being provided (purchased), over what time period was the service provided (or purchased);
2. Who are the buyers (sellers);
3. What are the terms for payment? Are the terms for payment driven by industry norms or by company policy? Is there flexibility in the terms for payment;
4. Are any changes expected to the terms for payment either driven by industry or internally by HUC? What is the basis for such changes (if any);
5. Are there any new rules and regulations governing such transactions that are expected to materialize over the time frame considered in this report; and
6. How payments are made (i.e., cash, check, electronic funds transfer)

Data for calendar year 2012 was used in the analysis. Development of the data set entailed gathering raw data from the HUC's General Accounting, Accounts Payable, Customer Service, Payroll, and Tax Systems. Once the raw data had been gathered from the multiple in-house systems, data validation was performed to the extent necessary and appropriate.

Section III: Revenue Lags

A distribution utility providing service to its customers generally derives its revenue from bills paid for service by its customers. A revenue lag represents the number of days from the date service is rendered by HUC until the date payments are received from customers and funds are available to HUC.

Interviews with HUC personnel indicate that its distribution business primarily receives funds from Retail Customers. The Ontario Clean Energy Benefit ("OCEB") was considered in this study, however since the OCEB expires on December 31, 2015 and since Horizon is applying for a 2014-2019 rate application, the OCEB will be excluded from the calculation of Retail Customer Revenue lag.

Retail Customer Revenue lag consists of the four following sequential components:

1. Service Lag;
2. Billing Lag;
3. Collections Lag; and
4. Payment Processing Lag.

The lag times for each of the above components, when added together, results in the Retail Customer Revenue Lag for the purpose of calculating the WCA for HUC's distribution business. Table 2 below summarizes the total weighted average Revenue Lag.

Table 2: Summary of Weighted Average Revenue Lag Days

Description	Lag Days
Retail Revenue	69.34

Table 3 below summarizes the components of Retail Revenue Lag.

Table 3: Summary of Retail Revenue Lag

Description	Weighted Lag Days
Service Lag	27.06
Billing Lag	18.98
Collections Lag	21.77
Payment Lag	1.54
Total	**69.34**

The estimation of each component of the Retail Revenue Lag is described below.

Service Lag

The Service Lag is the time from HUC's provision of electricity to a customer, to the time the customer's service period ends, which is typically defined as when the meter is read. Interviews with Customer Service Staff at HUC indicated that "Residential Retail", "General Service < 50", "Unmetered and Scattered" and "Sentinel" customers are on a bi-monthly service schedule, and "General Service > 50", "Large User" and Streetlight customers are on a monthly service schedule. Taking this information into account and using a mid-point methodology, the Service Lag was estimated to be 27.06 days.

Billing Lag

The Billing Lag is the time period from when the customer's service period ends, which is typically defined as when the meter is read, and the time that the customer's bill is generated and provided to the customer. Interviews with Billing Staff at HUC and analyses regarding meter reading and billing dates both indicated that both Residential and General Service customers have an average billing lag of 18.98 days.

Collections Lag

The Collections Lag is the time period from when the customer's bill is provided to the customer, to the time period that the customer provides a payment to HUC and when that payment is recorded in HUC's billing system. This period of time is measured by analyzing the receivables aging data contained in receivables reports used by HUC for normal business purposes. Using such data provided by HUC for the calendar year 2012, a dollar-weighted average collections lag of 21.77 days was determined for HUC's operations.

Payment Processing Lag

The Payment Processing Lag is the time period between the recording of a payment as having been received by HUC from the customer, and the payment being deposited into HUC's bank account. Based on interviews with HUC's staff, it was discovered that different payment methods result in different dates in which the payment is received in HUC's bank account. The following payment processing methods were considered in this study:

1. If the customer paid by Credit Card, that payment is in HUC's bank account two days after;
2. If the customer paid by Cheques or through ATM/Tellers, that payment is in the HUC's bank account three days after; and
3. If the customer paid by Internet, or Pre-authorization, that payment is in HUC's bank account two days after.

Taking into account HUC's different Payment Processing methods, an overall Payment Processing Lag of 1.54 days is the result and was used in the determination of HUC's overall revenue lag time.

Section IV: Expense Leads

The determination of working capital requires both a measurement of the lag in the collection of revenues for services provided by HUC's distribution business, and the lead times associated with payments for services provided to HUC. Therefore, in conjunction with the calculation of the revenue lag, expense lead times were calculated for the following items:

1. Cost of Power;
2. Payroll and Benefits;
3. OM&A Expenses;
4. Payments in Lieu of Taxes;
5. Interest Expenses; and
6. Debt Retirement Charge.

HUC's benefits and costs in terms of the WCA associated with the HST are discussed separately.

Cost of Power

HUC purchases its power supply requirements on a monthly basis from the IESO and pays for such supplies on a schedule defined within the IESO's billing and settlement procedures. HUC also settles payments to Hydro One for the use of their transmission system. Taking all this information on actual payments made by HUC in 2012, a dollar-weighted Cost of Power expense lead time of 32.86 days was calculated. Table 4 below summarizes the components of the Cost of Power expense lead calculation. Table 5 and Table 6 show the derivation of the weighted lag days for the components of Cost of Power.

Table 4: Summary of Cost of Power Expenses

Description	Amounts ($M)	Weighting Factor %	Lead Time	Weighted Lead Time
IESO	$399.68	98.93%	32.58	32.23
Hydro One	$4.32	1.07%	58.84	0.63
Total	**$404.00**	**100.00%**		**32.86**

Table 5: Summary of IESO Cost of Power Expenses

Delivery Month	Amounts ($M)	Weighting Factor %	Payment Date	Service Lead Time	Payment Lead Time	Total Lead Time	Weighted Lead Time
Jan 12	$32.62	8.16%	1/18/2012	15.50	18.00	33.50	2.73
Feb 12	$32.05	8.02%	2/16/2012	15.50	16.00	31.50	2.53
Mar 12	$31.31	7.83%	3/16/2012	14.00	16.00	30.50	2.39
Apr 12	$30.95	7.74%	4/19/2012	15.50	19.00	34.50	2.67
May 12	$28.82	7.21%	5/16/2012	15.00	16.00	31.00	2.24
Jun 12	$31.80	7.96%	6/18/2012	15.50	18.00	33.50	2.67
Jul 12	$36.89	9.23%	7/18/2012	15.00	18.00	33.00	3.05
Aug 12	$39.47	9.88%	8/17/2012	15.50	17.00	32.50	3.21
Sep 12	$42.81	10.71%	9/19/2012	15.50	19.00	34.50	3.69
Oct 12	$29.52	7.39%	10/17/2012	15.00	17.00	32.00	2.36
Nov 12	$30.99	7.75%	11/15/2012	15.50	15.00	30.50	2.37
Dec 12	$32.46	8.12%	12/18/2012	15.00	18.00	33.00	2.68
Total	**$399.68**	**100.00%**					**32.58**

Table 6: Summary of Hydro One Cost of Power Expenses

Delivery Month	Amounts ($M)	Weighting Factor %	Payment Date	Service Lead Time	Payment Lead Time	Total Lead Time	Weighted Lead Time
Jan 12	$0.32	7.38%	3/20/2012	15.00	42.00	58.00	4.28
Feb 12	$0.31	7.24%	4/19/2012	15.50	43.00	58.00	4.20
Mar 12	$0.29	6.74%	5/18/2012	15.50	43.00	58.00	3.91
Apr 12	$0.28	6.44%	6/20/2012	14.00	43.00	60.00	3.86
May 12	$0.40	9.20%	7/19/2012	15.50	43.00	58.00	5.33
Jun 12	$0.45	10.53%	8/16/2012	15.00	41.00	56.50	5.95
Jul 12	$0.46	10.66%	9/18/2012	15.50	45.00	60.00	6.40
Aug 12	$0.42	9.84%	10/18/2012	15.00	42.00	59.00	5.81
Sep 12	$0.38	8.76%	11/19/2012	15.50	45.00	60.00	5.25
Oct 12	$0.30	7.01%	12/18/2012	15.50	42.00	58.50	4.10
Nov 12	$0.32	7.47%	1/21/2013	15.00	46.00	61.50	4.60
Dec 12	$0.38	8.74%	2/19/2013	15.50	42.00	59.00	5.16
Total	**$4.32**	**100.00%**					**58.84**

Payroll and Benefits

For the purpose of the distribution lead-lag study, the following items were considered to be expenses related to the Payroll and Benefits of HUC:

1. Regular Staff Payroll;
2. Board of Director Payroll;
3. Great West Life – MDV;
4. Great West Life – HCS;
5. Group Life Insurance & LTD Insurance;
6. WSIB; and,
7. Pensions.

Expense lead times were calculated individually for each of the items listed above and then dollar-weighted to derive a composite expense lead time of 11.13 days for Payroll and Benefit expenses. A summary of the dollar-weighted expense lead time is provided in Table 7 below.

Table 7: Summary of Payroll and Benefit Expenses

Description	Amounts ($M)	Weighting Factor %	Lead (Lag) Time	Weighted Lead Time
Regular Staff Payroll	$37.64	82.42%	6.00	4.94
Board of Directors Payroll	$0.43	0.94%	47.75	0.45
Great West Life – MDV	$3.01	6.60%	27.93	1.84
Great West Life – HCS	$0.04	0.09%	53.13	0.05
Group Life Insurance & LTD Insurance	$1.01	2.21%	27.31	0.60
WSIB	$0.31	0.69%	29.30	0.20
Pensions (OMERS)	$3.22	7.06%	43.09	3.04
Total	**$45.67**	**100.00$**		**11.13**

Regular Payroll

HUC's Regular Payroll Staff are paid on a weekly basis on every Wednesday of every week for the prior week's services. Based on HUC's payroll data for 2012, an average service lead time of 4.00 days and an average payment lag time of 2.00 days were determined. Taking this information into account, a dollar-weighted net expense lead time of 6.00 days was determined for Regular Staff Payroll.

Board of Directors Payroll

HUC's Board of Directors Staff is paid to ADP on a quarterly basis on every second day of the quarter beginning month for the prior quarters pay period services. Based on HUC's payroll data for 2012, an average service lead time of 45.75 days and an average payment lead time of 2.00 days were determined. Taking this information into account, a dollar-weighted expense lead time of 47.75 days was determined for Board of Directors Payroll.

Great West Life – Medical, Dental, and Vision

HUC pays for Medical, Dental, and Vision medical coverage in arrears for the prior month. Based on HUC's benefits data for 2012, an average service lead time of 15.25 days and an average payment lead time of 12.68 days were determined. Taking this information into account, a dollar-weighted expense lead time of 27.93 days was determined for Great West Life – Medical, Dental and Vision medical coverage.

Great West Life – Health Care Spending Account

HUC pays for employee Health Care Spending accounts in arrears for the prior month. Based on HUC's benefits data for 2012, an average service lead time of 15.23 days and an average payment lead time of 37.90 days were determined. Taking this information into account, a dollar-weighted expense lead time of 53.13 days was determined for Great West Life – Medical, Dental and Vision medical coverage.

Group Life & Long Term Disability Insurance

HUC pays for employee Group Life & Long Term Disability Insurance in arrears for the prior month. Based on HUC's benefits data for 2012, an average service lead time of 15.25 days and an average payment lead time of 12.06 days were determined. Taking this information into account, a dollar-weighted expense lead time of 27.31 days was determined for Group Life & Long Term Disability Insurance.

Workplace Safety & Insurance Board

HUC pays for employee Workplace Safety & Insurance Board payments in arrears for the prior month. Based on HUC's benefits data for 2012, an average service lead time of 15.23 days and an average payment lead time of 14.08 days were determined. Taking this information into account, a dollar-weighted expense lead time of 29.30 days was determined for Workplace Safety & Insurance Board payments.

Pensions (OMERS)

HUC pays for employee Pensions, also known as Ontario Municipal Employees Retirement System ("OMERS") payments in arrears for the prior month. Based on HUC's benefits data for 2012, an average service lead time of 15.23 days and an average payment lead time of 27.86 days were determined. Taking this information into account, a dollar-weighted expense lead time of 43.09 days was determined for Pensions (OMERS) payments.

OM&A Expenses

For the purpose of the distribution lead-lag study, OM&A expenses were considered to consist of payments made by HUC to its vendors in the following categories:

1. P Card;
2. Contract Labour;
3. Vehicles;
4. Computer Maintenance;
5. Software;
6. Cellphone & Pager;
7. Wireless;
8. Freight, Postage & Delivery;
9. Consulting;
10. Tree Trimming;
11. Outside Services; and,
12. Property Taxes.

Expense lead times were calculated individually for each of the items listed above and then dollar-weighted to derive a composite expense lead time of 1.23 days for OM&A expenses. A summary of the dollar-weighted expense lead time is provided in Table 8 below.

Table 8: Summary of OM&A Expenses

Description	Amounts ($M)	Weighting Factor %	Lead Time	Weighted Lead Time
Credit Card	$ 0.30	2.86%	44.21	1.27
Contract Labour	$ 0.21	2.02%	29.30	0.59
Vehicles	$ 0.02	0.16%	31.65	0.05
Computer Maintenance	$ 0.63	6.03%	(357.55)	(21.57)
Software	$ 2.42	23.23%	15.21	3.53
Cell & Pager	$ 0.29	2.76%	29.45	0.81
Wireless	$ 0.23	2.22%	31.84	0.71
Freight / Postage / Delivery	$ 0.11	1.09%	33.31	0.36
Consulting Services	$ 2.37	22.75%	33.03	7.52
Tree Trimming	$ 0.55	5.27%	33.71	1.78
Outside Services	$ 2.62	25.11%	31.76	7.98
Property Taxes	$ 0.68	6.47%	(27.66)	(1.79)
Total	**$ 10.43**	**100.00%**		**1.23**

P Card

During 2012, HUC used Credit Cards for a variety of services procured by its employees. Based on HUC's Credit Card expense data for 2012, an average service lead time of 15.24 days and an average payment lead time of 28.97 days were determined. Taking this information into account, a dollar-weighted expense lead time of 44.21 days was determined for Credit Card expenses.

Contract Labour

During 2012, HUC procured Contract Labour for a variety of services required for distribution services. Based on HUC's Contract Labour data for 2012, an average service lead time of 15.26 days and an average payment lead time of 14.03 days were determined. Taking this information into account, a dollar-weighted expense lead time of 29.30 days was determined for Contract Labour.

Vehicles

During 2012, HUC expensed Vehicles for a variety of services required for distribution services. Based on HUC's Vehicle spending data for 2012, an average service lead time of 15.38 days and an average payment lead time of 16.27 days were determined. Taking this information into account, a dollar-weighted expense lead time of 31.65 days was determined for Vehicle expenses.

Computer Maintenance

During 2012, HUC procured services from multiple vendors for Computer Maintenance agreements. Based on HUC's Computer Maintenance Procurement data for 2012, an average service lead time of 373.61 days and an average payment lead time of (731.16) days were determined. Taking this information into account, a dollar-weighted expense lead time of (357.55) days were determined for Computer Maintenance.

Software

During 2012, HUC procured licenses from multiple vendors for computer Software. Based on HUC's Software Procurement data for 2012, an average service lead time of 23.93 days and an average payment lead time of (8.71) days were determined. Taking this information into account, a dollar-weighted expense lead time of 15.21 days was determined for Software expenses.

Cellphone & Pager

During 2012, HUC expensed Cellphone & Pager use for a variety of services required for distribution services. Based on HUC's Cellphone & Pager data for 2012, an average service lead time of 15.25 days and an average payment lead time of 14.20 days were determined. Taking this information into account, a dollar-weighted expense lead time of 29.45 days was determined for Cellphone & Pager expenses.

Wireless Services

During 2012, HUC expensed Wireless Services for a variety of services required for distribution services. Based on HUC's Wireless Services data for 2012, an average service lead time of 15.28 days and an average payment lead time of 16.55 days were determined. Taking this information into account, a dollar-weighted expense lead time of 31.84 days was determined for Wireless expenses.

Freight / Postage / Delivery

During 2012, HUC expensed Freight / Postage / Delivery services for a variety of activities required for distribution services. Based on HUC's Freight / Postage / Delivery data for 2012, an average service lead time of 15.25 days and an average payment lead time of 18.06 days were determined. Taking this information into account, a dollar-weighted expense lead time of 33.31 days was determined for Freight / Postage / Delivery expenses.

Consulting Services

During 2012, HUC procured Consulting Services required for a variety of activities related to distribution services. Based on HUC's Consulting Services data for 2012, an average service lead time of 15.23 days and an average payment lead time of 17.79 days were determined. Taking this information into account, a dollar-weighted expense lead time of 33.03 days was determined for Consulting Services.

Tree Trimming

During 2012, HUC expensed Tree Trimming services required for distribution services. Based on HUC's Tree Trimming spending data for 2012, an average service lead time of 15.17 days and an average payment lead time of 18.53 days were determined. Taking this information into account, a dollar-weighted expense lead time of 33.71 days was determined for Tree Trimming expenses.

Outside Services

During 2012, HUC procured Outside Services for a variety of activities required for distribution services. Based on HUC's Outside Services data for 2012, an average service lead time of 15.28 days and an average payment lead time of 16.48 days were determined. Taking this information into account, a dollar-weighted expense lead time of 31.76 days was determined for Outside Services.

Property Taxes

During 2012, HUC paid property tax payments to the following municipalities:

1. City of Hamilton; and,
2. City of St. Catharines.

Based on HUC's Property Tax data for 2012, an average service lead time of 183.00 days and an average payment lead (lag) time of (210.66) days were determined. Since property taxes are an annual expense, services were rendered on an annual basis, with (27.76) days resulting as the service lead time associated with property taxes.

Payments in Lieu of Taxes

HUC makes payments in lieu of taxes ("PILs") in monthly installments to the relevant taxing authorities. In 2012, HUC made (12) payments for each month of the year. Based on HUC's PILs data for 2012, an average service lead time of 15.21 days and an average payment lead (lag) time of (0.25) days were determined. Taking this information into account, a dollar-weighted expense lead time of 14.96 days was determined for PILs.

Debt Retirement Charge

HUC makes a Debt Retirement Charge in monthly installments to the Ontario Electricity Finance Corporation. The payment for the current charge month is made during the middle of the following month. Based on HUC's Debt Retirement Charge data for 2012, an average service lead time of 15.26 days and an average payment lead time of 10.34 days were determined. Taking this information into account, a dollar-weighted expense lead time of 25.59 days was determined for Debt Retirement Charge.

Interest Expense

HUC has two outstanding debt issuances which incur interest expenses. Based on HUC's Interest Expense data for 2012, an average service lead time of 91.50 days and an average payment lead (lag) time of (158.65) days were determined. Taking this information into account, a dollar-weighted expense lead (lag) time of (67.15) days were determined for Interest Expense.

Harmonized Sales Tax

The expense lead (lag) times associated with the following items that attract HST were considered in this study:

1. Customer Revenues including Cost of Power;
2. Cost of Power expenses; and
3. OM&A Expenses.

Effective July 1, 2010, the Ontario government implemented the harmonization of the Provincial Sales Tax with the Federal Goods and Service Tax into a single Harmonized Sales Tax. Given this is a known and measurable change forward looking; the WCA was calculated using the HST rate of 13.00%. Note that the statutory approach described at the outset was used to determine the expense lead times associated with HUC's remittances and disbursements of HST (i.e., both remittances and collections are generally on the last day of the month following the date of the applicable invoice)
A summary of the expense lead (lag) times associated with each of the above items is provided in Table 10 and Table 10 below.

Table 9: HST Working Capital Factor

HST Category	HST Lead/Lag Days	Working Capital Factor	Working Capital Factor (Leap Year)
HST Rate	13%	13%	13%
Revenues [inc. COP] Lead Days	(21.08)	-5.77%	-5.76%
Cost of Power Lead Days	43.73	11.98%	11.95%
OM&A Lead Days	2.55	0.70%	0.70%

Table 10: Summary of Expense Lead Times Associated With HST

HST Category	2014	2015	2016	2017	2018	2019
Revenues [incl. COP]	$622,203,415	$638,342,404	$664,944,611	$688,586,511	$711,468,938	$734,283,591
HST Rate	13.00%	13.00%	13.00%	13.00%	13.00%	13.00%
Revenues [incl. COP]	$622,203,415	$638,342,404	$664,944,611	$688,586,511	$711,468,938	$734,283,591
Cost of Power	$514,946,434	$520,720,617	$542,171,542	$562,422,662	$583,269,859	$602,042,446
OM&A	$30,783,301	$29,728,985	$29,849,980	$30,659,445	$31,709,813	$33,108,690
Revenues [incl. COP]	-$4,671,108	-$4,792,269	-$4,978,342	-$5,169,470	-$5,341,257	-$5,512,535
Cost of Power	$8,020,726	$8,110,664	$8,421,707	$8,760,209	$9,084,921	$9,377,320
OM&A	$28,011	$27,052	$27,088	$27,899	$28,854	$30,127
Total	**$3,377,630**	**$3,345,447**	**$3,470,453**	**$3,618,637**	**$3,772,519**	**$3,894,913**

Section V: HUC's Working Capital Allowance

Using the results described under the discussion of revenue lags and expense leads, and applying them to HUC's distribution expenses for 2014-2019, the weighted average WCA was determined to be 12.7% of HUC's distribution OM&A expenses (including Cost of Power) for each of the test years 2014-2019. A summary of HUC's WCA for individual 2014-2019 years is provided in the subsequent tables below. These tables include HST amounts which have been derived from Table 10 above.

Table 11: Summary of Working Capital Allowance - 2014

Description	Revenue Lag Days	Expense Lead Days	Net Lag Days	Working Capital Factor	Amounts ($M)	Working Capital Allowance ($M)
Cost of Power	69.34	32.86	36.48	10.0%	$514,946,434	$51,463,007
OM&A Expenses[3]	69.34	7.30	62.04	17.0%	$64,986,015	$11,046,321
PILs	69.34	14.50	54.84	15.0%	$555,146	$83,406
Debt Retirement Charge	69.34	25.59	43.74	12.0%	$32,180,619	$3,856,729
Interest Expense	69.34	(67.15)	136.49	37.4%	$9,519,067	$3,559,569
Sub-Total					**$622,187,281**	**$70,009,032**
HST						$3,377,630
Total						**$73,386,661**
WCA as a % of OM&A (incl. Cost of Power)						**12.7%**

Table 12 - Summary of Working Capital Allowance - 2015

Description	Revenue Lag Days	Expense Lead Days	Net Lag Days	Working Capital Factor	Amounts ($M)	Working Capital Allowance ($M)
Cost of Power	69.34	32.86	36.48	10.0%	$520,720,617	$52,040,070
OM&A Expenses[4]	69.34	7.30	62.04	17.0%	$64,479,807	$10,960,275
PILs	69.34	14.50	54.84	15.0%	$2,874,217	$431,828
Debt Retirement Charge	69.34	25.59	43.74	12.0%	$31,854,423	$3,817,636
Interest Expense	69.34	(67.15)	136.49	37.4%	$9,831,640	$3,676,453
Sub-Total					**$629,760,705**	**$70,926,262**
HST						$3,345,447
Total						**$74,271,709**
WCA as a % of OM&A (incl. Cost of Power)						**12.7%**

[3] Includes Payroll and Benefits

[4] Includes Payroll and Benefits

Table 13 – Summary of Working Capital Allowance - 2016

Description	Revenue Lag Days	Expense Lead Days	Net Lag Days	Working Capital Factor	Amounts ($M)	Working Capital Allowance ($M)
Cost of Power	69.34	32.86	36.48	10.0%	$542,171,542	$54,035,801
OM&A Expenses[5]	69.34	7.30	62.04	17.0%	$65,940,947	$11,178,015
PILs	69.34	14.50	54.84	15.0%	$4,252,792	$637,202
Debt Retirement Charge	69.34	25.59	43.74	12.0%	$31,531,534	$3,768,614
Interest Expense	69.34	(67.15)	136.49	37.3%	$10,204,633	$3,805,504
Sub-Total					**$654,101,448**	**$73,425,136**
HST						$3,470,453
Total						**$76,895,589**
WCA as a % of OM&A (incl. Cost of Power)						**12.6%**

Table 14 – Summary of Working Capital Allowance - 2017

Description	Revenue Lag Days	Expense Lead Days	Net Lag Days	Working Capital Factor	Amounts ($M)	Working Capital Allowance ($M)
Cost of Power	69.34	32.86	36.48	10.0%	$562,422,662	$56,207,712
OM&A Expenses[6]	69.34	7.30	62.04	17.0%	$67,692,855	$11,506,429
PILs	69.34	14.50	54.84	15.0%	$4,496,240	$675,524
Debt Retirement Charge	69.34	25.59	43.74	12.0%	$31,211,917	$3,740,634
Interest Expense	69.34	(67.15)	136.49	37.4%	$10,624,086	$3,972,781
Sub-Total					**$676,447,760**	**$76,103,080**
HST						$3,618,637
Total						**$79,721,717**
WCA as a % of OM&A (incl. Cost of Power)						**12.7%**

Table 15 – Summary of Working Capital Allowance - 2018

Description	Revenue Lag Days	Expense Lead Days	Net Lag Days	Working Capital Factor	Amounts ($M)	Working Capital Allowance ($M)
Cost of Power	69.34	32.86	36.48	10.0%	$583,269,859	$58,291,151
OM&A Expenses[7]	69.34	7.30	62.04	17.0%	$69,773,217	$11,860,049
PILs	69.34	14.50	54.84	15.0%	$3,925,141	$589,721
Debt Retirement Charge	69.34	25.59	43.74	12.0%	$30,895,541	$3,702,717
Interest Expense	69.34	(67.15)	136.49	37.4%	$11,632,105	$4,349,720
Sub-Total					**$699,495,863**	**$78,793,359**
HST						$3,772,519
Total						**$82,565,878**
WCA as a % of OM&A (incl. Cost of Power)						**12.6%**

[5] Includes Payroll and Benefits
[6] Includes Payroll and Benefits
[7] Includes Payroll and Benefits

Table 16 – Summary of Working Capital Allowance - 2019

Description	Revenue Lag Days	Expense Lead Days	Net Lag Days	Working Capital Factor	Amounts ($M)	Working Capital Allowance ($M)
Cost of Power	69.34	32.86	36.48	10.0%	$602,042,446	$60,167,257
OM&A Expenses[8]	69.34	7.30	62.04	17.0%	$72,228,903	$12,277,466
PILs	69.34	14.50	54.84	15.0%	$4,021,290	$604,166
Debt Retirement Charge	69.34	25.59	43.74	12.0%	$30,582,371	$3,665,185
Interest Expense	69.34	(67.15)	136.49	37.4%	$12,600,791	$4,711,952
Sub-Total					**$721,475,801**	**$81,426,026**
HST						$3,894,913
Total						**$85,320,939**
WCA as a % of OM&A (incl. Cost of Power)						**12.7%**

[8] Includes Payroll and Benefits

TREATMENT OF STRANDED ASSETS RELATED TO SMART METER DEPLOYMENT

STRANDED METERS

The Board's Guideline G-2008-0002 – Smart Meter Funding and Cost Recovery – Final Disposition ("Guideline") provided two options to distributors regarding the accounting treatment of stranded meters related to the installation of Smart Meters: (1) leave them in rate base (i.e. Account 1860); or (2) record them in "Sub-account Stranded Meter Costs" of Account 1555. Horizon Utilities adopted Option 1 and left the stranded meters in rate base. Horizon Utilities confirms that the recording of depreciation expenses has continued in order to reduce the net book value through accumulated depreciation.

The value of stranded meters remaining in rate base at December 31, 2014 is provided in the table below.

Table 2-42 - Appendix 2-S

Year	Notes	Gross Asset Value	Accumulated Amortization	Contributed Capital (Net of Amortization)	Net Asset	Proceeds on Disposition	Residual Net Book Value
		(A)	(B)	(C)	(D) = (A) - (B) - (C)	(E)	(F) = (D) - (E)
2006					$ -		$ -
2007		$ 5,986,770	$ 2,394,708	$ -	$ 3,592,062	$ -	$ 3,592,062
2008		$13,854,519	$ 6,095,988	$ -	$ 7,758,530	$ -	$ 7,758,530
2009		$21,727,434	$ 10,429,168	$ -	$ 11,298,266	$ -	$11,298,266
2010		$23,034,373	$ 11,977,874	$ -	$ 11,056,499	$ -	$11,056,499
2011		$11,386,535	$ 948,878	$ -	$ 10,437,657	$ -	$10,437,657
2012		$11,636,996	$ 1,939,499	$ -	$ 9,697,497	$ -	$ 9,697,497
2013		$11,834,810	$ 2,958,703	$ -	$ 8,876,108	$ -	$ 8,876,108
2014	(1)	$11,961,886	$ 3,987,295	$ -	$ 7,974,590	$ -	$ 7,974,590

Notes:

(1) *For 2014 to 2019 the amounts provided are on a forecast basis.*

Some distributors have transferred the cost of stranded meters from Account 1860 - Meters to "Sub-account Stranded Meter Costs of Account 1555", while in some cases distributors have left these costs in Account 1860. Depending on which treatment the applicant has chosen please provide the information under either of the two scenarios (A and B below), as applicable.

Scenario B: *If the stranded meter costs remained recorded in Account 1860, the above table should be completed and the following information should be provided in Exhibit 9:*

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

Prior to adoption of IFRS, the stranded meters that were replaced by smart meters were allowed to be amortized continuously over their remaining useful life. Accordingly, Horizon Utilities continued with the amortization of these assets that were pooled in Account 1860.

Upon adoption of IFRS, Horizon Utilities took the IFRS 1 exemption and recognized the stranded meters at their Net Book Value on December 31, 2010 in Account 1860; and continued to amortize them over their remaining useful life.

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

Horizon Utilities does not allocate any contributed capital to meters.

3 A statement as to whether or not the recording of depreciation expenses continued in order to reduce the net book value through accumulated depreciation. If so, provision of the total (cumulative) depreciation expense for the period from the time that the meters became stranded to December 31, 2010.

Horizon Utilities continued to record depreciation expense, reducing the NBV of the stranded meters.

The total cumulative depreciation expense for the period from the time the meters became stranded to Dec 31, 2010 was $11,977,874.

4 If no depreciation expenses were recorded to reduce the net book value of stranded meters through accumulated depreciation, the total (cumulative) depreciation expense amount that would have been applicable for the period from the time that the meters became stranded to December 31, 2010.

N/A

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

see above table

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

described in Exhibit 2, Tab 5, Schedule 1

Table 2-42 - Appendix 2S - continued

Distributors should also provide the Net Book Value per class of meter as of December 31, 2010 as well as the number of meters that were removed / stranded. In preparing this information, distributors should review the Board's letter of January 16, 2007 *Stranded Meter Costs Related to the Installation of Smart Meters* which stated that records were to be kept of the type and number of each meter to support the stranded meter costs.

Total NBV for all stranded meters by class at Dec 31, 2010

	#	$
Residential	214,501	9,152,043
GS<50	11,539	1,624,691
Total Residential and GS<50	**226,040**	**10,776,734**
GS>50	1,185	279,765
Total	**227,225**	**11,056,499**

Total NBV for all stranded meters by class at Dec 31, 2014

	#	$
Residential	216,280	6,141,165
GS<50	17,852	1,561,125
Total Residential and GS<50	**234,132**	**7,702,291**
GS>50	1,953	272,299
Total	**236,085**	**7,974,590**

In the Board's Decision on Horizon Utilities' 2011 Smart Meter Prudence Application (EB-2011-0417), the Board expressed its expectation that the remaining balance of stranded meters be brought forward for disposition in Horizon Utilities' next cost of service application. The Board's Guideline *G-2011-0001*, issued December 15, 2011 states: *"It is expected that a distributor, as part of its application for the disposition of smart meter costs in a cost of service application, will propose (a) rate rider(s) to recover the NBV of the stranded meters."* However, Guideline *G-2011-0001* infers that a distributor should take into account rate impacts on its affected customers, and that it may make proposals to mitigate potential material and adverse impacts in Section 3.7, the under heading "Allocation of Costs, Proposed Recovery Period and Rate Rider".

Section 2.5.1.4 of the Chapter 2 Filing Requirements provides for the possibility of a different approach from that set out in Guideline G-2011-0001 as follows: "Distributors wishing to propose a different approach to that outlined above must provide a full explanation of the proposed approach and justifications for it, including why the described approach would not be applicable to their circumstances."

Horizon Utilities proposes to leave the stranded meter amounts in rate base until they are fully depreciated in order to mitigate rate impacts to customers. Table 2-43 provides an analysis of the total revenue requirement impact to customers based on:

i.) **Revenue Requirement with Stranded Meters in Rate Base** – which computes the revenue requirement in each year from 2015 until the stranded meters are fully amortized as if they had been left in rate base (Option 1 above and Proposed Approach);

ii.) **Revenue Requirement with NBV recovered over 5 year IR term** – which computes the revenue requirement in each year from 2015 assuming that the stranded meters are fully and evenly amortized over the five year incentive rate term from 2015 to 2019 (above and Alternative Approach).

Table 2-43 - Revenue Requirement: Proposed Approach vs. Full Recovery over 5 years

Description	2015	2016	2017	2018	2019	Total 2015-2019	2020	2021	2022	Total 2015-2022
Revenue Requirement with Stranded Meters in Rate Base	$1,530,340	$1,459,204	$1,388,069	$1,321,048	$1,251,532	$6,950,193	$1,178,758	$1,105,984	$1,033,211	$10,268,146
Revenue Requirement with NBV recovered over 5 year IR term	$2,107,094	$1,993,277	$1,879,460	$1,767,838	$1,653,137	$9,400,805	$0	$0	$0	$9,400,805
Difference	($576,754)	($534,072)	($491,391)	($446,790)	($401,605)	($2,450,612)	$1,178,758	$1,105,984	$1,033,211	$867,341

The determination of Revenue Requirement under both i. and ii. follows the Board's ratemaking methodology applied to the average net fixed asset balance in each year.

The Proposed Approach mitigates the impact to customers over the term covered in the Application by $2,450,612 relative to the Alternative Approach. However, under the Proposed Approach, customers will pay $867,341 more in absolute terms by 2022; which is the year in which stranded meters are fully amortized. Horizon Utilities submits that, despite the absolute amount of additional cost to 2022 (approximately $3.64 in aggregate per customer from 2015 to 2022), this is a favourable approach considering the time value of money to its customers given the choice to pay considerably less during the 2015-2019 Test Year period.

CAPITAL EXPENDITURES

INTRODUCTION

Horizon Utilities' capital expenditures have increased from $39,000,000 in the 2011 Board-Approved to $39,939,967 in the 2015 Test Year and $51,272,477 by 2019. This increase is driven by the necessary renewal of Horizon Utilities' distribution assets, buildings and information systems technology.

Investment Categories

Chapter 5 of the Board's *Filing Requirements for Electricity Transmission and Distribution Applications – Consolidated Distribution System Plan Filing Requirements,* ("Chapter 5 Requirements"), in Section 5.1.1, directs distributors to group each investment project and activity for filing purposes into one of four investment categories: System Access; System Renewal; System Service; or General Plant. The first three categories for distribution system investments generally align with historical categories: Customer Demand; Renewal; and Non-Renewal, respectively. The OEB category General Plant aligns with Horizon Utilities' non-distribution assets. A mapping of historical distribution investment categories to the categories identified in the Chapter 5 Requirements is provided in the following table.

Table 2-44: Mapping of Asset Categories

Investment Sub Category	Horizon Utilities' Historical Categorization	OEB Chapter 5 Categorization
Customer Demand	Customer Demand	System Access
Renewal	Renewal	System Renewal
Substation Renewal	Renewal	System Renewal
Capacity	Non-Renewal	System Service
Reliability	Non-Renewal	System Service
Security	Non-Renewal	System Service
Regulatory	Non-Renewal	System Access
N/A	Non-Distribution Assets	General Plant

Distribution System Capital

Horizon Utilities operates within the cities of Hamilton and St. Catharines. These service territories contain some of the oldest distribution assets in the province. Hamilton and St. Catharines evolved around a heavy industrial base and have in-service distribution assets approaching 100 years of age.

A significant portion of Horizon Utilities' asset infrastructure was installed during the local economic expansion years of the 1950s, 1960s, and 1970s. This infrastructure is now largely due for renewal. Horizon Utilities has been able to extend the life of this equipment through careful management and prudent investments focused on the long term stewardship of these assets. However, a significant portion of these assets is at, or nearing, end-of-life, and must be replaced along a carefully managed timeframe in a manner that balances distribution system risks and customer rate impacts. Horizon Utilities has submitted this Application on this basis.

At Horizon Utilities' 2013 level of renewal investment, the ratio of assets operating at an unacceptable Health Index distribution will continue to increase, which will result in declining reliability and more frequent and longer service interruptions to customers. It is important to take steps now to reverse this trend in a manner where it is still possible for managed gradual growth in both capital expenditure and related customer costs.

Horizon Utilities has an ongoing need to increase investment in the renewal of aging distribution system infrastructure; a theme advanced in Horizon Utilities' last two Cost of Service Applications (EB-2007-0697 and EB-2011-0131). Horizon Utilities identified the need for careful planning, review, and prioritization of the increased investment. Horizon Utilities subsequently reviewed its capital investment strategies to ensure the continued financial and operational viability of the distribution system and began increasing its distribution capital expenditures, excluding meters, at a graduated rate from $17,841,422 (CGAAP) in 2008 to $31,380,634 (CGAAP) by 2011.

The capital investment strategy review resulted in the adoption of a comprehensive, formal Asset Management ("AM") philosophy in 2008 and included the development of an AM strategy, framework and implementation plan. This work involved age and condition assessments of distribution assets and designs of comprehensive asset investment prioritization models. These outputs were the basis for the development of a strategic investment plan starting in 2008, which evolved into the Asset Management Plan ("AMP") filed with the 2011 Cost of Service Application (EB-2010-0131).

Horizon Utilities has continued to improve its asset management processes as demonstrated by the work completed with Kinectrics in 2012 and 2013, where the evaluation of distribution asset condition has evolved from an end-of-life assessment to a more sophisticated Health Index model. Horizon Utilities is committed to investing in long-term asset management and continues to develop and improve investment strategies through the application of a continuous improvement cycle including ongoing review of related processes and procedures. The DSP filed with this Application as Appendix 2-4 presents Horizon Utilities' approach to lifecycle asset management planning and a plan for capital-related expenditures over the five-year forecast period.

Asset Condition Assessment

Horizon Utilities engaged Kinectrics to perform an ACA of its key distribution assets at the end of 2012, as mentioned earlier in this Exhibit.

Kinectrics was expected to provide: a quantifiable evaluation of the asset condition; aid in prioritizing and allocating sustainment resources; and facilitate the continued development of Horizon Utilities' asset management planning.

The ACA was performed on 22 asset groups and consolidated into fifteen asset categories. An example of an asset category is underground cable, which is comprised of two asset groups – primary XLPE cable and primary paper insulated lead cable ("PILC"). The following asset categories were reviewed by Kinectrics:

- Substation Transformers
- Substation Circuit Breakers
- Substation Switchgear
- Pole Mounted Transformers
- Overhead Conductors
- Overhead Line Switches

- Wood Poles
- Concrete Poles
- Underground Cables
- Pad Mounted Transformers
- Pad Mounted Switchgear
- Vault Transformers
- Utility Chambers
- Vaults
- Submersible Load Break Switches

The ACA included the following tasks for each asset category:

- Gathering relevant condition data;
- Developing a formula to identify a variable that represents the health of each asset (the "Health Index");
- Calculating the Health Index for each asset;
- Determining the Health Index distribution; and
- Developing a 20-year condition-based plan flagging individual assets in need of specific action ("Flagged-For-Action Plan")

KPMG LLP (Canada) ("KPMG") was retained to provide an independent assurance review of the methodology and analytics used in the Kinectrics ACA. KPMG completed a report for Horizon Utilities on January 23, 2014, appended as Appendix C of the DSP)("KPMG Report"), in which it provided its opinion that the approach used by Kinectrics to arrive at the presented results is in line with industry practice and generally accepted methodologies. Horizon Utilities used the KPMG Report as validation of the outcomes of the Kinectrics ACA.

Horizon Utilities applied the principles and opinions endorsed by both the Kinectrics ACA and the KPMG Report as key elements informing its DSP as such pertains to distribution assets. Further details are provided in Section 3 of the DSP, included as Appendix 2-4 to this Exhibit.

Health Index

Health Indexing quantifies equipment condition based on numerous condition parameters that are related to the long-term degradation factors that cumulatively lead to a determination that an asset is at the end of its productive life ("end-of-life") and must be replaced. The Health Index is an indicator of the overall health of an asset and is typically given in terms of a percentage; with 100% representing an asset in brand new condition.

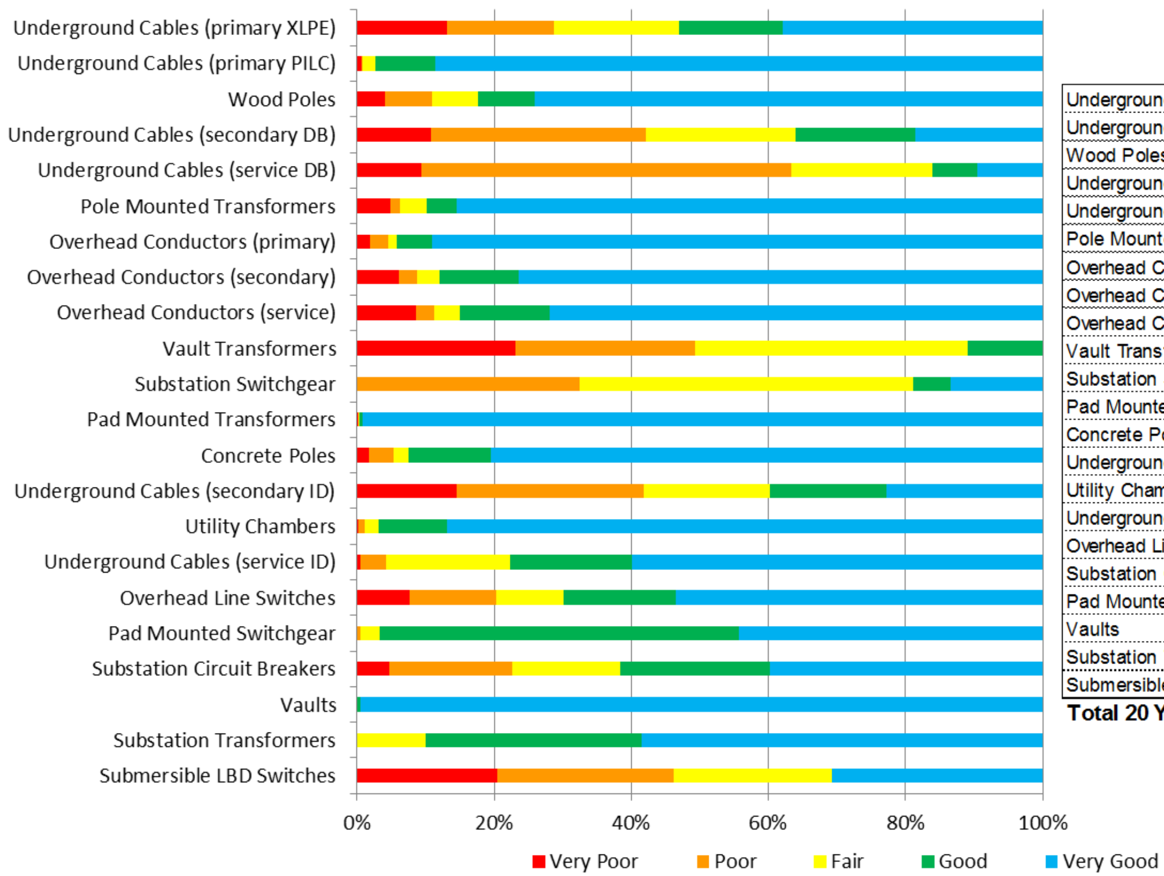
The Health Index distribution given for each asset group illustrates the overall condition of the asset group. The results are aggregated into five categories and the categorized distribution for each asset group is given.

The Health Index categories are typically as follows:

Very Poor	Health Index < 25%
Poor	25 <= Health Index < 50%
Fair	50 <= Health Index <70%
Good	70 <= Health Index <85%
Very Good	Health Index >= 85%

A visual representation of the Health Index Results for Horizon Utilities' assets as of July 1, 2013 is provided in Figure 2-1 below.

Figure 2-1 – Health Index Distribution of All Asset Groups



(000s)

Underground Cables (primary XLPE)	$	172,742
Underground Cables (primary PILC)	$	83,810
Wood Poles	$	72,575
Underground Cables (secondary DB)	$	64,819
Underground Cables (service DB)	$	43,841
Pole Mounted Transformers	$	38,784
Overhead Conductors (secondary)	$	34,959
Overhead Conductors (service)	$	33,549
Overhead Conductors (primary)	$	29,617
Vault Transformers	$	28,964
Substation Switchgear	$	19,500
Pad Mounted Transformers	$	18,751
Concrete Poles	$	11,005
Underground Cables (secondary ID)	$	9,084
Utility Chambers	$	7,792
Underground Cables (service ID)	$	6,392
Overhead Line Switches	$	5,246
Substation Circuit Breakers	$	4,005
Pad Mounted Switchgear	$	3,850
Vaults	$	1,958
Substation Transformers	$	750
Submersible LBD Switches	$	672
Total 20 Year Expenditure	**$**	**692,664**

ACA Conclusions and Recommendations

Kinectrics' ACA was conducted for the 22 key distribution asset groups and fifteen categories as identified above. The Health Index distribution was determined for each asset group and a condition-based 20-year renewal investment profile was developed.

Kinectrics' conclusions and recommendations are provided below[1]. Further details are provided in Section 2.2.3 of the DSP, filed as Appendix 2-4 of this Exhibit.

1. *In general, sufficient data and/or information was available for all the asset categories to develop a meaningful Health Index distribution. Horizon Utilities should continue existing data collection practices with some improvements as recommended in the Data Assessment section of the Kinectrics ACA.*

2. *Horizon Utilities' investment in substation infrastructure in recent years has been effective in improving the overall health of the substation asset groups as compared to the previous asset condition assessments. Substation transformers are in good shape with substation circuit breakers and switchgear being in adequate condition. A small portion of breakers remain in "poor" condition.*

3. *For overhead asset groups (including conductors, pole top transformers, switches and poles), even though their overall condition is fairly good, because they represent large populations, a significant number of units were still determined to be in "very poor" and "poor" condition and sustained investments will be required over the next 20 years to maintain overall condition at the existing level.*

4. *For asset groups associated with underground system, XLPE cables, direct buried cables, secondary in-duct cables and submersible LBD switches have a significant portion of population in "very poor" and "poor" condition and substantial investments will be required over the next 20 years to improve the overall condition of these asset categories. Even though the overall condition of PILC cables, service in-duct cables and*

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[1] Horizon Utilities 2013 Asset Condition Assessment, November 27, 2013, Kinectrics Inc.

pad mounted transformers is fairly good, a sustained investment over the next 20 years is required to maintain their overall condition at the existing level.

5. *The combination of health and installed population will require significant investment over the next 20 years in order to at least sustain the existing level of reliability in the following asset categories:*

   - pole mounted transformers
   - overhead primary, secondary and service conductors
   - wood poles
   - underground primary XLPE cables
   - underground PILC cables
   - underground secondary/service direct buried cables
   - vault transformers

6. *It is recommended to put in place asset specific programs to not only address improving the overall condition of asset categories listed in point 4 above but also to maintain existing overall condition level for the remaining asset categories, particularly the ones listed in point 5 above. Not doing so will results in deteriorating reliability performance, taking unnecessary risks associated with failures of assets with significant consequence of failure (such as underground cables, substation breakers and overhead conductors) and bow wave of future investment needs that would be substantially higher than the historical levels. It is important to note that the recommendations in this report are primarily condition-based. In putting in place a long-term asset strategy other factors, such as obsolescence, system growth, municipal initiatives, Regional Integrated Planning, etc. should be taken into account. Furthermore, the appropriate cost effective action for units flagged for action should be selected by considering options other than replacement, such as refurbishment, spare units strategy adjustment, intensified maintenance, real time monitoring or "doing nothing". This is particularly effective when dealing with proactively replaced assets.*

The results of Kinectrics' asset analysis are consistent with a relatively old distribution system requiring significant renewal investment. Distribution system assets become less resilient to adverse weather and foreign interference as they age. Foreign interference is defined by the Canadian Electricity Association as: "Customer interruptions beyond the control of the utility such as birds, animals, vehicles, dig-ins, vandalism, sabotage and foreign objects". Horizon Utilities' distribution system has many components which have reached end-of-life and are contributing to a greater amount of equipment failures and service interruptions to customers. These service failures are further exaggerated as the aged assets require longer repair times or outright replacement; extending the duration of the outage experienced by the customer.

Capital Investment Programs

The capital investment programs identified below address the investment renewal requirements confirmed by Horizon Utilities' asset management analysis. These programs existed prior to Kinectrics' ACA and the results of Kinectrics' ACA substantiate that Horizon Utilities' capital investment programs need to address the assets with the highest priority for investment. The level of investment proposed for each program is guided by the level of investment derived from the flagged-for-action (i.e. at high risk of failure) asset volumes identified by Kinectrics ACA. Table 2-45 (from Section 3.1.3 in the DSP) maps assets with either a poor Health Index distribution (at least 20% of assets are in either 'poor' or 'very poor' health) or a significant 20-year investment requirement (greater than $5,000,000 over five years) against Horizon Utilities' capital investment programs.

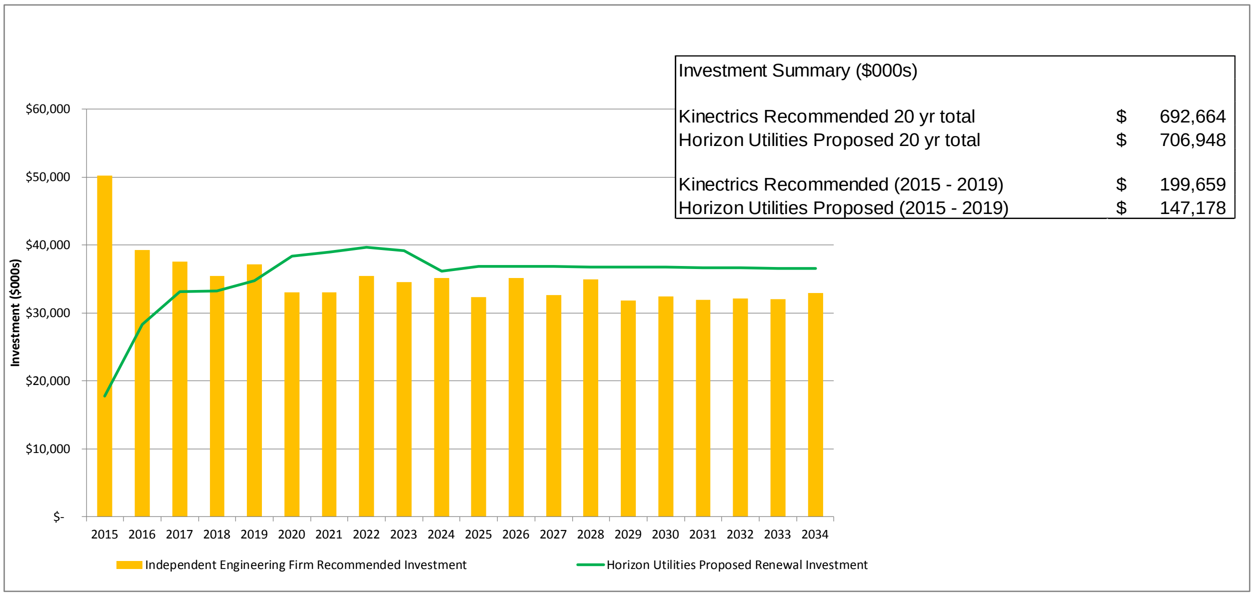
Table 2-45 – Health Index Distribution and Capital Investment Programs by Asset Group

Asset Group	Kinectrics Recommended 5 Year Replacement Value	Percentage of Assets with 'Poor' or 'Very Poor' Health Index	4kV and 8kV Renewal Program	XLPE Cable Renewal Program	Pole Residual Program	Proactive Transformer Replacement	LBDS Maintenance	Reactive Replacement
Underground Cables (primary XLPE)	$ 54,684,156	29%		X				X
Wood Poles	$ 24,443,926	11%	X		X			
Underground Cables (secondary DB)	$ 17,265,561	42%		X				X
Underground Cables (primary PILC)	$ 14,472,205	1%						X
Overhead Conductors (service)	$ 12,565,410	11%	X					X
Underground Cables (service DB)	$ 12,248,968	63%		X				X
Pole Mounted Transformers	$ 11,840,422	6%	X			X		X
Overhead Conductors (secondary)	$ 11,818,950	9%	X					X
Vault Transformers	$ 9,643,423	49%		X				X
Overhead Conductors (primary)	$ 9,049,700	5%	X					
Substation Switchgear	$ 5,250,000	32%	X					
Underground Cables (secondary ID)	$ 2,555,198	42%		X				X
Substation Circuit Breakers	$ 1,665,000	23%	X					
Overhead Line Switches	$ 1,653,832	20%					X	
Submersible LBD Switches	$ 308,960	46%						

Kinectrics recommended implementing asset specific programs not only to address improving the overall condition of the asset categories listed above, but also to maintain the existing overall condition level for the remaining asset categories. The failure to do so could result in deteriorating reliability performance; taking unnecessary risks associated with failures of assets with significant consequence of failure (such as underground cables, substation breakers and overhead conductors); and creating future investment needs that would be substantially higher than historical levels.

Kinectrics identified a 20 year System Renewal investment requirement of $692,664,000, as identified in Figure 2-2. The asset replacement costs are calculated using 2013 asset replacement costs for the 20 years, and do not include inflation. The Kinectrics analysis provides clear corroboration for the assertion that, based on sound engineering principles and best asset management practices, the health of Horizon Utilities' distribution system is unacceptable for certain assets, and generally degrading, and increased investment is required to halt further system health degradation to increasingly unacceptable levels. Kinectrics' recommended investment profile is highest in year one due to the number of assets with a Health Index of either “very poor” or “poor” that need to be addressed ideally today, and then decreases annually through the remainder of the 20-year planning cycle. The high proportion of assets with a Health Index of “very poor” or “poor”, identified in Figure 2-1 corresponds to the large backlog of assets at end-of-life identified in previous asset management plans.

Figure 2-2 - Kinectrics' Recommended Investment vs. Horizon Utilities' Proposed Investment



Horizon Utilities' initial asset management analysis in 2008 identified under-investment in system renewal and the need to increase such level of investment. Annual renewal investment has risen from below $10,000,000 in 2008 to $18,070,415 in 2015. Kinectrics' recommended investment for 2015, in comparison, is $49,675,877. Horizon Utilities' assessment of the investment level and profile recommended by Kinectrics determined that this investment profile would result in a very large and material rate impact on the customer base within such a short period of time. Doing nothing to address the end-of-life of these assets, however, is irresponsible. Additionally, a sharp increase in investment to this level without corresponding levels of cash flow from customer rate increases would not be affordable for Horizon Utilities.

In order to balance distribution system risks and customer bill impacts, Horizon Utilities proposes increasing annual renewal investment at a graduated rate from $18,070,000 in 2015 to $34,706,000 by 2019 and peaking at $39,661,000 in 2022. Horizon Utilities' proposed 20 year renewal investment profile is provided in Figure 2-2 above.

The increased renewal investment will be primarily directed at Horizon Utilities' 4kV and 8kV Renewal Program and Underground XLPE Cable Renewal Program. These programs are discussed in further detail below.

4kV and 8kV Renewal Program

Background

Horizon Utilities currently serves 75,000 customers with its 4kV and 8kV distribution systems. Horizon Utilities has 28 municipal substations which convert the electricity from the Hydro One supplied voltage of 13.8kV or 27.6kV to the distribution voltage of 4kV or 8kV, in order to serve these customers. The 4kV and 8kV distribution system and the associated substation assets are Horizon Utilities' oldest assets.

It is necessary to renew both the distribution assets and the substation assets, due to the condition and age of the assets as described in the Kinectrics ACA provided as Appendix B in the DSP. Horizon Utilities had two options to renew these assets:

i. Convert the 4kV and 8kV distribution system to a higher voltage by:

    a. Converting the distribution system to 13.8kV or 27.6kV while renewing the distribution assets. Customers could be serviced directly from 13.8kV or 27.6kV distribution assets and there is no incremental cost to renew at the higher voltage level;

    b. Investing in a limited number of substation assets to support the 4kV and 8kV system while the long-term 4kV and 8kV Renewal Program is being implemented; and

    c. Decommissioning the substation assets when the voltage conversions are completed. By utilizing distribution pole top transformers instead of the substation transformers, capital investment to renew substations will be avoided.

ii. Maintain the 4kV and 8kV distribution systems which requires:

    a. The renewal of all substation assets at the current voltage; and

b. The renewal of the distribution assets at the current voltage

Horizon Utilities chose to convert the 4kV and 8kV distribution system to a higher voltage to avoid the cost of the investment in the renewal of the substations. The proposed investments in the 4kV and 8kV Renewal Program will allow nine substations to be decommissioned between 2015 and 2019. The decommissioning of these nine substations will result in the avoided capital substation renewal investment of $22,500,000. Regardless if the area is converted from 4kV or 8kV to a higher voltage, the fundamental fact is that the distribution assets (the poles and wires) need to be replaced because they have reached end-of-life.

Scope

The 4kV and 8kV Renewal Program is the primary vehicle to address the renewal of the distribution assets and the substation assets. As discussed above, Kinectrics' ACA provided the Health Index for 22 asset groups. Fifteen of these asset groups have an unacceptable Health Index distribution.

An unacceptable Health Index distribution occurs when:

- at least 20% of the assets within the group have a Health Index of either "very poor" or "poor"; or

- the assets within the group, which have a "very poor" or "poor" Health Index, require a significant five year investment (greater than $5,000,000).

Horizon Utilities' 4kV and 8kV Renewal Program addresses the renewal of assets in seven of the fifteen asset groups. The seven asset groups are:

- Wood poles;
- Overhead conductors (primary);
- Overhead conductors (secondary);
- Overhead conductors (service);
- Pole mounted transformers;
- Substation switchgear; and

- Substation circuit breakers.

Horizon Utilities' service area originates from the amalgamation of six former local distribution companies. In the municipal amalgamation that created the current City of Hamilton in 2001, five local distribution companies were amalgamated when their local municipalities were amalgamated through provincial legislation. Later, the local distribution companies in the City of Hamilton and the City of Hamilton and the City of St. Catharines came together through an amalgamation approved by the Board in 2005 (EB-2004-0504).

The 4kV and 8kV Renewal Program utilizes an area-wide approach centred on the substation and the surrounding area it serves. Generally a substation is normally backed up by one or more other substations in the area. This provides security and network resiliency for contingency purposes. In fact at the next level down from the substation the feeders themselves also are backed up by other feeders in the surrounding area. The prudent execution of the renewal program for these assets must consider converting adjoining feeders that back each other up and ultimately the substation to substation impact as the substation is converted over time, in order to maintain backup and operational contingency for the area. To do otherwise would result in exposing customers to possibly lengthy outages and would require repairs to be fully completed prior to allowing customers to be restored. Depending on the nature of the repairs required it would not be unusual for it to take over 24 hours to complete. The ability to utilize a backup feeder or substation alleviates this concern by switching power flows around so as to restore customers back to service in minutes/hours rather than days.

Once the distribution assets are converted to the higher voltage, the substation assets will be decommissioned. Failure to renew the entire area would:

- Leave a large number of customers stranded in the event of a service interruption, due to lack of interconnection with an adjacent substation; and

- Require old substation assets to remain in service with high and increasing risk of critical failure.

The failure of these substation assets would result in a large number of customers without service for an extended period of time; potentially greater than 24 hours. The schedule for the 4kV and 8kV projects in the 2015 to 2019 Test Years is provided in Table 2-46 below.

Table 2-46 - 4kV and 8kV Renewal Program

	2015 Test Year	2016 Test Year	2017 Test Year	2018 Test Year	2019 Test Year
Aberdeen S/S	$ -	$ -	$ 2,418,000	$ 2,643,000	$ 2,900,000
Baldwin S/S	$ -	$ -	$ -	$ 1,788,000	$ 4,403,000
Central S/S	$ -	$ 1,556,000	$ 1,876,000	$ 1,652,000	$ 648,000
Grantham S/S	$ 650,000	$ 2,633,000	$ 1,871,000	$ 13,000	$ 159,000
Highland S/S	$ 1,128,000	$ -	$ 658,000	$ -	$ -
John S/S	$ -	$ -	$ -	$ 2,516,000	$ 8,259,000
Strouds S/S	$ 1,020,000	$ 1,533,000	$ 1,787,000	$ 3,831,000	$ -
Taylor S/S	$ -	$ -	$ -	$ 26,000	$ 159,000
Vine S/S	$ 978,000	$ 2,472,000	$ 5,645,000	$ 13,000	$ 159,000
Welland S/S	$ -	$ -	$ -	$ 13,000	$ 159,000
Whitney S/S	$ 4,384,000	$ 1,966,000	$ 1,509,000	$ 2,115,000	$ -
York S/S	$ -	$ -	$ -	$ 1,074,000	$ -
4kV & 8kV Renewal Subtotal	**$ 8,160,000**	**$ 10,160,000**	**$ 15,764,000**	**$ 15,684,000**	**$ 16,846,000**

The operating areas serviced by the substations identified in Table 2-46 above are:

- St. Catharines – Grantham, Taylor, Vine, and Welland substations;
- Dundas – Baldwin, Highland, John, and York substations;
- Hamilton West – Strouds and Whitney substations; and,
- Hamilton Downtown – Aberdeen and Central substations.

The selection and prioritization of these areas for renewal is either driven by substation asset health (St. Catharines, Hamilton West, and Hamilton Downtown operating areas) or by the health of the distribution system and operational constraints (Dundas operating area). The York substation distribution assets, located in the Dundas operating area, do not interconnect with any other assets and therefore have no back-up. The selection and prioritization of these operating areas for renewal is fully described in the 4kV and 8kV Renewal Program at Section 3.5.3 of the DSP provided as Appendix 2-4 of this Exhibit.

The proposed investments in the 4kV and 8kV Renewal Program will allow nine substations to be decommissioned between 2015 and 2019. Regardless of whether the area is converted from 4kV or 8 kV to a higher voltage, the fundamental fact is that the distribution assets (the poles and wires) would need to be replaced because they have reached their end of life. By converting the distribution assets to a higher voltage (from 4 kV or 8 kV to 13.8 kV or 27.6kV respectively) the substation asset (i.e. transformer, switchgear, breakers, relays, and building enclosure) does not need to be renewed and as stated earlier this results in a more streamlined distribution system with a net economic benefit of $22,500,000, the value of the substation assets for the nine locations. Put another way, the decommissioning of these nine substations will result in an avoided capital substation renewal investment of $22,500,000.

The total avoided substation renewal investment over the remaining 35 years of the plan is $70,000,000 for all 28 substations. The consequence of not executing the conversions within the 40 year timeframe is that substation assets reaching end-of-life prior to being decommissioned will require unavoidable renewal investment to maintain service to those customers who are still served by the lower voltage system. The timing of the conversion of assets to the higher voltage in the 4kV and 8kV Renewal Program is such that the conversion is completed prior to the substation assets reaching end-of-life and otherwise requiring investment. Once the distribution assets are renewed, the substation assets are decommissioned.

Horizon Utilities is proposing to increase investment in the 4kV and 8kV Renewal Program from an annual investment in the 2015 Test Year of $8,160,000 to an annual investment in the 2019 Test Year of $16,846,000. The justification for this investment is identified below by area.

St. Catharines Operating Area

The three substations in service (Vine, Welland, and Grantham; Taylor is not in service, however has not yet been decommissioned) within the St. Catharines' operating area service a total of 4,000 customers and were constructed between 1959 and 1965. These substations are in poor health and require renewal. The overall substation Health Index for Vine, Welland and Grantham substations is 57%, 59%, 58%, respectively, as identified in the 4kV and 8kV Renewal Program included in the DSP as Appendix 2-4. There is limited back-up between these substations. The loss of the Grantham or Vine substations would result in 900 and 1,100 customers respectively being without service for several days, at a minimum. Restoration of power to these customers would require the costly and unplanned emergency construction of new distribution assets all while customers are without service. The situation is untenable and must be rectified as soon as possible.

The 4kV distribution assets in St. Catharines are underperforming, subjecting customers served by this system to a higher level of service interruptions than the remaining customers in St. Catharines. The System Average Interruption Duration Index ("SAIDI") for these customers is 28% higher than for the customers served by the 13.8kV system in St. Catharines and 100% higher than Horizon Utilities' corporate target. Horizon Utilities has included additional information in this regard in Section 2.2.2 of the DSP filed as Appendix 2-4 of this Exhibit.

Dundas Operating Area

The four substations (Highland, Baldwin, John, and York) within the Dundas operating area service 3,000 customers. These substations are all single substations (i.e., they each have one power transformer and switchgear) with no allowance for a contingency event. Any transformer or switchgear failure would lead to the compete loss of the substation and would necessitate the transfer of load to neighbouring stations.

The switchgear at the Highland substation is 44 years old, with an effective age of 58 years old as determined by Kinectrics. The "effective age" is different from the chronological age in that it is based on the asset's condition and the stresses that have been applied to it over the life of the asset. Kinectrics' evaluation found that the failure of the switchgear was imminent. Switchgear failure will result in the complete loss of the substation. Failure of the Highland substation will necessitate the transfer of load to the John substation. This will result in John substation operating in excess of capacity. Furthermore, system operating analysis indicates that, due to the loading conditions, many customers will experience an under-voltage condition, referred to as "brownout", that if sustained will damage customer-owned equipment, as well as cause outages.

The failure of any of the Highland, Baldwin and John substations will result in a load transfer to, and overload of, a neighbouring back-up station; thereby increasing the risk of failure of the back-up station. This cascading effect is highly likely and could lead to multiple failure points, causing over 1,000 customers to be without service. Horizon Utilities has provided further details in Section 3.5.3 of the DSP filed as Appendix 2-4 of this Exhibit.

York substation does not have connections to the Highland, Baldwin and John substations and therefore the load cannot be transferred in the event of a failure. Loss of this substation will leave the 400 customers served by this substation stranded without power for an extended period until an alternate supply can be constructed.

The distribution assets in the Dundas operating area are in poor health and have significant operating constraints. This area has numerous radial feeds without backup. The Dundas operating area also contains 25% of the 4kV XLPE cable. The 4kV XLPE cable is in poor health with 38% of the assets having a Health Index of either ‘very poor’ or ‘poor’. The renewal of the assets in this area has the additional benefits of renewing the underground XLPE cable and allowing for the replacement of the radial feeders with a loop-fed system. A loop-fed system has two sources of supply which provides switching options to restore power more quickly. The underground XLPE Renewal Program is discussed in further detail in this Schedule.

The substations in the Dundas operating area are all single stations which require the transfer of the total substation load in the event of failure. This attribute, combined with the operational constraints and lack of backup at the distribution level, result in a high risk of sustained outages (greater than four hours) to a large number of customers.

Hamilton West Operating Area

The two substations within this operating area service a total of 5,400 customers and provide backup for each other. The Strouds and Whitney substations were constructed in 1938 and 1962 respectively. The switchgear at these stations have a Health Index of ‘very poor’ as identified in the Substation Asset Condition Assessment (“SACA”) and confirmed by the Kinectrics’ ACA. The switch gear at the Strouds and Whitney substations are 44 and 46 years old, with an effective age, as determined by Kinectrics, of 57 and 56 years old, respectively. Kinectrics forecasted the failure of both substations’ switchgear within one to three years. Switchgear failure will result in the complete loss of the substation. A loss of both substations would result in an outage that would affect all 5,400 customers. These customers would be without power until the substation assets were repaired. Horizon Utilities does not maintain spare parts for all substation assets. The time required to procure replacement parts, if not obsolete and still available, would be several months.

<u>Hamilton Downtown Operating Area</u>

The two substations within this operating area are Aberdeen and Central. These substations service a total of 7,400 customers. The substations were constructed in 1950 and 1960. The overall Station Health Index for Aberdeen and Central substations is 53% and 56% respectively, as identified in the 4kV and 8kV Renewal Program filed as Appendix F to the DSP. The switchgear at the Aberdeen substation is 40 years old; Kinectrics determined its effective age is 54 years old. Kinectrics' analysis determined that the failure for this switchgear will occur within five years. Aberdeen substation, which services 2,600 customers, has inadequate backup for all feeders. The failure of the switchgear at this substation will leave customers without power or subject them to rotating blackouts. The Central substation has ten breaker positions; six of which are obsolete, oil-filled breakers at end-of-life. The Health Index for these breakers is "very poor" and Kinectrics forecasted that the failure of the breakers will be within three years. Two of the six feeders are radial feeders with no backup. Failure of the breakers for these feeders would result in the loss of service for over 50 commercial customers in downtown Hamilton for a minimum of several hours to several days. Central substation has limited interconnection with other substations. The loss of the entire substation would affect all 3,100 customers who would be out of power until the substation assets were repaired. Repair and restoration of a failed substation can take months. Horizon Utilities does not maintain spare parts for all substation assets. The time required to procure replacement parts, if not obsolete and still available, would be months.

In summary, the investment in the 4kV and 8kV Renewal Program is necessary to address the risk of imminent asset failures and prolonged customer outages.

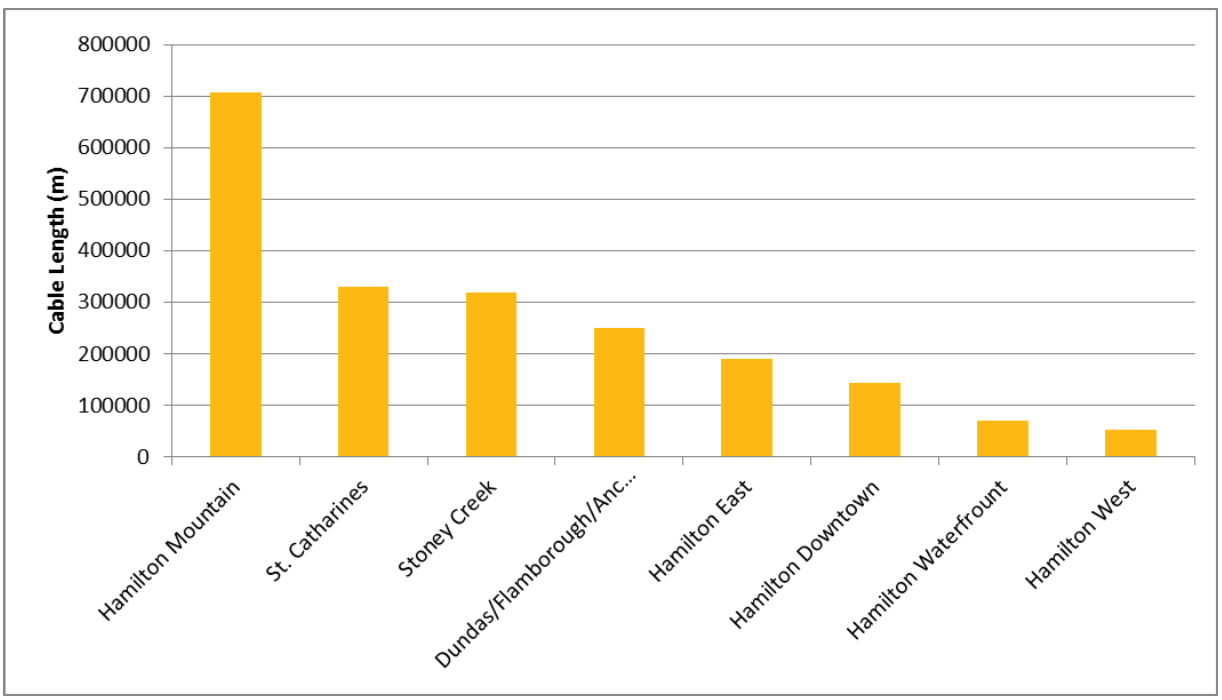
Underground XLPE Cable Renewal Program

Background

Underground distribution assets present the largest area of risk to the continued safe and reliable operation of Horizon Utilities' distribution system. XLPE cable is the asset group within the underground distribution assets with the largest investment requirement over the 20-year planning cycle, due to its poor health and the high volume of cable. Failure of underground distribution assets presents the largest impact on interruptions of service to Horizon Utilities' customers. Horizon Utilities experiences a high volume of outages due to failures of underground distribution assets affecting thousands of customers.

Locating, repairing, and restoring service due to an underground cable failure is time consuming and results in prolonged service interruptions. An analysis of all service interruptions, caused by material or equipment failure from 2010 to 2013, revealed that 50% of service interruptions, measured by customer minutes of outage, were due to failures of underground cable and equipment. Over 30% of these outages exceeded four hours in duration, while 5% of these outages exceeded twelve hours in duration. These durations far exceed Horizon Utilities' corporate target of one hour and nine minutes of outage on average per customer. Horizon Utilities' corporate reliability targets are defined in Section 1.3.2 of the DSP. Horizon Utilities currently has 2,060km of underground XLPE cable located in eight operating areas as identified in Figure 2-3 below.

Figure 2-3 – Metres of XLPE Primary Cable by Operating Area



Scope

The Underground XLPE Cable Renewal Program is the primary vehicle to renew Horizon Utilities' underground distribution assets. Horizon Utilities' proposed investment for this program in the 2015 to 2019 Test Years is provided in Table 2-47 below.

Table 2-47 – Underground XLPE Renewal Program

U/G (XLPE) Renewal	2015 Test Year	2016 Test Year	2017 Test Year	2018 Test Year	2019 Test Year
Ancaster/Flamborough/Dundas	$2,257,000	$1,269,000	$0	$0	$2,702,000
Hamilton Mountain	$0	$1,996,000	$6,607,000	$4,641,000	$3,473,000
St. Catharines	$310,000	$1,661,000	$1,759,000	$2,835,000	$4,096,000
Stoney Creek	$0	$0	$500,000	$1,908,000	$0
U/G (XLPE) Renewal	**$2,567,000**	**$4,926,000**	**$8,866,000**	**$9,384,000**	**$10,271,000**

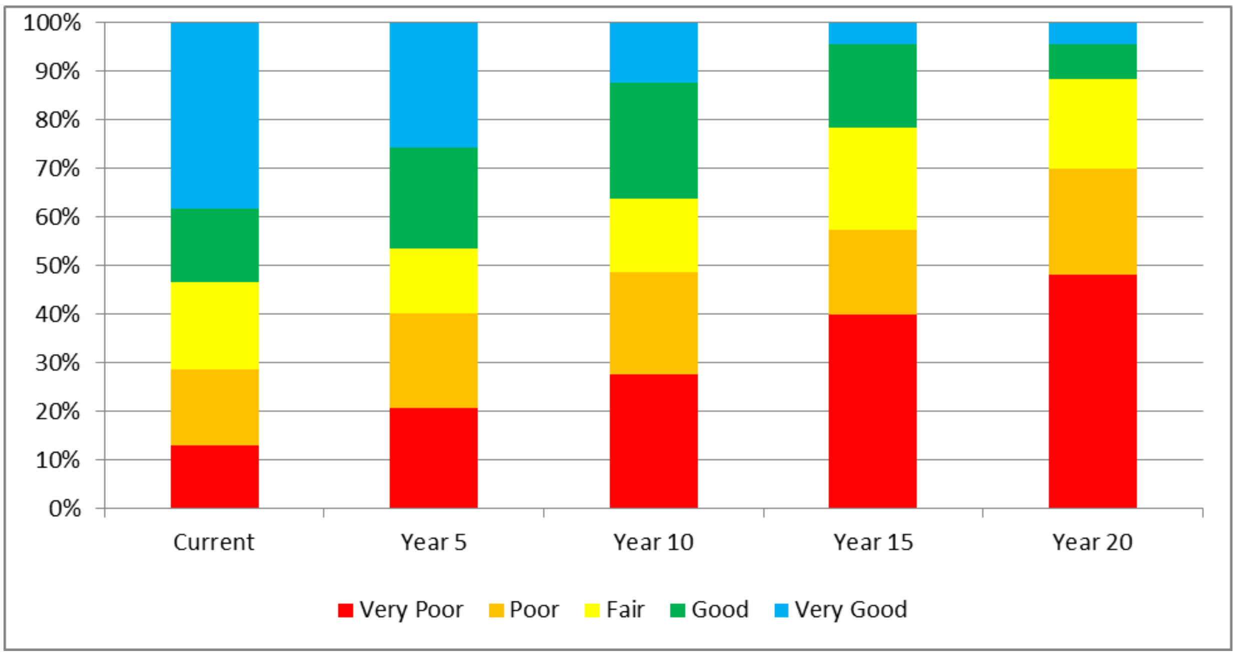
Horizon Utilities' XLPE Renewal Program addresses the renewal of assets in six of the fifteen asset groups, which were identified by Kinectrics as having an unacceptable Health Index distribution. These six asset groups are:

- XLPE Cables (Primary)
- Underground Cables (Secondary Direct Buried)
- Underground Cables (Secondary In Duct)
- Underground Cables (Service Direct Buried)
- Underground Cables (Service In Duct); and
- Vault Transformers

The total length of XLPE primary cable which has an unacceptable Health Index distribution, is 597km or 29% of Horizon Utilities' total installed XLPE cable asset base. XLPE cable, according to the Kinectrics ACA and provided in Section 3.1.3 – Table 29 and 30 of the DSP, has the highest investment requirement of the 22 asset groups due to the high percentage of cable with an unacceptable Health Index distribution and the high volume of installed cable. The Kinectrics ACA identified that a total investment requirement $172,742,000 over twenty years is required to remedy this situation. The investment required over the next five years is $54,684,000 according to Kinectrics' ACA.

Maintaining the XLPE cable renewal investment at 2013 levels would result in a continual decrease in the Health Index distribution of this asset group as identified in Figure 2-4 below. The percentage of XLPE primary cable having a Health Index of either “poor” or “very poor” would increase from the current value of 30% to 70% or 1,400km by 2034, if ongoing annual investment is held at the current 2013 level.

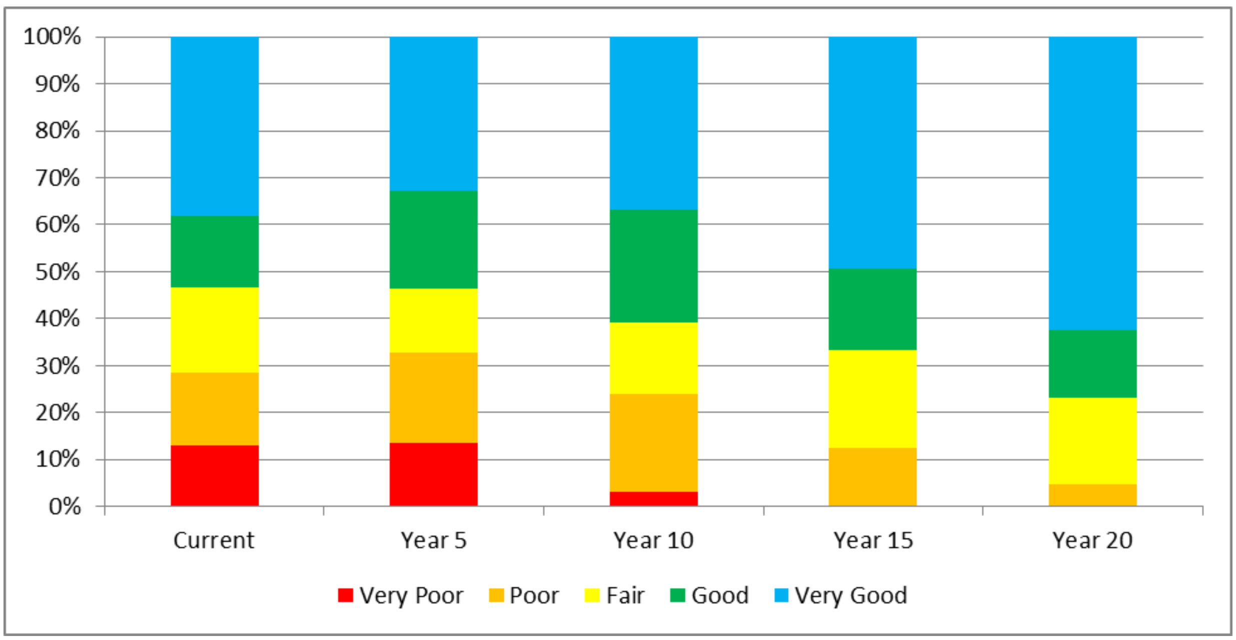
Figure 2-4 – XLPE Health Index Distribution at 2013 Investment Levels



The failure rates associated with this level of risk will result in a significant increase in the number of outages experienced by customers compared to current levels and increased operational and maintenance costs associated with the location of faults, restoration, and repair. Without proactive replacements, as assets continue to age and degrade, the cable will fail at an exponential rate and in the worst case scenario will exceed Horizon Utilities’ ability to keep pace with repairs. Reliability will also deteriorate to unacceptable levels. Reactive replacements will be materially more expensive than the plan that has been submitted in this Application. Reactive renewal is estimated to be three times more costly than planned renewal.

The current backlog volume of XLPE cable requiring renewal cannot be addressed in a single year and requires a multiple year investment strategy. The optimal level of renewal for XLPE cable, based on a 40-year useful life replacement cycle, is 50km/year. Horizon Utilities' proposed aggregate investment of $36,014,000 for the 2015 to 2019 Test Years, provides for the replacement of 180km of cable over this period. This represents a managed, gradual increase in investment in order to balance rate payer concerns and practical operational limitations. This proposed investment is below the minimum investment required to maintain the current Health Index in 2015 to 2019, as identified in Figure 2-5 below. The backlog of XLPE cable with a "very poor" or "poor" Health Index continues to grow until 2019. It will take Horizon Utilities until 2017 to reach the optimal level of renewal, due to long lead times required to address planning and municipal consent processes and customer stakeholdering.

Figure 2-5 – XLPE Health Index Distribution at Proposed Investment Levels



The Kinectrics ACA provided the guidance for determining the annual investment requirement. Horizon Utilities used operational performance analysis, including: failure rates; location; and the identification of worst performing feeders to prioritize XLPE cable renewal projects.

The Hamilton Mountain, Stoney Creek, and St. Catharines operating areas are the focus areas for the proactive replacement of XLPE primary cable. These areas contain 66% of the total XLPE cable in Horizon Utilities' distribution system. Failed cable will be replaced reactively in the remaining areas, as the reliability and equipment failure statistics for these areas do not warrant a more proactive approach at this time. These areas will be candidates for renewal projects beyond the 2019 Test Year.

In summary, failure to invest in XLPE cable renewal at Horizon Utilities' proposed level of $36,014,000 over 2015 to 2019 will result in increased and continued service interruptions to large volumes of customers, with outages lasting several hours.

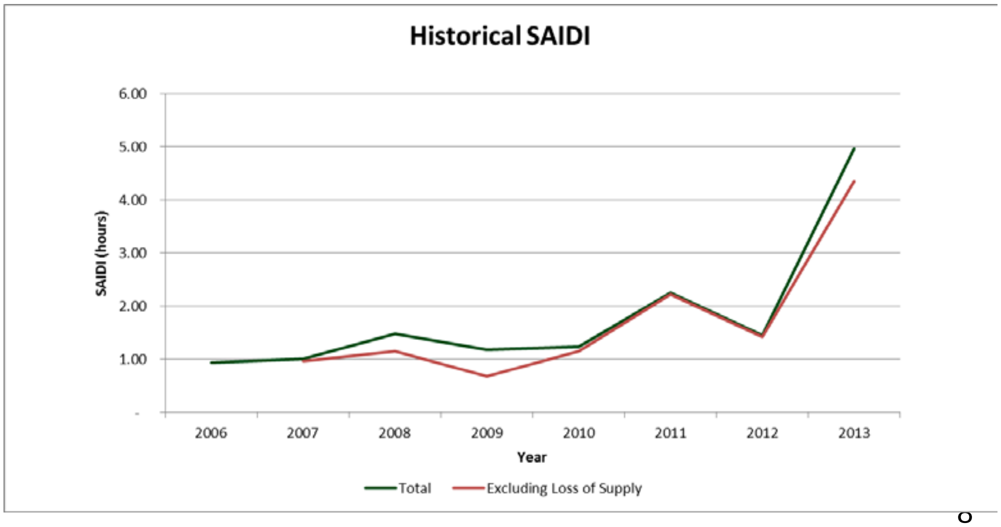
The underground XLPE Cable Renewal and the 4kV and 8kV Renewal Programs address twelve of the fifteen asset groups identified in Kinectrics ACA as having an unacceptable Health Index distribution. Investments in the 4kV and 8kV Renewal Program and the XLPE Renewal Program are necessary to address the risk of imminent asset failures. Failure to invest in the renewal of these assets at the proposed rates will result in continued degradation of distribution assets and decreased service levels to Horizon Utilities' customers. Service interruptions could impact thousands of customers with prolonged outage durations lasting many days.

System Reliability

SAIDI and System Average Interruption Frequency Index ("SAIFI"), Horizon Utilities' two primary system performance metrics, have been trending negatively since 2006, representing a decrease in service to customers. The decline in these metrics is consistent with an aging distribution system requiring significant renewal investment.

SAIDI, a measure of the average outage duration experienced by a customer, has increased by 430% since 2006, as illustrated in Figure 2-6. The significant increase in 2011 was the result of a major windstorm in Horizon Utilities' St. Catharines service area in April of that year. Two major storms, a windstorm in July and an ice storm in December, drove the increase in SAIDI in 2013.

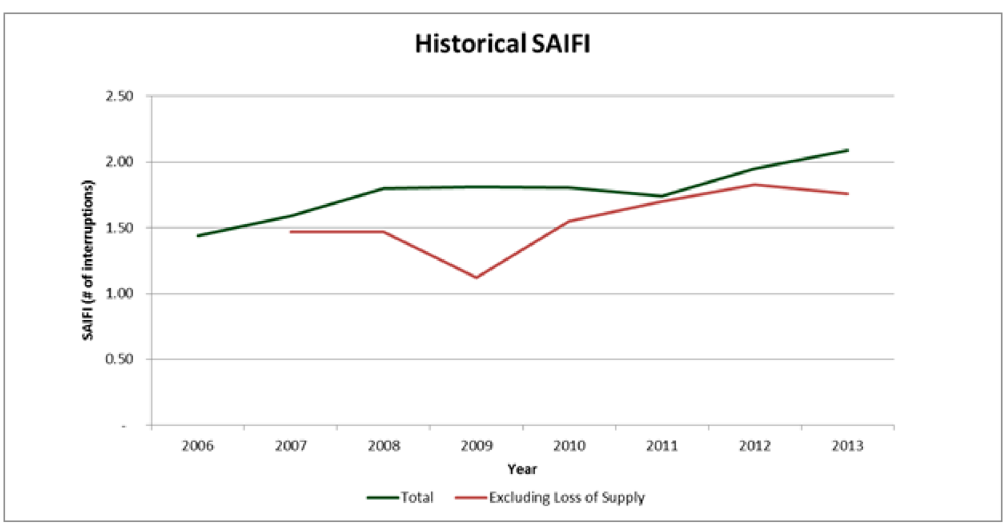
Figure 2-6 - SAIDI for 2006-2013



SAIDI increased by 17% from 2006 to 2013 after the impact of these major storms was removed. Horizon Utilities' SAIDI for 2013 was 4.97 hours; Horizon Utilities' 2014 target for SAIDI is 1.15 hours.

SAIFI, a measure of the average number of interruptions per customer, has increased by 45% since 2006, as shown in Figure 2-7.

Figure 2-7 - SAIFI for 2006-2013



Horizon Utilities' SAIFI continues to escalate indicating that customers experienced a higher frequency of outages, on average, in 2013 than in 2006.

General Plant

The OEB category of general plant includes Horizon Utilities'' capital expenditures on buildings, fleet, and information systems technology. An overview of Horizon Utilities' capital expenditures in each of these categories is provided below.

Buildings Capital

Horizon Utilities has five main buildings on four properties, comprised of two adjacent Head Office buildings and three Service Centres, as identified in Table 2-48 below. Horizon Utilities also has 28 substations, 23 of which are inside separate building enclosures in the cities of Hamilton and St. Catharines.

These buildings were constructed between 1914 and the early 1980s. The majority of the office space was largely as originally built prior to renovations that commenced in 2012.

Table 2-48 – Vintage of Horizon Utilities Main Buildings

Location	Type	Vintage
John Street, Hamilton	Head Office	1950-1960
Hughson Street, Hamilton		1914
Nebo Road, Hamilton	Service Centre	1980
Vansickle Road, St. Catharines	Service Centre	1970
Hwy 8, Stoney Creek	Service Centre	1980

Based on asset condition assessment studies, and with consideration for accommodating productivity within a growing workforce, significant renewal and refurbishment of buildings and related systems is required over the next several years as provided in this Application in order to sustain the office and operating environments and provide opportunity for productivity. Building infrastructure systems are at or nearing the end of their productive life, resulting in: inefficient equipment performance; increased risk of system failure; poor work environments for employees; and increased health and safety risks. The original floor layouts, building systems and structures do not meet the needs of the current workforce.

The buildings have not been renovated since their original construction and as such, the floor layout and design includes large offices and work areas which do not meet the needs of the current organization. This is creating a congested and unsafe work environment. Meeting rooms have been used as office space to house employees from the same functional group, reducing the availability of meeting room space. Numerous workstations have been installed inside existing offices due to the lack of available open office space. The Space Study identifies opportunities to balance the space available to support the organization's current and future requirements by reducing congestion and creating appropriate work flows.

Horizon Utilities' buildings are comprised primarily of: office space; common areas that are available to all employees; and areas to support customer service, warehousing, fleet parking, and garage spaces.

The renovation projects allow Horizon Utilities to make more effective and efficient use of available space through:

- Rationalization of existing office spaces and creation of new office spaces to meet operational requirements;
- Creation of necessary common spaces, including meeting rooms, washrooms, and lunchrooms to accommodate the needs of 440 employees;
- Re-claiming under-utilized spaces; and,
- Updating security to provide for controlled access to buildings and employees.

Horizon Utilities has taken a cost effective approach to refurbishment and renovations by maintaining the existing building footprint. The allocation of building space pre and post renovations is identified in Tables 2-49, 2-50 and 2-51 below.

Table 2-49 – Allocation of Building Space prior to Renovations

Description	Total	John Street	Hughson Street	Nebo Road	Vansickle Road	Hwy 8, Stoney Creek
Square Footage Consumed by Office Space [1]	33,663	24,728	1,740	3,373	3,494	328
Square Footage Consumed by Common Area [2]	66,597	38,172	660	11,387	8,606	7,772
Square Footage Allocated to Customers	2,900	2,700	0	0	200	0
Square Footage Allocated to Warehousing, Fleet, Parking and Garage [3]	154,200	24,900	2,400	73,500	35,100	18,300
Unusable Building Space [4]	4,500	0	4,500	0	0	0
Total Available Building Space	**261,860**	**90,500**	**9,300**	**88,260**	**47,400**	**26,400**
1. office space square footage excludes hallways, common areas, service areas, warehouses, garages and tenant space						
2. includes space utilized by all employees - e.g. hallways, meeting rooms, training rooms, lunch rooms, washrooms, first aid, lockers and showers, printing/photocopying						
3. includes Warehouse, Internal Parking & Fleet Shop Garage						
4. Unusable Building Space is a substation which will be converted into a meeting room						

Table 2-50 – Allocation of Building Space Post Renovations

Description	Total	John Street	Hughson Street	Nebo Road	Vansickle Road	Hwy 8, Stoney Creek
Square Footage Consumed by Office Space [1]	26,968	19,648	1,340	2,652	3,096	232
Square Footage Consumed by Common Area [2]	105,992	48,852	7,960	29,408	11,904	7,868
Square Footage Allocated to Customers	3,800	2,700	0	700	400	0
Square Footage Allocated to Warehousing, Fleet, Parking and Garage [3]	125,100	19,300	0	55,500	32,000	18,300
Total Usable Building Space	**261,860**	**90,500**	**9,300**	**88,260**	**47,400**	**26,400**
1. office space square footage excludes hallways, common areas, service areas, warehouses, garages and tenant space						
2. includes space utilized by all employees - e.g. hallways, meeting rooms, training rooms, lunch rooms, washrooms, first aid, lockers and showers, printing/photocopying						
3. includes Warehouse, Internal Parking & Fleet Shop Garage						

Table 2-51 – Summary of Building Space Allocation

Description	Prior to Renovations	Post Renovations	Net Change Decr/(Incr)
Square Footage Consumed by Office Space	33,663	26,968	6,695
Square Footage Consumed by Common Area	66,597	105,992	(39,395)
Square Footage Allocated to Customers	2,900	3,800	(900)
Square Footage Allocated to Warehousing, Fleet, Parking and Garage	154,200	125,100	29,100
Unusable Building Space	4,500	0	4,500
Total Usable Building Space	**261,860**	**261,860**	**0**

Office Space

Horizon Utilities has developed standards for office space to ensure appropriate support of the operational needs of the business, which resulted in the necessary reallocation of space to common areas. Through the application of standards for office space, the average square footage per employee will decrease by 20 square feet as identified in Table 2-52 below. This will result in the reclamation of 6,695 square feet.

The number of employees indicated in the table below represents employees who require office space on a regular basis, and therefore excludes field employees.

Table 2-52 – Office Space Allocation per Employee

	Prior to Renovation			Post Renovation		
Location	**Total Office Space Footage [1]**	**Number of Employees [2]**	**Average Square Footage per Employee**	**Total Office Space Footage [1]**	**Number of Employees [2]**	**Average Square Footage per Employee**
John Street, Hamilton Hughson Street, Hamilton	26,468	244	108	20,988	244	86
Nebo Road, Hamilton	3,373	39	86	2,652	39	68
Vansickle Road, St. Catharines	3,494	51	69	3,096	51	61
Hwy 8, Stoney Creek	328	3	109	232	3	77
Total	**33,663**	**337**	**100**	**26,968**	**337**	**80**

1. office space square footage excludes common areas, service areas, warehouses, garages and tenant space
2. number of employees as at December 31, 2013, including contract staff and students; exclusive of field staff who do not require dedicated office space

Common Areas

Horizon Utilities defines common areas as any space that may be utilized by all or a group of employees. The Office Space Study confirmed that common space resources were insufficient to support the Horizon Utilities workforce, and to meet existing Ontario Building Code ("OBC") regulations.

The renovation will allow for the addition of 39,395 square feet of common space, reclaimed from warehouse, mechanical rooms, storage rooms, loading docks and office space, and consisting primarily of:

- Meeting rooms at the Head Office, Stoney Creek, Nebo Road, Vansickle Road, and Hughson Street locations;

- Dedicated training rooms located at the Head Office and Vansickle Road Service Centre locations;
- One lunch room or kitchenette per floor or building;
- One washroom for each gender per floor or building as per OBC;
- Locker and shower facilities at four of the buildings;
- Printing and photo-copying areas;
- A dedicated First Aid area at the Head Office location;
- Three Prayer/Meditation rooms, one located at Head Office, one located at the Vansickle Road Service Centre and one located at the Nebo Road Service Centre;
- Computing and data centres at the Head Office location and Vansickle Road Service Centre; and,
- Hallways.

Customer Lobbies

Horizon Utilities has dedicated lobbies for customer support where customers may submit customer service inquiries, meet with staff, or access their account information. The lobbies also serve as security checkpoints for the buildings and employees. Horizon Utilities will have customer support areas at the Vansickle Road and Nebo Road Service Centres and Head Office, totalling 3,800 square feet post renovation.

Warehousing, Fleet Parking, and Garage Space

Horizon Utilities' buildings are situated on four properties that are located at key vantage points across its service territory. The utilization of each as a service centre for field staff reduces the travel time of work crews to job sites as compared to a single operation centre.

The Nebo Road, Stoney Creek and Vansickle Road Service Centres have internal parking facilities which house approximately 70% of the vehicles and associated equipment in the Horizon Utilities fleet. Warehousing of inventory is primarily managed from the Nebo Road and Vansickle Road Service Centres with inventory staging areas located at Head Office and the Stoney Creek Service Centre. Maintenance of the Horizon Utilities fleet is performed in the garages of the Nebo Road and Vansickle Road Service Centres.

As a result of the planned renovations, warehousing, fleet parking and garage space, mechanical rooms, and storage room space will decrease by 29,100 square feet to 125,100 square feet as identified in the table below. This is possible through reductions of inventory levels, re-organization of inventory items and replacement of HVAC units with smaller, more energy efficient units. Post renovation, project inventory staging will be primarily performed at the Stoney Creek Service Centre.

Table 2-53 – Warehouse, Fleet Parking and Garage Space

Location	Warehouse Square Footage	Inventory Items [1]	Internal Parking Garage Square Footage	Vehicles Inventory	Fleet Shop Garage Square Footage	Total Square Footage
John St. & Hughson St.	1,500	200	17,576	24	N/A	**19,300**
Nebo Road	22,600	1,661	24,666	73	6,500	**55,500**
Vansickle Road	14,503	1,460	13,200	37	2,800	**32,000**
Stoney Creek	5,500	710	12,080	10	N/A	**18,300**
Total	**44,103**	**4,031**	**67,522**	**144**	**9,300**	**125,100**

1. inventory items include bolts and nuts, switches, transformers and wire reels

Overall expenditures for the maintenance and operations of the Horizon Utilities' buildings are increasing year-over-year as indicated in Table 2-54 below.

Table 2-54 – Building Operational Expenditures 2011 to 2013

	2011 Actual	2012 Actual	2013 Actual
Building Equipment Repairs and Maintenance	$ 89,321	$ 69,668	$ 11,388
Building Utilities	$ 745,804	$ 720,988	$ 848,373
Building Repairs and Maintenance	$ 257,633	$ 569,104	$ 735,761
HVAC Maintenance	$ 63,402	$ 23,965	$ 86,850
Janitorial and Landscaping Service	$ 224,854	$ 226,431	$ 124,785
Building Security Service	$ 144,067	$ 149,024	$ 134,444
Building Maintenance Service Agreements	$ 340,864	$ 380,518	$ 559,934
Total	**$ 1,865,945**	**$ 2,139,698**	**$ 2,501,535**

The increased expenditures are due to:

- increased maintenance on end-of-life systems;
- required structural repairs; and
- additional expense to procure replacement parts for obsolete systems.

Horizon Utilities identified that a long-term building asset renewal plan was necessary and commenced a series of studies in 2010 in order to:

- understand building and operational requirements;
- determine the level of required investment; and,
- prioritize and pace the prospective building renewal projects in order to balance related costs and customer rate implications against the risks and benefits of such projects.

The independent studies included: a Resource and Office Space Utilization Study Report ("Space Study"), filed as Appendix J of the DSP filed as Appendix 2-4 of this Exhibit by PRISM Partners Inc.; a Building Condition Assessment ("BCA") by Evans Consulting Services, filed as Appendix K in the DSP ; Horizon Utilities Physical Security Report ("Security Study") filed as Appendix L in the DSP; a window assessment for the John Street building by MMM Group Limited ("Horizon Window Study Report") filed as Appendix M in the DSP; and a roof assessment for the John Street and Hughson buildings by Garland Canada Inc. ("Roof Inspection Review") filed as Appendix N in the DSP.

The studies were undertaken to aid in the development of Horizon Utilities' long-term building renewal strategy and to assess and evaluate the following:

- the health of building infrastructure systems including heating and air ventilation conditions, and their risk of failure;
- office space environmental conditions;
- health and safety concerns related to poor air quality, and unsecured access points;
- continued compliance with the Ontario Building Code ("OBC") and Fire Codes;
- the structural integrity of the buildings;
- office space availability to support current and future workforce and equipment; and

- options to renovate the five existing buildings as compared to building a new centralized Horizon Utilities' office.

Space Study

Horizon Utilities engaged PRISM Partners Inc., a leading project management and consulting firm with roots in the healthcare, research, academic, municipal and private sectors, to conduct a Space Study in 2010. The Space Study is provided as Appendix J in the DSP.

The Space Study evaluated all five of Horizon Utilities' buildings. It determined that the office work environment was congested and some business units were housed at multiple locations which led to operational inefficiencies and unproductive, overcrowded work environments. The Space Study determined that Horizon Utilities existing office space cannot support the current requirements of the current work force.

The Space Study also identified health and safety concerns, including:

- air quality was compromised by vehicle emissions and was at the lowest end of the acceptable threshold range.
- certain electrical and fire and life support systems were not compliant with the current OBC. Any systems installed prior to the current OBC are grandfathered and may remain in operation with proper maintenance and regular inspections. However, these systems had reached end-of-life and were at risk of not functioning effectively.
- pedestrian work flows and vehicle traffic were in the same work areas which created dangerous environments for employees and customers.

The Space Study identified opportunities to reclaim under-utilized space and restructure existing space to resolve congested work areas and support the requirements of the current and future workforce.

Key findings and recommendations from the Space Study were:

<u>55 John Street and Hughson Street buildings:</u>

- The Customer Connections office staff and the Metering Testing Lab shared a common space, creating potential safety risks from live electrical testing in an open environment in close proximity to office staff;

- Customer Connections office staff were working within a “warehouse” environment with insufficient lighting for an office. The staff did not have access to local washroom facilities which is not compliant with current OBC and the under-sized Heating Ventilation and Air Conditioning (“HVAC”) systems exposed staff to health and safety risks related to poor air quality;

- Employees within the same departments such as Procurement, Customer Service, Conservation and Demand Management, Customer Connections, and Information System Technology were located either in different buildings or on different floors resulting in communication, alignment and operational inefficiencies;

- Customer Service staff had a congested work space, which necessitated some staff to be located on the main floor adjacent to the customer lobby. This posed potential security concerns and provided a noisy work environment due to the volume of employee and customer traffic. Other deficiencies included poor lighting, air quality concerns and non-ergonomic office furniture that did not comply with current ergonomic best practices;

- The size of the Computer Training room could not accommodate the number of computers required for training sessions, and was equipped with temporary electrical outlets and extensions which created fire and tripping hazards; and

- Washroom facilities were non-existent or required renovations to support current and future employee occupancy as per the current OBC and *Accessibility for Ontarians with Disabilities Act (“AODA”)*.

<u>Nebo Road, Vansickle Road, and Hwy # 8 Service Centres:</u>

- Entrances used by employees and customers were not adequately secured from unauthorized access;
- The ventilation systems were inadequate, resulting in air quality tests at Vansickle Road and Nebo Road Service Centres that were at the low end of the acceptable threshold range for office spaces, primarily as a result of vehicle emissions from nearby parking garages;
- The present building configurations did not support the safe and effective management of the flow of people, vehicles, equipment, and stock within the Service Centres;
- There was a need for additional office space and meeting and training rooms to support the current and future workforce at these locations. The lack of training and meeting space necessitated travel time to other locations and reduced productive time;
- Garages at the service centres located in Hamilton, Stoney Creek and St. Catharines, built between 1970 and 1980, were not designed or built to physically accommodate the current number and size of vehicles and equipment utilized by Horizon Utilities' staff. Some of the vehicles required to support Horizon Utilities' current distribution system are by design, larger; such as the 68 foot double bucket trucks required to reach longer pole lengths. Vehicles have been consolidated into the existing service centres as a result of amalgamations and mergers; creating traffic congestion, and an environment which is unsafe for employees and can cause damage to vehicles and equipment;
- Locker, washroom, and shower space for field staff was congested, requiring additional lockers to be located in hallways and nearby rooms. Plumbing fixtures and air systems required ongoing repairs and replacement as they had reached the end of their useful life;

- An elevator was required at the Vansickle Service Centre to conform to current OBC and AODA regulation; and

- The staircase at the Nebo Road Service Centre needed to be rebuilt to improve the safety of employees due to lack of fire exits.

Despite some identified structural deficiencies and end-of-life equipment and systems, in general, the buildings were found to be structurally sound.

Based upon the observations and recommendations of the Space Study, Horizon Utilities commenced renovations of the Head Office and Service Centre buildings to: begin the necessary refurbishment and upgrades of the building assets; address safety related deficiencies; achieve compliance with current building code requirements; rationalize workspace to improve productivity and employee engagement; and accommodate the needs of a growing workforce.

In order to validate the decision to undertake renewal and refurbishment investments in the existing buildings, Horizon Utilities considered the conceptual alternatives of: i) procuring a modern facility to replace the Head Office, Nebo Road and Stoney Creek Service Centres; or ii) building a new Head Office and Service Centre at a location appropriate to support its customers and employees.

It was determined that it would be difficult to procure an existing building which would be appropriate to fully provide for combined Head Office and Service Centre operations. Such centralized facilities would need to meet: i) the operational needs of the 363 employees collectively residing within and operating from Head Office and the Nebo Road and Stoney Creek Service Centres; and ii) the corresponding requirements for office space, fleet parking, warehouse space suitable for large items such as transformers and poles, and garages for fleet maintenance.

As part of the evaluation of a new centralized facility, consideration was also given to: the estimated expenditures related to the renovation of a newly procured facility; and the logistical challenges and business impacts inherent in a move to a new facility.

Horizon Utilities also reviewed the experience of Enersource Corporation, which procured and renovated a new Head Office building for a projected 189 employees in 2011. The Enersource 2012 Cost of Service application (EB-2012-0033) provides details of capital costs related to the procurement and renovation of the building, which aggregated approximately $20,000,000.

Horizon Utilities reviewed the experience of PowerStream Inc. as detailed in its 2008 Cost of Service application (EB-2008-0244). PowerStream Inc. constructed a modern Head Office for a subset of its office staff at a reported capital cost of $27,700,000, inclusive of property procurement expenditures.

Horizon Utilities' asset renewal strategy for the renovation and refurbishment of its head office and service centres (five buildings in total) and related systems is expected to aggregate $19,157,000 over eight years at an average cost of $158 per square foot, based on 121,305 total square feet. This option is prudent as compared to procurement and construction alternatives and allows Horizon Utilities to implement a paced plan of refurbishment and addition to rate base in order to balance rate payer and utility affordability.

Horizon Utilities' current Head Office and operational requirements for building space include 261,860 square feet of: office space; common areas; warehousing; fleet parking; and garage areas.

Horizon Utilities' building renewal strategy includes the reclamation of 40,295 square feet of under-utilized areas, reconfiguration, and standardization of office sizes in order to rationalize and provide for more productive work space.

The Space Study provided Horizon Utilities with an initial 5-year project plan, prioritized according to highest risk and greatest need. Work commenced in 2012 with the renovations of the Customer Connections work space at the John Street building; the provision of an elevator at the Vansickle Road Service Centre; and the reclamation of the third floor of the Hughson Street building to convert warehouse and storage space to usable office space.

Horizon Utilities undertook a series of specific studies to assess the health and condition of the buildings and related systems and security, as part of its continuous improvement efforts and to ensure that investments were prudent and prioritized.

BCA

A BCA for each of the main Horizon Utilities buildings and 23 substation buildings was conducted in 2013 by Evans Consulting Services, a leading firm in building assessments to identify structural and systems deficiencies and forecast required expenditures to assist with the development of a long term building asset strategy.

The BCA included: the identification of each building's physical conditions; its systems and equipment conditions; and recommendations to address deficiencies. The assessment also included a forecast of replacement costs for major building and system components based on the predicted life of an asset. The building components that were assessed included the structural interior and exterior elements, and electrical, fire and life safety, and HVAC systems.

The information collected during the BCA process provided Horizon Utilities with enhanced asset condition data and a refreshed view of corresponding long-term capital expenditure requirements. This further informs the buildings planning process undertaken by Horizon Utilities in the pursuit of efficient and prudent building asset management.

The BCA findings included:

- HVAC, fire and life safety, and lighting systems had reached end-of-life at all of the buildings, and were not designed to support the current number of employees or current technologies. On-going repairs, which increased system downtime, were becoming too costly to maintain corresponding systems and it was difficult to source replacement components. Over the period of 2012 and 2013, Facilities had responded to 1,719 calls related to heating and cooling system issues. Facilities staff assess each call and contract out the required repair work. The number of calls regarding heating and cooling issues will decrease, along with the third party costs required for repair, as the HVAC, fire and life safety, and lighting systems are replaced.

- Vehicle and equipment emissions were present in the air within some of the office environments such as at the John Street building lobby, the Vansickle Road Service Centre's second floor, and the Nebo Road Service Centre's mezzanine offices, which posed potential health concerns for employees;

- Hazardous materials, such as asbestos and mould, were present within some of the office environments;

- The building fire annunciator devices were at end-of-life, and additional units were required to achieve the audibility requirements as per the current OBC;

- [redacted];

- Renovations to building entrances and stairwells are necessary in order to meet current OBC requirements for all buildings;

- Building construction deficiencies, such as unsealed windows and uninsulated walls, were contributing to energy inefficiencies;

- The main vehicle exhaust systems at the fleet garages at the Vansickle and Nebo Road Service Centres were insufficient to remove vehicle exhaust from the work area;

- A number of fire and life safety-related deficiencies were identified including the need for fire dampers, fire rated walls to prevent fire from spreading, and the replacement of the existing fire rated doors and frames to comply with the OBC;

- Many components within electrical equipment and systems had deteriorated, were damaged, or were at end-of-life including receptacles, switches, light fixtures, conduit, wiring, panels and disconnects; and

- The Service Centres' interior and exterior overhead doors had reached end of life; maintenance and repairs had increased; and parts were becoming difficult to procure. These conditions increased downtime and created potential safety risks to employees if an unsecured door were to fall.

The BCA recommended total capital expenditure investments of $12,768,330 over 20 years to address the restoration of end-of-life assets. That report recommends the total capital expenditure over 2014-2019 period of $5,473,880. The Space Study recommends a total capital expenditure over a five year period of $10,382,000. The total recommended investment over five years of $15,855,880 is necessary to address operational deficiencies, building accessibility, the removal of hazardous materials, security, and air quality; and to replace assets which have reached end-of-life and ensure compliance with Ontario Building and Fire Codes.

Security Study

The Security Study was undertaken in 2013 by CAPSYS Integrated Technology Consultants. The scope included [redacted]

The replacements [redacted] are scheduled to begin in 2014 and continuing through to 2016.

Roof Assessment

In 2013, a rooftop assessment was conducted by Garland Canada Inc. with respect to the rooftops at each of the John Street building, Hughson Street building, Hughson Substation building, and parking garage. The consultant concluded that these rooftops had reached end-of-life and were in poor condition. These rooftops were originally installed in 1999.

There were visible signs of deterioration. The rooftop membranes were starting to de-granulate, reducing the strength and UV resistance of the rooftop. Some adjacent exterior walls were in very poor condition and required new cladding, stucco or coating. There were some blisters on the rooftops which are caused when air and/or air vapour is trapped. Previous repairs to the rooftops have degraded and water leaks have damaged the windows and floor walls below.

Window Assessment

The condition of the windows at the 55 John Street building was evaluated in a 2013 energy efficiency gap assessment conducted by independent consultant MMM Group Limited. MMM Group Limited and its subsidiaries/affiliates comprise a global firm with more than 50 offices in Canada and around the world. MMM Group is a partner of choice for major design-build and P3 transportation and building projects in Canada, the U.S. (through Lochner MMM Group), and around the world.

The assessment was conducted using visual inspections, air leakage testing, and building energy simulations. The testing concluded that the condition of the operable windows at the John Street location is poor. The windows are no longer weather resistant or energy efficient and allow cold drafts to enter the building in the winter. Heat convection during the summer months leads to air conditioning inefficiency and additional stress on HVAC systems. The windows collect frost on the inside in the winter which melts and damages interior walls and carpeting. The windows, installed in 1994, have reached end-of-life and require replacement in order to reduce energy costs and to maintain the comfort of the employees from a climate and noise perspective. Weather stripping was determined to be insufficient as identified through air leakage tests.[2]

Building Asset Management Plan

A building asset management plan was created to detail and prioritize the renovations that were required to renew critical building systems, ensure the health and safety of employees, and meet the capacity requirements of the current work force.

Horizon Utilities' original renovation plan was for five years, commencing in 2012, based on the results of the Space Study. The plan was expanded, based on the additional assessments completed in 2013, to ensure that all end-of-life systems were addressed as renovations were planned.

The building renovation plans were subsequently refined and aligned to long-term operational requirements as supported by the recommendations from the Space Study, the BCAs, the security reviews, and window and rooftop assessments.

The planning activities of the building renovation include the following major considerations:

- Building system demand;
- Building occupancy demand;
- Forecasted changes in employee headcount and office equipment requirements;
- Building equipment and systems failure reporting; and
- Operational performance planning.

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[2] Air leakage sampling testing conducted by Intertek was in accordance with the test methods outlined in ASTM E783-02 (Reapproved 2010), "*Standard Test Method for Field Measurement of Air Leakage Through Installed Exterior Windows and Doors*" at a pressure differential of 75 Pa.

The planned renovation projects will be reviewed annually and, as necessary, modified to incorporate any changes arising from new business requirements, asset and systems conditions, or regulations.

The forecast to renovate the 55 John Street and Hughson Street buildings and three Service Centres from 2012 to 2019 is $19,157,000. As discussed above, this compares favourably to published utility sector expenditures related to the construction or purchase of new office space.

Table 2-55 below identifies the material capital expenditures required for the building asset management plan from 2012 through to 2019.

Table 2-55 – Material Buildings Capital Expenditures 2012 – 2019

Buildings - Capital Expenditures $	2012 Actual	2013 Actual	2014 Bridge Year	2015 Test Year	2016 Test Year	2017 Test Year	2018 Test Year	2019 Test Year
Reporting Basis	*MIFRS*	*MIFRS*	*MIFRS*	*MIFRS*	*MIFRS*	*MIFRS*	*MIFRS*	*MIFRS*
Building Renovations - Vansickle Road	$ 460,000	$ 2,060,000	$ 1,300,000	$ -	$ -	$ -	$ -	$ -
Building Renovations - John and Hughson Streets	$ 1,307,000	$ 1,900,000	$ -	$ 2,000,000	$ 1,600,000	$ 2,200,000	$ 1,200,000	$ -
Building Renovations - Nebo Road	$ -	$ 1,530,000	$ 2,400,000	$ -	$ -	$ -	$ -	$ -
Building Renovations - Stoney Creek	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,200,000
Total Buildings Renovations $	**$ 1,767,000**	**$ 5,490,000**	**$ 3,700,000**	**$ 2,000,000**	**$ 1,600,000**	**$ 2,200,000**	**$ 1,200,000**	**$ 1,200,000**

Building Renovation Plans – Year over Year

All suppliers and contractors involved in the building renovations have been sourced and procured using the activities, practices and processes defined within Horizon Utilities' Corporate Procurement and Corporate Expenditure Approval Policies. The Corporate Procurement and Corporate Expenditure Approval Policies are provided in Exhibit 4, Tab 4, Appendix 4-8, and Exhibit 4, Tab 4, Appendix 4-9 respectively.

Procurement of services and materials are supported by an approved Purchase Order ("PO") prior to any commitments. A minimum of three quotes was obtained for each sub-contractor service per project to ensure that fair pricing was obtained, in accordance with Horizon Utilities' Procurement Policy. Sub-contractor selection was based on pricing, service provision, and availability.

Horizon Utilities forecasts that the building renovations as planned will cost on average $157 per square foot. Average renovation expenditures per square foot in the Hamilton and St. Catharines areas are generally in the range of $115 to $181 before consideration for material relocation expenses.

2010 Building Renovations – Capital $0

Horizon Utilities did not implement any building renovations in 2010.

2011 Building Renovations – Capital $0

Horizon Utilities did not implement any building renovations in 2011.

2012 Building Renovations – Capital $1,767,000

The building renovation plans commenced in 2012 with the three main projects that were identified to be of highest priority to the organization. These projects focused on health and safety deficiencies, the replacement of HVAC and fire and life safety systems, and compliance with OBC and AODA regulations.

Customer Connections Department Renovation (John Street)

The Customer Connections department is located on the first floor of the John Street building. The office staff was working in close proximity with live electrical testing equipment. The office space did not comply with the current OBC and AODA regulations, specifically with regard to a lack of washroom facilities. The air quality in the Customer Connections department was sub-standard due to the prevalence of vehicle emissions from the nearby parking and loading docks. The space in the Customer Connections department was not well utilized, and some staff were located on a different floor.

The warehouse office environment was renovated to include: renovated office space for employees; a separate climate controlled room for Metering Testing Equipment; washrooms in order for the new space to be compliant with the OBC; meeting facilities; new lighting; and the installation of new HVAC Systems to address the poor air quality. The renovations enabled the relocation of all Customer Connections staff to a single area to improve operational processes.

Reclaiming of Warehouse/Storage Space at the Hughson Building

The warehouse and storage space on the third floor of the Hughson Building was identified as an area that could be reclaimed for new office space which would address staff congestion.

The new office space was planned to house the Procurement workgroup. The Procurement team was located on the fourth floor of the John Street building, with six people situated in a single office with filing cabinets, and printing and fax machines. Procurement staff had 33 square feet per employee, which did not provide an adequate working environment. Horizon Utilities' standard work space is 56 square feet per employee.

Renovations to the third floor of the Hughson building included: the installation of washrooms, lighting and HVAC systems; and the replacement of the freight elevator with a passenger elevator.

Vansickle Road Service Centre – Phase 1

The Vansickle Road Service Centre did not meet OBC and AODA regulations, and safety concerns related to employee security were identified due to a lack of barriers to prevent public access to employees.

Renovations included the installation of a passenger elevator to comply with AODA legislation; a secure customer reception area; and the renovation of the lunchroom. The renovations were planned as the first phase of a larger project which would relocate the Customer Service Call Centre, and provide alternate back-up locations for the Control Room and IST systems.

2013 Building Renovations – Capital $5,490,000

Renovations completed in 2013 included: the second phase of the Vansickle Road Service Centre; the fourth floor of the John Street building; and the first phase of the Nebo Road Service Centre.

Vansickle Road Service Centre – Phase 2

The Vansickle Service Centre is comprised of two physical buildings. The north building contains the Utility Operations staff and a garage for vehicle and equipment. The second floor of this building was vacant and provided unused space within which staff could be consolidated.

The south Vansickle building is smaller and was the location of the Customer Service Call Centre and customer reception area. The two buildings are joined together by a walkway.

Consolidation of the staff into a single building reduced operating expenditures related to maintenance and repairs. The renovations included:

- the reclamation of approximately 900 square feet of mechanical room space which was transformed into office space for the Call Centre;

- the replacement of 22 electrical and HVAC systems that had reached end of life, with a high-efficiency system on the roof, which will reduce operating expenditures;
- removal of asbestos in the ceiling and around the plumbing; and
- the installation of new windows which were identified during the renovation process to be leaking.

Fourth Floor – John Street Building

Many components on the fourth floor of the John Street building were original as built in 1950. The Space Study identified a number of concerns including poor air quality, inadequate lighting, congested floor space, and a lack of compliance with current OBC and AODA regulations. There is no grandfathering for the AODA. As of January 1 2012, the AODA legally requires all organizations, both public and private, that provide goods or services either directly to the public or to other organizations in Ontario to provide accessible customer service to persons of all ability levels.

The renovations of the fourth floor included:

- the removal of large amounts of asbestos;
- the installation of proper fire barriers to meet current fire code; the installation of duct work to the HVAC systems to improve air quality;
- raising the ceiling to improve air quality and lighting; and
- re-designing the floor to create functional spaces for each workgroup. This included renovations to Horizon Utilities Control Room. The Control Room operates 24/7, is secured to limit access and, as a result, requires its own heating and cooling systems. After normal business hours, overall building systems shut down but the Control Room still requires proper heating, cooling, and air quality control. Operators are required to

stay in the Control Room for their shifts in order to respond promptly to calls and system emergencies and, as a result, kitchen and washroom facilities are required inside the Control Room secured facilities.

Nebo Road – Phase 1

The Nebo Road Service Centre was originally built in the 1980's. Deficiencies with regard to public and employee safety were identified in the Space Study, and systems were not compliant with current OBC and AODA regulations.

Phase 1 of the Nebo Road Service Centre renovations included:

- the expansion of the locker, washrooms, and shower space which was congested and inadequate to meet the needs of the current workforce;
- the disposal of hazardous materials including asbestos and mould that were found on the exterior walls during the demolition phase;
- the construction of an employee and customer entrance to improve employee, building and asset security; and
- the replacement of end-of-life fire and life safety systems to comply with current fire code regulations.

2014 Planned Building Renovations – Capital $3,700,000

Two main projects are planned for 2014 to address health and safety issues related to air quality at the Service Centres, reclaim unused spaces to address congestion, and to comply with current fire codes and the OBC.

Vansickle Road Service Centre – Phase 3

The Vansickle Road Service Centre was originally built in the 1970s. Deficiencies with regard to public and employee safety were identified in the Space Study, and fire and life safety systems were not compliant with current OBC and AODA regulations.

Phase 3 of the Vansickle Road Service Centre renovations will include:

- the expansion of the locker, washrooms, and shower space which is inadequate to meet the needs of the current workforce. Lockers are small and cannot accommodate the storage of Personal Protective Equipment ("PPE");
- the building of washroom facilities for female trade line maintainers to comply with OBC. Currently, female staff washrooms, lockers, and showers are located in trailers across from the fleet garage;
- the anticipated disposal of hazardous materials including asbestos and mould;
- the replacement of end-of-life fire and life safety systems to comply with current fire code regulations; and
- the connection of HVAC components to the main unit installed in Phase 2 to address identified air quality issues.

Nebo Road Service Centre – Phase 2

Phase 2 of the Nebo Road Service Centre project will include:

- the installation of electrical and fire and life safety systems to comply with current fire codes and OBC;
- the reclamation of the south mezzanine currently used as a warehouse and storage space to usable office space;
- the creation of a training space to increase tool time by reducing travel time required to attend training sessions at alternate locations;
- the implementation of an HVAC system to address air quality conditions which are currently compromised by vehicle emissions;

- the installation of lighting systems suitable for an office environment; and
- the creation of work spaces to accommodate the current workforce.

2015 Planned Building Renovations - $2,000,000

Two main projects are planned for 2015 to address congestion, consolidate work groups to improve organizational work flows, and to comply with current fire codes and the OBC.

Fifth Floor – John Street building

This project will consolidate IST staff which is currently housed in three different locations, and provide sufficient space for the Human Resources, Health and Safety, and Corporate Communications departments.

Hughson Substation – Phase 2

The project will include the reclamation of Hughson Substation building, which was an active distribution station prior to its planned decommissioning scheduled for 2014. This industrial space is more than 100 years old, and requires full restoration including:

- the removal of hazardous materials such as asbestos and mould;
- the installation of HVAC systems;
- the installation of life and safety support systems; and
- the installation of lighting systems suitable for an office environment.

The space will be converted into a large training room which will become the main corporate training room for John Street employees. This will reduce travel time for John Street employees who currently travel approximately 30 minutes or 20 km from John Street to the Stoney Creek Service Centre Training Room.

Reclamation of the industrial space is anticipated to be a capital expenditure of $1,500,000.

2016 Planned Building Renovations - Capital $1,600,000

The project planned for 2016 will focus on the second floor of the John Street building, which remains in similar condition to that originally constructed in 1950. The project will address employee security, safety, and deficiencies related to fire and OBC codes, air quality, and lighting.

Second Floor – the John Street building

The second floor of the John Street building will be renovated to consolidate Customer Service and CDM employees into contiguous workgroups for organizational efficiency and to improve employee security and safety by relocating certain Customer Service staff from the area adjacent to the customer lobby on the first floor.

The fire and life safety and electrical systems will be updated to comply with current fire codes and the OBC. All HVAC components will be replaced and redirected as required to ensure air quality meets appropriate standards.

2017 Planned Building Renovations - Capital $2,200,000

The renovation of the sixth floor of the John Street building is planned for 2017. This floor is virtually unchanged from its time of construction in the 1960s, with limited updates approximately twelve years ago.

The Space Study conducted in 2010 concluded that additional space was required at the John Street building to reduce the congestion and improve the work environment. Horizon Utilities reclaimed part of the 6th floor from the City of Hamilton Water Division to provide the additional space required. This space has been effectively used as “swing space” to support building renovation and renewal projects from 2012 to 2016. The swing space will be renovated to replace much of the electrical, mechanical, lighting systems when the building projects are complete. Building systems engineered and installed in the 1960s, are at end-of-life and cannot support the current occupancy demand. Renovations will also include removal of all existing walls, the remediation of hazard materials and expansion of the floor foot print to current space requirements.

Sixth Floor – the John Street building

The renovation of the sixth floor, which presently hosts certain members of the Executive Management Team and includes temporary swing space for re-located departments as renovation projects occur, will include:

- the creation of additional office space to address organizational congestion;
- the installation of HVAC and fire and life safety systems that are at end-of-life;
- the anticipated disposal of hazardous materials including asbestos and mould; and
- the creation of necessary meeting room space.

2018 Planned Building Renovations - Capital $1,200,000

The project planned for 2018 is the renovation of the basement and lobby of the John Street building, which is largely original to the 1950s building.

Basement / Lobby – the John Street building

The project will include the following:

- renovation of the locker, washroom, and shower space which is relatively unchanged from those originally constructed the 1950's building. These facilities have leaking plumbing and are unable to accommodate the size and needs of the current workforce;

- the removal of anticipated hazardous materials and the replacement of end-of-life HVAC and fire and life safety systems; and
- renovations to the public and customer entrance to improve the utilization of space and [redacted]

2019 Planned Building Renovations - Capital $1,200,000

One project is planned for 2019; primarily to address employee and public safety concerns at the Stoney Creek Service Centre and replace end-of-life systems.

Stoney Creek Service Centre

The Stoney Creek Service Centre is utilized as an outdoor trades training facility and is a service centre for the east end of Horizon Utilities' service territory.

The project will include:

- the renovation of the locker, washroom, and shower space to replace end-of life assets;
- the replacement of end-of-life plumbing, lighting, and HVAC;
- the replacement of fire and life support systems;
- [redacted]
- The creation of a centralized storage location for records retention and storage of furniture and assets. This would address improper storage of equipment at the John Street building and resolve compliance issues with fire codes and building codes for the John Street building and the Stoney Creek locations.

These renovations will support the needs of the current and future workforces, and improve employee safety due to the renewal of fire and life support systems.

Additional Buildings Projects

The BCA, security studies and window and roof assessments identified a number of major systems and assets that are at end-of-life and require replacements or upgrades including: building security; the roof at the John Street and Hughson Street buildings; the John Street building windows; and a back-up emergency generator at the Nebo Road Service Centre.

The four projects are planned between 2014 and 2018 at a total capital expenditure of $2,900,000 as provided in Table 2-56 below. Horizon Utilities has scheduled the projects as multi-year initiatives in order to decrease the organizational impacts, address immediate risks associated with end-of-life assets, and manage the pace of capital investment in order to balance rate payer and utility affordability.

Table 2-56 - Additional Material Buildings Projects

Buildings - Capital Expenditures $	2014 Bridge Year	2015 Test Year	2016 Test Year	2017 Test Year	2018 Test Year	2019 Test Year
Building Security Replacement	$ 400,000	$ 300,000	$ 200,000	$ -	$ -	$ -
John Street Roof Replacement	$ -	$ 900,000	$ -	$ -	$ -	$ -
John Street Window Replacement	$ -	$ 300,000	$ 300,000	$ 200,000	$ -	$ -
Nebo Road Emergency Backup Generator	$ -	$ 300,000	$ -	$ -	$ -	$ -
Buildings Capital Expenditures	**$ 400,000**	**$ 1,800,000**	**$ 500,000**	**$ 200,000**	**$ -**	**$ -**

All suppliers and contractors involved in the additional projects will be sourced and procured using the activities, practices and processes defined within Horizon Utilities' Corporate Procurement and Corporate Expenditure Approval Policies. The Corporate Procurement and Corporate Expenditure Approval Policies are provided in Exhibit 4, Tab 4, Appendix 4-8, and Exhibit 4, Tab 4, Appendix 4-9 respectively. Horizon Utilities has provided a description of its procurement of services and materials at Tab 6, Schedule 1 of this Exhibit.

Building Security Replacement

[redacted]

[redacted]

[redacted] is a multi-year project forecast to be $900,000 over [redacted]

Roof Replacement

The rooves at the John Street and Hughson Street buildings have surpassed end-of-life as per the Roof Assessment, provided as Appendix N of the DSP, and require replacement. The roof was last replaced in 1999 and, despite annual maintenance, leaks have caused damage to the floors below.

The replacement of the roof is planned for 2015 at a capital expenditure of $900,000. The capital expenditure includes repair of surrounding walls, which are damaged, and the cost of replacement and expansion of the roof railing to ensure compliance with the OBC. The forecast is based on $18 per square foot, which is consistent with industry comparators. Horizon Utilities will conduct a Request for Proposal ("RFP") to obtain competitive pricing in accordance with Horizon Utilities' procurement practices as defined within its Procurement Policy.

Window Replacements

The windows at the John Street building, which were installed in 1994, were assessed by the MMM Group Limited in 2013. The assessment is provided as Appendix M of the DSP.

The windows are reaching end-of-life, and have been identified to be in very poor condition and in need of replacement. The condition of the windows is discussed in further detail in Tab 6, Schedule 1 of this Exhibit.

The replacement of the windows is forecast at $800,000 in capital expenditures between 2015 and 2017.

Nebo Road Emergency Back-up Generator

Nebo Road, Horizon Utilities' largest Service Centre, supports all customers in the Central and West Hamilton service area and is the Emergency Control Centre for the outside operations during emergencies. Horizon Utilities has experienced outages to the Nebo Service Centre during large scale outages, with the result that the dispatching of emergency crews and contractors was impaired. Portable generators did supply partial power to the building for lights and gas pumps, but major electrical equipment such as overhead cranes and fleet hoists were not in service. The use of portable generators is no longer an option due to their non-conformance with safety regulations.

The Nebo Road electrical service was evaluated in 2013 by T. Lloyd Electric, a leading full service electrical contractor, which concluded that, in order to safely connect a generator to power up the Service Centre in the event of a power failure, Horizon Utilities would need to re-work the existing switch gear and install an automatic transfer switch for the new generator.

The report issued by T. Lloyd Electric recommended the installation of a 300kW generator to provide permanent back up power to the facility.

The cost to install a new generator and associated equipment is forecast at $300,000 in 2015.

Fleet

Horizon Utilities owns and operates a fleet of approximately 189 vehicles including 45 trailers; garages for the fleet are located at the Nebo Road and Vansickle Road Service Centres.

Fleet Maintenance Processes

The maintenance of a reliable fleet is essential to the efficiency and productivity of Horizon Utilities' workforce. Horizon Utilities performs the majority of basic maintenance and repairs in-house. This saves both time and cost associated with vehicles being sent out for service. However, specialty repairs such as those related to body work, engine re-builds, and windshield replacements that require specialized tools, and facilities and experienced specialized technicians, are outsourced to local repair shops. The labour associated with this outsourced work is covered under warranty should an issue arise subsequently related to the workmanship. Horizon Utilities does not have the in-house expertise to perform specialty repairs cost-effectively. Horizon Utilities utilizes its IFS ERP fleet management module to schedule preventative maintenance and inspection requirements and to log all vehicle maintenance and repair activities. Preventative maintenance and inspections are carried out in accordance with vehicle manufacturer guidelines and all general and industry specific requirements such as those prescribed by the:

- Ontario *Highway Traffic Act*;
- Ontario Drive Clean program;
- Canadian Motor Vehicle Safety Standards ("CMVSS");
- Motor Vehicle Inspection Station ("MVSS") requirements;
- Electrical and Utility Safety Association ("E&USA Rule Book"); and,
- Horizon Utilities Health and Safety and Environment policies.

Fleet Asset Optimization Measures

Horizon Utilities has implemented a number of technologies and processes to optimize the availability, reliability and utilization of its fleet assets.

The optimization measures include:

- the utilization of an electronic fleet and fuel management system to monitor and manage fuel usage;
- where practical, the sharing of vehicles and trailers between Service Centres to reduce unnecessary duplication of assets; and
- analysis of the Global Positioning System ("GPS") data which includes engine hours, power take-off ("PTO"), engine idling hours, traffic patterns, utilization, and mileage to determine the optimal maintenance scheduling.

Fleet Replacement Plan

Horizon Utilities has a six year Fleet Replacement Plan which is updated annually. The Fleet Replacement Plan is provided as Appendix O in the DSP.

The Fleet Replacement Plan provides direction for the management of the fleet inventory including condition assessment, based upon: vehicle class; vehicle specification; system requirements; regulation changes; organizational needs; employee safety; and environmental risks.

Horizon Utilities' fleet replacement expenditures are required to maintain vehicles and associated equipment, such as trailers, on a sustainable basis in support of safe, reliable, and responsive customer service.

Horizon Utilities has replacement assessment criteria for each classification of fleet assets; specifically, light duty vehicles, heavy duty vehicles, and trailers. The assessment considers: the general condition of the asset; its mileage; engine hours; and the years of service of the vehicle to determine whether a vehicle should be replaced.

The replacement criteria for the fleet is provided in Table 2-57 below and is a combination of a number of standards as referenced in the Fleet Replacement Plan filed as Appendix O in the DSP.

Table 2-57 - Fleet Replacement Assessment Criteria

Fleet Class	Replacement Assessment Criteria
Light Duty Vehicles	Assessed at 6 years and every year after, and/or high mileage (excess of 150,000 km)
	Typical replacement schedule: 6 to 8 years
Heavy Duty Vehicles	Assessed at 11 year service, and every year after, and/or high mileage (excess of 200,000 km)
	High engine hours (excess of 15,000 engine hours)
	Typical replacement schedule: 16 to 19 years
Trailers	Trailer replacement will follow the same core principles as the vehicle replacement criteria with the following differences:
	i) When assessing trailer conditions, trailers will be refurbished rather than replaced
	ii) When trailers cannot be refurbished due to application change or condition, trailers will be flagged for replacement

The fleet replacement assessments are completed annually or as required by the mechanics, who provide recommendations to the Fleet Manager. The Fleet Manager reviews the recommendation in conjunction with the vehicle utilization and the needs of the organization. An evaluation is made as to whether the vehicle should be retained, re-allocated, refurbished, or replaced. If the decision is that the vehicle should be replaced, an evaluation occurs to determine if the asset should be replaced with the same class of vehicle or a different vehicle configuration based on the current and future needs of the workforce.

Vehicles are refurbished whenever possible, in particular for larger vehicles such as bucket trucks and digger and derrick trucks, due to the high cost of replacement. Safety, operational requirements and financial impact are key considerations.

Horizon Utilities changed the fleet replacement assessment criteria in 2012 to extend the service life for Light Duty and Heavy Duty vehicles by an additional year in order to reduce the overall fleet capital budget with minimal impact to vehicle availability and repair cost.

The replacement cycle for Light Duty Vehicles is six to eight years as identified in Table 2-57 above. Horizon Utilities has 93 Light Duty Vehicles, of which 45 or 48% are currently eight years and older.

The replacement cycle for Heavy Duty Vehicles is sixteen to nineteen years as identified in Table 2-57 above. Horizon Utilities has 39 Heavy Duty Vehicles, of which 8 or 21% will be nineteen years or older within the next five years. In addition, some vehicles will need to be replaced prior to the end of their useful life, because they have either exceeded 200,000km in mileage or 15,000 engine hours.

Operation of vehicles past their useful life results in increased expenditures related to operating and maintenance. When a vehicle requires frequent maintenance, it is unavailable for use and impacts crew work and scheduled projects. Vehicle maintenance and repair costs have increased by 37% (or a Compound Annual Growth Rate of 7%) from 2009 to 2014 as identified in Table 2-58 below; an indication that fleet cannot continue to operate reasonably past its recommended useful life.

Table 2-58 - Vehicles Maintenance and Repairs Expenditures 2009-2014

Location	2009 Actual	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Bridge Year
Hamilton	$ 577,384	$ 521,762	$ 565,685	$ 826,845	$ 651,499	$ 790,000
St. Catharines	$ 127,786	$ 148,706	$ 172,185	$ 159,987	$ 194,598	$ 175,000
Total	**$ 705,170**	**$ 670,468**	**$ 737,870**	**$ 986,832**	**$ 846,097**	**$ 965,000**

Horizon Utilities has used the fleet asset replacement criteria to identify 24 light and heavy duty vehicles that require replacement between 2015 and 2019 as identified in Table 2-59 below:

Table 2-59 - Light and Heavy Duty Vehicle Proposed Replacement Schedule

Vehicle	Model Year	Proposed Replacement Year
Unit 246 – Heavy Duty Pickup	1998	2015
Unit 220 – Double Bucket	1997	2015
Unit 296 – Passenger Vehicle/Cargo Van	2002	2015
Unit 292 – Low Duty Pickup	2002	2015
Unit 380 – Low Duty Pickup	2001	2015
Unit 234 – Passenger Vehicle/Cargo Van	1999	2015
Unit 213 – Heavy Duty Pickup	2000	2015
Unit 298 – Heavy Duty Pickup	2000	2016
Unit 241 – Passenger Vehicle/Cargo Van	1998	2016
Unit 248 – Knuckle Crane Truck	1997	2016
Unit 217 – Single Bucket	2000	2016
Unit 277 – Single Bucket	2000	2017
Unit 267 – Heavy Duty Pickup	1999	2017
Unit 330 – Cable Pulling/Digger Derrick Truck	2003	2017
Unit 293 – Heavy Duty Pickup	2000	2017
Unit 279 – Step Van	2001	2017
Unit 327 – Passenger Vehicle/Cargo Van	2002	2017
Unit 286 – Single Bucket	2002	2018
Unit 287 – Single Bucket	2002	2018
Unit 295 – Heavy Duty Pickup	2003	2018
Unit 291 – Heavy Duty Pickup	2003	2018
Unit 257 – Single Bucket	1999	2019
Unit 285 – Single Bucket	2002	2019
Unit 281 – Step Van	2001	2019

The actual and forecast costs for Horizon Utilities' vehicle replacement for the 2011 to 2013 actuals and the 2014 to 2019 forecast are identified in Table 2-60 below.

Table 2-60 - Vehicle Replacement

Year	$
2010 Actual	1,590,516
2011 Actual	1,033,975
2012 Actual	1,057,410
2013 Actual	36,365
2014 Bridge Year	785,000
2015 Test Year	778,000
2016 Test Year	780,000
2017 Test Year	775,000
2018 Test Year	785,000
2019 Test Year	785,000

Horizon Utilities plans to reduce the annual cost of vehicle replacement as identified in Table 2-60 above. Fleet expenditures of $1,000,000, planned for 2013 were reassigned to the buildings renewal initiatives. The budget for 2014 to 2019 has been reduced by an additional $300,000/year on average to mitigate necessary expenditures for building renewal and to align with Horizon Utilities' vehicle replacement assessment criteria, revised in 2012. Horizon Utilities continues to proactively address its aging fleet and has taken the following actions to ensure its fleet continues to be reliable, available, and safe:

- Extended the replacement age criteria by one year in 2012 as identified in the Fleet Replacement Plan attached as Appendix O of the DSP;
- Extended the hours of fleet operations in 2012, which allowed mechanics to perform maintenance and emergency repairs after business hours to ensure the next day availability of vehicles. These extended hours have also decreased overtime costs within the fleet services department. These productivity savings are discussed in further detail in Exhibit 4, Tab 3, Schedule 4.
- The budget for the 2014 Bridge Year and the 2015 to 2019 Test Years does not include incremental additions to the overall fleet, but only replacements for end-of-life vehicles;

- Horizon Utilities will reassess and test the components of each heavy duty vehicle and will replace components of the vehicle to extend its life, thereby deferring vehicle replacement to a later date, starting in 2014; and
- Used and/or demo vehicles will be sourced to reduce vehicle replacement costs, starting in 2015.

Information Systems Technology Capital

Horizon Utilities' capital investment in Information Technology is focused on the delivery of processes, technology, and systems that support five key strategic areas:

- **Friction Attrition**: The reduction of the operating cost base through replacement of inefficient paper-bound and electronic processes and activities through broad adoption of technology;
- **Enterprise Telecommunications Management:** Use of robust, scalable, enterprise-wide telecommunications standards, processes and tools to cost-effectively and securely drive business and operations processes. This includes the pervasive use of mobile technologies;
- **Enterprise Information Management:** Use of advanced information management techniques and technologies to effectively manage ever increasing and large volumes of data in order to provide business and operational analytics that improve integration and management of key business processes;
- **Lifecycle Upgrades of Major Enterprise Business System:** Planned upgrade of major business systems (IFS Enterprise Resource Planning ("ERP") system and Daffron Customer Information System ("CIS") to mitigate risks related to age of systems and ongoing vendor support; and
- **Lifecycle Upgrades and/or New Implementations of Enterprise Operations Systems:** Planned upgrade of key operations systems (GIS, SCADA) to mitigate risks related to the age of systems, ongoing vendor support, and to provide new or improved modern capabilities for key operations processes such as Outage Management.

Capital investments must be made to ensure a robust, scalable and secure information technology foundation. These investments are grouped into the following two areas:

- **eFrastructure -** Providing an integrated, cost-effective infrastructure in terms of:
    - Technology components;

    - Core business and operations applications;
    - Common, interchangeable, navigable and reusable data; and
    - Flawless infrastructure operations.

- **IST Capability - Development and/or restructuring of the IST function through:**
    - Implementation of new tools and development of new competencies required to support new technologies;
    - Standardized and integrated services;
    - More efficient utilization of outside services, such as, managed services and cloud computing;
    - Streamlined decision processes; and
    - Simplified IST administrative processes.

The two significant upgrades to enterprise-wide systems are identified below.

IFS ERP Upgrade 2013-2015

This is an enterprise-wide project commencing in 2013 through to 2015 to upgrade Horizon Utilities' ERP system from IFS version 7.3 to version 8.1. This is a major upgrade to the Horizon Utilities ERP system installed in 2007-2008. This project was required to eliminate operational risks due to software, database and operating systems that will not be supported by respective vendors beyond 2014. The upgrade is also required to provide an updated application for the implementation of redesigned, optimized and/or new business processes that will allow Horizon Utilities to deliver planned productivity improvements. These productivity savings are discussed in further detail in Exhibit 4, Tab 3, Schedule 4.

This project was planned in three phases in order to effectively manage the internal resources requirements and impact on the business:

- Phase 1 - Upgrade from IFS 7.3 to IFS 8.1 (Go Live was September 2013);
- Phase 2 - Remove customizations that are now part of core functionality (Go Live phased throughout 2014); and

- Phase 3 - Process redesign/optimization (Go Live phased by process throughout 2015).

The costs associated with each phase of the project are identified in Table 2-61 below:

Table 2-61 - ERP Upgrade Capital Expenditures

Phase	Year	$
1	2013 Actuals	$ 1,225,762
2	2014 Bridge Year	$ 980,260
3	2015 Test Year	$ 1,382,600
Total ERP Upgrade		**$ 3,588,622**

The justification for this project by phase is provided below. Further justification is provided in Section 3.5.3 of the DSP.

<u>Phase 1- Upgrade from IFS version 7.3 to IFS version 8.1 (completed in 2013)</u>

This phase was operationalized in September 2013 at a capital cost of $1,225,762. This phase was required to eliminate operational risks related to software, database and operating systems that will not be supported by the respective vendors beyond 2014.

Other benefits realized during this phase were:

- A reduced capital expenditure of approximately $450,000 by migrating the ERP environment to a cloud-based managed service from IFS thereby eliminating the need to purchase and implement new in-house servers;

- A reduction in annual operating expenditure requirements of approximately $172,000 per year achieved primarily through the elimination of one technical support FTE position as IFS provides these services as part of the managed services.

<u>Phase 2 – Removal of Custom Modifications (planned for 2014)</u>

This phase is focused on the removal of custom modifications from the Horizon Utilities' IFS implementation. The budget for this phase of the project is $980,260.

The justification for this phase is:

- A reduction in ongoing annual software maintenance related to custom modifications of approximately $50,000 per year;

- Annual future cost avoidance of approximately $40,000 related to current modifications for which IFS has not yet started billing Horizon Utilities;

- A reduction in future upgrade costs by not having to migrate custom modifications to new versions. IFS, the software development company, has stated that the next major upgrade of the application will require the rewrite custom modifications as the customization platform will change. The cost of rewriting Horizon Utilities' custom modifications during the next upgrade is estimated at $658,000, if custom modifications are not otherwise removed – this represents a recurring opportunity for savings at each following major upgrade. The next major upgrade is planned for 2018;

- Removal of the IFS custom modifications to establish an IFS ERP system foundation upon which to cost-effectively redesign and optimize business processes using core functionality in the application.

<u>Phase 3 – Business Process Redesign and Optimization (planned for 2015)</u>

This 2015 initiative is the third and final phase of an enterprise-wide project that commenced in 2013 to upgrade Horizon Utilities' ERP system from IFS version 7.3 to version 8.1 and to enhance the ERP system. The objective for this phase is the redesign, optimization and implementation of new business processes using features and functions available in IFS version 8.1 to deliver annual operational efficiencies and staff productivity improvements of approximately $703,500 as identified in Exhibit 4, Tab 3, Schedule 4. Horizon Utilities will achieve a lower cost per transaction and expand staff capacity without increasing headcount. Horizon Utilities has also included further details regarding this initiative in Appendix A of the DSP which is included as Appendix 2-4 of this Exhibit.

Horizon Utilities is planning a subsequent ERP upgrade in 2018 as identified below.

2018 IFS ERP Upgrade

This is an enterprise-wide project in 2018 for the lifecycle upgrade of Horizon Utilities' ERP system from IFS version 8.1 to the then current vendor supported version. This is a major upgrade to the IFS ERP system which was last upgraded in 2013. This project is required to mitigate operational risks dependent on software not supported by the vendor. This project will be a straight migration of functionality to the new version.

The estimated capital expenditure for this project in 2018 is $1,225,000 with a target implementation date of September 2018.

Horizon Utilities has provided the justification for this project in Appendix A of the DSP which is included as Appendix 2-4 of this Exhibit.

GIS Renewal

The implementation of the GIS system is a multi-year project that commenced in 2012 and will continue into 2015. The total investment is $3,985,026 and will be implemented over the period of 2012 - 2015 as identified in Table 2-62 below.

Table 2-62 – GIS Capital Expenditures by Year

Year	$
2012 Actuals	$ 807,000
2013 Actuals	$ 1,103,442
2014 Bridge Year	$ 1,869,308
2015 Test Year	$ 205,276
Total GIS	**$ 3,985,026**

Horizon Utilities will continue to enhance the customer value proposition through the convergence of Operations and Customer Service systems and expand upon Horizon Utilities' vision of customer service excellence over the next five years. The GIS/OMS systems will be the foundational building block for these integration efforts.

The GIS tracks and maintains the geo-spatial location of distribution assets along with related age, health, and maintenance data. The data warehoused within GIS is critical to supporting asset management, engineering, and construction. GIS is also the design platform utilized for engineering plans. GIS is a foundational database system providing core functionality required to achieve enterprise level data management and analysis including distribution system investment optimization.

Horizon Utilities' current GIS System, CableCad, was selected eighteen years ago to meet departmental needs at that time. The GIS is a critical system which supports Asset Management, Capital Design, Field Operations, and Asset Locates. Although the system has been enhanced over the years by the manufacturer and by Horizon Utilities' staff, CableCad remains a departmental level solution. It is clear today that Horizon Utilities cannot use its current technology to satisfy the information needs of Horizon Utilities at an enterprise level. Horizon Utilities' current GIS has reached end-of-life and the vendor will not support enterprise level upgrades. The current GIS will not be operable on Horizon Utilities' operating systems within two years.

The following daily operational activities, required to support the distribution system, are dependent on a functioning GIS:

- Engineering design of capital and maintenance projects;
- Production of construction drawings and plans for construction and maintenance activities;
- Ability to support underground cable locates;
- Asset data for asset management purposes; and
- Production of maps for control and operation of the distribution system.

Horizon Utilities will not be able to execute the above-mentioned critical functions or adopt some of the necessary strategic future initiatives in the absence of a functioning contemporary GIS.

An Outage Management System ("OMS') cannot be implemented with the current GIS system. The implementation of Mobile Applications and Work Management systems will be expensive and less effective without the use of modern open architecture GIS technologies that are specifically designed for enterprise level interoperability.

The primary benefits of the GIS upgrade are:

- sustainment and enhancement of asset data;
- mitigation of a material risk related to a foundational system that is no longer supported and at the end of its useful life; and
- interoperability and interfacing with other key business systems to enhance investment optimization through more informed decision making.

<u>OMS</u>

OMS comprises technology and systems to assess, predict, and manage outages as well as to enable bi-directional communication channels with customers to provide greater transparency into system operations. The GIS is a necessary pre-requisite system to enable an OMS. A basic requirement for an OMS is an understanding of the nature and location of distribution system assets which is only made available digitally through a GIS system.

The OMS receives information from a variety of sources such as: GIS; Smart Meters through the AMI; the Interactive Voice Response system ("IVR") (i.e., customer calls); and the CIS. Ultimately, the OMS monitors for an actual or likely outage as a result of status information from these sources. The OMS reacts to this information by predicting potential causes and identifying the source (e.g., fuse, transformer, switch) and location (e.g., street, pole number) of an outage. Horizon Utilities is then able to react in a timely and precise manner by dispatching crews for outage resolution and communicating with customers on the nature and expected duration of such.

The principal benefits derived from the implementation of OMS are as follows:

- a meaningful reduction in the duration of service outages for customers;
- proactive customer communication on outages (i.e., posting on the Horizon Utilities' website, recorded message on the IVR, and/ or e-mail/ telephone contact with customer in advance of the customer calling us to identify their outage;

- improved productivity as power outages can be identified without sending a crew to investigate;
- improved productivity as a result of the elimination of the current manual process of entering outage data from SCADA into CIS and other systems to manage outages under the status quo; and
- improved productivity due to the consolidation of multiple operating maps into a single map in OMS.

Vendor Selection Process

Proposals were issued and received according to Horizon Utilities' Procurement Policy, from three bidders. The functional and financial evaluations of the RFP responses were completed independently of each other. An evaluation team completed functional and financial reviews of RFP responses. Each vendor was invited to present a demonstration to the evaluation team. Site visits to other Local Distribution Companies ("LDC(s)") using respondent vendor technologies were undertaken to validate claims made during the vendor demonstrations.

Evaluations were combined and then jointly reviewed to discuss the differences between respective rankings. Intergraph was the unanimous choice of the evaluation team as the preferred vendor based on the following objective criteria:

- Company background, capabilities, expertise and experience;
- Proven experience of proposed personnel and ability to have qualified personnel in place to undertake the project;
- Ability of proposed solution to meet Horizon Utilities' in-scope enterprise business requirements;
- Ability of proposed solution to meet Horizon Utilities' longer term strategic needs;
- Ability of provider to convert legacy GIS data to proposed enterprise system;
- Proven/demonstrated system integration capabilities;

- Proven/demonstrated capabilities of system functionality;
- Experienced and satisfaction level of existing customers with same or similar installations;
- Acceptance and compliance with all Commercial Conditions;
- Cost, terms of payment and other aspects of the relationship that concerns financial arrangements;
- Ability to meet delivery schedule requirements;
- Quality and completeness of submission; and
- Cost Evaluation based on costs to include:
    - hardware, software and data migration;
    - maintenance for in scope software;
    - future requirements (OMS, CYME, etc.); and
    - maintenance for future software.

PLANNING

Horizon Utilities is filing its consolidated DSP as a stand-alone document which includes all elements of the DSP as Appendix 2-4 of this Exhibit in accordance with the Chapter 2 Filing Requirements. Horizon Utilities has organized its information using the headings indicated in the Chapter 5 Requirements.

REQUIRED INFORMATION

Overall Summary of Capital Expenditures

Horizon Utilities carefully manages its capital expenditures with a focus on the continued safe, reliable, and cost-effective operation of its distribution system. Substantial investment in certain asset categories is required to deliver service quality and reliability.

Horizon Utilities' capital expenditure summary is provided in Table 2-63 below. This table provides an overall summary of capital expenditures for the past four historical years, the 2014 Bridge Year and the 2015 to 2019 Test Years. The 2011 actual results have been provided on both a CGAAP and MIFRS reporting basis for comparative purposes. Horizon Utilities' capital expenditures in the 2015 Test Year are expected to be $39,939,967.

Table 2-63 – Appendix 2-AB Capital Expenditure Summary

First year of Forecast Period: *2014*

CATEGORY	Historical Period (previous plan[1] & actual)																		Forecast Period (planned)				
	2010 (CGAAP)			2011 (CGAAP)			2011 (MIFRS)			2012 (MIFRS)			2013 (MIFRS)			2014 (MIFRS)			2015	2016	2017	2018	2019
	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		13,558	--		8,914	--		5,629	--		6,602	--		6,369	--	7,540			8,243	8,472	7,896	8,092	8,273
System Renewal		14,082	--		22,475	--		17,171	--		14,091	--		18,425	--	15,372			18,070	28,294	33,168	33,208	34,706
System Service		3,583	--		3,125	--		2,374	--		2,885	--		2,151	--	4,101			4,140	295	535	2,032	2,057
General Plant		6,208	--		4,584	--		4,584	--		8,748	--		12,559	--	10,760			9,487	5,887	5,827	5,611	6,236
TOTAL EXPENDITURE BEFORE SMART METERS	**-**	**37,432**	**--**	**-**	**39,098**	**--**	**-**	**29,758**	**--**	**-**	**32,326**	**--**	**-**	**39,505**	**--**	**37,773**			**39,940**	**42,948**	**47,426**	**48,943**	**51,272**
Smart Meter Implementation		-			-			-			23,278			-		-			-	-	-	-	-
TOTAL EXPENDITURE INLCUDING SMART METERS	**-**	**37,432**	**--**	**-**	**39,098**	**--**	**-**	**29,758**	**--**	**-**	**55,604**	**--**	**-**	**39,505**	**--**	**37,773**	**-**		**39,940**	**42,948**	**47,426**	**48,943**	**51,272**
Hydro One Contribution		-			-			-			10,000			-		-			-	-	-	-	-
TOTAL EXPENDITURES	**-**	**37,432**	**--**	**-**	**39,098**	**--**	**-**	**29,758**	**--**	**-**	**65,604**	**--**	**-**	**39,505**	**--**	**37,773**	**-**		**39,940**	**42,948**	**47,426**	**48,943**	**51,272**
Change in WIP		- 2,841			743			743			4,654			- 1,597		2,019			175	-	-	-	-
TOTAL ADDITIONS	**-**	**34,590**	**--**	**-**	**39,841**	**--**	**-**	**30,501**	**--**	**-**	**70,258**	**--**	**-**	**37,908**	**--**	**39,792**	**-**		**40,115**	**42,948**	**47,426**	**48,943**	**51,272**
System O&M		18,742			19,654			n/a			27,755			29,928		33,776			34,571	35,504	36,355	37,337	38,084

Notes:
1. 2013 values include 12 months of actuals
2. 2014 values include 12 months of forecast

Notes to the Table:
1. Historical "previous plan" data is not required unless a plan has previously been filed
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. histrical budgets by category
n/a

Notes on year over year Plan vs. Actual variances for Total Expenditures
n/a

Notes on Plan vs. Actual variance trends for individual expenditure categories
n/a

Explanatory Notes on Variances in Capital Expenditure Summary

Horizon Utilities has completed Appendix 2-AB in accordance with the Chapter 2 Filing Requirements and Chapter 5 Requirements. Historical prior plan data has not been provided since a DSP has not previously been filed with the Board. Horizon Utilities has provided a summary of Appendix 2-AB by category below.

<u>System Access</u>

System Access investments are comprised of projects outside of Horizon Utilities' control that are required to meet customer service obligations in accordance with the DSC and Horizon Utilities' Conditions of Service.

These projects include connecting new customers; metering; building new subdivisions; and relocating system plant for roadway reconstruction work. Horizon Utilities uses an economic evaluation methodology prescribed in the DSC to determine the level, if any, of capital contributions for each project; with such levels incorporated into the annual capital budget. These investments are typically a high priority, cannot be deferred and must proceed as planned.

Historical year over year variances in 2011, 2012 and 2013 are primarily due to increased road relocations for municipalities and the connection of Municipalities, Universities, Schools and Hospitals ("MUSH") sector customers in Hamilton and St. Catharines.

The level of system access expenditures in each of 2010 to 2013 historical years was as follows:

- 2010 actual (CGAAP) was $13,558,203, net of capital contributions of $8,512,542.
- 2011 actual (MIFRS) was $5,629,314, net of capital contributions of $4,165,260. The decrease from 2010 of $7,928,889 was due to the expensing of overhead costs previously capitalized under CGAAP, and a decrease in system access projects. The change to the capitalization of overhead costs as a result of the transition to IFRS is discussed in further detail in Tab 6, Schedule 5 of this Exhibit.

- The 2012 actual, excluding the Smart Meter implementation, was $6,602,316, net of capital contributions of $9,810,885. The increase of $973,003 from 2011 was due to an increase in road relocation projects. The 2012 expenditures also included the addition of $23,277,588 related to the Smart Meter Implementation. Horizon Utilities substantially completed its mass deployment of Smart Meters in 2009 and, as at the end of 2011, had installed Smart Meters for 229,322 customers or 98.0% of all metering points. Further details are provided in Tab 1, Schedule 1, page 6 of this Exhibit.

- The 2013 actual was $6,369,274, net of capital contributions of $6,605,934. The decrease of $233,043 from 2012 was due to a reduction in road relocation projects partly offset by an increase in the number of customer connections projects.

The level of system access expenditures from the 2014 Bridge Year to the 2019 Test Year is as follows:

- The forecast for the 2014 Bridge Year is $7,539,601, net of capital contributions of $4,473,000. The increase from 2013 is $1,170,327, primarily due to an increase in meters of $840,397, an increase in road relocation projects and customer connections. The justification for the forecast for road relocation projects and customer connections is provided on pages 21 and 19, respectively, of Tab 6, Schedule 3 of this Exhibit.

- The forecast for the 2015 Test Year is $8,242,598, net of capital contributions of $4,633,000. The increase from 2014 of $702,997 is primarily due to an increase in road relocations, partly offset by a decrease in customer connections.

- The forecast for the 2016 Test Year is $8,471,952, net of capital contributions of $4,654,000. The increase from 2015 of $229,354 is primarily due to an increase in road relocation projects and customer connections.

- The forecast for the 2017 Test Year is $7,896,202, net of capital contributions of $4,677,000. The decrease from 2016 of $575,750 is primarily due to a decrease in road relocation projects.

- The forecast for the 2018 Test Year is $8,091,602, net of capital contributions of $4,700,000. The increase compared to 2017 of $195,400 is primarily due to road relocation expenditures.

- The forecast for the 2019 Test Year is $8,273,338, net of capital contributions of $4,730,000. The increase compared to 2018 of $181,736 is primarily due to road relocation expenditures.

System Renewal

System renewal investments comprise the replacement of aging equipment and/or refurbishment of distribution assets.

The level of system renewal expenditures in each of the 2010 to 2013 historical years was as follows:

- 2010 actual (CGAAP) was $14,082,166;

- 2011 actual (MIFRS) was $17,170,921. The increase from 2010 of $3,088,755 was due to a higher level of investment in in the 4kV and 8kV Renewal Program, partly offset by a decrease in the level of capitalized overhead costs due to the transition to IFRS. Further discussion of overhead costs and the impact of the transition to IFRS has been provided in Tab 6, Schedule 5 of this Exhibit and Exhibit 6, Tab 2, Schedule 1. The 4kV and 8kV Renewal Program is discussed in further detail in Tab 6, Schedule 1 of this Exhibit and in the DSP which is included at Appendix 2-4 of this Exhibit.

- 2012 actual was $14,090,964. The decrease from 2011 of $3,079,957 was due to a decline in reactive renewal expenditures and in expenditures on the 4kV and 8kV Renewal Program. The reductions were required to offset increased expenditures in system access projects.

- 2013 actual was $18,424,977. The increase from 2012 of $4,334,013 was due to the start of the underground XLPE Cable Renewal Program, and an increase in substation breaker and relay renewal and reactive renewal, partly offset by the completion of the downtown network renewal for St. Catharines. The XLPE Cable Renewal Program is discussed in further detail in Tab 6, Schedule 1 of this Exhibit and in the DSP which is included at Appendix 2-4 of this Exhibit.

- The level of system renewal expenditure from the 2014 Bridge Year to the 2019 Test Year is as follows:
    - The forecast for the 2014 Bridge Year is $15,372,195. The decrease from 2013 of $3,052,782 is driven by the completion of the substation and relay renewal program in 2013.
    - The forecast for the 2015 Test Year is $18,070,415. The increase from the 2014 Bridge Year of $2,698,220 is due to increased investment in the 4kV and 8kV Renewal and underground XLPE Cable Renewal Programs.
    - The forecast for the 2016 Test Year is $28,293,649. The significant increase from the 2015 Test Year of $10,223,234 is due to the Gage TS rebuild of $4,793,000, and an increase in the 4kV and 8kV Renewal and underground XLPE Cable Renewal Programs. Horizon Utilities has provided further elaboration and justification for the Gage TS rebuild in Appendix A and Appendix G of the DSP.
    - The forecast for the 2017 Test Year is $33,167,877. The increase from the 2016 Test Year of $4,874,227 is primarily due to increased investment in the 4kV and 8kV Renewal and underground XLPE Cable Renewal Programs.
    - The forecast for the 2018 Test Year is $33,208,155. The main drivers of the investment are the continuation of the 4kV and 8kV Renewal and underground XLPE Cable Renewal Programs, which are forecast to be at the same level as the 2017 Test Year.
    - The forecast for the 2019 Test Year is $34,706,031. The increase from the 2018 Test Year of $1,497,876 is driven by further investment in the 4kV and 8kV Renewal and underground XLPE Cable Renewal Programs.

The significant increase in system renewal expenditure over the 2015 to 2019 Test Years is a result of the necessary investment in the 4kV and 8kV Renewal and the underground XLPE Cable Renewal Programs.

Expenditures for the 4kV and 8kV Renewal Program are forecast to increase from $8,160,000 in 2015 to $16,846,000 in 2019 as identified in Table 2-64 below.

Table 2-64 - 4kV and 8kV Renewal Program 2015-2019

4kV and 8kV Renewal Program	2015 Test Year	2016 Test Year	2017 Test Year	2018 Test Year	2019 Test Year
Total	$ 8,160,000	$ 10,160,000	$ 15,764,000	$ 15,684,000	$ 16,846,000

Horizon Utilities' 4kV and 8kV distribution system services approximately 75,000 customers, representing 31% of its customer base. The 4kV and 8kV distribution system was largely constructed in the 1950s and is at or nearing end-of-life thus exposing customers to a higher risk of equipment failure and outages. The 2015-2019 Test Year investments in the 4kV and 8kV Renewal Program are necessary to address this risk. Without these investments, these customers will be subject to higher rates of service interruptions, with outage durations potentially lasting for several hours, days or months depending on the nature of the failed asset. Further justification for the 4kV and 8kV renewal plan is provided in Tab 6, Schedule 1 of this Exhibit and Section 3.5.3 of the DSP.

Expenditures for the underground XLPE Cable Renewal Program are forecast to increase from $2,567,000 in 2015 to $10,271,000 in 2019 as identified in Table 2-65 below.

Table 2-65 – Underground XLPE Cable Renewal Program 2015-2019

U/G (XLPE) Renewal	2015 Test Year	2016 Test Year	2017 Test Year	2018 Test Year	2019 Test Year
Ancaster/Flamborough/Dundas	$2,257,000	$1,269,000	$0	$0	$2,702,000
Hamilton Mountain	$0	$1,996,000	$6,607,000	$4,641,000	$3,473,000
St. Catharines	$310,000	$1,661,000	$1,759,000	$2,835,000	$4,096,000
Stoney Creek	$0	$0	$500,000	$1,908,000	$0
U/G (XLPE) Renewal	**$2,567,000**	**$4,926,000**	**$8,866,000**	**$9,384,000**	**$10,271,000**

Historically, cable renewal has primarily been performed reactively. Horizon Utilities must initiate proactive replacement of its underground cable to address increasing risk resulting from the declining health of the extensive underground system. The XLPE Cable Renewal Program is the primary plan to address the renewal of underground assets. Failure to invest in XLPE cable renewal at Horizon Utilities' proposed investment of $36,014,000 over the 2015 to 2019

Test Years will result in increased frequency and duration of service interruptions to large numbers of customers. The justification for this plan is provided in Tab 6, Schedule 1 of this Exhibit and Section 3.5.3 of the DSP.

<u>System Service</u>

Projects in this category are driven by Horizon Utilities' expectations that the evolving use of the system may create system capacity constraints or adversely impact system reliability.

These investments are required to support the expansion, operation and reliability of the distribution system. Horizon Utilities further classifies these investments in sub-categories of capacity, reliability, and security.

The level of system service expenditure in each of the 2010 to 2013 historical years is as follows:

- 2010 actual (CGAAP) was $3,582,988, which includes a Hydro One contribution to increase capacity at the Vansickle TS;

- 2011 actual (MIFRS) was $2,373,505. The decrease from 2011 of $1,209,483 is due to the expensing of overhead burden costs previously capitalized under CGAAP, and a decrease in investments to address system capacity. Further discussion of overhead cost burdens and the impact of the transition to IFRS has been provided in Tab 6, Schedule 5 of this Exhibit and Exhibit 6, Tab 2, Schedule 1.

- 2012 actual was $2,885,476. The increase from 2011 of $511,971 was due to the construction of an additional feeder from the Vansickle Transformer Station to address system capacity and a Hydro One contribution to upgrade the capacity at the Nebo TS.

- 2013 actual was $2,151,349, including an additional Hydro One contribution to increase capacity at the Nebo TS. The decrease from 2012 of $734,127 was due to a lower level of system capacity investments. The completion of the additional feeder from the Vansickle TS was partly offset by the final Hydro One contribution to upgrade the capacity at the Nebo TS.

The level of system service expenditure from the 2014 Bridge Year to the 2019 Test Year is as follows:

- The forecast expenditure for the 2014 Bridge Year is $4,101,053. The increase from 2013 of $1,949,704 is a result of a Green Energy Act ("GEA") feeder automation project and the completion of a new feeder at the Nebo TS.

- The forecast expenditure for the 2015 Test Year is $4,139,747. The increase from 2014 is $38,694. The completion of the additional feeder from the Nebo TS in 2014 is offset by the construction of a third feeder in the Waterdown area, and the establishment of increased capacity and back up supply to the redeveloped Caroline and George Street area of downtown Hamilton. Justification for these projects is provided in Appendix A and Appendix G of the DSP. Horizon Utilities' Basic GEA Plan-related feeder automation project is expected to be completed in 2015.

- The forecast expenditure for the 2016 Test Year is $294,732. The decrease from 2015 of $3,845,015 is due to the completion of capacity projects in 2015. Investment levels are expected to decline as a result of a higher prioritization of system renewal projects in this year, as identified above.

- The forecast expenditure for the 2017 Test Year is $535,135. The increase from the 2016 Test Year of $240,403 is to accommodate security/redundancy projects. More details on these projects, which are forecast to continue into 2018, are provided in Appendix A and Appendix G of the DSP.

- The forecast for the 2018 Test Year is $2,031,847. The increase from the 2017 Test Year of $1,496,712 is primarily due to projects required to address security/redundancy. The main driver is a conductor upgrade at St. Paul Street in St. Catharines. This project is discussed in further detail in Appendix A and Appendix G of the DSP.

- The forecast for the 2019 Test Year is $2,057,209, driven by projects to address security/redundancy. Horizon Utilities also anticipates a payment to Hydro One to increase the capacity at the Mohawk or Nebo TSs. These projects are discussed in further detail in Appendix A and Appendix G of the DSP.

General Plant

General plant projects include investments in tools, vehicles, building and information systems technology equipment that are required to support the operation and maintenance of the distribution system.

The level of general plant expenditure in each of the 2010 to 2013 historical years was as follows:

- 2010 actual (CGAAP) was $6,208,326;

- 2011 actual (MIFRS) was $4,584,443. The decrease of $1,623,883 versus 2010 actual was driven by a decrease in vehicle replacement and office equipment; partly offset by a project to replace Horizon Utilities' existing two analog radio systems with a single digital system. The replacement of vehicles is discussed in further detail in Tab 6, Schedule 1 of this Exhibit. The fleet radio replacement is discussed in further detail in Tab 6, Schedule 3, page 48 of this Exhibit.

- 2012 actual was $8,747,623. The increase from 2011 of $4,163,180 was driven by the start of a multi-year initiative (2012 – 2019) to renew and upgrade Horizon Utilities' buildings and information systems. Horizon Utilities' building renewal projects are provided in further detail in Tab 6, Schedule 1 of this Exhibit and in Appendix A and Appendix G of the DSP. Horizon Utilities also commenced a multi-year project (2012-2015) to replace its end-of-life GIS. This project is discussed in further detail in Tab 6, Schedule 1 of this Exhibit.

- 2013 actual was $12,559,044, an increase of $3,811,421 from 2012. The multi-year initiatives to renew and refurbish Horizon Utilities' buildings and to replace the GIS system continued into 2013. Horizon Utilities commenced a multi-year initiative in 2013 to upgrade its IFS ERP. The justification for this project is provided in Tab 6, Schedule 1 of this Exhibit and in Appendix A of the DSP.

The level of general plant expenditure from the 2014 Bridge Year to the 2019 Test Year is provided below. Table 2-66 identifies the general plant expenditures for the 2015 to 2019 Test Years.

Table 2-66 – General Plant Capital Expenditures 2014-2019

Description	2014 Bridge Year	2015 Test Year	2016 Test Year	2017 Test Year	2018 Test Year	2019 Test Year
Fleet	$785,000	$778,000	$780,000	$775,000	$785,000	$785,000
Building and Facilities [1]	$4,250,000	$4,000,000	$2,195,000	$2,495,000	$1,595,000	$1,595,000
Computer Hardware & Software	$4,435,965	$3,707,347	$2,181,000	$1,886,700	$2,532,700	$3,107,700
Communication Equipment	$6,200	$245,000	$5,000	$5,000	$5,000	$5,000
Tools, Shop, Garage and Measurement Equipment	$665,300	$687,860	$657,200	$596,200	$620,200	$670,200
Office Furniture and Equipment	$618,000	$69,000	$69,000	$69,000	$73,000	$73,000
Total General Plant	**$10,760,465**	**$9,487,208**	**$5,887,200**	**$5,826,900**	**$5,610,900**	**$6,235,900**
1 Buildings and Facilities includes building security						

- The forecast for the 2014 Bridge Year is $10,760,465. The decrease from 2013 of $1,798,579 is primarily due to a decrease in expenditures for the building renewal, partly offset by an increase in expenditures for the GIS project, and an increase in vehicle replacement costs. No vehicles were replaced in 2013 in order to redeploy investment capital into necessary building refurbishments. The project to upgrade the IFS ERP system is expected to continue into 2014.

- The forecast for the 2015 Test Year is $9,487,208. The decrease from the 2014 Bridge Year of $1,273,257 is primarily due to a reduction in expenditures for the GIS project which is expected to be completed in 2015, and a reduction in building and office equipment expenditures. This decrease is partly offset by an increase in expenditures for the ERP upgrade and a phone system upgrade. Justification for these projects is provided in Tab 6, Schedule 1 of this Exhibit and Appendix A of the DSP.

- The forecast for the 2016 Test Year is $5,887,200. The decrease from the 2015 Test Year of $3,600,008 is driven by lower IST expenditures and facilities compared to 2015. 2015 IST expenditures include the completion of the GIS project and ERP upgrade in 2015. 2015 building expenditures include: the completion of the John Street and Hughson Street roof replacements; the Nebo Rd emergency back-up generator; investment required for the John Street and Hughson Street building renovations; and the completion of the communications system upgrades.

- The forecast for the 2017 Test Year is $5,826,900, primarily due to the building renewal and refurbishment initiative. Justification and project details by year for this multi-year initiative are provided in Tab 6, Schedule 1 of this Exhibit.
- The forecast for the 2018 Test Year is $5,610,900. The decrease from the 2017 Test Year of $216,000 is due to a decrease in expenditures for building renewal and refurbishment, partly offset by a lifecycle upgrade of the IFS ERP system. This project is discussed in further detail in Appendix A and G of the DSP.
- The forecast for the 2019 Test Year is $6,235,900, primarily due to the building renewal and refurbishment at the Stoney Creek Service Centre and IST expenditures. Further details are provided in Tab 6, Schedule 1 of this Exhibit.

Capital Expenditures on a Project Specific Basis

The following tables and narrative analysis summarize Horizon Utilities' capital expenditures on a project specific basis for: 2010, 2011, 2012 and 2013 on an actual basis; the 2014 Bridge Year; and the 2015-2019 Test Years on a forecast basis. A summary of Horizon Utilities' capital projects by year is provided in Table 2-67 and Table 2-68 - Appendix 2-AA. Please observe that the sub-totals for each of the four categories in Appendix 2-AA: System Access, System Renewal, System Service, and General Plant are not all inclusive of respective total capital expenditures in these categories. All projects below the materiality threshold of $300,000 have been included in the miscellaneous line and therefore, will not balance to Appendix 2-AB by category.

Table 2-67 – Appendix 2-AA Capital Projects Table

Projects ($)	2010	2011	2012	2013	2014 Bridge Year	2015 Test Year	2016 Test Year	2017 Test Year	2018 Test Year	2019 Test Year
Reporting Basis	**CGAAP**	**CGAAP**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**
System Access										
Customer Connections	1,023,336	2,030,541	1,652,000	3,541,455	4,063,471	3,686,273	4,031,103	4,139,076	4,250,289	4,364,837
Subdivision Development	0	0	536,000	0	0	0	0	0	0	0
Road Relocations	2,889,575	894,524	3,151,887	340,491	977,024	2,085,651	2,339,675	1,710,951	1,778,139	1,845,327
MUSH Customer "X"	1,764,021	454,118	0	0	0	0	0	0	0	0
MUSH Customer "Y"	2,784,061	358,102	0	0	0	0	0	0	0	0
MUSH Customer "W"	684,675	540,603	0	0	0	0	0	0	0	0
Caroline/George Feeder	0	0	0	1,683,902	0	0	0	0	0	0
St. Catharines Downtown Expansion - MUSH Customer "A" and "P"	0	0	0	388,780	0	0	0	0	0	0
Meters	1,715,776	3,467,413	25,168,043	1,658,707	2,499,104	2,470,674	2,101,174	2,046,174	2,063,174	2,063,174
System Access Total	**10,861,444**	**7,745,301**	**30,507,930**	**7,613,335**	**7,539,599**	**8,242,598**	**8,471,952**	**7,896,201**	**8,091,602**	**8,273,338**
System Renewal										
4kV & 8kV Renewal										
Aberdeen S/S	0	2,516,000	469,652	0	0	0	0	2,418,000	2,643,000	2,900,000
Baldwin S/S	0	0	0	0	0	0	0	0	1,788,000	4,403,000
Caroline S/S	264,713	1,341,000	430,000	0	1,205,000	0	0	0	0	0
Central S/S	0	0	0	0	0	0	1,556,000	1,876,000	1,652,000	648,000
Grantham S/S	0	0	0	0	0	650,000	2,633,000	1,871,000	13,000	159,000
Highland S/S	0	0	0	0	0	1,128,000	0	658,000	0	0
Hughson S/S	627,636	2,297,000	1,813,000	4,134,216	0	0	0	0	0	0
John S/S	0	0	0	0	0	0	0	0	2,516,000	8,259,000
Strouds S/S	0	0	0	0	1,406,000	1,020,000	1,533,000	1,787,000	3,831,000	0
Taylor S/S	964,597	1,609,000	2,139,000	0	0	0	0	0	26,000	159,000
Vine S/S	0	0	0	0	0	978,000	2,472,000	5,645,000	13,000	159,000
Webster S/S	699,130	0	305,789	0	0	0	0	0	0	0
Welland S/S	0	1,057,000	111,000	938,017	1,327,000	0	0	0	13,000	159,000
Whitney S/S	0	0	0	0	2,496,000	4,384,000	1,966,000	1,509,000	2,115,000	0
York S/S	0	0	0	0	0	0	0	0	1,074,000	0
4kV & 8kV Renewal Subtotal	**2,556,076**	**8,820,000**	**5,268,441**	**5,072,233**	**6,434,000**	**8,160,000**	**10,160,000**	**15,764,000**	**15,684,000**	**16,846,000**
U/G (XLPE) Renewal										
Ancaster/Flamborough/Dundas	0	0	0	0	0	2,257,000	1,269,000	0	0	2,702,000
Hamilton Mountain	0	0	0	0	0	0	1,996,000	6,607,000	4,641,000	3,473,000
St. Catharines	0	0	0	1,237,371	437,000	310,000	1,661,000	1,759,000	2,835,000	4,096,000
Stoney Creek	0	0	0	334,719	456,000	0	0	500,000	1,908,000	0
U/G (XLPE) Renewal Subtotal	**0**	**0**	**0**	**1,572,090**	**893,000**	**2,567,000**	**4,926,000**	**8,866,000**	**9,384,000**	**10,271,000**
Reactive Renewal	**8,745,125**	**8,230,970**	**4,032,000**	**6,069,566**	**4,840,000**	**4,780,000**	**4,339,000**	**4,457,000**	**4,536,000**	**4,608,000**
Substation Renewal										
Breaker and Relay Renewal	0	223,000	1,998,000	3,864,456	0	0	0	0	0	0
Parkdale S/S Switchgear Replacement	0	1,621,000	900,000	0	0	0	0	0	0	0
Infrastructure Renewal	146,477	326,000	305,000	168,507	455,503	464,000	473,000	482,000	491,000	500,000
Substation Renewal Subtotal	**146,477**	**2,170,000**	**3,203,000**	**4,032,963**	**455,503**	**464,000**	**473,000**	**482,000**	**491,000**	**500,000**
Other Renewal										
Pole Residual Replacements	1,326,407	895,000	930,000	718,074	1,190,000	1,226,000	1,262,000	1,297,000	1,333,000	1,369,000
St. Catharines Downtown Network Renewal	843,662	815,000	945,862	0	0	0	0	0	0	0
Load Break Disconnect Switch ("LDBS") Renewal	0	0	0	212,000	312,000	323,000	334,000	345,000	357,000	368,000
Proactive TX Replacements	0	104,447	185,523	276,978	339,000	350,000	361,000	373,000	384,000	395,000
Gage TS Egress Feeder Renewal	0	0	0	0	0	0	4,793,000	0	0	0
Chestnut Street M16 and M5	385,000	0	0	0	0	0	0	0	0	0
Rear Lot Conversion	0	0	0	0	0	0	1,342,000	1,382,000	696,000	0
Civil Infrastructure Renewal	0	0	0	0	0	0	0	0	147,000	151,000
Other Renewal Subtotal	**2,555,069**	**1,814,447**	**2,061,385**	**1,207,052**	**1,841,000**	**1,899,000**	**8,092,000**	**3,397,000**	**2,917,000**	**2,283,000**
System Renewal Total	**14,002,747**	**21,035,417**	**14,564,826**	**17,953,904**	**14,463,503**	**17,870,000**	**27,990,000**	**32,966,000**	**33,012,000**	**34,508,000**

Table 2-68 – Appendix 2-AA Capital Projects Table continued

Projects ($)	2010	2011	2012	2013	2014 Bridge Year	2015 Test Year	2016 Test Year	2017 Test Year	2018 Test Year	2019 Test Year
Reporting Basis	**CGAAP**	**CGAAP**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**
System Service										
Vansickle T/S M82 Feeder- Macturnbull	0	0	1,049,000	0	0	0	0	0	0	0
# 6 Wire Replacement	208,622	626,000	349,000	69,121	418,000	570,000	0	0	0	0
Hamilton Industrial Waterfront Redevelopment	0	0	389,000	0	0	0	0	0	0	0
Glen Morris Line Upgrade	0	0	510,375	0	0	0	0	0	0	0
24 Ft Solid Concrete Pole Replacement	0	432,103	0	0	0	0	0	0	0	0
Mohawk M61 Extension	0	465,000	0	0	0	0	0	0	0	0
Vansickle T/S M72 Feeder	0	1,055,077	0	0	0	0	0	0	0	0
Vansickle T/S M61 Feeder	0	975,000	0	0	0	0	0	0	0	0
Stirton TS M51 Capacity	496,719	0	0	0	0	0	0	0	0	0
Nebo T/S Capacity Increase	0	0	970,000	1,449,847	1,708,000	0	0	0	0	0
Vansickle T/S Capacity Increase	2,356,667	0	-1,261,409	0	0	0	0	0	0	0
Distribution Automation - GEA Feeder	0	0	0	0	1,250,000	1,250,000	0	0	0	0
Horning T/S M45	873,883	0	0	0	0	0	0	0	0	0
Garth Street Underground to Rymal	902,507	0	0	0	0	0	0	0	0	0
Waterdown 3rd Feeder	0	0	0	0	0	984,000	0	0	0	0
Caroline/George Redundancy	0	0	0	0	0	952,000	0	0	0	0
Duct Structure - Elgin TS to King St.	0	0	0	0	0	0	0	535,000	0	0
East 16th and Mohawk Security Project	0	0	0	0	0	0	0	0	324,000	0
St. Paul Street Conductor Upgrade	0	0	0	0	0	0	0	0	1,362,000	0
Grays Road	0	0	0	0	0	0	0	0	0	413,000
Mohawk/Nebo T/S Upgrade	0	0	0	0	0	0	0	0	0	1,000,000
System Service Total	**4,838,398**	**3,553,180**	**2,005,966**	**1,518,968**	**3,376,000**	**3,756,000**	**0**	**535,000**	**1,686,000**	**1,413,000**
General Plant										
Information Systems Technology										
Capital Lease - IBM	0	0	820,000	0	0	0	900,000	0	0	900,000
Annual Corporate Computer Replacement	336,000	227,000	312,000	364,947	366,200	319,000	324,000	353,000	361,200	361,200
Enterprise Backup Solution	0	0	0	351,995	0	0	0	0	0	0
IFS ERP Upgrade	0	0	0	1,225,762	980,260	1,382,600	0	0	1,225,000	0
Storage Area Network ("SAN") Expansion	0	0	626,000	0	0	200,000	0	200,000	0	300,000
Enterprise Phone System Upgrade	0	0	0	0	0	400,000	0	0	0	0
GIS Renewal	0	0	807,000	1,103,442	1,869,308	205,276	0	0	0	0
Information Systems Technology Sub-Total	**336,000**	**227,000**	**2,565,000**	**3,046,146**	**3,215,768**	**2,506,876**	**1,224,000**	**553,000**	**1,586,200**	**1,561,200**
Buildings										
Building Renovations - Vansickle Road	0	0	460,000	2,060,000	1,300,000	0	0	0	0	0
Building Renovations - John and Hughson Street	0	0	1,307,000	1,900,000	0	2,000,000	1,600,000	2,200,000	1,200,000	0
Building Renovations - Nebo Road	0	0	0	1,530,000	2,400,000	0	0	0	0	0
Building Renovations - Stoney Creek	0	0	0	0	0	0	0	0	0	1,200,000
Building Security Replacement	0	0	0	0	400,000	300,000	200,000	0	0	0
John Street Roof Replacement	0	0	0	0	0	900,000	0	0	0	0
John Street Window Replacement	0	0	0	0	0	300,000	300,000	200,000	0	0
Nebo Road Emergency Backup Generator	0	0	0	0	0	300,000	0	0	0	0
Buildings Sub-Total	**0**	**0**	**1,767,000**	**5,490,000**	**4,100,000**	**3,800,000**	**2,100,000**	**2,400,000**	**1,200,000**	**1,200,000**
Office Furniture and Equipment	**386,855**	**24,344**	**295,717**	**873,925**	**618,000**	**69,000**	**69,000**	**69,000**	**73,000**	**73,000**
Vehicles										
Vehicle Replacement	1,590,516	1,033,975	1,057,410	36,365	785,000	778,000	780,000	775,000	785,000	785,000
Radio Replacement	0	827,000	0	0	0	0	0	0	0	0
Vehicles Sub-Total	**1,590,516**	**1,860,975**	**1,057,410**	**36,365**	**785,000**	**778,000**	**780,000**	**775,000**	**785,000**	**785,000**
Tools, Shop and Garage Equipment	515,236	493,820	279,587	417,572	511,300	555,560	567,600	508,600	530,600	580,600
General Plant Total	**2,828,607**	**2,606,139**	**5,964,715**	**9,864,008**	**9,230,068**	**7,709,436**	**4,740,600**	**4,305,600**	**4,174,800**	**4,199,800**
Miscellaneous	4,900,487	4,157,803	2,560,531	2,554,428	3,164,144	2,361,933	1,744,981	1,723,313	1,978,102	2,878,339
Total	**37,431,683**	**39,097,840**	**55,603,967**	**39,504,643**	**37,773,314**	**39,939,967**	**42,947,533**	**47,426,114**	**48,942,504**	**51,272,477**
Less Renewable Generation Facility Assets and Other Non Rate-Regulated Utility Assets *(input as negative)*										
Total	**37,431,683**	**39,097,840**	**55,603,967**	**39,504,643**	**37,773,314**	**39,939,967**	**42,947,533**	**47,426,114**	**48,942,504**	**51,272,477**

2011 Actual (CGAAP) vs. 2010 Actual (CGAAP)

Horizon Utilities' 2011 total capital expenditures are $1,666,128 higher than 2010 total capital expenditures as identified in Table 2-69 below.

Table 2-69 – 2011 vs. 2010 Capital Projects

Projects ($)	2010 Actual	2011 Actual	Variance 2011 Actual vs 2010 Actual
Reporting Basis	**CGAAP**	**CGAAP**	
Customer Connections	1,023,336	2,030,541	1,007,205
Road Relocations	2,889,575	894,524	(1,995,051)
Meters	1,715,776	3,467,413	1,751,637
Other Material System Access	5,232,757	1,352,823	(3,879,934)
System Access Total	**10,861,444**	**7,745,301**	**(3,116,143)**
4kV & 8kV Renewal	2,556,076	8,820,000	6,263,924
U/G (XLPE) Renewal	0	0	0
Reactive Renewal	8,745,125	8,230,970	(514,155)
Substation Renewal	146,477	2,170,000	2,023,523
Other Renewal	2,555,069	1,814,447	(740,622)
System Renewal Total	**14,002,747**	**21,035,417**	**7,032,670**
System Service Total	**4,838,398**	**3,553,180**	**(1,285,218)**
Vehicles	1,590,516	1,860,975	270,459
Buildings	0	0	0
Office Furniture and Equipment	386,855	24,344	(362,511)
IST	336,000	227,000	(109,000)
Tools, Shop and Garage Equipment	515,236	493,820	(21,416)
General Plant	**2,828,607**	**2,606,139**	**(222,468)**
Total Material Capital Projects	**32,531,196**	**34,940,037**	**2,408,841**
Miscellaneous	4,900,487	4,157,803	(742,684)
Total Capital Expenditures	**37,431,683**	**39,097,840**	**1,666,157**

System Access

Expenditures on system access projects decreased by $3,116,143 in 2011 as compared to 2010. Multi-year projects to provide service to three MUSH-sector customers decreased by $3,879,934 and the number of road relocation projects requested by the City of Hamilton, the

City of St. Catharines and the Region of Niagara increased versus 2010. This decrease was partly offset by the following:

- an increase in the number of customer connections from 209 in 2010 to 228 in 2011; and
- an increase in the number of meters installed, primarily driven by wholesale and commercial meter installations.

These system access projects are discussed in further detail in Tab 6, Schedule 3, pages 19-27 of this Exhibit.

System Renewal

Expenditures on system renewal projects increased significantly in 2011 as compared to 2010 consistent with Horizon Utilities' plans for increased renewal investment. The 2011 System Renewal investment in the 4kV and 8kV Renewal Program was identified in Horizon Utilities' 2011 Cost of Service Application (EB-2010-0131). Expenditures for the 4kV and 8kV Renewal Program in 2011 were $8,820,000, an increase of $6,263,924 from 2010 as identified in Table 2-70 below. Justification for the continued need to increase investment in the 4kV and 8kV Renewal Program is provided in Tab 6, Schedule 1 of this Exhibit and in Section 3.5.3 of the DSP.

Table 2-70 – 2011 4kV and 8kV Renewal Program

Area Served by	Phase	Start Date	End Date	2010 Actual	2011 Actual	2012 Actual	2013 Actual
Aberdeen Substation	Single	2011	2011	$ -	$ 2,516,000	$ 469,652	$ -
Caroline Substation	Multi	2008	2014	$ 264,713	$ 1,341,000	$ 430,000	$ -
Hughson Substation	Multi	2011	2014	$ 627,636	$ 2,297,000	$ 1,813,000	$ 4,134,216
Taylor Substation	Multi	2009	2012	$ 964,597	$ 1,609,000	$ 2,139,000	$ -
Webster Substation	Multi	2008	2012	$ 699,130	$ -	$ 305,789	$ -
Welland Substation	Multi	2011	2014	$ -	$ 1,057,000	$ 111,000	$ 938,017
Total				**$ 2,556,076**	**$ 8,820,000**	**$ 5,268,441**	**$ 5,072,233**

Expenditures also increased for substation renewal. A two-year project to replace the switchgear at Parkdale substation commenced in 2011 and was completed in 2012, with expenditures totalling $1,621,000 in 2011 and $900,000 in 2012. The multi-year program to renew substation breaker and protection relay assets continued in 2011 and was completed in 2013. Expenditures associated with the on-going program to replace obsolete poles and poles that were determined to be at end-of-life were $895,000.

An increase in System Renewal expenditures was partly offset by a decrease in System Service expenditures as compared to 2010.

System Service

Expenditures for system service projects in 2011 were $3,553,180, a decrease of $1,285,218 from 2010 as identified in Table 2-71 below.

Table 2-71 – 2010 and 2011 System Service Expenditures

System Service Expenditures	2010 Actual	2011 Actual
# 6 Wire Replacement	$ 208,622	$ 626,000
24 Ft Solid Concrete Pole Replacement	$ -	$ 432,103
Mohawk M61 Extension (Henderson Hos	$ -	$ 465,000
Vansickle T/S M72 Feeder	$ -	$ 1,055,077
Vansickle T/S M61 Feeder	$ -	$ 975,000
Stirton TS M51 Capacity(Henderson Hos	$ 496,719	$ -
Vansickle T/S Capacity Increase	$ 2,356,667	$ -
Horning T/S M45	$ 873,883	$ -
Garth Street Underground to Rymal	$ 902,507	$ -
Total	**$ 4,838,398**	**$ 3,553,180**

Horizon Utilities continued a multi-year program in 2011 to proactively replace #6 overhead primary conductor throughout its service territory. The justification for this program is provided in Tab 6, Schedule 3, page 42 of this Exhibit and in Appendix A of the DSP. The following one-time projects were also completed in 2011:

- the replacement of sub-standard 24’ concrete poles;
- the extension of the Mohawk M61 feeder to address capacity and security issues with the back-up feeders to a MUSH customer “Z”;
- the construction of two additional feeders from the Vansickle Transformer Station (M72 and M61 Feeders) to service a MUSH customer “X”;

The decrease in system service projects versus prior year was a result of the completion of four projects in 2010 as described below:

- construction costs to install cable to address the capacity issues with the main dedicated feeder at Stirton TS;
- construction costs required to increase the capacity of Vansickle TS from 40MVA to 90MVA;
- construction costs to install an additional feeder from Horning TS to improve capacity and address power quality issues and;
- the construction of underground infrastructure on Garth Street to address general load growth in the Hamilton West Mountain area which could not be serviced by the primary feed from Nebo TS.

General Plant

General plant expenditures for material capital projects in 2011 were $140,043 higher than in 2010. An increase in expenditures associated with the fleet radio replacement was partly offset by lower expenditures for vehicle replacement. The 2011 General plant expenditures included a project to replace Horizon Utilities' existing two analog radio systems deployed throughout its fleet with a single digital system which required an investment of $827,000. This investment is included in the vehicle category in Table 2-69. Expenditures for vehicle replacement decreased by $556,541 in 2011 as compared to 2010. Expenditures in 2010 included the replacement of several vehicles which had reached/exceeded end-of–life or met the vehicle replacement criteria as identified in Tab 6, Schedule 1 of this Exhibit. Vehicle replacement in 2010 included a trouble truck, two splicer vans, a single bucket truck, a digger derrick with trailer and a dump truck. Material replacements in 2011 included a digger derrick truck, a single bucket truck and a knuckle crane truck.

Detailed descriptions of the 2011 capital expenditures for material projects are provided in the capital project templates below.

2011 System Access Projects

Project Name: Customer Connections

Driver: System Access

Scope: System Access projects are investments required to meet customer service obligations in accordance with the DSC and Horizon Utilities' Conditions of Service. This is an on-going program comprised of non-discretionary projects initiated by customers or developers, where investment is required to enable customers to connect to Horizon Utilities' distribution system. This program includes customer service orders, such as new and upgraded service connections for residential, commercial and industrial customers.

Horizon Utilities uses economic evaluation methodology prescribed by the DSC to determine the level, if any, of capital contributions for each project; with such levels incorporated into the annual capital budget. These investments cannot be deferred and must proceed as planned.

The amount of annual investment for this program over the period from 2011 to 2019 is identified in Table 2-72 below.

Table 2-72 – Customer Connections

Year	$
2011 Actual	2,030,541
2012 Actual	1,652,000
2013 Actual	3,541,455
2014 Bridge Year	4,063,471
2015 Test Year	3,686,273
2016 Test Year	4,031,103
2017 Test Year	4,139,076
2018 Test Year	4,250,289
2019 Test Year	4,364,837

Expenditures related to customer connection project costs are based on a number of factors which include: historical levels of activity and investment; known projects; a review of economic factors; and, inflationary adjustments for labour and materials.

The known projects are typically larger services that Horizon Utilities is able to plan for over a longer period of time (more than one year). System access projects are non-discretionary and outside of Horizon Utilities' control. There is a potential for actual expenditures to vary significantly from financial plans and from year to year. Annual plans are tracked monthly and new forecasts are issued quarterly as new customer connection information becomes available.

Justification of Project: Horizon Utilities completed 228 customer requests for service connections in 2011, as provided in Table 2-73 below:

Table 2-73 - Annual Number of Customer Connections Projects

	2010 Actual	2011 Actual	2012 Actual	2013 Actual
Services Residential	31	71	73	79
Services <=300kW - >50 kW	81	83	83	66
Services over 300kW	36	26	36	57
Services <=50kW	43	39	57	51
Embedded Generation	0	0	0	20
Other Customer Requests	12	7	8	9
Services Customer Owned Sub-Station	6	2	9	5
Total	**209**	**228**	**266**	**287**

Customer connection projects typically include the provision and installation of transformation and switching equipment, cabling, and metering. None of the individual connections projects in 2011 required an investment of greater than $300,000. The 2011 customer connection projects included:

- 83 projects for service connections for customers between 50 kW and 300 kW at a net capital investment of $1,536,841;
- 71 projects for service connections for residential customers at a net capital investment of $358,516; and
- miscellaneous customer connection projects at a net capital investment of $135,184.

Project Name: Road Relocations

Driver: System Access

Scope: Projects in this category involved the relocation of Horizon Utilities' assets to support road relocation and road reconstruction projects at the request of the City of Hamilton, the City of St. Catharines, and the Region of Niagara. The initiation and timing of these projects is outside of Horizon Utilities' control and therefore the timing and value of investment required by Horizon Utilities is subject to change.

Annual expenditures are required for road relocation projects. The amount of annual investment over the period from 2011 to 2019 is identified in Table 2-74 below.

Table 2-74 – Road Relocation Projects

Year	$
2011 Actual	894,524
2012 Actual	3,151,887
2013 Actual	340,491
2014 Bridge Year	977,024
2015 Test Year	2,085,651
2016 Test Year	2,339,675
2017 Test Year	1,710,951
2018 Test Year	1,778,139
2019 Test Year	1,845,327

Horizon Utilities completed fifteen projects in 2011, at a total cost of $894,524, which are identified in Table 2-75 below:

Table 2-75 – 2011 Road Relocation Projects

2011 Road Relocation Projects - Hamilton
Woodward Ave - Melvin to QEW
Rebecca St. W/O John St Duct Damage
Centennial Pkwy - CNR Bridge Re-hab
Queensdale - Upper Gage to Upper Ottawa
Woodward Ave - Barton to Rennie
Rebecca St - Street Light Repair
Old Guelph Road - Slope Stabilization
McNeiley Rd - Barton to South Service Rd
2011 Road Relocation Projects - St. Catharines
Niagara St and Trapnel - MTO
Fourth Ave Road Widening
Welland Ave - Region Road Reconstruction
Glendale Ave - Region Road Reconstruction
Pelham Rd - First to Fifth St
Watermain Edgedale - Eastchester
Haig St and Scott St

Justification of Project: Road relocation projects are customer initiated. Horizon Utilities is obligated under the DSC and its Conditions of Service to perform these projects and incur related expenditures. These investments cannot be deferred and must proceed as planned, in compliance with the DSC and the Horizon Utilities' Conditions of Service. Timelines for the execution of these projects are dictated by the City of Hamilton or St. Catharines, the Ontario Ministry of Transportation or the Region of Niagara. Horizon Utilities coordinates work with these stakeholders on planned distribution projects wherever possible. Horizon Utilities follows the *Public Service Works on Highways Act* and associated regulations governing the recovery of costs related to road reconstruction work by collecting contributed capital for 50% of the labour, labour saving devices, and equipment rentals. Horizon Utilities collects capital contributions toward the cost of all customer demand projects in accordance with the DSC and the provisions of its Conditions of Service.

Project Name: Meters

Driver: System Access

Scope: This program includes the installation of Horizon Utilities' metering assets, in compliance with Measurement Canada standards. The work includes:

- installation of complex and commercial meters at new service locations;
- upgrading metering installations for expanded service requirements;
- inspection and replacement of defective meters;
- installation of new and replacement metering for residential and multi-residential metered customers; and
- Smart Meter gatekeepers for replacement and growth.

The amount of annual investment over the period from 2011 to 2019 for meters is provided in Table 2-76 below:

Table 2-76 – Meters

Year	$
2011 Actual	3,467,413
2012 Actual	25,168,043
2013 Actual	1,658,707
2014 Bridge Year	2,499,104
2015 Test Year	2,470,674
2016 Test Year	2,101,174
2017 Test Year	2,046,174
2018 Test Year	2,063,174
2019 Test Year	2,063,174

Justification of Project: New meter installations are customer initiated and Horizon Utilities is obligated under the DSC and its Conditions of Service to perform these installations and incur related expenditures.

Meter replacements are completed to address meter failures and to maintain metering assets in compliance with Measurement Canada regulations. Measurement Canada requires reverification of meter upon seal expiry either through compliance sampling or full reverfication programs.

These investments cannot be deferred and must proceed as planned to meet customer requirements and maintain regulatory compliance.

The investment in 2011 was $3,467,413. This was comprised primarily of:

- wholesale metering expenditures from Hydro One Networks, including the upgrading of meters at Kenilworth Transformer Stations, Elgin Transformer Station and Gage Transformer Stations, at a capital investment of approximately $1,200,000;
- the procurement and installation of commercial meters at a capital investment of approximately $1,900,000; and
- the procurement and installation of residential metering at a capital investment of approximately $275,000.

Project Name: System Access for MUSH Customer "X"

Driver: System Access

Scope: Investment in this project was required to enable the connection of the new large MUSH sector customer in the St. Catharines service territory to Horizon Utilities' distribution system. The investment required in 2011 was $454,118, for a total investment of $2,218,139 including 2010 expenditures.

Justification of Project: System Access projects are investments required to meet customer service obligations in accordance with the DSC of the OEB and Horizon Utilities' Conditions of Service. Horizon Utilities uses the economic evaluation methodology prescribed by the DSC to determine the level, if any, of capital contributions for each project; with such levels incorporated into the annual capital budget. These investments cannot be deferred and must proceed as planned.

Project Name: System Access for MUSH Sector Customer "Y"

Driver: System Access

Scope: This project involved the construction of a new direct primary feeder and the connection of an additional back-up feeder. Two primary direct feeds and two backup feeds now supply this location.

This project was initiated in 2010 and completed in 2011. The investment required in 2011 was $358,102 for a total investment of $3,142,166.

Justification of Project: System Access projects are investments required to meet customer service obligations in accordance with the DSC of the OEB and Horizon Utilities' Conditions of Service. Horizon Utilities uses the economic evaluation methodology prescribed by the DSC to determine the level, if any, of capital contributions for each project; with such levels incorporated into the annual capital budget. These investments cannot be deferred and must proceed as planned.

Project Name: System Access for MUSH Sector Customer "W"

Driver: System Access

Scope: Upgraded the existing M52 Circuit to accommodate new load of 3MW and provided a new backup feeder from Vansickle TS for MUSH sector customer "W".

This project was initiated in 2010 and completed in 2011. The investment required in 2011 was $540,603 for a total investment of $1,225,278.

Justification of Project: System Access projects are investments required to meet customer service obligations in accordance with the DSC of the OEB and Horizon Utilities' Conditions of Service. Horizon Utilities uses the economic evaluation methodology prescribed in the DSC to determine the level, if any, of capital contributions for each project; with such levels incorporated into the annual capital budget. These investments cannot be deferred and must proceed as planned.

2011 System Renewal Projects

Project Name: 4kV and 8kV Renewal

Program Driver: System Renewal

Scope: This project involved the conversion of all existing 4kV and 8kV assets to either 13.8kV or 27.6kV, depending upon the supply voltage from Hydro One which varies by operating area. The 4kV and 8kV Renewal Program for these assets utilizes an area-wide approach centred on the substations servicing each area. The selection and prioritization of these areas for renewal is either driven by substation asset health (St. Catharines, Hamilton West, and Hamilton Downtown operating areas) or by the health of the distribution system and operational constraints (Dundas operating area), and is fully described in the 4kV and 8kV Renewal Program in Section 3.5.3 of the DSP provided in Appendix 2-4 this Exhibit and in Tab 6, Schedule 1 of this Exhibit. The substation assets will be decommissioned once the assets are converted to the higher voltages. In 2011, renewal occurred in areas served by five substations as identified in Table 2-77 below.

Table 2-77 – 2011 4kV and 8kV Renewal Program

Substation	$
Aberdeen Substation	2,516,000
Caroline Substation	1,341,000
Hughson Substation	2,297,000
Taylor Substation	1,609,000
Welland Substation	1,057,000

Justification of Project: A 40-year 4kV and 8kV Renewal Program identified in Appendix F of the DSP was created, which consolidated both distribution asset conditions and substation asset conditions to provide a prioritized long term plan for renewal. The 4kV and 8kV distribution system represents the majority of Horizon Utilities' oldest distribution assets, constructed in the 1950's, which are at or near end-of-life and have an unacceptable Health Index distribution as defined in Tab 1, Schedule 1, page 9-10 of this Exhibit. Conversion to a higher voltage level will provide greater security as higher voltage systems are designed with more redundancy and better interoperability. Horizon Utilities has provided details of the 4kV and 8kV Renewal Program in Tab 6, Schedule 1 of this Exhibit.

Projects were executed from 2011 - 2013 to address the risk of failure inherent within 4kV substation equipment deemed to have an unacceptable Health Index distribution (as defined in Tab 1, Schedule 1, page 9 of this Exhibit) yet required to stay in-service for another 40 years to facilitate the 4kV and 8kV Renewal Program.

Horizon Utilities prioritized these voltage systems for renewal and these projects are the primary vehicle for renewal of the overhead distribution system.

Further justification for this project is provided in Tab 6, Schedule 1 of this Exhibit and Section 3.5.3 and Appendix F of the DSP which is filed as Appendix 2-4 in this Exhibit.

Project Name: Reactive Renewal

Driver: System Renewal

Scope: Unplanned failures of overhead and underground system components are corrected in a reactive manner to restore service to customers. Material project expenditures in 2011 were $8,230,970 due to:

- Immediate replacement of failed assets that have resulted in a service interruption;
- Urgent replacements identified through trouble calls from customers or other external parties where failure of the assets is imminent;
- Urgent and necessary replacement of assets resulting from inspections, and/or in response to findings pursuant to the Electrical Safety Authority ("ESA") due diligence requirements;
- Urgent and necessary replacement of assets identified through Horizon Utilities' inspection and maintenance programs; and
- Projects required addressing customer power quality issues.

Justification of Projects: Horizon Utilities experiences a large volume of equipment failures on an annual basis, resulting in service interruption to customers. Capital investment is required to repair the distribution system and restore service to customers. These expenditures are reactive in nature, originating from 3,516 customer outage calls to Horizon Utilities' System Control Centre. These investments are necessary to restore service to the affected customers. The cost to replace failed assets and restore power was $5,263,530 in 2011. These costs included the replacement of 112 poles and 185 transformers along with the required conductors, cables and hardware.

Investment is also required annually to address power quality and other urgent issues identified through internal inspection programs or as reported by external organizations (e.g. the ESA). Failure to perform these investments will result in:

- The inability to address safety concerns identified by the ESA and internal inspection programs; and
- The inability to address power quality concerns identified by customers.

Horizon Utilities completed 138 projects in 2011 to address the safety and power quality concerns noted above, at a cost of $2,967,440.

Project Name: Parkdale Substation Switchgear Replacement

Driver: System Renewal

Scope: Replacement of the 4kV switchgear at Parkdale substation. The scope of this project included the switchgear, breakers, electronic relays, and the replacement of the SCADA communication infrastructure. Execution of this project required building feeder ties to neighbouring substations to off-load Parkdale feeders which allowed the substation to be off loaded while the switchgear was being replaced. This was a multi-year project with annual investment identified in Table 2-78 below:

Table 2-78 – Parkdale Substation Switchgear Replacement

Year	$
2011 Actual	1,621,000
2012 Actual	900,000

Justification of Project: The SACA as filed in 2011 CoS Application (EB-2010-0131), identified that the Parkdale switchgear was in substandard condition and was likely to fail at some point during the remaining life of the substation. The high risk and impact of failure prior to decommissioning justified the investment in the replacement of the switchgear at this substation.

The existing 1948 vintage metal clad switchgear, consisting of 25 cells, was replaced with new arc resistant switchgear consisting of 12 cells. The new switchgear addressed end-of-life equipment; safety issues and reduced on-going maintenance costs as follows:

- Existing switchgear was 63 years old, and in poor health. Parkdale substation is required to stay in service for another 36 years and required renewal;
- New arc resistant switchgear provides a safer working environment for Horizon Utilities' employees, who work in close proximity to the switchgear. Arc flash hazards are present with old switchgear and employees were required to wear Class 4 arc rated protective clothing which is extremely cumbersome and difficult to work in for prolonged periods of time; and,

- Maintenance costs are reduced. The number of breakers in the new switchgear is 50% less than in the old switchgear. The switchgear and breaker maintenance cycles have been extended from 3 years to 6 years.

Parkdale Substation, in the Hamilton East operating area, has one of the longest remaining "useful lives" and is therefore one of the last substations to be decommissioned in the 4kV and 8kV Renewal Program. The renewal investment addressed the unacceptable Health Index distribution of the substation assets as well as the requirement for this substation to remain in service until 2047.

Project Name: Substation Breaker and Relay Renewal

Driver: System Renewal

Scope: This program involved the renewal of the breakers and protection relays at Horizon Utilities' substations servicing the Hamilton East and Hamilton Mountain 4kV operating areas. This was a multi-year project with the following annual investment requirements identified in Table 2-79 below.

Table 2-79 – Substation Breaker and Relay Renewal

Year	$	Substation	Replacements
2011 Actual	223,000	Bartonville	Breaker
2012 Actual	1,998,000	Wentworth	Relay
		Bartonville	Relay
		Spadina	Relay
		Ottawa	Breaker and Relay
2013 Actual	3,864,456	Mountain	Breaker and Relay
		Mohawk	Breaker and Relay
		Kenilworth	Breaker and Relay
		Wellington	Relay
		Cope	Relay

Justification of Project: Horizon Utilities replaced nine existing 1951 vintage oil filled breakers with nine vacuum breakers in 2011 at the Bartonville Substation at a total cost of $223,000.

Many substations rely on the original oil-filled or air-blast circuit breakers for protection. These old breakers require extensive maintenance and many replacement parts are now obsolete or unavailable. Modern vacuum circuit breakers are virtually maintenance free by design and have significantly better operating characteristics which provide a greater level of system protection.

Breakers and protection relays are major substation components responsible for the protection and control of the distribution system. Failure of a breaker would result in significant service interruptions to customers (each breaker serves approximately 500 customers on average). Failure of a relay could result in an increased risk to public or worker safety through the inability to isolate or de-energize feeders when required (for example, a primary wire on the ground).

The investment was required to allow these stations to remain in service, with a low risk of failure of these critical substation components.

These stations, located in the Hamilton East and Hamilton Mountain operating areas, are the last areas scheduled for renewal. Decommissioning dates for these stations range from 2029 to 2049.

Project Name: Substation Infrastructure Renewal

Driver: System Renewal

Scope: This program involves the ongoing renewal of substation infrastructure in substations throughout Horizon Utilities' service territory. Horizon Utilities performs annual substation maintenance and inspection programs. Through these inspections, Horizon Utilities identified a number of required investments for the continued safe and reliable operation of Horizon Utilities' substations. Investments within this program include battery replacements, SCADA and communication upgrades, and grounding improvements.

This is a multi-year project with the following annual investment requirements identified in Table 2-80 below.

Table 2-80 – Substation Infrastructure Renewal

Year	$
2011 Actual	326,000
2012 Actual	305,000
2013 Actual	168,507
2014 Bridge Year	455,503
2015 Test Year	464,000
2016 Test Year	473,000
2017 Test Year	482,000
2018 Test Year	491,000
2019 Test Year	500,000

Justification of Project: This program is required for the ongoing safe and reliable operation of Horizon Utilities' municipal substations, and other miscellaneous investments in the electrical and supervisory infrastructure, as identified through Horizon Utilities' substation maintenance and inspection programs. Safety related investments include installation of eye wash stations, end-of-life replacements of batteries and chargers for the emergency backup breaker operation circuits, and the replacement of end-of-life or obsolete station service transformers. These transformers are required to light and heat the substation and are the main source of power for the substation equipment. Miscellaneous investments include reactive replacement of relays, communication equipment and protection instrument transformers. These are critical to the safe and reliable operation of the substation. Failure to perform these required investments could lead to premature failure of substation components resulting in service interruptions and increased operating or reactive capital expenditures.

Project Name: **Pole Residual Replacements**

Driver: System Renewal

Scope: This project addressed the replacement of obsolete poles and poles that were determined to be at end-of-life by Horizon Utilities' maintenance and inspection programs, as further described below.

This is a multi-year project with the following annual investment requirements as identified in Table 2-81 below:

Table 2-81 – Pole Residual Replacements

Year	$
2011 Actual	895,000
2012 Actual	930,000
2013 Actual	718,074
2014 Bridge Year	1,190,000
2015 Test Year	1,226,000
2016 Test Year	1,262,000
2017 Test Year	1,297,000
2018 Test Year	1,333,000
2019 Test Year	1,369,000

Justification of Project: Horizon Utilities replaced 79 poles in 2011 at a total cost of $895,000.

Wood pole replacement requirements are primarily identified through the following programs representing best utility practices:

Wood Pole Testing Program: Horizon Utilities annually tests the structural integrity of wood poles through non-destructive testing procedures. All wood poles are tested on a seven year interval. Failed poles as identified through visual, sound and resistograph testing are scheduled for replacement.

Visual Inspection Program: Horizon Utilities performs a visual inspection of the entire distribution system on a three year interval to identify defective poles at end-of-life due to major rot and decay, cracks to ground line, hollow hearts (centres) and significant insect (e.g.

carpenter ants or bees) damage or infestation. Such poles are identified as urgent replacements and are replaced in the same year.

Individual pole replacements that are necessary as a result of identification under either of these programs must be undertaken immediately, since a failure of a pole typically results in a service interruption and often presents a hazard to public safety. Wood poles are a foundational piece of the distribution infrastructure and, for the above reasons, it is prudent to replace poles based on proactive testing rather than on failure-based replacement approaches. More details are provided in Section 2.3.1 of the DSP and in Exhibit 4, Tab 3, Schedule 2.

Project Name: St. Catharines Downtown Network

Driver: System Renewal

Scope: This project involved:

- the conversion of 26 submersible network-style transformers to pad mounted and/or vault style loop-fed transformers along the St. Catharines downtown core;

- the replacement of primary cables and switchgear locations in Horizon Utilities-owned stations residing on customer properties; and

- the removal of Paper Insulated Lead Covered ("PILC") primary cable from the distribution system in the St. Catharines downtown core.

This was a multi-year project which concluded in 2013 at a total cost of $2,604,524 as identified in Table 2-82 below.

Table 2-82 – St. Catharines Downtown Network

Year	$
2011 Actual	843,662
2012 Actual	815,000
2013 Actual	945,862
Total	**2,604,524**

Justification of Project: The original underground distribution system in St. Catharines was a secondary network constructed in the late 1950s and 1960s. The primary feeders were PILC that were installed in a duct and manhole system. There were 26 network transformers installed below grade in sidewalk vaults. The network transformers, network protectors and primary cables were over 40 years old and at the end of productive life. In addition to the network system that supplied all of the smaller buildings and businesses in the downtown, the larger buildings constructed in the 1970's were supplied by a primary selective system constructed in the same area as the network. This system was less expensive to construct than a network, and it provided a lower level of reliability. Switching operations were labour intensive (e.g. typically requiring 3-4 hours to switch equipment either out of or into service) due to the presence of two differently designed systems. Furthermore, switching was performed inside the confined space of transformer vaults and the equipment lacked the necessary visible isolation points and grounding provisions to comprehensively apply the Work Protection Code for maintenance and repair work.

The new design incorporated numerous safety improvements, as well as addressed reliability and end-of-life equipment. All switching is performed above grade through sidewalk access hatches and will no longer be conducted in a confined space. Each component of the system including cable, transformers and switches can be isolated and de-energized in full compliance with the Work Protection Code.

2011 System Service Projects

Project Name: #6 Wire Replacement

Driver: System Service

Scope: Horizon Utilities has an ongoing program to proactively replace #6 overhead primary conductor throughout its service territory. Most of the #6 Wire Replacement will be captured under the 4kV and 8kV Renewal Program. Areas with #6 wire not covered in the 4kV and 8kV Renewal Program are identified and prioritized for replacement based on: Health Index; volume of #6 wire; and the need to address operational deficiencies. The cost of each project is based on the volume of wire and complexity of effort required for replacement.

This is a multi-year project with the following annual investment requirements as identified in Table 2-83 below:

Table 2-83 – #6 Wire Replacement

Year	$
2011 Actual	626,000
2012 Actual	349,000
2013 Actual	69,121
2014 Bridge Year	418,000
2015 Test Year	570,000

Justification of Project: Horizon Utilities replaced 4.5 km of #6 wire in 2011 as part of the #6 wire replacement project, at a cost of $626,000. The costs are inclusive of pole and transformer replacements which are required to meet current engineering standards. Horizon Utilities experiences a number of ‘wire down’ incidents annually for a variety of reasons such as pole or insulator failures and conductor failures. Investigations of these incidents indicate a higher risk associated with #6 primary conductors than other conductor types due to the following factors:

- Solid #6 conductors have a higher probability of failure which may result in a wire down incident.

- This small gauge solid conductor is not as durable as the current standard which provides for a multi-stranded conductor.

- This overhead conductor is also replaced when 4kV conversion projects are completed.

Horizon Utilities has established a program to proactively replace #6 primary conductors to address the higher risk of failure. Horizon Utilities has removed 102 km of conductor (as of July 1, 2013) from the inception of this program in 2002, through both the #6 Wire Replacement Program and the 4kV and 8kV Renewal Program. This replacement of #6 wire will continue beyond the 2019 Test Year, primarily through the 4kV and 8kV Renewal Program, as there will still be 131 km of #6 conductor in service that will require removal.

These types of projects are directly linked to ensuring public safety and are therefore non-discretionary in nature.

Project Name: 24 ft. Solid Concrete Pole Replacement

Driver: System Service

Scope: This 24 ft. solid concrete pole replacement program involved the replacement of 40 solid 24' concrete poles. The 2011 phase of the project encompassed Herkimer St, Stanley Ave, Homewood Ave and Mountain Ave. and focused on the poles with primary distribution and secondary clearance concerns over the roadway.

The investment required in 2011 was $432,103.

Justification of Project: Horizon Utilities has approximately 900 24' solid concrete poles installed in old residential neighbourhoods approximately 70 years ago. There are safety clearance issues with 200 of these poles in the City of Hamilton. Secondary services to houses cross roadways and create clearance issues for some large vehicles. This replacement program started in 2009, and the following work was completed:

- 2009 – 40 poles were replaced
- 2010 – no poles were replaced specific to this project, but poles were replaced as part of the 4kV and 8kV Renewal Program for the area served by the Caroline substation.
- 2011 – 40 poles were replaced
- 2012 – seven poles were replaced under this project, but additional poles were replaced as part of the 4kV and 8kV Renewal Program for the area served by the Hughson substation.

Any remaining poles with safety clearance issues will be replaced as part of the 4kV and 8kV Renewal Program for the areas served by the Caroline, Hughson and Aberdeen substations. The remainder of the 24' poles will be replaced as part of the 4kV and 8kV Renewal Program for 2013 and beyond.

Project Name: Mohawk M61 Feeder Extension

Driver: System Service

Scope: A series of projects was completed in 2010 and 2011 to increase capacity and security for MUSH Customer "Z". This project addressed the capacity constraints that were present on the back-up feeder to the customer. The capacity issue was addressed with the installation of 1.5 km of 500 circular mils ("MCM") underground from Mohawk TS to Concession Street to provide security back-up to the MUSH Customer "Z".

This was the final project in a series of projects which addressed capacity and security constraints on the distribution system feeding the MUSH Customer "Z".

The actual project costs were $465,000 in 2011.

Justification of Project: The MUSH Customer "Z" in Hamilton completed an expansion to its existing facility in 2010. This project initiated a review of the feeders servicing this customer although there was no incremental load increase for this customer.

The review identified that the existing shared back-up feeder (0611X) was overloaded. A feeder extension was required to accommodate the load requirement for the back-up feeder. The new 500 MCM extension from Mohawk TS to Concession Street provided the following:

- necessary capacity for Customer "Z"'s back-up circuit; and
- provided security for the adjacent feeder which services a large commercial district in Hamilton.

Project Name: Vansickle TS M72 Feeder

Driver: System Service

Scope: Construct a new overhead feeder for approximately 2km on Vansickle Road from Vansickle TS to Ridley Road in St. Catharines.

The total project costs were $1,055,077 in 2011.

Justification of Project: Horizon Utilities was able to initiate a number of necessary projects to address capacity and security issues in St. Catharines, upon completion of the Vansickle TS upgrade. The Carlton TS M20 feeder had loading issues during the summer peaks and could not adequately be backed up. The Vansickle TS M72 feeder was built along Vansickle Road from Vansickle TS to Ridley Road to allow the offloading of the Carlton TS M20 feeder. The construction of the new feeder provided the capacity to back-up MUSH customer “X”.

Project Name: Vansickle TS M61 Feeder

Driver: System Service

Scope: This project involved the construction of a new feeder from Vansickle TS to create an additional interconnection point (intertie) with Carlton TS.

The total investment in 2011 was $975,000.

Justification of Project: The Vansickle TS capacity upgrade project, completed in 2010, provided Horizon Utilities with additional capacity and feeders from the Vansickle TS. This upgrade was required to provide capacity to service load growth in the west end of St. Catharines and to provide additional backup and load transfer capabilities through increased interconnections with Carlton TS. The new Vansickle TS M61 feeder unloaded the existing Vansickle TS M51 feeder which in turn created additional capacity at the Carlton TS.

The construction of the Vansickle TS M61 Feeder was required to create an intertie with Carlton TS for the provision of backup and load transferring capability. The backup to the Carlton TS increased reliability and security of the retail district in the St. Catharines.

2011 General Plant Projects

Project Name: Fleet Radio Replacement

Driver: General Plant

Scope: This project involved the replacement of Horizon Utilities' existing two analog radio systems, deployed throughout its fleet, with a single digital system. Radio communication between the system control room and the field crews is a critical component of utility operations. The analog systems were at the end of their useful lives and effectively obsolete. Horizon Utilities experienced ongoing systems failure and the units required repairs for which parts were no longer available. The system could not support additional units nor did it have the capability to access the frequencies to support Horizon Utilities' service areas.

A Request for Information ("RFI") process was conducted in 2010 to identify available technologies, solutions and service providers to develop the scope for a RFP for the replacement of Horizon Utilities' current 2-way radio analog system with an enterprise solution platform. The RFI provided a high level overview of expectations of the new system including; capabilities, features, equipment requirements and implementation requirements. After analyzing RFI results, consulting with other utilities, industries and key Horizon Utilities stakeholders, it was determined that the best suited radio system to fulfill Horizon Utilities present and future communications needs was the Motorola Connect Plus.

Horizon Utilities developed and issued an RFP to eight service providers using the RFI results. The evaluation team completed an evaluation matrix and shortlisted the bidders list to three respondents; Glentel, Mobile Business Communications and Kelcom. The three service providers were invited to present to Horizon Utilities key stakeholders their solution in greater detail. The evaluation team concluded that the best service provider to implement the solution was Glentel Inc. due to: cost structure, support within Horizon Utilities' service territories, and access to a 24/7 Call-in Customer Care Center. Glentel Inc. is the service provider for Hamilton Police and Emergency Services and was tasked with implementing the Motorola solution to meet their radio needs. This is an important factor in the event that Horizon Utilities is required to communicate with essential services or the City of Hamilton.

The total cost of this project was $827,000.

Justification of Project: The replacement resulted in the use of single digital system that:

- was able to service the combined service area of Hamilton and St. Catharines;
- had updated technology to access frequencies needed for communication;
- eliminated the duplication of costs previously incurred to maintain and operate two systems, and the difficulty of maintaining reliable units;
- is capable of being deployed in all existing and future vehicles; and
- was necessary to replace the existing end-of-life, obsolete system.

The existing two separate and incompatible systems required replacement due to the following issues and risks:

- both radio systems were at end-of-life and effectively obsolete, making it difficult procure replacement parts or new units to support operations;
- analog systems did not have the ability to provide radio coverage across the service territory, resulting in dead spots where workers could not communicate via radio and had to rely on cellular service if available.
- Since the two radio systems were incompatible, the control room would lose the ability to communicate with Hamilton crews if they were dispatched to St. Catharines, and vice versa. This resulted in a lost opportunity to safely provide resources where needed in an emergency.
- The radio system failures were becoming more frequent, and workers lost the ability to communicate. This communication failure resulted in crews that were idle until communication was restored either through radio or cell phone.

- System operators experienced confusion when simultaneous radio calls came into the control room from these two systems. Workers were concerned that operators could not hear an emergency call under this situation.
- Operating costs and down time were increasing due to ongoing repairs and maintenance of these obsolete systems.

The new single digital radio system provides radio coverage to all crews working within the entire Horizon service territory. Additional benefits of the new radio system are:

- **improved communications** - capability of more talk groups and better expansion capabilities;
- **improved employee safety** - texting ability, lone worker feature (can send auto signal to a lone worker at a predetermined time; if there is no response from the lone worker, the system sends an alarm);
- **accommodates future growth -** better capability for territory expansion;
- **high system availability -** dedicated control slot makes it possible to quickly access voice and data communication even during high traffic times;
- **no need to change channels -** As the worker travels from one site to the next; he/she can keep focus on the job instead of coping with manual site changes. Dynamic site roaming automatically registers the unit with the nearest site so worker can travel and always stay connected;
- **high security -** three-level check helps to prevent unauthorized users from accessing the system and the network manager's disable feature makes it easy to remotely deactivate a lost or stolen radio;
- **no downtime -** seamless maintenance makes it possible to update radio records and radios or even add sites without disrupting business activity;
- **infrastructure renewal -** to protect investment in IT and IP infrastructures, multiple sites can be linked together using existing technology.

Project Name: Tools, Shop and Garage Equipment

Driver: General Plant

Scope: This project includes capital expenditures pertaining to the replacement of tools and equipment, which are worn; beyond repair; or where the continued use of such creates health and safety risk. This equipment is used by various trades employees at Horizon Utilities including: Distribution System Line Trades (Line and, Cable Splicers, Substation Maintainers, and Labourers); Meter Technicians; Vehicle Mechanics; Facility Maintainers; Logistics (Warehouse Staff); and engineering related positions. Equipment can be categorized into the following groups:

- Safety Equipment – includes traffic control equipment; dielectric tools and cover up; rescue devices and personal protective equipment;
- Storage Systems – includes warehouse shelving and storage systems and equipment;
- Rigging and Grounding – includes grips, hoists, conductor stringing equipment and cable pulling equipment, and grounding devices;
- Tools and Equipment – includes battery-operated equipment; and hydraulic and mechanical tools;
- Measurement/Test/Computing Equipment – includes volt meters, gas detectors, mobile computing accessories and GPS units.

This is a multi-year project with the following annual investment requirements, as identified in Table 2-84 below:

Table 2-84 - Tools, Shop and Garage Equipment Annual Investment

Year	$
2011 Actual	$ 493,820
2012 Actual	$ 279,587
2013 Actual	$ 417,572
2014 Bridge Year	$ 511,300
2015 Test Year	$ 555,560
2016 Test Year	$ 567,600
2017 Test Year	$ 508,600
2018 Test Year	$ 530,600
2019 Test Year	$ 580,600

Justification of Project: Each year a condition assessment is conducted on the inventory of tools and equipment in use, to determine a forecast for expected replacements. Feedback from the crews that use the tools and equipment, together with feedback from the Fleet Mechanics who maintain the tools and equipment on each vehicle, is used to establish the annual budgets. It becomes unsafe, costly and inefficient to use or maintain this type of equipment which has reached the end of its useful life.

New tools become available on the market, on a periodic basis, that offer improved safety, ergonomics and productivity features which Horizon Utilities evaluates for use. Changes in regulations, which require a different standard of equipment, may necessitate a replacement of tools and equipment. Fall arrest equipment for example, needs to be exchanged when new standards come into effect, and any required new equipment is included in the budget.

Project Name: Vehicle Replacement

Driver: General Plant

Scope: Horizon Utilities' fleet expenditures are required to maintain vehicles and major equipment on a sustainable basis in support of safe, reliable, and responsive customer service.

Horizon Utilities' vehicle replacement forecast is based on the following criteria guidelines:

- Manufacturing Standards
- Industry Standards
- Non-Industry Standards
- Vehicle Operational Conditions
- Vehicle Age
- Vehicle Total Mileage
- Ontario Highway Traffic Act ("HTA"), which contains guidelines on vehicle safety
- CMVSS
- All related CSA standards, specifically those that relate to aerial devices and hydraulic equipment
- MVIS requirements
- Infrastructure Health & Safety Association ("IHSA") of Ontario, where applicable
- Corporate Health & Safety and Environmental Policies

Table 2-85 identifies the vehicles that were replaced in 2011 and the associated replacement cost.

Table 2-85 – 2011 Material Vehicle Replacement

Unit	Model Year	Vehicle	KMs	$
383	1996	Digger Derrick Truck	198,598	398,559
219	1992	Knuckle Crane Truck	207,391	171,531
202	1996	Overhead Single Bucket	198,598	210,900

Justification of Project:

These specific units were beyond their respective end-of-life. Productive vehicle time has been adversely affected by an increase in time required to repair and maintain these vehicles; with associated cost. Horizon Utilities' vehicle replacement cycle is described in the 2014-2019 Fleet Replacement Plan appended as Appendix O of the DSP and in Tab 6, Schedule 1 of this Exhibit.

Project Name: Annual Corporate Computer Replacement Program

Driver: General Plant

Scope: This initiative is part of an ongoing business requirement to replace end user computers. Personal Computers ("PCs") are considered a strategic asset because they are Horizon Utilities' primary productivity tool for many employees. Horizon Utilities' has streamlined its PC lifecycle management processes to: ensure maintenance and delivery of services to customers; provide the necessary tools to maintain and improve staff productivity; cost-effectively manage total cost of PC ownership; and support investments in new applications, infrastructure, and business capabilities. Horizon Utilities' utilizes a PC refresh cycle of 36 months. Approximately one third of Horizon Utilities' PCs (~150 PCs) are replaced annually.

This is a multi-year project with annual capital investment requirements as identified in Table 2-86 below.

Table 2-86 – Annual Corporate Computer Replacement

Year	$
2011 Actual	227,000
2012 Actual	312,000
2013 Actual	364,947
2014 Bridge Year	366,200
2015 Test Year	319,000
2016 Test Year	324,000
2017 Test Year	353,000
2018 Test Year	361,200
2019 Test Year	361,200

Justification of Project: Horizon Utilities' corporate computer replacement program is based on achieving a balance between: maintaining and improving customer service levels; managing capital expenditure; and maintaining effective IT operations and support.

A three year replacement schedule is utilized for laptop and tablet computers. Over 50% of Horizon Utilities' personal computers are laptops and tablets. These are replaced every three years to manage the impact on worker productivity related to hardware performance and hardware failures. Many of these tablets and laptops are used by staff working in harsh operating environments outside the office, or by staff utilizing applications that require increased power to process large volumes of data, such as, GIS, Planning and Scheduling, business analytics, and Budgeting and Forecasting.

A three year replacement schedule is utilized for desktop computers. The majority of desktop computers are used in business critical operations such as the customer call centre and Network Operations, where staff downtime can directly impact customers. It is critical for Network Operations to able to respond quickly to electrical system issues; response time and customer safety could be compromised if computer hardware is not functioning properly.

Horizon Utilities' has invested heavily in new systems such as GIS and OMS in recent years. These systems are data and processing intensive, requiring increased computational power.

2011 Actual vs. 2011 Board-Approved (CGAAP)

Horizon Utilities' 2011 total actual capital expenditure of $39,097,841 was 0.3% over the 2011 Board-Approved value of $39,000,000. Horizon Utilities does not have 2011 Board Approved on a project specific basis.

2012 Actual (MIFRS) vs. 2011 Actual (CGAAP)

Horizon Utilities' 2012 total capital expenditures (MIFRS) are $16,506,127 higher than 2011 total capital expenditures (CGAAP) as identified in Table 2-87 below. The variance was primarily due to:

- an increase of $23,277,588 due to cumulative additions of Smart Meters partly offset by;
- the removal of overhead costs from capital expenditures reported for 2011 under CGAAP as a result of the transition to IFRS. The impact of the transition to IFRS is discussed in further detail in Exhibit 6, Tab 2, Schedule 1.

Table 2-87 – 2012 Actual (MIFRS) vs. 2011 Actual (CGAAP) Capital Projects

Projects ($)	2011 Actual	2012 Actual	Variance 2012 Actual vs 2011 Actual
Reporting Basis	**CGAAP**	**MIFRS**	
Customer Connections	2,030,541	1,652,000	(378,541)
Road Relocations	894,524	3,151,887	2,257,363
Meters	3,467,413	25,168,043	21,700,630
Other Material System Access	1,352,823	536,000	(816,823)
System Access Total	**7,745,301**	**30,507,930**	**22,762,629**
4kV & 8kV Renewal	8,820,000	5,268,441	(3,551,559)
U/G (XLPE) Renewal	0	0	0
Reactive Renewal	8,230,970	4,032,000	(4,198,970)
Substation Renewal	2,170,000	3,203,000	1,033,000
Other Renewal	1,814,447	2,061,385	246,938
System Renewal Total	**21,035,417**	**14,564,826**	**(6,470,591)**
System Service Total	**3,553,180**	**2,005,966**	**(1,547,214)**
Vehicles	1,860,975	1,057,410	(803,565)
Buildings	0	1,767,000	1,767,000
Office Furniture and Equipment	24,344	295,717	271,373
IST	227,000	2,565,000	2,338,000
Tools, Shop and Garage Equipment	493,820	279,587	(214,233)
General Plant	**2,606,139**	**5,964,715**	**3,358,575**
Total Material Capital Projects	**34,940,037**	**53,043,436**	**18,103,399**
Miscellaneous	4,157,803	2,560,531	(1,597,272)
Total Capital Expenditures	**39,097,840**	**55,603,967**	**16,506,127**

The following explanations are without regard for accounting policy differences between CGAAP and MIFRS. 2011 values are expressed in CGAAP. 2012 expenditures are presented in MIFRS.

System Access

System Access expenditures increased by $22,762,629 compared to such expenditures in 2011 as follows:

- $23,277,588 of the increase was due to the smart meter implementation. Horizon Utilities substantially completed its mass deployment of Smart Meters in 2009 and, as at the end of 2011, had installed Smart Meters for 229,322 customers or 98.0% of all metering points. The Smart Meter implementation is discussed in further detail in Tab 1, Schedule 1 of this Exhibit; and,

- Expenditures on system access projects increased in 2012 as compared to 2011, mainly due to the Glendale Avenue road widening project in the City of St. Catharines which commenced and was completed in 2012 at a total cost of $2,857,788, partly offset by;

- The completion of three system access projects for MUSH sector customers in 2011 at a total cost of $1,352,823 and an update to the CCRA evaluation model which resulted in increased customer contributions and subsequently reduced the net Customer Connections expenditures in 2012.

System Renewal

Expenditures on material system renewal projects decreased in 2012 as compared to 2011 by $6,470,591 primarily as a result of the following:

- the first phase of the 4kV and 8kV Renewal Program in the area served by the Aberdeen substation was completed in 2012 at an annual cost of $469,652 compared to an annual cost of $2,516,000 in 2011; representing a decrease of $2,046,348;

- expenditures for 4kV and 8kV renewal in the areas served by the Caroline, Hughson and Welland substations were reduced by $2,341,000 to mitigate increased expenditures in system access; and,
- reactive renewal of failed assets was $4,198,970 lower in 2012 as compared to 2011.

These decreases were partially offset by:

- increased expenditures for substation renewal of $1,033,000. 2012 expenditures for the renewal of breakers and relays at Horizon Utilities' substations increased $1,775,000 from 2011. The renewal of breakers and relays is a multi-year project commencing in 2010 with completion scheduled for 2013. The project is discussed in further detail in Tab 6, Schedule 3, page 34. This increase was partly offset by a decrease of $721,000 for the Parkdale substation switchgear replacement; and
- increased expenditures for 4kV and 8kV renewal in the areas served by the Taylor and Webster substations of $835,789.

System Service

System Service expenditures in 2012 were lower than in 2011 by $1,547,214. Projects in 2012, as identified in Table 2-88 below included:

- the construction of an additional feeder at the Vansickle Transformer Station (M82 Feeder);
- the ongoing project to replace #6 Wire;
- an expansion project to supply the brownfield development of an area of the Hamilton Port Authority Lands;
- a project to upgrade the Glen Morris Line to increase capacity and redundancy between Vansickle TS and Glendale TS;
- the first installment of a payment to Hydro One for construction costs required to increase capacity at the Nebo Transformer Station; and

- a credit of $1,261,409 from Hydro One related to the reconciliation of construction costs to increase the capacity of Vansickle TS from 40MVA to 90MVA.

Table 2-88 – 2012 and 2011 Material System Service Capital Expenditures

System Service Expenditures	2011 Actual	2012 Actual
Vansickle T/S M82 Feeder- Macturnbull	$ -	$ 1,049,000
# 6 Wire Replacement	$ 626,000	$ 349,000
Hamilton Industrial Waterfront Redevelopment		$ 389,000
Glen Morris Line Upgrade		$ 510,375
24 Ft Solid Concrete Pole Replacement	$ 432,103	
Mohawk M61 Extension (Henderson Hospital -	$ 465,000	
Vansickle T/S M72 Feeder	$ 1,055,077	$ -
Vansickle T/S M61 Feeder	$ 975,000	$ -
Nebo T/S Capacity Increase	$ -	$ 970,000
Vansickle T/S Capacity Increase	$ -	($1,261,409)
Horning T/S M45	$ -	$ -
Garth Street Underground to Rymal	$ -	
Total	**$ 3,553,180**	**$ 2,005,966**

General Plant

The aggregate of general plant expenditures for material capital projects in 2012 was $3,358,575 higher than in 2011.

In 2012, IST capital expenditures were $2,565,000, an increase of $2,338,000 from 2011, as identified in Table 2-89 below.

Table 2-89 – 2012 Material IST Capital Expenditures

	2011 Actual	2012 Actual
Capital Lease IBM		$ 820,000
Windows Server Consolidation		$ 626,000
GIS Renewal		$ 807,000
Annual Computer Refresh	$ 227,000	$ 312,000
Total IST Projects	**$ 227,000**	**$ 2,565,000**

This increase was driven by the following investments:

- End of lease replacement of the IBM iSeries server hardware environment at a cost of $820,000. This hardware is used to run the Daffron CIS which supports customer management and meter-to-cash processes. This lease, commencing in 2013, qualified as a capital lease whereas the previous lease for the server hardware qualified as an operating lease. The annual lease cost included in operating costs is replaced principally by depreciation expense. Replacement of the hardware has delivered ongoing annual savings of $155,575 due to a $31,305 reduction in annual costs from the lease and a $124,270 reduction in annual maintenance costs. This project is discussed in further detail in Tab 6, Schedule 3, page 80 of this Exhibit.

- Microsoft Windows Server Consolidation project at a cost of $626,000 to address business risks related to data centre network switch port capacity and physical space limitations in the Hamilton data centre and disaster recovery data centre in St. Catharines. Without this consolidation, the data centres would have to be physically expanded and the network switch would have to be replaced to accommodate server expansion requirements for new applications such as, GIS and OMS. The consolidated server architecture alleviated of network switch port capacity issues in the two Horizon Utilities' data centres freeing up over 40 switch ports at both sites and resolved the physical space issues. This project is discussed in further detail in Tab 6, Schedule 1 of this Exhibit.

- A multi-year initiative to replace of Horizon Utilities' end-of-life GIS system with a new enterprise level solution. An enterprise level solution allows integration with other systems and involves: the deployment of the Intergraph GIS system; conversion of Horizon Utilities' GIS data from the current CableCad system to the new Intergraph system; the integration and deployment of Intergraph's OMS with GIS; and integration with the Supervisory Control and Data Acquisition ("SCADA") system. Capital expenditures for 2012 were $807,000. Further justification for this initiative and capital expenditures by year is provided in Tab 6, Schedule 1 of this Exhibit.

Buildings investments increased by $1,767,000 due to a multi-year initiative, which commenced in 2012, to address the health of building infrastructure systems, structural deficiencies, continued compliance with the OBC and Fire Codes, and health and safety concerns related to poor air quality and unsecured access points. This initiative is discussed in further detail in Tab 6, Schedule 1 of this Exhibit.

Capital expenditures for vehicles and tools, shop and garage equipment decreased in 2012 by $1,017,798. The project to replace Horizon Utilities' existing two analog radio systems with a single digital system in vehicles was completed in 2011 at a cost of $827,000. Tools, shop and garage equipment expenditures decreased by $214,233 versus 2011.

Detailed descriptions of the 2012 capital expenditures for material projects are provided in the capital project templates below.

2012 System Access Projects

Project Name: Customer Connections

Driver: System Access

Scope: This is an on-going program comprised of projects initiated by customers or developers, where investment is required to enable customers to connect to Horizon Utilities' distribution system. This program includes customer service orders, such as new and upgraded service connections for residential, commercial and industrial customers. Further details are provided in Tab 6, Schedule 3, page 19 of this Exhibit.

The amount of investment for this program is $1,652,000 as identified in Table 2-72.

Justification of Project: In 2012, 266 customer-requested connection projects were completed as shown in Table 2-73 of this Exhibit.

Customer connection projects typically include the provision and installation of transformation and switching equipment, cabling, and metering. None of individual connections projects required an investment of greater than $300,000. The 2012 customer connection projects included:

- 83 projects for service connections for customers between 50 kW and 300 kW at a net capital investment of $784,286;
- 73 projects for service connections for residential customers at a net capital investment of $413,373; and
- miscellaneous customer requested projects for service connections at a net capital investment of $454,341.

The customer contribution evaluation model was updated in 2012 to reflect current OM&A requirements. This resulted in increased customer contributions in 2012 as compared to 2011; contributing to a decrease in customer connection expenditures. Expenditures in 2012 decreased by $378,541 as compared to 2011.

Project Name: Road Relocations

Driver: System Access

Scope: Projects in this category involved the relocation of Horizon Utilities' assets to support road relocation and road reconstruction projects. The initiation and timing of these projects is outside of Horizon Utilities' control and therefore the timing and value of investment required by Horizon Utilities is subject to changes.

In 2012, $3,151,887 was required to support road relocation projects, as identified in the 2011 material project description in Tab 6, Schedule 3, page 21. The increased level of investment required in 2012 relative to other years was driven by the widening of Glendale Avenue in St. Catharines. Horizon Utilities was required to relocate assets east and west of the Hydro One TS on both the north and south side of the road. The project included burying the egress feeders exiting the Hydro One TS, in addition to the relocation of poles. The project included the replacement of poles and overhead wire and the installation of new egress ducts and cable from the Hydro One TS.

22 projects were completed in 2012 at a cost of $3,151,887 and are listed below:

Table 2-90 – 2012 Road Relocation Projects

2012 Road Relocation Projects - Hamilton
Centennial Pkwy - Feedermain/Sewer
Upper James St - Rymal Rd to Stone Church
Upper Wellington St - City Relocations
City Pole/Vault Adjustments
Barton St & Ottawa St - Sanitary Sewer
McNeiley Rd - Barton St to South Service Rd
Bay St N - Stuart to Strachan
City of Hamilton Projects
West 5th Road Reconstruction
Burlington St & Wellington St
Pole 5222 Relocation - Upper James St
Wilson St - Halson to Fiddlers Green
Wilson St E. - 1-2E Cameron Dr.
West 5th Adjustments
King St. E - 403 Bridge Rebuild
2012 Road Relocation Projects - St. Catharines
Fourth Ave Road Widening
Geneva St. and Lakeshore Rd
Regional Rd #81 Reconstruction
Lakeshore Road Upgrades OH
Lakeshore Road Upgrades UG
Riverview Blvd
Pelham Rd - First to Fifth St

Justification of Project: Justification for road relocations projects has been provided in Tab 6, Schedule 3, page 21 of this Exhibit.

Project Name: Meters

Driver: System Access

Scope: This program includes the installation of Horizon Utilities' metering assets, in compliance with Measurement Canada standards. Further details are provided in Tab 6, Schedule 3, page 23 of this Exhibit.

Justification of Project:

A general justification for meter installations is provided in Tab 6, Schedule 3, page 23 of this Exhibit. The investment in 2012 was $25,168,043. This was comprised primarily of:

- The cumulative capital expenditures of $23,277,588 for the installation of Smart Meters as provided in Tab 1, Schedule 1, page 6-7 of this Exhibit;
- the continuation of the wholesale metering program which included the upgrade of metering at Elgin Transformation Station at a capital investment of approximately $600,000;
- the procurement and installation of meters for new connections and the installation of commercial Smart Meter conversions at a capital investment of approximately $1,050,000; and
- the procurement and installation of residential metering at a capital investment of approximately $200,000.

2012 System Renewal Projects

Project Name: 4kV and 8kV Renewal Program

Driver: System Renewal

Scope**:** This project involved the conversion of all existing 4kV and 8kV assets to either 13.8kV or 27.6kV, dependent upon the supply voltage from Hydro One which varies by operating area. The 4kV and 8kV Renewal Program for these assets utilizes an area-wide approach centred on the substations servicing each area. The selection and prioritization of these areas for renewal is either driven by substation asset health (St. Catharines, Hamilton West, and Hamilton Downtown operating areas) or by the health of the distribution system and operational constraints (Dundas operating area), and is fully described in the 4kV and 8kV Renewal Program, Section 3.5.3 of the DSP provided as Appendix 2-4 of this Exhibit. Once the assets are converted to the higher voltages, the substation assets will be decommissioned. In 2012, renewal occurred in areas served by five substations as indicated in Table 2-91 below:

Table 2-91 – 2012 4kV and 8kV Renewal Program

Substation	$
Aberdeen Substation	469,652
Caroline Substation	430,000
Hughson Substation	1,813,000
Taylor Substation	2,139,000
Webster Substation	305,789
Welland Substation	111,000
Total	**5,268,441**

Justification of Project: The justification for this project has been provided in Tab 6, Schedule 3, page 28 of this Exhibit.

Project Name: Reactive Renewal

Driver: System Renewal

Scope: Unplanned failures of overhead and underground system components are corrected in a reactive manner to restore service to customers. Reactive renewal expenditures were $4,032,000 in 2012. Further details on the scope of this project have been provided in Tab 6, Schedule 3, page 30.

Justification of Projects:

Horizon Utilities experiences a large volume of equipment failures on an annual basis, resulting in service interruption to customers. Capital investment is required to repair the distribution system and restore service to customers. These are reactive expenditures originating from 2,896 customer outage calls to Horizon Utilities' System Control Centre, and are necessary to restore service to Horizon Utilities' affected customers. The costs to replace failed assets and restore power was $2,775,093 in 2012. These costs included the replacement of 107 poles and 123 transformers along with the required conductors, cables and hardware.

Investment is also required annually to address power quality and other urgent issues identified through internal inspection programs or as reported by external organizations (e.g. the ESA). Failure to perform these investments will result in:

- The inability to address safety concerns identified by the ESA and internal inspection programs; and
- The inability to address power quality concerns identified by customers.

Horizon Utilities completed 124 projects in 2012, to address the safety and power quality concerns noted above, at a cost of $1,256,907.

Project Name: Parkdale Substation Switchgear Replacement

Driver: System Renewal

Scope: This project, as identified and fully described in the 2011 Material Project description in Tab 6, Schedule 2, page 32, involved the replacement of the 4kV switchgear at Parkdale substation.

Justification of Project: In 2012, $900,000 was invested in the final year of this two-year project. The justification for this project has been provided in Tab 6, Schedule 3, page 32 of this Exhibit.

Project Name: Substation Breaker and Relay Renewal

Driver: System Renewal

Scope: This program involved the renewal of the breakers and protection relays at substations servicing the Hamilton East and Hamilton Mountain 4kV operating areas, as identified in Tab 6, Schedule 3, page 34 of this Exhibit. The investment in 2012 for this multi-year program was $1,998,000. This program was initiated in 2010 and completed in 2013.

Justification of Project: The justification for this project has been provided in Tab 6, Schedule 3, page 34 of this Exhibit and in the 4kV and 8kV Renewal Program in Section 3.5.3 of the DSP.

Table 2-92 – Substation Breaker and Relay Renewal

Year	$	Substation	Replacements
2011 Actual	223,000	Bartonville	Breaker
2012 Actual	1,998,000	Wentworth	Relay
		Bartonville	Relay
		Spadina	Relay
		Ottawa	Breaker and Relay
2013 Actual	3,864,456	Mountain	Breaker and Relay
		Mohawk	Breaker and Relay
		Kenilworth	Breaker and Relay
		Wellington	Relay
		Cope	Relay

Justification of Project: Horizon Utilities replaced thirteen breakers and 51 relays and switchgear doors in 2012, at a cost of $1,998,000.

The thirteen breakers and relays at Ottawa Substation were 1966 vintage and were at end-of-life. The replacement of this equipment was necessary as this substation is required to be in service until 2047.

Thirty-eight electromechanical relays were replaced with digital relays at the Wentworth, Bartonville and Spadina substations to replace end-of life assets. The Wentworth and Spadina substations need to remain in service until 2041, and the Bartonville substation needs to remain in service until 2038.

Project Name: Substation Infrastructure Renewal

Driver: System Renewal

Scope: This program involved the necessary renewal of substation infrastructure in substations throughout Horizon Utilities' service territory, as identified in Tab 6, Schedule 3, page 36 of this Exhibit.

Justification of Project: The investment in 2012 for this multi-year program was $305,000 and included the following:

- Battery charger replacements;
- Ion meters at five stations for SCADA visibility;
- A breaker test station at Bartonville Substation;
- A station service transformer at Welland Substation;
- Eyewash stations; and
- Battery replacements.

Further justification for this project has been provided in Tab 6, Schedule 3, page 36 of this Exhibit.

Project Name: **Pole Residual Replacements**

Driver: System Renewal

Scope: This project addressed the replacement of obsolete poles and poles that were determined to be at end-of-life through maintenance and inspection programs, as identified in Tab 6, Schedule 3, page 38 of this Exhibit.

Justification of Project: Horizon Utilities replaced 87 poles in 2012 at a cost of $930,000.

Justification for the pole residual replacement program has been provided in Tab 6, Schedule 3, page 38 of this Exhibit.

2012 System Service Projects

Project Name: Nebo Transformer Station Capacity Increase

This project involves increasing the capacity of the 27.6kV Nebo TS. This is a shared station which supplies both: i) Horizon Utilities customers in the Stoney Creek service area of Hamilton; and ii) Hydro One customers in the area. Both Horizon Utilities and Hydro One identified the need to increase capacity in this system since Nebo TS exceeded the 10 day Limited Time Rating[3] ("LTR") of the station during the summer peak period, which puts reliability at risk. Managing to this LTR rating is a best practice for utilities to manage security and reliability of the distribution system at a station capacity level.

This project required a $970,000 contribution to Hydro One in 2012.

Justification of Project: The Stoney Creek area south of the escarpment has experienced an increase in peak demand of 30% over the period of 2009-2011, and is forecast to increase an additional 15% by 2019. Horizon Utilities' allocation of capacity at the Nebo TS has exceeded the 10 day LTR during peak periods in each of 2011, 2012, and 2013. Exceeding the 10 day LTR presents reliability risk, and Hydro One has the authority to request load transfers and/or load shedding to reduce the peak load below the 10 day LTR threshold. Horizon Utilities entered into a CCRA with Hydro One in 2012 to upgrade this station to increase capacity. Costs to upgrade the transformers at Nebo TS will be shared between Horizon Utilities and Hydro One.

[3] The capacity of a Hydro One transformer at a TS is determined by its ability to safely withstand a certain loading level for 10 continuous days without a perceptible impact in the expected life of the transformer. This is termed the "10 day long term rating" (10 day LTR). Loading a TS transformer above this 10 day LTR design limit will shorten its useful life expectancy. The 10 day LTR ratings are monitored closely and not exceeding this limit for any appreciable time limit is strictly desirable.

Project Name: Vansickle TS M82 Feeder – Mac Turnbull

Driver: System Service

Scope: This project involved the necessary construction of a new feeder from Vansickle TS to create an additional intertie with Carlton TS. The total investment in 2012 was $1,049,000.

Justification of Project: The Vansickle TS capacity upgrade project completed in 2010 provided Horizon Utilities with additional capacity and feeders from the Vansickle TS. This upgrade was required to provide capacity to service load growth in the west end of St. Catharines and to provide additional backup and load transfer capabilities through increased interconnections with adjacent TSs.

The construction of the Vansickle TS M82 Feeder was required to create an intertie with Carlton TS for the provision of backup and load transferring capability. The backup to the Carlton TS increased reliability and security of the retail district in the St. Catharines downtown core.

Project Name: #6 Wire Replacement

Driver: System Service

Scope: Horizon Utilities has an ongoing program to proactively replace #6 overhead primary conductor throughout the service territory, as identified in Tab 6, Schedule 3, page 42 of this Exhibit.

Justification of Project: Horizon Utilities completed four projects in 2012 to replace an aggregate of 4 km of #6 wire at a cost of $349,000. The costs were inclusive of pole and transformer replacements which were required to meet current engineering standards.

Justification of the #6 wire replacement project has been provided in Tab 6, Schedule 3, Page 42 of this Exhibit.

Project Name: Hamilton Waterfront Industrial Expansion

Driver: System Service

Scope: This project was required to provide additional capacity for the brownfield redevelopment areas of the Hamilton waterfront. An investment of $389,000 was required in 2012 to execute this project.

Justification of Project: Horizon Utilities has service obligations in accordance with the DSC and Horizon Utilities' Conditions of Service. Feeders within the Hamilton waterfront area were utilized to their maximum capacity. This meant no additional load could be supported and redundancy of adjacent feeders could not be provided. Furthermore, the redevelopment of vacant and under-utilized areas of the Hamilton waterfront area required additional capacity. Horizon Utilities' distribution system had insufficient capacity to service any further potential development or provide the proper redundancy to adjacent feeders in this area. Therefore a project to provide capacity to the area through the construction of Feeder 5612X was undertaken and work was completed in 2012.

Project Name: Glen Morris Drive Line Upgrade

Driver: System Service

Scope: Upgrade the existing undersized overhead conductor on Glen Morris Drive. This included replacing poles, insulators and stringing 1 km of new 556 MCM aluminum conductors to bring the feeder to full capacity.

The investment required in 2012 was $510,375.

Justification of Project: The conductor along Glen Morris Drive in St. Catharines was originally constructed in the late 1960s with undersized conductor, which did not allow loads to be transferred between Vansickle TS and Glendale TS during peak load periods. The inability to transfer loads between these two transformer stations would have resulted in lengthy outages to residential and commercial customers in the east end of St. Catharines.

<u>2012 General Plant Projects</u>

Project Name: Capital Lease - IBM

Driver: General Plant, $820,000

Scope: This project was related to the 2012 end of lease replacement of the IBM iSeries server hardware environment used to run the Daffron CIS which supports Horizon Utilities' customer management and meter-to-cash processes. The environment includes a production IBM iSeries server in Hamilton and an identical IBM iSeries server at Horizon Utilities' Disaster Recovery Data Centre in St. Catharines.

This lease, commencing in 2013, is a capital lease, whereas the previous lease for 2010 to 2012, for the server hardware, was an operating lease. The annual lease cost included in operating costs is replaced principally by depreciation expense.

Justification of Project: The existing IBM iSeries Hardware was at the end of its lease and replacement was required to maintain the continued operation of Horizon Utilities' Daffron CIS system. Replacement of the hardware has delivered ongoing annual savings of $155,575 due to a $31,305 reduction in annual costs from the lease and a $124,270 reduction in annual maintenance costs.

Other Benefits:

The new IBM iSeries environment has provided significant performance enhancements as follows:

- reduction in the length of time required to process day-end and month-end processing
- reduction in the length of time required for overnight processing resulting in:
    - faster bill-calculation processing;
    - faster meter read processing; and
    - faster back-up processing.

- shortened planned outage durations which increase the availability of website services for access to customer billing information.

Advancements in technology have reduced the physical footprint of the IBM iSeries environment from two physical racks to one, thereby increasing the space available for future expansion of the data centres. The reduced footprint to one physical rack has also reduced power consumption.

Project Name: Annual Corporate Computer Replacement Program

Driver: General Plant

Scope: This initiative is part of an ongoing business requirement to place end user computers, as identified in Tab 6, Schedule 3, page 55 of this Exhibit. Horizon Utilities utilizes a three-year lifecycle for replacement of end user computers with approximately 150 PCs replaced annually.

The 2012 investment was $312,000 for this multi-year initiative.

Justification of Project: Justification for the annual corporate computer replacement program is provided in Tab 6, Schedule 3, page 55 of this Exhibit.

Project Name: Storage Area Network ("SAN") Expansion

Driver: General Plant

Scope: This 2012 project involved the consolidation of Horizon Utilities' Microsoft Windows server environment and SAN to address the following issues and risks:

- End-of-life replacement of the Windows Server environment;
- End-of-life replacement of the Advanced Metering Infrastructure ("AMI") servers and data storage environment to support an upgrade of the Elster Energy Axis AMI application required for regulatory compliance related to reading of 3-phase Smart Meters;
- Physical space capacity issues in the two Horizon Utilities data centres;
- Network switch port exhaustion in the two Horizon Utilities data centres;
- Server and SAN capacity to support new business applications, such as, GIS and OMS;
- Provision of scalability requirements for server and SAN environments to provide for future growth; and
- Reduction in the technical support effort related to management of the server, SAN and backup environments to avoid the need to increase support staff.

The 2012 investment was $626,000.

Justification of Project: This investment has provided Horizon Utilities' with the following benefits:

- Resolution of physical space, network switch port capacity and power consumption issues that would have required significant capital investments to expand or move the data centres, expand data centre electrical services, and replace the network switch infrastructure;

- Provision of the technical environment to enable an upgrade of the Elster Energy Axis AMI application to support regulatory compliance requirement related to reading of 3-phase Smart Meters; and

- Consolidation of the Windows Server environment and AMI server environment into a single server and SAN architecture which led to an increase in staff productivity by simplifying the environment and reducing time required to manage the environment.

Project Name: Geospatial Information System ("GIS") Renewal

Driver: General Plant

Scope: This multi-year initiative involves the replacement of Horizon Utilities' end-of-life GIS system with a new enterprise level solution. An enterprise level solution allows integration with other systems as described below.

This project involves the deployment of the Intergraph GIS system; conversion of Horizon Utilities' GIS data from the current CableCad system to the new Intergraph system; the integration and deployment of Intergraph's OMS with GIS; and integration with the SCADA system. This is a multi-year initiative with annual investment requirements as identified in Table 2-93 below:

Table 2-93 – GIS Renewal

Year	$
2012 Actual	807,000
2013 Actual	1,103,442
2014 Bridge Year	1,869,308
2015 Test Year	205,276

Justification of Project: Horizon Utilities' current GIS is eighteen years old and has reached end-of-life. The system is no longer compatible with Horizon Utilities' current IST infrastructure. Furthermore, the application vendor ceased support of the product and it has not been updated since 2003. This project is discussed in further detail in Tab 6, Schedule 1 of this Exhibit.

Project Name: 2012 Building Renovations

Driver: General Plant

Scope: Horizon Utilities identified that a long-term building asset maintenance and renewal plan was necessary and, in 2010, commenced a series of studies to understand the building related requirements; the level of required investment; and to prioritize the prospective building renewal projects.

Renovations commenced in 2012 and were completed at two locations as identified in Table 2-94 below.

Table 2-94 – 2012 Building Renovations

Location	$
Vansickle Road Service Centre	460,000
John Street Head Office and Hughson Building	1,307,000

Justification: A detailed description and justification of the building renovations for 2012 is provided in Tab 6, Schedule 1 of this Exhibit.

Project Name: Vehicle Replacement

Driver: General Plant

Scope: Horizon Utilities' fleet expenditures are required to maintain vehicles and major equipment on a sustainable basis in support of safe, reliable, and responsive customer service.

Table 2-95 below identifies the vehicles that were replaced in 2012 at a cost of $978,000.

Table 2-95 – 2012 Vehicle Replacement

Unit	Model Year	Vehicle	KMs	$
253	1986	Reel Truck	291,935	376,000
275	1996	Single Bucket Truck	202,574	327,000
205	1997	Single Bucket Truck	200,146	275,000

Justification of Project:

A more detailed justification is provided in the project template for 2011 in Tab 6, Schedule 3, page 53.

2013 Actual (MIFRS) vs. 2012 Actual (MIFRS)

Horizon Utilities' 2013 total capital expenditures (MIFRS) were $16,099,354 lower than 2012 total capital expenditures (MIFRS) as identified in Table 2-96 below. A decrease in system access projects of $22,894,595, driven primarily by 2012 expenditures of $23,277,588 associated with the smart meter implementation, was partly offset by an increase in system renewal and general plant expenditures of $7,053,873. A more detailed variance analysis is provided below.

Table 2-96 – 2013 Actual vs. 2012 Actual Capital Projects

Projects ($)	2012 Actual	2013 Actual	Variance 2013 Actual vs. 2012 Actual
Reporting Basis	**MIFRS**	**MIFRS**	
Customer Connections	1,652,000	3,541,455	1,889,455
Road Relocations	3,151,887	340,491	(2,811,396)
Meters	25,168,043	1,658,707	(23,509,336)
Other Material System Access	536,000	2,072,682	1,536,682
System Access Total	**30,507,930**	**7,613,335**	**(22,894,595)**
4kV & 8kV Renewal	5,268,441	5,072,233	(196,208)
U/G (XLPE) Renewal	0	1,572,090	1,572,090
Reactive Renewal	4,032,000	6,069,566	2,037,566
Substation Renewal	3,203,000	4,032,963	829,963
Other Renewal	2,061,385	1,207,052	(854,333)
System Renewal Total	**14,564,826**	**17,953,904**	**3,389,078**
System Service Total	**2,005,966**	**1,518,968**	**(486,998)**
Vehicles	1,057,410	36,365	(1,021,045)
Buildings	1,767,000	5,490,000	3,723,000
Office Furniture and Equipment	295,717	873,925	578,208
IST	2,565,000	3,046,146	481,146
Tools, Shop and Garage Equipment	279,587	417,572	137,984
General Plant	**5,964,715**	**9,864,008**	**3,899,293**
Total Material Capital Projects	**53,043,436**	**36,950,215**	**(16,093,221)**
Miscellaneous	2,560,531	2,554,428	(6,103)
Total Capital Expenditures	**55,603,967**	**39,504,643**	**(16,099,324)**

System Access

Expenditures on system access projects decreased in 2013 as compared to 2012. The 2012 expenditures included $23,277,588 with respect to the Smart Meter implementation, as previously described. There was also a significant decrease in the investment required to relocate Horizon Utilities' assets resulting from less road widening requests. The value of these requests was $3,151,887 in 2012, versus $340,591 in 2013. These decreases were partly offset by the following:

- increased investment in capital expenditures of $1,889,455 to support a higher number of customer connections projects than in 2012. Customer requested projects increased by 21 in 2013 to a total of 287 projects, and consisted of more general service greater than 300 kW projects which are more costly to connect than smaller services;
- the construction of a new feeder to supply the redevelopment of the Caroline and George Street area of downtown Hamilton; and
- the construction of a new feeder in St. Catharines to supply MUSH sector customers "P" and "A".

System Renewal

Expenditures on system renewal projects increased by $3,389,078 in 2013 as compared to 2012. A proactive replacement of underground primary XLPE cable in St. Catharines and Stoney Creek commenced in 2013. Primary XLPE cable is the asset category with the largest investment requirements due its poor and declining health as described in Tab 6, Schedule 1 of this Exhibit, and justified in Appendix A and Appendix G of the DSP.

Substation renewal expenditures were higher in 2013 than in 2012 due to an increase in the Breaker and Relay renewal project, which was completed in 2013. This project is discussed in further detail in Tab 6, Schedule 3, page 34 of this Exhibit.

Reactive renewal increased by $2,037,566 from 2012 to 2013. A primary driver of this increase was equipment failures as a result of the July 2013 windstorm and the December 2013 ice storm. The impact of these storms is discussed in further detail in Exhibit 4, Tab 3, Schedule 3. More details are provided at Tab 6, Schedule 3, page 30 of this Exhibit.

The decrease in the Other Renewal category by $854,333 is explained by lower pole replacements than in the prior year, and the completion of the downtown network renewal for St. Catharines in 2012. This was partly offset by Load Break Disconnect Switch ("LBDS") renewal. The justification for this project is provided in Tab 6, Schedule 3, page 101 of this Exhibit.

System Service

System Service expenditures in 2013 were $486,998 lower than in 2012. There was only one material capital project in this category in 2013 – the final payment to Hydro One for construction costs required to increase capacity at the Nebo Transformer Station. The justification for this project is provided in Tab 6, Schedule 3, page 74 of this Exhibit. The expenditures in 2012 included: the construction of an additional feeder at the Vansickle Transformer Station; an expansion project for the Hamilton Port Authority; and the Glen Morris Drive line upgrade. These projects are discussed in further detail in Tab 6, Schedule 3, pages 75-78.

General Plant

General plant expenditures for material capital projects in 2013 of $9,864,008 were $3,899,293 higher than in 2012. Buildings expenditures increased by $3,723,000 versus 2012, driven by the commencement of facility renewal at the Nebo Road location. IST expenditures were also higher than in the prior year due to an IFS ERP system lifecycle upgrade and a project to implement a new data backup and recovery system. Office equipment increased versus prior year as a result of the replacement of end-of-life furniture and fixtures. Further justification for office equipment is provided in Tab 6, Schedule 3, page 108 of this Exhibit. Vehicle replacements were deferred from 2013 to 2014 to balance the overall capital plan for the year as a result of higher than planned building expenditures.

Detailed descriptions of the 2013 capital expenditures for material projects are provided below.

2013 System Access Projects

Project Name: Customer Connections

Driver: System Access

Scope:

This is an on-going program comprised of projects initiated by customers and developers, where investment is required to enable customers to connect to Horizon Utilities' distribution system. This program includes customer service orders, such as new and upgraded service connections for residential, commercial and industrial customers.

Customer connection investments may include the provision and installation of transformation, switching equipment, cabling, and metering. The net 2013 capital investment was $3,541,455 as identified in Table 2-72.

Justification of Project:

System Access projects are investments required to meet customer service obligations in accordance with the DSC and Horizon Utilities' Conditions of Service. Horizon Utilities uses the economic evaluation methodology prescribed by the DSC to determine the level, if any, of capital contributions for each project; with such contribution incorporated into the annual capital budget. These investments are non-discretionary, cannot be deferred, and must proceed as planned.

The CCRA evaluation model was revised to reflect current OM&A requirements in 2013. This revision resulted in increased net capital costs of approximately $1,200,000 as a result of decreased customer contributions.

In 2013, 287 customer-requested connection projects were completed, an increase of 21 projects over the previous year. The most significant project cost driver was an increase of 21 connections for the general service greater than 300 kW customers as compared to 2012 and as shown in Table 2-73 of this Exhibit. Service connections for larger customers typically require an average investment of approximately $30,000 or more per project as they are generally more expensive than connections for smaller customers due to additional switching and transformation requirements.

None of the individual connections projects required an investment of greater than $300,000. The 2013 customer connection projects included:

- 57 projects for service connections for commercial and industrial customer greater than 300 kW at a net capital investment of $1,533,347;
- 83 projects for service connections for commercial and industrial customers between 50 kW and 300 kW at a net capital investment of $1,088,374;
- 79 projects for service connections for residential customers at a net capital investment of $524,391; and,
- miscellaneous customer requested service connections at a net capital investment of $395,343.

Project Name: Road Relocations

Driver: System Access

Scope: Projects in this category involved the relocation of Horizon Utilities' assets to support road relocation and road reconstruction projects, as identified in Tab 6, Schedule 3, page 21. The initiation and timing of these projects is outside of Horizon Utilities' control and therefore the timing and value of investment required by Horizon Utilities is subject to changes.

Horizon Utilities completed twenty projects in 2013, identified in table 2-97 below, at a total cost of $340,491.

Table 2-97 – 2013 Road Relocation Projects

2013 Road Relocation Projects - Hamilton
Centennial Pkwy - Sanitary Sewer
Sanatorium Rd - COH Road Work
Barton St. E - Kenora to Centennial
Ferguson & Charlton
King St. E - 403 Bridge Rebuild
Manhole Adjustments - King St.
Centennial Pkwy - Sanitary Sewer Phase 3
Barton St & Ottawa St - Sanitary Sewer
2013 Road Relocation Projects - St. Catharines
Rural Rd 87 (Main St) Widening
Fourth Ave East Road Work
Burgoyne Bridge North Portion
St. Paul/First Louth Intersection
Regional Rd 81 Phase 3
Burgoyne Bridge - Renown Portion
Burgoyne Bridge Rebuild
Glendale Ave Deficiences
Niagara Street Road Widening
Riverview Blvd
Regional Rd. 81 - Phase 2
279 Niagara St.

Justification of Project: Justification of road relocations has been provided in Tab 6, Schedule 3, page 22 of this Exhibit.

Project Name: Meters

Driver: System Access

Scope: This program includes the installation of Horizon Utilities' metering assets, in compliance with Measurement Canada standards. Further details are provided in Tab 6, Schedule 3, page 23 of this Exhibit.

Justification of Project:

A justification for meter installations is provided in Tab 6, Schedule 3, page 24 of this Exhibit. The investment in 2013 was $1,658,707. This investment was comprised primarily of:

- the provision and installation of meters for new commercial connections and the installation of commercial Smart Meter conversions at a cost of approximately $900,000;
- the provision of residential, multi-residential, and suite metering at a cost of approximately $450,000; and
- the completion of the wholesale metering program, including the upgrading of meters at Birmingham Transformation Station at a cost of approximately $170,000.

Project Name: **Caroline & George Street Feeder**

Driver: System Access

Scope: The Caroline and George Street area of downtown Hamilton is undergoing an urban renewal with the construction of several large commercial and high density residential buildings. Horizon Utilities' existing infrastructure in this area of the downtown core has insufficient capacity to service the new developments. This project involves the construction of a new feeder from Elgin TS to the Caroline and George Street area. The total project investment was $1,683,902.

Justification of Project: System Access projects are investments required to meet customer service obligations in accordance with the DSC and Horizon Utilities' Conditions of Service. Horizon Utilities uses the economic evaluation methodology prescribed by the DSC to determine the level, if any, of capital contributions for each project; with such levels incorporated into the annual capital budget. These investments cannot be deferred and must proceed as planned. With the re-development of the Hamilton downtown core, the upgrade and installation of new infrastructure was necessary. This project will allow Horizon Utilities to provide a reliable supply of power to five new developments in the Caroline and George Street area, with a total expected connection demand of 8MW by 2017.

Project Name: St. Catharines Downtown Enhancement

Driver: System Access

Scope: This project involves the construction of a new feeder from Carlton TS to support new load growth in the St. Catharines downtown area. The 2013 investment for this project was $388,780.

Justification of Project: System Access projects are investments required to meet customer service obligations in accordance with the DSC and Horizon Utilities' Conditions of Service. Horizon Utilities uses the economic evaluation methodology prescribed by the DSC to determine the level, if any, of capital contributions for each project; with such levels incorporated into the annual capital budget. These investments cannot be deferred and must proceed as planned. Horizon Utilities received three connection requests in the St. Catharines downtown area totalling 5.5 MVA of new load. Horizon Utilities' distribution system could not accommodate this load and a new feeder from the Carlton TS was required.

2013 System Renewal Projects

Program: 4kV and 8kV Renewal Program

Driver: System Renewal

Scope: This project involved the conversion of all existing 4kV and 8kV assets to either 13.8kV or 27.6kV, depending upon the supply voltage from Hydro One which varies by operating area. The 4kV and 8kV Renewal Program for these assets utilizes an area-wide approach centred on the substations servicing each area. The selection and prioritization of these areas for renewal is either driven by substation asset health (St. Catharines, Hamilton West, and Hamilton Downtown operating areas) or by the health of the distribution system and operational constraints (Dundas operating area), and is fully described in the 4kV and 8kV Renewal Program, Section 3.5.3 of the DSP provided in Appendix 2-4 and Tab 6, Schedule 3, page 28 of this Exhibit. Once the assets are converted to the higher voltages, the substation assets will be decommissioned. In 2013, renewal occurred in areas served by two substations as identified in Table 2-98 below:

Table 2-98 – 2013 4kV and 8kV Renewal Program

Substation	$
Hughson Substation	4,134,216
Welland Substation	938,017

Justification of Project:

Justification for the 4kV and 8kV Renewal Program is provided in Tab 6, Schedule 3, page 28 of this Exhibit and Appendix A of the DSP.

Project: Underground XLPE Cable Renewal Program

Driver: System Renewal

Scope: This multi-year program relates to the proactive renewal of underground XLPE primary cable. Annual projects are determined using the combined analysis of XLPE asset condition assessment studies with XLPE failure data and the resulting service interruptions to customers.

This is a multi-year program with multiple projects forecast for each year. The annual investment required is identified in Table 2-99 below:

Table 2-99 – Underground XLPE Cable Renewal Program

Year	$
2013 Actual	1,572,090
2014 Bridge Year	893,000
2015 Test Year	2,567,000
2016 Test Year	4,926,000
2017 Test Year	8,866,000
2018 Test Year	9,384,000
2019 Test Year	10,271,000

XLPE renewal projects were completed in the areas identified in Table 2-100 below in 2013:

Table 2-100 – 2013 XLPE Cable Renewal Program by Area

Area	$
St. Catharines	1,237,371
Stoney Creek	334,719

Justification of Project: Justification for the XLPE Cable Renewal Program is provided in Tab 6, Schedule 1 of this Exhibit and Section 3.5.3 of the DSP.

Project Name: Reactive Renewal

Driver: System Renewal

Scope: Unforeseen failures of overhead and underground system components are corrected in a reactive manner to restore service to customers. More details on the scope of this project have been provided in Tab 6, Schedule 3, page 30 of this Exhibit.

Justification of Project: Reactive renewal expenditures in 2013 were $5,838,068.

Horizon Utilities experiences a large volume of equipment failures on an annual basis, resulting in service interruption to customers. Capital investment is required to repair the distribution system and restore service to customers. These expenditures are reactive in nature, originating from 4,143 customer outage calls to Horizon Utilities' System Control Centre. These investments are necessary to restore service to the affected customers. The costs to replace failed assets and restore power were $3,307,029 in 2013. These costs included the replacement of 49 poles and 135 transformers as well as the required conductors, cables and hardware.

Investment is also required annually to address power quality and other urgent issues identified through internal inspection programs or as reported by external organizations (e.g. the ESA). Failure to perform these investments will result in the inability to address

- safety concerns identified by the ESA and internal inspection programs; and
- power quality concerns identified by customers.

Horizon Utilities completed 154 projects in 2013 to address the safety and power quality concerns noted above, at a total expenditure of $2,528,039.

Project Name: Substation Breaker and Relay Renewal

Driver: System Renewal

Scope: This program involved the renewal of the breakers and protection relays at Horizon Utilities' substations servicing the Hamilton East and Hamilton Mountain 4kV operating areas, as identified in Tab 6, Schedule 2, page 34 of this Exhibit. The investment in 2013 for this multi-year program was $3,864,456. The program was initiated in 2010 and completed in 2013.

Justification of Project: Justification for this project has been provided in Tab 6, Schedule 3, page 34 of this Exhibit.

Table 2-101 – Substation Breaker and Relay Renewal

Year	$	Substation	Replacements
2011 Actual	223,000	Bartonville	Breaker
2012 Actual	1,998,000	Wentworth	Relay
		Bartonville	Relay
		Spadina	Relay
		Ottawa	Breaker and Relay
2013 Actual	3,864,456	Mountain	Breaker and Relay
		Mohawk	Breaker and Relay
		Kenilworth	Breaker and Relay
		Wellington	Relay
		Cope	Relay

Justification of Project: Horizon Utilities replaced 40 oil and air breakers and 74 electromechanical relays with vacuum breakers and digital relays at a total cost of $3,864,456.

The Mountain, Mohawk and Wellington substations had 1948, 1951 and 1958 vintage equipment respectively which was at end-of-life. Replacement was necessary as these substations are required to be in service until 2035.

The Cope and Kenilworth substations had 1964 and 1967 vintage equipment respectively, which was at end-of-life. Replacement was necessary as these substations are required to be in service until 2049. Further justification is provided in Tab 6, Schedule 3 and in the 4kV and 8kV Renewal Program in Section 3.5.3 of the DSP.

Project Name: **Pole Residual Replacements**

Driver: System Renewal

Scope: This project addresses the replacement of obsolete poles and poles that are determined to be at end-of-life by Horizon Utilities maintenance and inspection programs, as identified in Tab 6, Schedule 3, page 38 of this Exhibit.

Justification of Project: Horizon Utilities replaced 70 poles in 2013 at a cost of $718,074. Justification for this project has been provided in Tab 6, Schedule 3, page 38 of this Exhibit.

Project Name: **LBDS Renewal**

Driver: System Renewal

Scope: This project involves the replacement of LBDS found to be either inoperable or beyond economic repair (where the cost of maintenance exceeds the cost of replacing the unit) as identified through Horizon Utilities' maintenance and inspection programs. Such switches will be replaced with automated switches for this program. This is a multi-year program with annual investment requirements identified in Table 2-102 below.

Table 2-102 – LBDS Renewal

Year	$
2013 Actual	212,000
2014 Bridge Year	312,000
2015 Test Year	323,000
2016 Test Year	334,000
2017 Test Year	345,000
2018 Test Year	357,000
2019 Test Year	368,000

Justification of Project: Horizon Utilities replaced eighteen LBDS in 2013. During routine inspection and maintenance of LBDS, a small percentage of switches is found to be inoperable or requires extensive maintenance that would exceed the cost of simply replacing the unit. LBDS have historically been installed at important operating points, and as such, an unplanned failure of these devices would severely impact Horizon Utilities' ability to restore power, resulting in extended outages. Annual costs are based on historical levels and Horizon Utilities expects this to remain fairly constant as the overall Health Index for LBDS is good (the percentage of this asset class with a "poor" or "very poor" Health Index is 20%).

<u>2013 System Service Projects</u>

Project Name: Nebo Transformer Station Capacity Increase

Scope: This project involves increasing the capacity of the 27.6kV Nebo TS. This is a shared station which supplies both: i) Horizon Utilities customers in the Stoney Creek service area of Hamilton; and ii) Hydro One customers in the area. The scope and justification of this project are described in further detail under 2012 System Service Projects in Tab 6, Schedule 3, page 74 of this Exhibit.

This project required a $1,449,847 contribution to Hydro One in 2013.

<u>2013 General Plant Projects</u>

Project Name: Annual Corporate Computer Replacement Program

Driver: General Plant

Scope: This initiative is part of an ongoing business requirement to replace end user computers, as identified in Tab 6, Schedule 3, page 55. Horizon Utilities utilizes a three-year lifecycle for replacement of end user computers with approximately 150 PCs replaced annually.

The investment in 2013 is expected to be $364,947 for this multi-year initiative.

Justification of Project: Justification to the annual corporate computer replacement program is provided earlier in Tab 6, Schedule 3, page 55 of this Exhibit.

Project Name: Enterprise Backup Solution

Driver: General Plant

Scope: This project involved the implementation of a new data backup and recovery system capable of supporting business data volume growth rates of between 50% and 60% annually. The existing system implemented in 2009 could be expanded to support all backup and recovery requirements of the business.

The investment in 2013 was $351,995.

Justification of Project: This was a risk-mitigation project. The project was required to provide increased capacity of the backup and recovery services for Horizon Utilities, ensuring that vital servers, data, and documents stored on the SAN, such as: GIS; AMI; Itron; Security Systems; and email can be backed up, archived and recovered to support legal and regulatory requirements, and ongoing business activity.

Project Name: IFS ERP Upgrade

Driver: General Plant

Scope: This is an enterprise-wide project that commenced in 2013 and continues through to 2015 to upgrade Horizon Utilities' ERP system from IFS version 7.3 to version 8.1. This is a major upgrade to the Horizon Utilities ERP system installed in 2007-2008. This project was required to eliminate operational risks dependent on software, database and operating systems that will not be supported by respective vendors beyond 2014. In addition, the upgrade is required to provide an updated application for the implementation of redesigned, optimized and/or new business processes that will allow Horizon Utilities' to deliver planned productivity improvements.

The 2013 investment was $1,225,762 for this multi-year initiative.

Justification of Project: The justification for this project was provided in Tab 6, Schedule 1 of this Exhibit.

Project Name: GIS Renewal

Driver: General Plant

Scope: This multi-year initiative involves the replacement of Horizon Utilities' end-of-life GIS system with a new enterprise level solution, as described in Tab 6, Schedule 1 of this Exhibit.

This project involved: the deployment of the Intergraph GIS system; conversion of Horizon Utilities' GIS data from the current CableCad system to the new Intergraph system; the integration and deployment of Intergraph's OMS with GIS; and integration with the SCADA system.

The 2013 investment was $1,103,442 for this multi-year project.

Justification of Project: The justification for this project was provided in Tab 6, Schedule 3, page 84 of this Exhibit.

Project Name: 2013 Building Renovations

Driver: General Plant

Scope: This multi-year initiative involves the renewal and refurbishment of Horizon Utilities' buildings.

The renovations occurred at three locations in 2013 as identified in Table 2-103 below.

Table 2-103 – 2013 Building Renovations

Location	$
Vansickle Road Service Centre	2,060,000
John Street	1,900,000
Nebo Road Service Centre	1,530,000

Justification: A detailed description and justification of the buildings renovations for 2013 is provided in Tab 6, Schedule 1 of this Exhibit.

Project Name: 2013 Office Furniture and Equipment

Driver: General Plant

Scope: The replacement of end-of-life office furniture and equipment at a total cost of $873,925 in 2013. This was primarily driven by the replacement of office furniture, including the replacement of 71 workstations and office suites.

Justification: Prior to 2013, office furniture was replaced on an as needed basis only, when it was beyond economic repair. The majority of office furniture dates back to the vintage of the buildings, and as such, was between 35-55 years old. Horizon Utilities replaced office furniture and equipment in conjunction with the multi-year initiative to address the health of building infrastructure for the following reasons:

- Office furniture and equipment was at end-of-life and as result required ongoing repairs which led to increased operating costs;
- Replacing office furniture in conjunction with the building refurbishment allowed Horizon Utilities to better utilize space and create the same number of offices within a smaller building footprint. Horizon Utilities developed standards for office space to ensure appropriate support of the operational needs of the business, which resulted in the reclamation of 6,695 square feet of office space which was reallocated to common areas as identified in Tab 6, Schedule 1 of this Exhibit;
- Many replacement parts were obsolete or unavailable;
- Employee incidents (health issues and absenteeism) related to ergonomic issues was increasing;
- Furniture was larger than current standards for allocated square footage/employee;
- Furniture did not facilitate the best use of renovated floor infrastructure and space; and
- Furniture did not support performance of current daily activities.

Horizon Utilities incorporated existing furniture and equipment into building renewal plans where possible. Further justification for the replacement of office furniture and equipment is provided in the Space Study appended as Appendix J of the DSP.

2014 Bridge Year (MIFRS) vs. 2013 Actual (MIFRS)

Horizon Utilities' 2014 total capital expenditures (MIFRS) are forecast to be $1,731,330 lower than 2013 total capital expenditures (MIFRS) as identified in Table 2-104 below.

Table 2-104 – 2014 Bridge Year vs. 2013 Actual Capital Projects

Projects ($)	2013 Actual	2014 Bridge Year	Variance 2014 Bridge Year vs. 2013 Actual
Reporting Basis	**MIFRS**	**MIFRS**	
Customer Connections	3,541,455	4,063,471	522,016
Road Relocations	340,491	977,024	636,533
Meters	1,658,707	2,499,104	840,397
Other Material System Access	2,072,682	0	(2,072,682)
System Access Total	**7,613,335**	**7,539,599**	**(73,736)**
4kV & 8kV Renewal	5,072,233	6,434,000	1,361,767
U/G (XLPE) Renewal	1,572,090	893,000	(679,090)
Reactive Renewal	6,069,566	4,840,000	(1,229,566)
Substation Renewal	4,032,963	455,503	(3,577,460)
Other Renewal	1,207,052	1,841,000	633,948
System Renewal Total	**17,953,904**	**14,463,503**	**(3,490,401)**
System Service Total	**1,518,968**	**3,376,000**	**1,857,032**
Vehicles	36,365	785,000	748,635
Buildings	5,490,000	4,100,000	(1,390,000)
Office Furniture and Equipment	873,925	618,000	(255,925)
IST	3,046,146	3,215,768	169,622
Tools, Shop and Garage Equipment	417,572	511,300	93,728
General Plant	**9,864,008**	**9,230,068**	**(633,940)**
Total Material Capital Projects	**36,950,215**	**34,609,170**	**(2,341,045)**
Miscellaneous	2,554,428	3,164,144	609,716
Total Capital Expenditures	**39,504,643**	**37,773,314**	**(1,731,330)**

System Access

Expenditures on system access projects are expected to decrease by $73,736 in 2014 as compared to 2013. The decrease is driven by the completion of two major projects in 2013 which are categorized as other material system access projects in Table 2-104 above:

i) the construction of a new feeder to supply the redevelopment of the Caroline and George Street area of downtown Hamilton; and

ii) the construction of a new feeder in St. Catharines to supply MUSH customer “P” and MUSH customer “A”.

The decrease is offset by increased expenditures resulting from an increase in the number of general service customer connections greater than 300 kW; and an increase in the complexity of road relocation projects.

System Renewal

Expenditures on system renewal projects in 2014 are expected to be $14,463,503 compared to $17,953,904 in 2013. The decrease of $3,490,401 from 2013 is due to the following:

- Expenditures for the XLPE Cable Renewal Program are expected to be $679,090 lower than 2013 due to lower expenditures in St. Catharines;
- Reactive renewal is expected to decrease by $1,229,566 as compared to 2013. The high number of equipment failures in 2013 was a result of the July 2013 windstorm and the December 2013 ice storm. More details are provided in Tab 6, Schedule 3, page 119 of this Exhibit.
- Expenditures for substation renewal are expected to be $3,577,460 lower than 2013 due to the completion of the substation breaker and relay program in 2013.

These decreases are partly offset by the following:

- An increase of $1,361,767 in expenditures for the 4kV and 8kV Renewal Program. The areas served by the Whitney and Strouds substations are scheduled for 2014, as is the continuation of the renewal of the area served by the Welland substation and the area served by the Caroline substation.

- Other renewal is expected to increase by $633,948. Pole replacements are expected to increase 66% to $1,190,000 in 2014 as compared to 2013. Lower pole residual replacement investments levels in 2011 through 2013 have resulted in a backlog of poles requiring an increased investment level in 2014. Horizon Utilities deferred 40% of the pole replacements from 2013 to 2014 to balance the overall capital plan for the year as a result of higher than planned customer connections. Horizon Utilities expects to continue to perform proactive transformer renewal in 2014 at a cost of $339,000. Further details are provided in Tab 6, Schedule 3, page 123 of this Exhibit.

System Service

System Service expenditures in 2014 are expected to be $1,857,032 higher than in 2013 due to:

- The initiation of a project to install egress cables to connect to new breaker positions at the Nebo TS in 2014 at a cost of $1,708,000;
- Expenditures of $418,000 for the #6 Wire replacement program, for which expenditures of $69,121 were incurred in 2013. The majority of the 2013 #6 Wire replacement projects were deferred so that projects which were a higher priority could be completed;
- The initiation of a Distribution Automation project for $1,250,000 to install automated overhead and underground switches throughout the Hamilton and St. Catharines service territories; partly offset by:
- The 2013 Hydro One contribution payment of $1,449,847 for construction of the capacity increase at the Nebo TS.

General Plant

General plant expenditures for material capital projects in 2014 are expected to be $533,940 lower than such expenditures in 2013. The multi-year initiative to address the health of building infrastructure systems, structural deficiencies, continued compliance with the OBC and Fire Codes, and health and safety concerns related to poor air quality and unsecured access points is also expected to continue into 2014, but at a lower cost than in 2013. Major multi-year initiatives such as the GIS renewal project and the IFS ERP upgrade are expected to continue into 2014.

Detailed descriptions of the 2013 capital expenditures for material projects are provided below.

<u>System Access Projects</u>

Project Name: Customer Connections

Driver: System Access

Scope: This on-going program involves a number of projects initiated by customers and developers, where investment is required to enable customers to connect to Horizon Utilities' distribution system, as described in Tab 6, Schedule 3, page 19 of this Exhibit. Program investments include new and upgraded service connections for residential, commercial and industrial customers.

The 2014 investment required is forecast to be $4,063,471.

Justification of Project: System Access projects are investments required to meet customer service obligations in accordance with the DSC and Horizon Utilities' Conditions of Service. Horizon Utilities uses the economic evaluation methodology prescribed by the DSC to determine the level, if any, of capital contributions for each project; with such contribution incorporated into the annual capital budget. These investments are non-discretionary, cannot be deferred, and must proceed as planned.

Horizon Utilities' customer connections forecast is based: on a review of the annual general service, embedded generation, and residential connection quantities of the previous four years of actual results; an assessment of the local economy; a review of the current customer requests project schedule; and, advisement of potential future projects from discussions with customers and developers.

Horizon Utilities responds to all customer requests for connections, regardless of any differences in actual and forecast customer demand.

Horizon Utilities reviews the number, scope and estimated net investments for each project required to support customer connections on a monthly basis and provides a new forecast on a quarterly basis.

The capital investment required to support customer requests for connections is $522,016 greater in 2014 as compared to 2013 as identified in Table 2-72 of this Exhibit. The higher forecast is based on the number and scope of customer requested projects currently scheduled for connection in 2014. Specifically, it is forecast that a large number of general service connections greater than 300 kW will be completed in 2014. General Service greater than 300 kW service connections are typically more expensive due to the higher cost of required infrastructure including switches and transformers as compared to smaller service connections.

Horizon Utilities is not aware of any 2014 customer connection projects that will require a net capital investment greater than $300,000.

Project Name: Road Relocations

Driver: System Access

Scope: Projects in this category involve the relocation of Horizon Utilities' assets to support road relocation and road reconstruction projects, as described in Tab 6, Schedule 2, page 21 of this Exhibit. The initiation and timing of these projects is outside of Horizon Utilities' control and therefore the timing and value of investment required by Horizon Utilities is subject to change.

The forecast to support road relocation projects is $977,024 in 2014. This value is based upon estimates for the known relocation projects identified by the City of St. Catharines, the City of Hamilton, the Region of Niagara, and the Ministry of Transportation. Fifteen projects have been identified and are listed in the table below:

Table 2-105 - 2014 Road Relocation Projects

2014 Road Relocation Projects - Hamilton
Rymal Rd - Dartnall to Trinity
West 5th - Stone Church to the Linc
Centennial Pkwy & Green Mountain Road
Duct work - Queenston Rd and Centennial Pkwy
Centennial Pkwy - King St to Barton St
Centennial Pkwy - CN/GO Bridge RW
West 5th Pole Relocations
Service Relocate - Birch St South of Burlington St
Parkside Drive - Hwy 6 to Main St
Centennial Pkwy O/H Relocate CN Bridge
2014 Road Relocation Projects - St. Catharines
Regional Rd 81 Phase 3
279 Niagara St
Lakeshore Rd Reconstruction
St. David's Rd Reconstruction
Eastchester Blvd

Justification of Project: Further justification of road relocations has been provided in Tab 6, Schedule 3, page 22 of this Exhibit and Section 3.5.3 of the DSP.

Project Name: Meters

Driver: System Access

Scope:

This program includes the installation of Horizon Utilities' metering assets, in compliance with Measurement Canada standards. Further details are provided in Tab 6, Schedule 3, page 23 of this Exhibit.

Justification of Project:

A general justification for meter installations is provided in Tab 6, Schedule 3, page 24 of this Exhibit. The investment in 2014 is forecast to be $2,449,104, comprised primarily of:

- the provision and installation of commercial meters for new connections and the installation of Smart Meter conversions at a capital investment of approximately $1,400,000; and
- the provision, installation, and compliance sampling of residential and multi-residential meters at a capital investment of approximately $925,000.

<u>2014 System Renewal Projects</u>

Program: 4kV and 8kV Renewal Program

Driver: System Renewal

Scope: This project involves the conversion of all existing 4kV and 8kV assets to either 13.8kV or 27.6kV, depending upon the supply voltage from Hydro One which varies by operating area. The 4kV and 8kV Renewal Program for these assets utilizes an area-wide approach centred on the substations servicing each area. The selection and prioritization of these areas for renewal is either driven by substation asset health (St. Catharines, Hamilton West, and Hamilton Downtown operating areas) or by the health of the distribution system and operational constraints (Dundas operating area), and is fully described in the 4kV and 8kV Renewal Program, Section 3.5.3 of the DSP provided in Appendix 2-4 and Tab 6, Schedule 3, page 28 of this Exhibit. Once the assets are converted to the higher voltages, the substation assets will be decommissioned.

In 2014, renewal is forecast to occur in areas served by the four substations as identified in Table 2-106 below.

Table 2-106 – 4kV and 8kV Renewal Program

Substation	$
Caroline Substation	1,205,000
Strouds Substation	1,406,000
Welland Substation	1,327,000
Whitney Substation	2,496,000

Justification of Project: Justification for the 4kV and 8kV Renewal Program is provided in Tab 6, Schedule 3, page 28 of this Exhibit, Appendix A of the DSP and Section 3.5.3 of the DSP.

Project Name: Underground XLPE Cable Renewal Program

Driver: System Renewal

Scope: This project is for the proactive renewal of underground XLPE primary cable, as identified in Tab 6, Schedule 3, page 97 of this Exhibit. Projects are determined using the combined analysis of XLPE asset condition assessment studies with XLPE failure data and the resulting service interruptions to customers.

Table 2-107 below identifies the XLPE renewal projects that will be completed in 2014.

Table 2-107 – Underground XLPE Cable Renewal Program

Area	$
St. Catharines	437,000
Stoney Creek	456,000

Justification: Justification for the underground XLPE Cable Renewal Program is provided in Tab 6, Schedule 3, page 97 of this Exhibit and Section 3.5.3 of the DSP.

Project Name: Reactive Renewal

Driver: System Renewal

Scope: Unplanned failures of overhead and underground system components are corrected in a reactive manner to restore service to customers. The 2013 investment level was insufficient to address all the urgent renewal investments identified in 2013, partially due to two significant storms in 2013. The forecast for 2014 represents a $250,000 decrease versus the 2013 actual, when the renewal costs associated with the two storms are excluded.

Justification of Projects: Reactive renewal expenditure is required to support the restoration of service to the customer. The 2014 forecast of $4,840,000 is based on the average expenditures over 2011 – 2013 (excluding the two storms in 2013), and is comprised of the replacement of 271 poles, 129 transformers and the associated conductors and hardware.

Justification for this project has been provided in Tab 6, Schedule 3, page 30 of this Exhibit.

Project Name: Substation Infrastructure Renewal

Driver: System Renewal

Scope: This program involves the renewal of substation infrastructure in substations throughout Horizon Utilities' service territory, as identified in Tab 6, Schedule 3, page 36 of this Exhibit. The investment in 2014 is forecast to be $455,503.

Justification of Project: Safety related investments include: the installation of eye wash stations; end-of-life replacements of batteries; and substation grounding improvements at Mohawk Substation. Justification for this project was provided earlier in Tab 6, Schedule 3, page 36 of this Exhibit.

Project Name: **Pole Residual Replacements**

Driver: System Renewal

Scope: This project addresses the replacement of obsolete poles and poles that are determined to be at end-of-life by Horizon Utilities' maintenance and inspection programs, as identified in Tab 6, Schedule 3, page 38 of this Exhibit.

Justification of Project: Horizon Utilities expects to replace 128 poles in 2014 at a cost of $1,190,000. The justification for this project was provided earlier in Tab 6, Schedule 3, page 38 of this Exhibit.

Project Name: **LBDS Renewal**

Driver: System Renewal

Scope: This project involves the replacement of LBDS found to be either inoperable or beyond economic repair (where the cost to repair the asset exceeds its replacement value) as found through Horizon Utilities' maintenance and inspection programs. Such switches will be replaced with automated switches for this program. This multi-year program is based on sixteen LBDS replacements per year. The annual investment requirements are identified in Table 2-108.

Table 2-108 - LBDS Renewal

Year	$
2013 Actual	212,000
2014 Bridge Year	312,000
2015 Test Year	323,000
2016 Test Year	334,000
2017 Test Year	345,000
2018 Test Year	357,000
2019 Test Year	368,000

Justification of Project: Justification for this project was provided earlier in Tab 6, Schedule 3, page 101 of this Exhibit.

Project Name: **Proactive Transformer Replacement**

Driver: System Renewal

Scope: This project was established to proactively replace distribution transformers when required. Renewal of distribution transformers has previously been completed reactively upon failure or proactively when included in the 4kV & 8KV Renewal or XLPE Cable Renewal Programs. There are instances where proactive replacement of transformers not identified through the above programs above is required. The budgeted amounts are based on replacing approximately 25 transformers per year at a 2013 replacement cost of $13,560 per transformer. Table 2-109 below identifies the investment requirements for this multi-year project. The annual increase in costs is due to an adjustment for inflation.

Table 2-109 – Proactive Transformer Replacement

Year	$
2011 Actuals	104,447
2012 Actuals	185,523
2013 Actuals	276,978
2014 Bridge Year	339,000
2015 Test Year	350,000
2016 Test Year	361,000
2017 Test Year	373,000
2018 Test Year	384,000
2019 Test Year	395,000

Justification of Project: Proactive transformer replacements are identified through Horizon Utilities' visual inspection programs and Polychlorinated Biphenyls ("PCB") testing programs. Proactive replacement criteria include:

- Transformers that have visibly deteriorated and have a high risk of imminent failure;
- Obsolete Transformers that do not have replacement units in inventory and where a reactive scenario would result in the customer(s) being subjected to extended outage duration;
- Transformers that have visible oil leaks; and
- Transformers that have been identified through testing as containing PCBs.

<u>2014 System Service Projects</u>

Project Name: #6 Wire Replacement

Driver: System Service

Scope: Horizon Utilities has an ongoing program to proactively replace #6 overhead primary conductor throughout the service territory, as identified in Tab 6, Schedule 3, page 42 of this Exhibit. The 2014 investment for this project is forecast to be $418,000.

Justification of Project: Two projects have been identified which will replace 3 km of #6 wire in 2014. The costs are inclusive of pole and transformer replacements required to update the area up to current engineering standards. Justification of the #6 wire replacement project has been provided in Tab 6, Schedule 3, Page 42 of this Exhibit.

Project Name: Nebo TS 27kV Egress Cables

Driver: System Service

Scope: This project comprises the installation of underground cables to new breaker positions at the Nebo TS. Horizon Utilities entered into a CCRA agreement with Hydro One for additional breaker positions to support expansion in the Nebo 27kV territory. The upgrade of the Nebo TS was completed in 2013. This project involves the construction of the infrastructure to utilize the two new breaker positions available to Horizon Utilities.

The project scope for 2014 involves the construction of civil infrastructure for both of the new feeders and the installation of electrical infrastructure for one of the two new feeders.

The 2014 investment for this project is forecast to be $1,708,000.

Justification of Project: The justification for the expansion of the Nebo TS to address the load growth in the Stoney Creek area south of the Niagara escarpment was provided in the 2012 project template “Nebo Transformer Station Capacity Increase” in Tab 6, Schedule 3, page 74 of this Exhibit.

The 2014 investment is necessary to construct the required infrastructure in order to utilize the increased capacity throughout Horizon Utilities’ distribution system. The Nebo TS upgrade provided increased capacity at the transformer station and provided Horizon Utilities with two extra breaker positions so that two new feeders can be built to utilize this capacity.

Project Name: Distribution Automation

Driver: System Service

Scope: This project involves the deployment of automated switches, reclosures, and fault indicators through Horizon Utilities' service territory.

This is a multi-year project originally identified in Horizon Utilities' Basic GEA Plan. The investment forecast for this project in 2014 is $1,250,000.

Justification of Project: The automation of the distribution system through the installation of automated load break disconnect switches (i.e. the ability to remotely identify faulted areas and remotely restore service through the use of remotely controlled switches) is fundamental towards reversing the recent trend of declining reliability and increased service interruptions. Automated switches will be installed on the poorest performing feeders and feeders with high customer counts and long lengths. Automated switches will be installed along these feeders to provide the ability to sectionalize the feeder and at normal open points to allow for the load to be transferred to a neighbouring feeder.

Distribution automation will provide the ability to decrease the duration of service interruptions to offset the impact on the customer of an increasing volume of interruptions due to equipment failures associated with the declining health of the distribution system. Distribution automation will also mitigate the impact of service interruptions resulting from significant weather events (i.e. the high volume of outages resulting from wind and ice storms).

During severe storms, contractors and other utilities are often engaged when the scale of restoration exceeds Horizon Utilities' crew capacity to deal with outages in a timely manner. Automation allows sections of the distribution plant to be restored remotely, allowing crews to be dispatched to other calls requiring on-site response. In this way, automation offers an opportunity to improve service restoration and lower the costs associated with on-site restoration.

The benefit of distribution automation was confirmed in the GEA Implementation project "Develop Standard Design and Locations for Overhead Automated Switches" appended at

Appendix A of the DSP, which identified a positive cost benefit ratio for the installation of automated switches.

2014 General Plant Projects

Project Name: Annual Corporate Computer Replacement

Driver: General Plant

Scope: This initiative is part of an ongoing business requirement to replace end user computers, as identified in Tab 6, Schedule 3, page 55 of this Exhibit. Horizon Utilities utilizes a 36 month lifecycle for replacement of end user computers with approximately 150 PCs replaced annually.

The 2014 investment is expected to be $366,200 for this multi-year initiative.

Justification of Project Justification to the annual corporate computer replacement program is provided earlier in Tab 6, Schedule 3, page 55 of this Exhibit.

Project Name: IFS ERP Upgrade

Driver: General Plant

Scope: This is an enterprise-wide project commencing in 2013 through to 2015 to upgrade Horizon Utilities' ERP system from IFS version 7.3 to version 8.1. This is a major upgrade to the Horizon Utilities ERP system installed in 2007-2008. This project was required to eliminate operational risks dependent on software, database and operating systems that will not be supported by respective vendors beyond 2014. The upgrade is required to provide an updated application for the implementation of redesigned, optimized and/or new business processes that will allow Horizon Utilities' to deliver planned productivity improvements.

The 2014 investment is expected to be $980,260 for this multi-year initiative.

Justification of Project: The justification for this project is provided in Tab 6, Schedule 3, page 105 of this Exhibit.

Project Name: GIS Renewal

Driver: General Plant

Scope: This multi-year initiative involves the replacement of Horizon Utilities' end-of-life GIS system with a new enterprise level solution, as identified in Tab 6, Schedule 3, page 84 of this Exhibit.

This project involved the deployment of the Intergraph GIS system; conversion of Horizon Utilities' GIS data from the current CableCad system to the new Intergraph system; and the integration and deployment of Intergraph's OMS with GIS and integration with the SCADA system.

The 2014 investment is expected to be $1,869,308 for this multi-year project.

Justification of Project: The justification for this project was provided in Tab 6, Schedule 3, page 84 and in Tab 6, Schedule 1 of this Exhibit.

Project Name: 2014 Building Renovations

Driver: General Plant

Scope: This multi-year initiative involves the renewal and refurbishment of Horizon Utilities' buildings.

Renovations are planned at two of Horizon Utilities' locations in 2014, as identified in Table 2-110 below:

Table 2-110 – Building Renovations

Location	$
Vansickle Road Service Centre	1,300,000
Nebo Road Service Centre	2,400,000

Justification: A detailed description and justification of the buildings renovations for 2014 is provided in Tab 6, Schedule 1 of this Exhibit.

Project Name: Building Security Replacements

Driver: General Plant

Scope: This multi-year initiative involves [redacted]

In 2014, $400,000 is forecast for this project.

Justification of Project: [redacted]

[redacted]

[redacted] This is discussed in further detail in Tab 6, Schedule 1, and in the Physical Security Report filed as Appendix L of the DSP.

Project Name: Vehicle Replacement

Driver: General Plant

Scope: Horizon Utilities' fleet expenditures are required to maintain vehicles and major equipment on a sustainable basis in support of safe, reliable, and responsive customer service.

The vehicles requiring replacement in 2014 are identified in Table 2-111 below.

Table 2-111 – 2014 Vehicle Replacement

Unit	Model Year	Vehicle	KMs	$
259 [1]	1997	Double Bucket Truck	120,000	390,000
209	2006	Heavy Duty Pickup Truck	314,000	70,000
468	1977	Tensioner Trailer	N/A	120,000
469	1977	Tensioner Trailer	N/A	120,000

1 Although this vehicle has low mileage, it is 17 years old and replacement parts are not available

Justification of Project: A more detailed justification is provided in Tab 6, Schedule 3, page 53.

Project Name: 2014 Office Furniture and Equipment

Driver: General Plant

Scope: The replacement of end-of-life office furniture and equipment at a total cost of $618,000 in 2014. This will be primarily driven by the replacement of office furniture, including the replacement of 58 workstations and office suites.

Justification: Horizon Utilities expects to replace end-of-life office furniture and equipment in conjunction with the multi-year initiative to address the health of building infrastructure systems. Further justification for this project is provided in Tab 6, Schedule 3, page 108 of this Exhibit.

2015 Forecast (MIFRS) versus 2014 Forecast (MIFRS)

Horizon Utilities' 2015 total capital expenditures (MIFRS) are forecast to be $2,166,654 higher than 2014 total capital expenditures (MIFRS) as identified in Table 2-112 below.

Table 2-112 – 2015 Test Year vs. 2014 Bridge Year Capital Projects

Projects ($)	2014 Bridge Year	2015 Test Year	Variance 2015 Test Year vs. 2014 Bridge Year
Reporting Basis	**MIFRS**	**MIFRS**	
Customer Connections	4,063,471	3,686,273	(377,198)
Road Relocations	977,024	2,085,651	1,108,627
Meters	2,499,104	2,470,674	(28,430)
Other Material System Access	0	0	0
System Access Total	**7,539,599**	**8,242,598**	**702,999**
4kV & 8kV Renewal	6,434,000	8,160,000	1,726,000
U/G (XLPE) Renewal	893,000	2,567,000	1,674,000
Reactive Renewal	4,840,000	4,780,000	(60,000)
Substation Renewal	455,503	464,000	8,497
Other Renewal	1,841,000	1,899,000	58,000
System Renewal Total	**14,463,503**	**17,870,000**	**3,406,497**
System Service Total	**3,376,000**	**3,756,000**	**380,000**
Vehicles	785,000	778,000	(7,000)
Buildings	4,100,000	3,800,000	(300,000)
Office Furniture and Equipment	618,000	69,000	(549,000)
IST	3,215,768	2,506,876	(708,892)
Tools, Shop and Garage Equipment	511,300	555,560	44,260
General Plant	**9,230,068**	**7,709,436**	**(1,520,632)**
Total Material Capital Projects	**34,609,170**	**37,578,034**	**2,968,864**
Miscellaneous	3,164,144	2,361,933	(802,211)
Total Capital Expenditures	**37,773,314**	**39,939,967**	**2,166,654**

System Access

Expenditures on system access projects are expected to increase by $702,999 in 2015 as compared to 2014, mainly due to the scope and complexity of the Highway 5 and Highway 6 grade separation project.

System Renewal

Expenditures on system renewal projects are expected to increase by $3,406,497 in 2015 as compared to 2014. This is primarily driven by an increase in expenditures for the underground XLPE Cable Renewal and 4kV and 8kV Renewal Programs of $1,674,000 and $1,726,000 respectively. The replacement of XLPE cable in Ancaster, Flamborough and Dundas is expected to commence in 2015 and continue into 2016. The 4kV and 8kV renewal will continue for the areas served by the Strouds and Whitney substations and will commence for the areas served by the Grantham, Highland and Vine substations.

System Service

System Service expenditure levels in 2015 are forecast to be comparable to 2014. The Distribution Automation project and #6 Wire replacement project are expected to continue into 2015. The project to install egress cables to connect a new breaker position at the Nebo Transformer Station will be completed in 2014 but the resulting reduction in overall expenditure will be offset by two new projects:

i) the construction of a feeder to provide an alternate supply for the Waterdown area for $984,000; and

ii) the provision of full capacity back-up supply to the redeveloped Caroline and George Street area of downtown Hamilton for $952,000.

General Plant

General plant expenditures for material capital projects in 2015 are expected to be $1,520,632 lower than in 2014. Major initiatives such as buildings renewal and refurbishment, the GIS renewal project, and the IFS ERP upgrade will continue into 2015.

Horizon Utilities is planning an upgrade to its Enterprise Phone System in 2015.

The decrease in expenditures versus the prior year is driven by lower expenditures for the GIS renewal project of $1,664,032 which is expected to be completed in 2015 and lower expenditures for buildings as refurbishments at the Vansickle Road and Nebo Road locations are expected to be completed. The renewal and refurbishment at the John Street and Hughson Street buildings is part of the 2015 building project and is discussed in further detail in Tab 6, Schedule 1.

Capital project templates for the 2015 capital projects completed in accordance with the Board's Chapter 5 Requirements are provided in Appendix A and Appendix G of the DSP.

2016 Test Year (MIFRS) vs. 2015 Test Year (MIFRS)

Total capital expenditures (MIFRS) for 2016 are forecast to be $3,007,566 higher than 2015 total capital expenditures (MIFRS) as identified in Table 2-113 below. Significant increases in system renewal investment are partly offset by decreases in system service and general plant as several major projects in these two categories are expected to be completed in 2015.

Table 2-113 – 2016 Test Year vs. 2015 Test Year Capital Projects

Projects ($)	2015 Test Year	2016 Test Year	Variance 2016 Test Year vs. 2015 Test Year
Reporting Basis	**MIFRS**	**MIFRS**	
Customer Connections	3,686,273	4,031,103	344,830
Road Relocations	2,085,651	2,339,675	254,024
Meters	2,470,674	2,101,174	(369,500)
Other Material System Access	0	0	0
System Access Total	**8,242,598**	**8,471,952**	**229,354**
4kV & 8kV Renewal	8,160,000	10,160,000	2,000,000
U/G (XLPE) Renewal	2,567,000	4,926,000	2,359,000
Reactive Renewal	4,780,000	4,339,000	(441,000)
Substation Renewal	464,000	473,000	9,000
Other Renewal	1,899,000	8,092,000	6,193,000
System Renewal Total	**17,870,000**	**27,990,000**	**10,120,000**
System Service Total	**3,756,000**	**0**	**(3,756,000)**
Vehicles	778,000	780,000	2,000
Buildings	3,800,000	2,100,000	(1,700,000)
Office Furniture and Equipment	69,000	69,000	0
IST	2,506,876	1,224,000	(1,282,876)
Tools, Shop and Garage Equipment	555,560	567,600	12,040
General Plant	**7,709,436**	**4,740,600**	**(2,968,836)**
Total Material Capital Projects	**37,578,034**	**41,202,552**	**3,624,518**
Miscellaneous	2,361,933	1,744,981	(616,952)
Total Capital Expenditures	**39,939,967**	**42,947,533**	**3,007,566**

System Access

Expenditures on material system access projects are expected to increase in 2016 as compared to 2015 due to:

- an increase in expenditures for road relocation projects related to the construction of the Highway 5 and Highway 6 grade separation; and
- an increase of $344,830 in customer connection investments to support customer project requests for new and upgraded service connections. The methodology to forecast investment to support customer connections is described in Tab 6, Schedule 3, page 21 of this Exhibit.

System Renewal

Expenditures on system renewal projects are expected to increase significantly in 2016 as compared to 2015. This is due to an increase in the 4kV and 8kV Renewal and underground XLPE Cable Renewal Programs, and other renewal as identified below:

- 4kV and 8kV renewal is expected to continue for the areas served by the Strouds, Whitney, Grantham, and Vine substations and commence for the areas served by the Central substation;
- There will be a significant increase in the underground XLPE Cable Renewal Program as renewal will continue for Ancaster, Flamborough, Dundas, and St. Catharines, and commence for Hamilton Mountain;
- Pole replacements and LBDS renewal are expected to continue into 2016;
- Hydro One is planning to renew Gage TS (one of the oldest transformer stations in its inventory). Gage TS supplies one of Horizon Utilities' Large Use customers and Horizon Utilities expects to invest $4,793,000 to renew the station egress cables in conjunction with Hydro One's renewal of the TS. The justification for this project is provided in Appendix A of the DSP; and

- Horizon Utilities expects to commence a rear lot conversion project in various areas of St. Catharines.

System Service

Horizon Utilities has not forecast any System Service projects in 2016 that exceed the materiality threshold. The following projects are expected to be completed in 2015 at a cost of $3,756,000:

- Distribution Automation;
- Replacement of #6 wire;
- Construction of a feeder to provide an alternate supply for the Waterdown area; and
- Provision of full capacity back-up supply to the redeveloped Caroline and George Street area of downtown Hamilton.

General Plant

General plant expenditures in 2016 are expected to be $2,968,836 lower than in 2015.

Expenditures for buildings renewal and refurbishment are expected to be $2,100,000 in 2016 as compared to $3,800,000 in 2015. Projects to replace the roof and windows at the John Street and Hughson Street locations are expected to be completed in 2015 at a cost of $1,200,000. Renewal and refurbishment will include the renovation of the 2nd floor of the John Street location in order to accommodate all customer service employees on one floor and the replacement of fire and safety systems which are at end-of-life. This project is discussed in further detail in Schedule 6, Tab 1 of this Exhibit.

IST expenditures are expected to be $1,224,000 in 2016 as compared to $2,506,876 in 2015. The following projects will be completed in 2015:

- the IFS ERP upgrade at a cost of $1,382,600;
- the GIS renewal project at a cost of $205,276; and

- the Enterprise Phone System upgrade at a cost of $400,000.

These decreases are partly offset by the end of lease replacement of the IBM iSeries server hardware environment used to run the Daffron CIS for $900,000.

Capital project templates for the 2016 capital projects completed in accordance with the Board's Chapter 5 Requirements are provided in Appendix A and Appendix G of the DSP.

2017 Test Year (MIFRS) vs. 2016 Test Year (MIFRS)

Horizon Utilities' 2017 total capital expenditures (MIFRS) are forecast to be $4,478,580 higher than 2016 total capital expenditures (MIFRS) as identified in Table 2-114 below.

Table 2-114 – 2017 Test Year vs. 2016 Test Year Capital Projects

Projects ($)	2016 Test Year	2017 Test Year	Variance 2017 Test Year vs. 2016 Test Year
Reporting Basis	**MIFRS**	**MIFRS**	
Customer Connections	4,031,103	4,139,076	107,973
Road Relocations	2,339,675	1,710,951	(628,724)
Meters	2,101,174	2,046,174	(55,000)
Other Material System Access	0	0	0
System Access Total	**8,471,952**	**7,896,201**	**(575,751)**
4kV & 8kV Renewal	10,160,000	15,764,000	5,604,000
U/G (XLPE) Renewal	4,926,000	8,866,000	3,940,000
Reactive Renewal	4,339,000	4,457,000	118,000
Substation Renewal	473,000	482,000	9,000
Other Renewal	8,092,000	3,397,000	(4,695,000)
System Renewal Total	**27,990,000**	**32,966,000**	**4,976,000**
System Service Total	**0**	**535,000**	**535,000**
Vehicles	780,000	775,000	(5,000)
Buildings	2,100,000	2,400,000	300,000
Office Furniture and Equipment	69,000	69,000	0
IST	1,224,000	553,000	(671,000)
Tools, Shop and Garage Equipment	567,600	508,600	(59,000)
General Plant	**4,740,600**	**4,305,600**	**(435,000)**
Total Material Capital Projects	**41,202,552**	**45,702,801**	**4,500,249**
Miscellaneous	1,744,981	1,723,313	(21,669)
Total Capital Expenditures	**42,947,533**	**47,426,114**	**4,478,580**

System Access

Expenditures for system access projects are expected to decrease in 2017 as compared to 2016, mainly due to a return to historical levels for road relocation projects. Horizon Utilities' actively communicates with the Cities of Hamilton and St. Catharines, the Region of Niagara, and the Ministry of Transportation and actively participates in Public Utility Coordinating Committee ("P.U.C.C.") meetings to identify the volume of road projects forecast in future years. Lead times for notification of projects range from 6 to 24 months, depending on the scope of the project. Horizon Utilities has not been notified of any large relocation projects for 2017 at this time and as such, the 2017 investment is based on historical expenditures.

Horizon Utilities' investment requirements for the 2015 Test Year are based upon the volume and scope of known road relocation projects. The 2016 to 2019 Test Year investment requirement is based on a forecast of 25 projects annually; the average annual number of road relocation projects based on 2011 to 2013 actuals and 2013 to 2015 forecasts. A more detailed description of the methodology for forecasting road relocations is provided in Section 3.5.3 of the DSP filed as Appendix 2-4 in this Exhibit.

The 2017 road relocation expenditures are forecast to be $1,710,951.

The decrease in road relocation projects is partly offset by an increase in customer connections investment of $107,973. The methodology to forecast the investment to support customer connections is described on page 20 of Tab 6, Schedule 3 of this Exhibit.

System Renewal

Expenditures on system renewal projects are expected to increase in 2017 to continue to renew distribution assets with an unacceptable Health Index distribution, and related high risk of failure. The principal expenditures in 2017 involve increases in the 4kV and 8kV Renewal and underground XLPE Cable Renewal Programs as follows:

- 4kV and 8kV renewal is expected to continue for the areas served by the Strouds, Whitney, Grantham, Central and Vine substations and commence for the areas served by the Aberdeen and Highland substations;

- Underground XLPE cable renewal is expected to increase by $3,940,000 as renewal will continue for Hamilton Mountain and St. Catharines and commence for Stoney Creek.

These increases are partly offset by a decrease of $4,695,000 in the Other Renewal category. The construction of the Gage TS egress feeder will be completed in 2016 at a forecast expenditure of $4,793,000. The rear lot conversion project, pole residual replacements and LBDS renewal are expected to continue into 2017.

System Service

System Service expenditure levels in 2017 are forecast to be $535,000. This expenditure involves the replacement of the duct structure from Elgin TS to King Street.

General Plant

General plant expenditures for material capital projects in 2017 are expected to be $435,000 lower than 2016. The end of lease replacement of the IBM iSeries server hardware environment in 2016 will be partly offset by increased expenditures for the following:

- the initiative to address the health of building infrastructure systems, structural deficiencies, continued compliance with the OBC and Fire Codes, and health and safety concerns related to poor air quality and unsecured access points at the John Street location; and
- a project to expand IT hardware (SAN) to ensure adequate data storage capacity.

Capital project templates for the 2017 capital projects completed in accordance with the Board's Chapter 5 Requirements are provided in Appendix A and Appendix G of the DSP.

2018 Test Year (MIFRS) vs. 2017 Test Year (MIFRS)

Horizon Utilities' 2018 total capital expenditures (MIFRS) are forecast to be $1,516,390 higher than 2017 total capital expenditures (MIFRS) as identified in Table 2-115 below.

Table 2-115 – 2018 Test Year vs. 2017 Test Year Capital Projects

Projects ($)	2017 Test Year	2018 Test Year	Variance 2018 Test Year vs. 2017 Test Year
Reporting Basis	**MIFRS**	**MIFRS**	
Customer Connections	4,139,076	4,250,289	111,213
Road Relocations	1,710,951	1,778,139	67,188
Meters	2,046,174	2,063,174	17,000
Other Material System Access	0	0	0
System Access Total	**7,896,201**	**8,091,602**	**195,401**
4kV & 8kV Renewal	15,764,000	15,684,000	(80,000)
U/G (XLPE) Renewal	8,866,000	9,384,000	518,000
Reactive Renewal	4,457,000	4,536,000	79,000
Substation Renewal	482,000	491,000	9,000
Other Renewal	3,397,000	2,917,000	(480,000)
System Renewal Total	**32,966,000**	**33,012,000**	**46,000**
System Service Total	**535,000**	**1,686,000**	**1,151,000**
Vehicles	775,000	785,000	10,000
Buildings	2,400,000	1,200,000	(1,200,000)
Office Furniture and Equipment	69,000	73,000	4,000
IST	553,000	1,586,200	1,033,200
Tools, Shop and Garage Equipment	508,600	530,600	22,000
General Plant	**4,305,600**	**4,174,800**	**(130,800)**
Total Material Capital Projects	**45,702,801**	**46,964,402**	**1,261,601**
Miscellaneous	1,723,313	1,978,102	254,789
Total Capital Expenditures	**47,426,114**	**48,942,504**	**1,516,390**

System Access

Expenditures on system access projects in 2018 are expected to be comparable to 2017, with expenditures for customer connections; road relocations; meters; and renewable connections forecast to be consistent with the prior year. Road relocation projects for the 2018 Test Year are based on a forecast of 25 projects annually; the average annual number of road relocation projects based on 2011 to 2013 actuals and 2013 to 2015 forecasts.

System Renewal

Expenditures on system renewal projects in 2018 are expected to be sustained at 2017 levels to continue the renewal of distribution assets with an unacceptable Health Index distribution and related high risk of failure. Underground XLPE cable renewal is expected to increase by $518,000 as renewal continues for the Hamilton Mountain, St. Catharines and Stoney Creek areas. These increases will be offset by anticipated decreases in 4kV and 8kV renewal investments in 2018 as compared to 2017. Renewal in the areas served by the Grantham, Strouds, and Vine substations are expected to be completed in 2017. Renewal is expected to continue in 2018 for the areas served by the Aberdeen, Central and Whitney substations and commence for areas served by the Baldwin, John and York substations. Pole residual replacements and LBDS renewal continue into 2018. Horizon Utilities expects to conduct a rear lot conversion project in various areas of Hamilton in 2018, but at a lower cost than 2017 and 2016.

System Service

System Service expenditure levels in 2018 are forecast to increase by $1,151,000 versus 2017. Horizon Utilities will initiate projects to:

- provide an alternative supply to a number of commercial customers that are currently radial-fed in the Hill Park Secondary School area; and,
- upgrade the conductor along St. Paul's Street to offer additional load transfer capabilities and increasing operational contingencies in the downtown area of St. Catharines.

These increases will be partly offset by a reduction in expenditures due to the completion of a project to replace the duct structure from Elgin TS to King Street in 2017.

General Plant

General plant expenditures in 2018 are expected to be $130,800 lower than in 2017. Horizon Utilities will upgrade its IFS ERP system to the current version supported by the vendor in 2018 at a cost of $1,225,000. Justification for the IFS ERP system upgrade is provided in Tab 6, Schedule 1 and Section 3.5.3 of the DSP. This increase will be partly offset by lower expenditures for the initiative to address infrastructure deficiencies in the lobby and basement at Horizon Utilities' John Street location. Renewal at this location is expected to be completed in 2018 and is discussed in further detail in Schedule 6, Tab 1 of this Exhibit.

Capital project templates for the 2018 capital projects prepared in accordance with the Board's Chapter 5 Requirements are provided in Appendix A and Appendix G of the DSP.

2019 Test Year (MIFRS) vs. 2018 Test Year (MIFRS)

Horizon Utilities' 2019 total capital expenditures (MIFRS) are forecast to be $2,329,973 higher than 2018 total capital expenditures (MIFRS) as identified in Table 2-116 below.

Table 2-116 – 2019 Test Year vs. 2018 Test Year Capital Projects

Projects ($)	2018 Test Year	2019 Test Year	Variance 2019 Test Year vs. 2018 Test Year
Reporting Basis	**MIFRS**	**MIFRS**	
Customer Connections	4,250,289	4,364,837	114,548
Road Relocations	1,778,139	1,845,327	67,188
Meters	2,063,174	2,063,174	0
Other Material System Access	0	0	0
System Access Total	**8,091,602**	**8,273,338**	**181,736**
4kV & 8kV Renewal	15,684,000	16,846,000	1,162,000
U/G (XLPE) Renewal	9,384,000	10,271,000	887,000
Reactive Renewal	4,536,000	4,608,000	72,000
Substation Renewal	491,000	500,000	9,000
Other Renewal	2,917,000	2,283,000	(634,000)
System Renewal Total	**33,012,000**	**34,508,000**	**1,496,000**
System Service Total	**1,686,000**	**1,413,000**	**(273,000)**
Vehicles	785,000	785,000	0
Buildings	1,200,000	1,200,000	0
Office Furniture and Equipment	73,000	73,000	0
IST	1,586,200	1,561,200	(25,000)
Tools, Shop and Garage Equipment	530,600	580,600	50,000
General Plant	**4,174,800**	**4,199,800**	**25,000**
Total Material Capital Projects	**46,964,402**	**48,394,138**	**1,429,736**
Miscellaneous	1,978,102	2,878,339	900,237
Total Capital Expenditures	**48,942,504**	**51,272,477**	**2,329,973**

System Access

Expenditures on system access projects in 2019 are expected to be comparable to 2018, with expenditures for customer connections; road relocations; meters; and renewable connections forecast to be consistent with the prior year.

Investments to support customer connection projects are planned to be $4,364,837 in 2019, an increase of $114,548 as compared to 2018. The methodology to forecast the investment to support customer connections is described in Tab 6, Schedule 3, page 19 of this Exhibit. The methodology for forecasting road relocations is provided in Section 3.5.3 of the DSP filed as Appendix 2-4 in this Exhibit.

System Renewal

Expenditures on system renewal projects in 2019 are expected to increase by $1,496,000 as compared to 2018 due to the following:

- Expenditures for the 4kV and 8kV Renewal Program are expected to increase compared to 2018. Although renewal in the areas served by the Whitney and York substations is expected to be completed in 2018, most of the related expenditure to renew the areas served by the John substation in Dundas is expected to be incurred in 2019;

- Investment in the underground XLPE Cable Renewal Program is expected to increase as the second phase of the renewal in Ancaster, Flamborough and Dundas commences in 2019; partly offset by

- A decrease in expenditures for other renewal. There are no expenditures in 2019 for rear lot conversion. Pole residual replacements and LBDS renewal are expected to continue into 2019.

System Service

System Service expenditure levels in 2019 will be comparable to 2018. The completion in 2018 of projects to build an alternate supply for back-up purposes in the Hill Park Secondary School area and the upgrade of the conductor along St. Paul's Street in St. Catharines will be offset by two new projects in 2019. Horizon Utilities expects to initiate a project in 2019 to provide a loop (back-up) feed to customers along Grays Road north of the QEW in Stoney Creek to increase security. Horizon Utilities also intends to execute on a project to increase the capacity at either the Mohawk or Nebo transformer stations as they are nearing capacity and are projected to exceed design and 10-day LTR ratings.

General Plant

General plant expenditures in 2019 for material projects are expected to be $25,000 higher than in 2018. IST expenditures are anticipated to be $25,000 lower than the prior year. Expenditures in 2019 include the following:

- an end of lease replacement of the IBM iSeries server hardware environment at a cost of $900,000. This hardware is used to run the Daffron CIS which supports customer management and meter-to-cash processes; and,
- SAN expansion to accommodate application and data growth. This project is described in detail in Appendix A of the DSP filed as Appendix 2-4 of this Exhibit.

These projects are offset by the IFS ERP system upgrade which is expected to be completed in 2018. The building renewal and refurbishment initiative will continue into 2019 for renovations at the Stoney Creek service centre, and is discussed in further detail in Schedule 6, Tab 1 of this Exhibit.

Capital project templates for the 2019 capital projects in accordance with the Board's Chapter 5 Requirements are provided in Appendix A and Appendix G of the DSP.

Treatment of Projects with a Life Cycle Greater than One Year

Horizon Utilities includes capital projects in fixed assets when such are completed as indicated by the point that they may be energized. An item of property, plant and equipment will be recognized as an asset if and only if: (i) it is probable that future economic benefits will flow to the company; (ii) the cost can be measured reliably; and (iii) the asset is available for use (i.e. when it is in the location and condition necessary for it to be capable of operating in the manner intended by management). Capital projects with a life cycle greater than one year will be carried over from one year to the next in WIP. Once projects are completed, expenditures are removed from WIP and transferred to fixed assets.

Treatment of Cost of Funds

Horizon Utilities capitalizes borrowing costs as a component of property, plant and equipment for all qualifying assets. A qualifying asset is an asset developed or constructed over a period that is greater than 12 months.

Components of Other Capital Expenditures

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

CAPITALIZATION POLICY

Horizon Utilities has outlined its capitalization policy below. It includes changes to the policy since its last rebasing application (EB-2010-0131) filed with the Board. Changes to the capitalization policy resulting from the conversion to IFRS are discussed in more detail in Exhibit 6, Tab 2, and Schedule 1.

The Board requires utilities to adhere to IFRS capitalization accounting treatments for rate making and regulatory reporting purposes after the date of adoption of IFRS. Additionally, each utility is required to file a copy of its capitalization policy as part of its first Cost of Service rate filing after IFRS adoption. Horizon Utilities adopted IFRS for financial reporting purposes with a transition date of January 1, 2011 and an effective date of January 1, 2012, and has adhered to IFRS capitalization accounting requirements for rate making and regulatory reporting purposes. Horizon Utilities capitalizes tangible physical assets and intangible assets, which are collectively referred to as capital assets.

IFRS establishes that an item of PP&E, which is defined as a tangible asset, will be recognized as an asset if it is probable that future economic benefits will flow to the Company, and the cost of the item can be measured reliably. Horizon Utilities capitalizes items of PP&E greater than $200 that meet these criteria.

Under IFRS, the cost of an item of PP&E includes only costs that are directly attributable to bringing the asset to the location and condition necessary for it to be capable of operating in the manner intended by management. The term “directly attributable” is not defined under IFRS. However, there must be a direct relationship that is established by fact between a cost element and a construction or acquisition activity in order for such cost to be “directly attributable” to such activities and, on this basis capitalized as PP&E.

CGAAP requires costs “directly attributable” to an asset to be capitalized as PP&E. However, CGAAP also permits capitalization of certain indirect costs as PP&E.

Consequently, IFRS diverges from CGAAP as it does not permit the capitalization of indirect overhead costs as PP&E.

Material Costs

Material costs include stocked items held in warehouses and issued out to each capital project, as well as materials purchased and delivered to capital project sites directly. These costs represent the purchase price, and initial delivery and handling costs of the materials.

Horizon Utilities capitalizes material costs as they are directly attributable costs of bringing the asset to the location and condition necessary for it to be capable of operating in the manner intended by management.

Labour Costs

Labour costs that are directly attributable to bringing the asset to the location and condition necessary for it to be capable of operating in the manner intended by management are capitalized. Labour costs are allocated to individual capital projects through timesheets. The timesheets are completed electronically by each employee on a weekly basis using the company's ERP computer system, IFS. Employees record time incurred by activity for each individual capital project. Horizon Utilities capitalizes labour costs.

Third Party (Direct Contract) Costs

Horizon Utilities engages third party sub-contractors to perform capital construction services. Third party costs are capitalized as they are directly attributable to bringing the asset to the location and condition necessary for it to be capable of operating in the manner intended by management.

Overhead Costs

Where it can be factually established that a direct relationship exists between overhead costs and the construction or acquisition of an item of PP&E, such costs are capitalized as part of the item of PP&E. Overhead costs are discussed further in Tab 6, Schedule 5 of this Exhibit, Capitalization of Overhead.

Borrowing Costs

International Accounting Standards ("IAS 23") establishes the criteria for the recognition of interest on borrowings as a component of the carrying amount of an acquired or self-constructed item of capital assets. IAS 23 requires that borrowing costs be expensed as they are incurred unless they relate to "qualifying" assets, in which case they must be capitalized if certain conditions are met. Borrowing costs that are directly attributable to the acquisition or construction of a qualifying asset will form part of the cost of that asset.

Under CGAAP, rate-regulated entities were permitted to include borrowing costs in the cost of an asset that is acquired, constructed, or developed over time. Horizon Utilities did not capitalize borrowing costs under CGAAP. Horizon Utilities did not capitalize borrowing costs under CGAAP on the basis that they were not significant and that the construction period was generally within a fiscal year.

Under IFRS, a qualifying asset is an asset that takes a "substantial period of time" to bring it to a state of intended use or sale. Horizon Utilities has defined substantial period of time as a period greater than twelve (12) months. This period will exclude "extended periods" of interruption or delays. Horizon Utilities has defined extended period as three (3) months or greater. Horizon Utilities will capitalize borrowing costs as part of the cost of a qualifying asset when the following conditions are met: (i) expenditures for the asset have been incurred; (ii) borrowing costs have been incurred; and (iii) activities have been undertaken that are necessary to prepare the asset for its intended use or sale.

Eligible borrowing costs are those directly attributable to the acquisition or construction of a qualifying asset that would have otherwise been avoided if the expenditures on the qualifying asset had not been made. Borrowing costs capitalized will be based on the weighted average of the actual borrowing costs incurred in respect of funds borrowed. Funds borrowed include interest on bank operating lines of credit and promissory notes.

Capital Contributions

Under CGAAP, capital contributions were netted against the cost of PP&E and amortized to net income as an offset to depreciation expense on the same basis as the corresponding assets.

Under IFRS, capital contributions are recognized initially as credit support for service delivery until the related asset is constructed, at which time the capital contributions are recognized as deferred revenue and amortized into net income over the life of the corresponding asset.

Under MIFRS, deferred revenue arising from capital contributions is classified as an offset to rate base with corresponding amortization recorded as an offset to depreciation expense.

Horizon Utilities elected to use the IFRS 1 (First-time Adoption of International Financial Reporting Standards) exemption regarding the treatment of customer contributions and the accounting treatment for customer contributions was adopted prospectively. Customer contributions received after January 1, 2011 were recorded as deferred revenue. Customer contributions received prior to this date have been netted against the cost of the related asset.

Intangible Assets

Intangible assets are identifiable non-monetary assets without physical substance. They have the following characteristics: (i) they can be specifically identified; and (ii) the entity has control of future economic benefits expected from the asset. Horizon Utilities capitalizes computer software and capital contributions as intangible assets under the same criteria used for PP&E.

Derecognition of Assets

Under CGAAP for rate regulated entities, using a pooled approach to fixed asset recognition, PP&E assets were removed at the end of their depreciable lives. Under IFRS, an item of PP&E is derecognized when it is disposed of or when no future economic benefits are expected from its continued use or retention.

Componentization

IFRS requires more rigorous accounting for significant components of PP&E than is required under CGAAP. IFRS requires each significant component of an item of PP&E and intangible asset to be depreciated separately. A significant component of an item of PP&E is characterized by a cost that is significant in relation to the total cost of the item and for which different depreciation methods or rates are appropriate relative to the useful lives of respective individual components. IFRS requires that the amount initially recognized in respect of an item of PP&E be allocated to its significant components, and that each component is depreciated separately. The PP&E item may be acquired as a whole or constructed. Component accounting is discussed in further detail in Exhibit 6, Tab 2, Schedule 1.

Costs Incurred After Initial Recognition and Betterments

Under IFRS, subsequent expenditures on an item of PP&E are capitalized only when it is probable that the expenditures will create future economic value. The concept of “betterment” does not exist under IFRS. In order to capitalize a subsequent expenditure, it must meet the criteria for initial recognition of an asset as previously described.

Spare Parts

Spare parts and servicing materials are carried as inventory and expensed in the period consumed. Major spare parts and standby equipment do however, qualify as PP&E under IFRS when such are expected to be consumed in an accounting period beyond the period in which such were acquired, or if such can only be used with one specific item of PP&E. Transformer and meter assets are treated as major spare parts, and are recorded as items of PP&E by Horizon Utilities.

Repairs and Maintenance

Repairs and maintenance costs, including day-to-day servicing costs, are expensed in the period incurred.

CAPITALIZATION OF OVERHEAD

Overhead costs refer to all ongoing business costs not including or related to direct labour, direct materials, and direct contract costs. Overhead costs are also referred to as “Burdens” or “Overhead Cost Burdens”.

Overhead costs can be direct or indirect costs. Under IFRS, direct overhead costs are overhead costs that are directly attributable to bringing an asset to the location and condition necessary for it to be capable of operating in the manner intended by management. Direct overhead costs can include specific capital engineering costs, fuel for vehicles used in the construction of an item of PP&E, and employee benefit costs for staff working on specific capital projects. Such direct overhead costs can be capitalized under IFRS.

Indirect overhead costs are overhead costs that are not directly attributable to bringing an asset to the location and condition necessary for it to be capable of operating in the manner intended by management. Indirect costs include costs of staff training, administration, repairs and maintenance and other general overhead costs. Indirect overhead costs must be expensed under IFRS.

Under IFRS, the cost of an item of PP&E includes only costs that are directly attributable to bringing an asset to the location and condition necessary for it to be capable of operating in the manner intended by management. The term “directly attributable” is not specifically defined under IFRS. However, there must be a direct relationship that is established by fact between a cost element and a construction or acquisition activity in order for such cost to be “directly attributable” to such activities and, on this basis capitalized as PP&E.

CGAAP requires costs “directly attributable” to an asset to be capitalized as PP&E. However, CGAAP also permits capitalization of certain indirect costs as PP&E.

Consequently, IFRS diverges from CGAAP as it does not permit the capitalization of indirect overhead costs as PP&E.

Horizon Utilities adopted IFRS effective January 1, 2012. Horizon Utilities engaged KPMG LLP as its external advisor for the transition to ensure compliance with the applicable IFRS standards and MIFRS guidance issued by the OEB, as well as any updates to the standards.

Horizon Utilities, in conjunction with its IFRS advisor, performed a thorough analysis of cost eligibility for capitalization under IFRS. Overhead costs were included under the following categories: (i) material burden (Procurement and Logistics); (ii) payroll burden; (iii) engineering burden; and (iv) fleet burden.

Material Burden (Procurement and Logistics)

Under CGAAP, the costs associated with acquiring, handling, and storing of materials within the Procurement and Logistics departments were identified as material burden. This material burden also included the labour costs and related employee benefits of staff working in the Procurement and Logistics departments. The material burden percentage rate was determined by dividing this material overhead burden amount by the material purchase costs and this fixed percentage rate was applied to the material purchase cost as the uplift factor for material burden.

Horizon Utilities concluded that a material burden would not be eligible for capitalization under IFRS. It was impractical for Horizon Utilities to determine whether these costs are directly attributable to an individual capital project. All costs related to the operations of the warehouses and procurement of goods and services are considered to benefit the organization as a whole. As such, under IFRS, these expenditures are considered as general overhead, and are recognized as an expense in the period incurred.

Payroll Burden

Under CGAAP, costs representing direct employee benefits including statutory benefits (Canada Pension Plan, Employment Insurance, Employer Health Tax), Workplace Safety and Insurance Board premiums, pension plan contributions, employee future benefits costs, group insurance benefits premiums, vacation and holiday pay and bonuses were identified as part of the payroll burden. The payroll burden also included other overhead costs such as training, travel allowances related to training, safety programs, protective equipment, small tools, communication costs, and other miscellaneous expenses. The payroll burden was applied as an uplift factor to the labour cost and capitalized if related labour cost was capitalized.

Under IFRS, employee benefit costs for staff working on specific capital projects are direct overhead costs and can be capitalized. The other overhead costs, that were part of the payroll burden under CGAAP, are not capitalized. IFRS specifically prohibits capitalization for some of the overhead costs included in the payroll burden, such as training. The remaining overhead costs were considered to benefit the organization as a whole and are not directly attributable to an item of PP&E at the time they were incurred. Therefore they are not eligible for capitalization.

Engineering Burden

Under both CGAAP and IFRS, wages and benefits of staff in the Engineering and Operations business unit that are directly attributable to bringing the asset to the location and condition necessary for it to be capable of operating in the manner intended by management are capitalized. Wages are allocated to individual capital projects via timesheets. Under CGAAP, the remaining costs of the Engineering and Operations business unit, were included in the engineering burden, and capitalized as PP&E.

Under IFRS, the wages and benefits of staff who cannot attribute their time directly to a capital project, (e.g. staff in the Engineering and Asset Management and Engineering Systems and Asset Records departments) and general and administrative costs are considered to benefit the organization as a whole and are not directly attributable to an item of PP&E. Therefore they are not eligible for capitalization. These indirect overhead costs are recognized as an expense in the period incurred.

Fleet Burden

Under CGAAP, a fixed percentage of fleet costs referred to as “fleet burden” was allocated to transportation costs and was capitalized. Fleet burden include wages and benefits of administrative personnel, general repairs and maintenance activities not directly attributable to each vehicle or individual projects, fuel, insurance, and other general and administrative costs.

Under IFRS, only fuel and insurance costs will be included in the fleet burden rate and will be capitalized based on the number of vehicle hours charged to a specific project. All other repairs, maintenance, and general and administrative costs of the Fleet department are recognized as expenses in the period incurred.

Wages and benefits of the Fleet department are capitalized only to the extent that such labour hours are incurred to perform a major overhaul of a vehicle, or the outfitting of a new vehicle. These costs will be capitalized to the related vehicle rather than to a capital project. Wages are allocated to individual capital projects via timesheets.

Horizon Utilities has identified the burden changes related to the capitalization of self-constructed assets in Table 2-117 below. The impact of removing non-directly attributable costs, identified in Table 2-117, from capital in 2011, as a result of the transition to MIFRS, was a reduction in PP&E of $9,339,658 at December 31, 2011 and a corresponding increase to operating expenses of $9,339,658 for the year ended December 31, 2011 ($8,008,136 of the increase is OM&A and $1,331,522 of the increase is stores and fleet depreciation).

Table 2-117 – Summary of Capital Cost Eligibility Differences

Category of Cost	CGAAP Treatment	MIFRS Treatment	Financial Impact in 2011 (reduction in $ capitalized)
Fleet	Hourly rate based on an allocation of maintenance costs, fuel, consumables, depreciation of equipment and administration costs	Hourly rate to include only fuel and vehicle insurance costs	$2,038,721
Materials (Procurement and Logistics)	25% charge to cover depreciation of Stores' equipment, purchasing and warehousing costs	Nil	$2,522,941
Engineering and Operations	341% charge to cover utility operations oversight, management and project coordination	Nil	$2,980,390
Payroll (Other Labour Costs)	% of hourly costs varies • Direct benefits (CPP,EI, dental, medical, OMERS) • Other administrative costs (training, safety, communications, tools protective equipment	% of hourly costs varies • Direct benefits (CPP,EI, dental, medical, OMERS)	$1,797,606
TOTAL			**$9,339,658**

Burden rates before and after the transition to IFRS are identified in Table 2-118 below.

Table 2-118 – Burden Rates 2011 to 2019

Burden	2011	2012	2013	2014	2015	2016	2017	2018	2019
Reporting Basis	*CGAAP*	*MIFRS*	*MIFRS*	*MIFRS*	*MIFRS*	*MIFRS*	*MIFRS*	*MIFRS*	*MIFRS*
Fleet	$31.39/hr	$4.68/hr	$6.44/hr	$4.09/hr	$5.29/hr	$5.77/hr	$6.30/hr	$6.88/hr	$7.52/hr
Materials (Stores and Procurement)	25%	0%	0%	0%	0%	0%	0%	0%	0%
Engineering	340.9%	0%	0%	0%	0%	0%	0%	0%	0%
Payroll (Other Labour Costs)	63.7%	60.6%	60.4%	64.0%	60.1%	59.7%	59.7%	60.6%	60.6%

Horizon Utilities has provided Appendix 2-DA in Table 2-119, which summarizes the overhead costs currently capitalized on self-constructed assets under MIFRS and the overhead costs that were capitalized under CGAAP but are no longer capitalized under MIFRS.

Table 2-119 – Appendix 2-DA Overhead Expense

The following table should be completed based on the information requested below. An explanation should be provided for any blank entries. The entries should include overhead costs that are currently capitalized on self-constructed assets under MIFRS.

	(A) [1]	(B)	(C)	(D)	(E) [1]	(F)	(G)
Nature of the Overhead Costs	**Dollar Impact on PP&E Historic Year (2013)**	**Dollar Impact on PP&E Bridge Year (2014)**	**Dollar Impact on PP&E Test Year (2015)**	**Dollar Impact - PP&E Variance Test versus Bridge**	**Dollar Impact - PP&E Variance Test versus Historic**	**Directly Attributable? (Y/N)**	**Reasons why the overhead costs are allowed to be capitalized under MIFRS or an alternate accounting standard given limitations on capitalized overhead**
employee benefits	$ 3,009,769	$ 3,256,268	$ 2,872,168	$ (384,099)	$ (137,601)	Y	Benefits are capitalized per IAS 16, since these represents directly attributable employee costs, such as CPP, EI, OMERS Pension, EHT, WSIB, dental and medical plans. Benefits are applied to the direct labour costs allocated via timesheets. These costs are capitalized both under IFRS and CGAAP.
costs of site preparation				$ -	$ -	Y	Horizon does not track these costs separately and cannot provide this information without unreasonable effort, but confirms that these costs are part of self-constructed assets.
initial delivery and handling costs				$ -	$ -	Y	Horizon does not track these costs separately and cannot provide this information without unreasonable effort, but confirms that these costs are part of self-constructed assets.
costs of testing whether the asset is functioning properly				$ -	$ -	Y	Horizon does not track these costs separately and cannot provide this information without unreasonable effort, but confirms that these costs are part of self-constructed assets.
professional fees				$ -	$ -	Y	Horizon does not track these costs separately and cannot provide this information without unreasonable effort, but confirms that these costs are part of self-constructed assets.
				$ -	$ -		
costs of opening a new facility				$ -	$ -	N	Horizon Utilities confirms that these type of costs are expensed under both CGAAP and IFRS and are not part of self-constructed asset costs.
costs of introducing a new product or service (including costs of advertising and promotional activities)				$ -	$ -	N	Horizon Utilities confirms that these type of costs are expensed under both CGAAP and IFRS and are not part of self-constructed asset costs.
costs of conducting business in a new location or with a new class of customer (including costs of staff training)				$ -	$ -	N	Horizon Utilities confirms that these type of costs are expensed under both CGAAP and IFRS and are not part of self-constructed asset costs.
administration and other general overhead costs				$ -	$ -	N	Horizon Utilities confirms that these type of costs are expensed under both CGAAP and IFRS and are not part of self-constructed asset costs.
				$ -	$ -		
Insert description of additional item(s) and new rows if needed.				$ -	$ -		
Total	$ 3,009,769	$ 3,256,268	$ 2,872,168	$ (384,099)	$ (137,601)		

1 # Table 2-119 – Appendix 2-DA Overhead Expense (continued)

The following table should be completed based on the information requested below. An explanation should be provided for any blank entries. The entries should include overhead costs that were capitalized on self-constructed assets under CGAAP but are no longer capitalized under MIFRS or an alternate accounting standard and are included in OM&A.

	(A) [1]	(B)	(C)	(D)	(E) [1]	(F)	(G)
Nature of the Overhead Costs	**Dollar Impact on OM&A Historic Year (2013)**	**Dollar Impact on OM&A Bridge Year (2014)**	**Dollar Impact on OM&A Test Year (2015)**	**Dollar Impact - OM&A Variance Test versus Bridge**	**Dollar Impact - OM&A Variance Test versus Historic**	**Directly Attributable? (Y/N)**	**Reasons why the overhead costs are not allowed to be capitalized under MIFRS or an alternate accounting standard given limitations on capitalized overhead**
employee benefits				$ -	$ -		
costs of site preparation				$ -	$ -		
initial delivery and handling costs				$ -	$ -		
costs of testing whether the asset is functioning properly				$ -	$ -		
professional fees				$ -	$ -		
costs of opening a new facility				$ -	$ -		
costs of introducing a new product or service (including costs of				$ -	$ -		
costs of conducting business in a new location or with a new class of				$ -	$ -		
administration and other general overhead costs - Engineering burden	$ 3,705,121	$ 5,023,523	$ 5,475,469	$ 451,946	$ 1,770,348	N	Where an employee is performing general and administrative tasks, not specifically related to a capital project, wages and employee benefit expenses are recognized as operating expenses. All other general and administrative costs of the department will be expensed to operating as incurred.
administration and other general overhead costs - Construction burden	$ 1,757,413	$ 1,340,996	$ 1,724,520	$ 383,524	-$ 32,893	N	These costs include wages and employee benefits that are related to employees performing general and administrative tasks not related to a capital projects. Therefore these costs cannot be attributable to specific capital project and expensed under IFRS.
administration and other general overhead costs -Fleet burden	$ 2,319,209	$ 2,340,645	$ 2,281,201	-$ 59,444	-$ 38,008	N	These costs include general maintenance costs such as wages and benefits of administrative personnel that and any other general activities that not directly attributable to each vehicle.
administration and other general overhead costs - Stores burden	$ 2,966,030	$ 3,536,284	$ 3,669,508	$ 133,224	$ 703,478	N	These costs are related to the operations of the warehouses and the procurement of goods and services. They are considered to benefit the organization as a whole and are difficult to link directly with the construction of a "specific asset". As such, these expenditures are recorded as operating expenses.
				$ -	$ -		
				$ -	$ -		
				$ -	$ -		
Insert description of additional item(s) and new rows if needed.				$ -	$ -		
Total	$ 10,747,773	$ 12,241,448	$ 13,150,698	$ 909,250	$ 2,402,925		

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APPENDIX 2-4: HORIZON UTILITIES' DISTRIBUTION SYSTEM PLAN

Horizon Utilities Corporation

Distribution System Plan

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1. Distribution System Plan (5.2 Filing Requirements)

On March 28, 2013, the Ontario Energy Board ("OEB" or the "Board") issued Chapter 5 of the Board's Filing Requirements for Electricity Transmission and Distribution Applications, entitled Consolidated Distribution System Plan Filing Requirements (the "Chapter 5 Requirements"). The Chapter 5 Requirements provide a standard approach to a distributor's filing of asset management and capital expenditure plan information in support of a rate application. Horizon Utilities Corporation's ("Horizon Utilities") Distribution System Plan (the "DSP") has been prepared in accordance with the Chapter 5 Requirements. Horizon Utilities has organized the required information using the section headings in the Filing Requirements. Specific references to the Chapter 5 Requirements are included in the section headings in this DSP.

The DSP identifies the capital investment required by Horizon Utilities from 2015 through 2019. The level of required investment and the allocation of investment by category and specific material projects are detailed.

The DSP sections and layout prescribed in Chapter 5 Requirements are as follows.

Section 1 provides an overview of the DSP. This section includes:

- An overview of the DSP that addresses:
    - Key elements of the plan that affect the proposed distribution rates such as prospective conditions that drive the size and mix of investments to achieve capital planning objectives;
    - Specific sources of cost savings expected to be achieved;
    - The period covered by the DSP;
    - Currency of information for investment drivers;
    - State of Horizon Utilities' Asset Management ("AM") systems since the last filing; and
    - Correlation to regional planning and any board decisions;
- Horizon Utilities' coordination efforts with third parties and participation in the Regional Infrastructure Planning process; and
- An overview of the performance metrics and measures utilized by Horizon Utilities to monitor the planning and implementation effectiveness of the DSP in efforts towards continuous improvement.

Section 2 provides an overview of Horizon Utilities' AM activities including:

- Horizon Utilities' AM process framework;
- An overview of how Horizon Utilities has implemented the AM framework;
- An overview of Horizon Utilities assets. This overview includes: identification of operating areas; areas within Horizon Utilities' service territory with unique design, construction and/or operating characteristics; and, therefore, unique investment requirements and plans. This overview also provides the results of Horizon Utilities' most recent Asset Condition Assessment ("ACA") performed by Kinectrics Inc. ("Kinectrics"). Kinectrics is an independent consulting engineering company with the advantage of over 100 years of expertise gained as part of one of North America's largest integrated electric power companies. Kinectrics has a depth of experience in the area of transmission and distribution systems and has become a prime source of Asset Management and Asset Condition services to some of the largest power utilities in North America. A summary of the strategic capital investment programs is provided to identify how Horizon Utilities intends to address the investment requirements identified by the ACA; and
- Horizon Utilities' asset lifecycle optimization practices. The project prioritization methodology, the replacement versus refurbishment practices are detailed; and
- The general plant investment requirements.

Section 3 provides an overview of Horizon Utilities' Capital Investment Plan, including:

- An overview of Horizon Utilities' capital investment requirements;
- A listing of all of Horizon Utilities capital investment requirements for 2015 through 2019; and
- Justifications for all capital investments greater than Horizon Utilities' materiality threshold.

1.1. Distribution System Plan Overview (5.2.1)

1.1.1. Key Elements of the DSP (5.2.1.a)

This DSP presents the summary of the processes, drivers, outcomes and justifications for the proposed capital investments in the 2015 to 2019 Test Years required for Horizon Utilities to achieve its planning objectives.

Horizon Utilities' corporate objectives are divided into four categories:

- Customer Focus – Easy to do Business with;
- Operational – Best Performing Utility;
- People – A Great Place to Work; and,
- Financial – Grow Our Business Profitably.

The relation of each objectives to the DSP and specifically to AM and capital expenditure planning processes are further detailed in Section 2.1.1 below.

The capital expenditure plan provided in this DSP is the product of Horizon Utilities' asset management planning cycle. This planning cycle, fully documented in Section 2.1.2, includes the following key drivers:

- System Planning - Identifies emerging and forecast demands on the utilities' assets;
- Asset Condition Planning - Identifies the condition of both distribution system and general plant ("General Plant") assets; and,
- Operational Performance Planning - Provides a measure of the how the assets are performing to inform future planning processes.

These three drivers identified the following high level business conditions addressed by this DSP:

- A backlog of assets with an unacceptable[1] Health Index;
- Decreasing distribution system performance resulting in an increased number and duration of service interruptions to customers;
- The degradation of facility assets;
- Growth in greenfield (i.e. previously undeveloped) development in certain areas of the service territory; and,
- An increasing level of infill development and redevelopment of underutilized properties.

Horizon Utilities' Investment Mix from 2015 to 2019

Chapter 5 of the Board's *Filing Requirements for Electricity Transmission and Distribution Applications – Consolidated Distribution System Plan Filing Requirements,* ("Chapter 5 Requirements"), in Section 5.1.1, directs distributors to group each investment project and activity for filing purposes into one of four investment categories: System Access; System Renewal; System Service; or General Plant. The first three categories for distribution system investments generally align with historical categories: Customer Demand; Renewal; and Non-Renewal, respectively. The OEB category General Plant aligns with Horizon Utilities' non-distribution assets.

The details of investments to address these business conditions and the capital investment mix proposed in this DSP are provided below in Table 1 and Figure 1 by category.

Category	2015 Test Year	2016 Test Year	2017 Test Year	2018 Test Year	2019 Test Year
System Access	$8,242,598	$8,471,952	$7,896,202	$8,091,602	$8,273,338
System Renewal	$18,070,415	$28,293,649	$33,167,877	$33,208,155	$34,706,031
System Service	$4,139,747	$294,732	$535,135	$2,031,847	$2,057,209
General Plant	$9,487,208	$5,887,200	$5,826,900	$5,610,900	$6,235,900
Total	**$39,939,967**	**$42,947,533**	**$47,426,114**	**$48,942,504**	**$51,272,477**

Table 1 - Horizon Utilities' Forecast Capital Investment Requirements (2015-2019)

[1] An unacceptable rated asset denotes an asset with a Health Index of either 'poor' or 'very poor'.

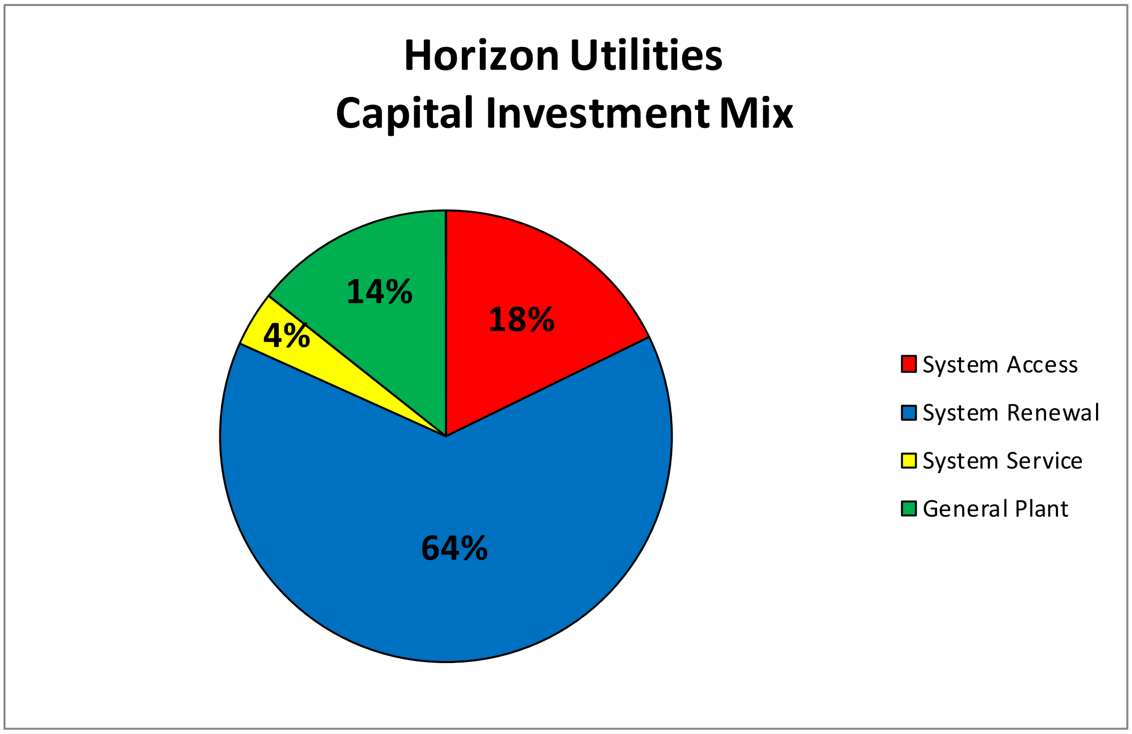

Figure 1 – Forecast Capital Investment Mix (as a percentage of total investment over 2015-2019)

Horizon Utilities engaged Kinectrics in Q4 2012 to improve its asset condition assessment process and perform a detailed ACA. Horizon Utilities determined a need to perform a condition assessment of its key distribution assets. Such an undertaking resulted in a quantifiable evaluation of asset condition, aided in prioritizing and allocating sustainment resources, as well as facilitated further development of the DSP. This approach is aligned with the performance-based rate setting established in the Board's *Renewed Regulatory Framework for Electricity* ("RRFE").

This information formed the basis for capital expenditure planning in this DSP.

The ACA was performed on the following asset categories:

- Substation Transformers
- Substation Circuit Breakers
- Substation Switchgear
- Pole Mounted Transformers
- Overhead Conductors
- Overhead Line Switches
- Wood Poles
- Concrete Poles

- Underground Cables
- Pad Mounted Transformers
- Pad Mounted Switchgear
- Vault Transformers
- Utility Chambers
- Vaults
- Submersible Load Break Switches

The ACA included the following tasks for each asset category:

- Gathering relevant condition data;
- Developing a formula to identify a variable that represents the health of each asset (the “Health Index”);
- Calculating the Health Index for each asset;
- Determining the Health Index distribution; and,
- Developing a 20-year condition-based plan flagging individual assets in need of specific action (“Flagged-For-Action Plan”).

KPMG LLP (Canada) (“KPMG”) was retained as a third party to conduct an independent assurance review and provide an opinion on Kinectrics’ methodology and the resultant findings and recommendations contained in their report. KPMG provided advisory services that consisted of inquiry, observation, analysis and comparison of Horizon-provided information. The findings relied on the completeness and accuracy of the information provided.

KPMG provided a report entitled “KPMG Assurance Review of Kinectrics' Asset Condition Assessment Review” to Horizon Utilities on January 23, 2014, included in Appendix C (the “KPMG Report”), providing their independent assessment on the validity and accuracy of methodologies implemented by Kinectrics and confirming the results. The KPMG Report was used by Horizon Utilities to ensure that the ACA represented leading utility practice before using it as an input in this DSP.

Horizon Utilities applied the principles and opinions endorsed by both the Kinectrics ACA and the KPMG Report as key elements to inform this DSP, to address all capital investment planning objectives identified in Section 3.

1.1.2. Sources of Cost Savings (5.2.1.b)

Horizon Utilities utilizes many approaches to identify and pursue potential costs savings, and cost effective service delivery, through good planning and efficient DSP execution and implementation. Sources of cost savings and effectiveness include:

- Developing principles and practices to manage Horizon Utilities' assets ("Asset Management" or "AM") and ensuring an understanding of the conditions of the assets, the risks, and a basis for replacing the assets in a timely manner consistent with customer expectations and feedback;

- Planning and coordination of work with third parties provides for potential cost savings. This is described further in section 1.2.2.

- Executing long term renewal plans such as the 4kV and 8kV Renewal Program. Horizon Utilities' 40 year plan not only replaces distribution assets that are beyond end of life for specified areas but also proactively eliminates the need to invest in more expensive substation-class assets and equipment by better utilizing the available capacity at the higher standard voltages of 13.8kV and 27.6kV systems. The proposed 4kV and 8kV Renewal Program investment will allow nine of Horizon Utilities' substations to be decommissioned. The decommissioning of these nine stations will provide operational cost savings in the following areas:

    - Reduced labour and expenditures required to maintain the electrical assets within the substations;

    - Reduced labour and expenditures related to the cleaning, maintenance, security monitoring, and regular inspections of the substations;

    - Elimination of potential environmental risks from transformer oil spills associated with a failure of a substation power transformer; and

    - Reduced expenditures for utilities and taxes upon disposal of the substation properties.

  The annual operating cost, on average, for each substation is $30,000, providing a total cost savings potential of $270,000. The full value of these savings will not be realized until after the 2019 Test Year. Horizon Utilities' 4kV and 8kV Renewal Program is further described in Section 3.1.3.

- The cross-linked polyethylene ("XLPE") Renewal Program will reduce expenditures required to identify, locate, repair, and restore service to failed underground distribution cables. The high volume of underground distribution assets, specifically XLPE cable, that have a Health Index of 'very poor' or 'poor' has resulted in a backlog of cable requiring replacement. This volume of backlog cannot be addressed in a single year and requires an investment strategy spanning across several years.

  A continuation of XLPE cable renewal at 2013 investment levels will result in a significant increase in the volume of XLPE cable with an unacceptable Health Index. The current investment levels are simply not keeping pace with the need and pace to replace XLPE cable. If the volume of XLPE cable to be replaced is allowed to continue to build as a backlog, the result will be a corresponding decrease in customer service and an increase in unplanned expenditures to: identify and locate faulted assets; restore service; and repair the failed equipment. The proposed investment levels for the XLPE Renewal Program for the 2015 to 2019 Test Years has been set to begin to address the backlog of XLPE cable requiring replacement, and will allow improvements in the overall XLPE cable Health Index to begin to be evident starting after the 2019 Test Year. The investment in the XLPE Renewal Program in the 2015 to 2019 Test Years will mitigate the increase in operational expenses that would otherwise be incurred without the investment. Decreases in operational expenses will be realized after the 2019 Test Year. Horizon Utilities' XLPE Renewal Program is further described in Section 3.1.3.

- Improving productivity of the internal workforce to improve overall worker efficiency by converting non-productive time to direct work time is on-going, and will remain a focus going forward. Horizon Utilities' productivity results are provided in Exhibit 4, Tab 3, Schedule 4.

1.1.3. DSP Period (5.2.1.c)

This DSP covers the 2010 to 2013 historical years, the 2014 Bridge Year, and the 2015 to 2019 Test Years.

1.1.4. Currency of Information (5.2.1.d)

All asset information provided to Kinectrics for the ACA was as of July 1, 2013. Reliability metrics and analysis presented in this DSP include all outage information to December 31, 2013.

1.1.5. Updates from Previous Filing (5.2.1.e)

Horizon Utilities has not previously filed a DSP.

Horizons Utilities engaged the services of independent third party experts to provide asset condition assessments on major assets for this first DSP filing. Studies were completed on the following:

- Customer Outreach and Stakeholdering;
- All major distribution system assets;
- All four of Horizon Utilities' owned office/operations centres;
- 23 Horizon Utilities substation buildings; and
- Roof and window assessments at Horizon Utilities' Head Office at 55 John Street North.

The results of the distribution asset assessment is provided in Section 2.2.3. Results of the buildings asset assessments are provided in Section 2.2.4.

The information collected during the ACA provided Horizon Utilities with enhanced asset condition data and the best most recently available information associated with the long term capital requirements for the distribution system. With this improved asset data quality, Horizon Utilities has been able to formulate its DSP process to address the outstanding needs of its distribution system. The ACA also facilitated the creation of a specific set of recommendations. The recommendations have since altered the manner in which Horizon Utilities approaches its project selection and prioritization techniques. This will be further addressed in Section 2.1.2.

1.1.6. Aspects of the DSP Contingent on Future Events (5.2.1.f)

The execution of distribution system capital investment programs often involves co-ordination with, and dependency on, external organizations. Horizon Utilities' co-ordination with third parties, elaborated in Section 1.2 below, has identified a number of projects where either the scope, timing or need for the project has external dependencies. These projects include:

- Gage Transformer Station ("TS") Egress Feeder Renewal – System renewal investment in this project presented in this DSP is based upon Hydro One Networks Inc. ("Hydro One") estimated project scope and timelines as presented to Horizon Utilities in February 2013. Horizon Utilities is facilitating discussions between Hydro One and the customers served by Gage TS to enable Hydro One to complete the technical design of the new TS. It is anticipated that the project will proceed on the timeline as presented to Horizon Utilities.

- Waterdown 3rd Feeder - The System Service investment in the construction of the Waterdown 3rd Feeder is dependent on the timing of the Ministry of Transportation's project for the construction of an overpass at the intersection of Highway 5 and Highway 6. Expenditures proposed in this DSP reflect the most current project timing provided by the Ministry of Transportation.

- Road Relocation Projects – System Access investments required to facilitate road relocation projects are dependent upon the City of St. Catharines, the City of Hamilton, the Region of Niagara, and the Ministry of Transportation. The planning timelines for road relocation projects often result in Horizon Utilities receiving notification of the projects between 6 to 24 months prior to the start of the project. The justification of corresponding forecasts included in this DSP are provided in Section 3.5.3.

- Regional Planning Projects - Horizon Utilities is actively participating in the Regional Planning Process ("RPP") with Hydro One. The RPP is in the early stages of development and projects identified to date have not required Horizon Utilities' capital investment. Horizon Utilities continues to participate and support the RPP and will make the required investments into projects arising from the RPP as identified.

- Customer Connections – System Access investments in the expansion of Horizon Utilities' distribution system may be required. The timing of these investments is dependent on the location and service requirements of new customers.

For further information on the coordination with other parties, please Section 1.2 below.

1.2. Coordinated Planning with Third Parties (5.2.2)

1.2.1. Confirmation (5.1.4.1)

Horizon Utilities has a regional interconnection with Hydro One. Both Horizon Utilities and Hydro One are connected to Hydro One's transmission system.

Horizon Utilities has included its load forecast for existing points of interconnection in the Long Term Load Forecast report, provided in Appendix H. There are no proposed points of interconnection.

Horizon Utilities has provided its forecast of renewable generation connections and any planned network investments to accommodate the connections in Appendix E.

Horizon Utilities has consulted with Hydro One, its regionally interconnected distributor and transmitter in the preparation of this DSP. Horizon Utilities has included a copy of the letter it received from Hydro One regarding participation in the RPP in Appendix I.

1.2.2. Consultations (5.2.2.a)

Hydro One

Horizon Utilities' regional planning primarily focuses on interactions with Hydro One, as Horizon Utilities is supplied by Hydro One Transmission. Fifteen of the seventeen transformer stations serving Horizon Utilities are dedicated stations for use by Horizon Utilities only. The two shared transformer stations serve Horizon Utilities and Hydro One's distribution customers.

Horizon Utilities provides Hydro One with a Long Term Load Forecast report, the most recent version of which is provided in Appendix H. The two organizations meet annually to review the long term supply needs of Horizon Utilities. When capacity investments are required at the transmission level, the investment options are evaluated from a regional perspective. The Nebo TS project is a recent example of this. Horizon Utilities and Hydro One required increased capacity at the aforementioned TS. The investment costs to increase the capacity of the existing Nebo TS were shared to avoid duplicating investment in transmission assets by Hydro One.

Horizon Utilities' Hamilton service area is within Region 1 - Burlington to Nanticoke, which falls into prioritization Group 1 for regional planning purposes. The St. Catharines service area is within Region 17 – Niagara, which falls into prioritization Group 3. The complete list of distributors in each region, as defined in the RPP, can be found at:

http://www.ontarioenergyboard.ca/OEB/_Documents/EB-2011-0043/App4_Table%20setting%20out%20distributors%20in%20each%20region.pdf

Hydro One has commenced the RPP for Region 1 and Horizon Utilities received the formal request to provide the Needs Screening ("NS") process on December 16, 2013. The objective of the regional planning process is to develop long-term electricity plans that thoughtfully integrate all relevant resource options such as: conservation and demand management; distributed generation; large-scale generation; transmission; and distribution.

Horizon Utilities provided the pre-populated customized load forecast template file, as required by this NS process, within the required 60 calendar day timeframe.

Horizon Utilities continues to participate in the regional planning initiative in accordance with the Board's Amendments to the *Transmission System Code* ("TSC") and *Distribution System Code* ("DSC"), dated August 26, 2013. Hydro One advised Horizon Utilities that the NS process for Region 1 is expected to be completed by Q2 2014 and that the RPP for Region 3 will commence in Q4 2016. Horizon Utilities does not have any further indication from Hydro One on final deliverables from this process for Region 1. Region 3 will not commence prior to 2016, as identified above.

Co-ordination with Cities and non-electrical Utilities

Horizon Utilities' local planning involves co-ordination with: neighbouring non-electrical utilities; the Cities of Hamilton and St. Catharines; and other external parties.

P.U.C.C – Hamilton and St. Catharines:

Horizon Utilities participates in the Public Utility Coordinating Committee ("P.U.C.C.") in both the St. Catharines and Hamilton service areas. The P.U.C.C. provides a forum for communication between utilities and the cities of St. Catharines and Hamilton and the Region of Niagara to ensure safe and efficient management of the infrastructure within road allowance and other right-of-way (municipal, county and Region). Regular and effective communication between the City and the owners of infrastructure in the City creates an efficient and coordinated effort for all parties involved. Membership within the P.U.C.C. is provided below.

The P.U.C.C. meets on a quarterly basis and discuss common issues; share information;, and develop solutions to issues or project related matters. Issues to be discussed include: efficiency enhancements through improved construction scheduling coordination; damage prevention initiatives; and development of standards.

The P.U.C.C. has been formed to ensure that projects undertaken on any City road allowance are completed using current standards and are recorded for future reference through the Municipal Consent Approval process.

The P.U.C.C. is responsible for:

- Approving non-standard locations of utility installations based on the understanding that, wherever possible, utilities will be placed in the approved standard corridor locations;

- Developing appropriate policies and procedures with respect to construction and utility installations;

- Improve communication and the exchange of information among the road allowance stakeholders;

- Coordinate the scheduling of the road allowance, capital improvement and maintenance projects.; and

- Chair quarterly meetings.

<u>Members of the P.U.C.C. include:</u>

- City of Hamilton;
- City of St. Catharines;
- Region of Niagara;
- Horizon Utilities;
- Hydro One;
- Bell Canada;
- Union Gas Limited;
- Cogeco Inc.;
- Source Cable Limited; and
- Rogers Communications.

Local Distribution Company (“LDC”) Co-ordination

Horizon Utilities has initiated periodic informal discussion with neighbouring utilities (including Burlington Hydro Inc., Hydro One Networks Inc., Niagara-on-the-Lake Hydro Inc., Niagara Peninsula Energy Inc., and Grimsby Power Inc.) to review infrastructure and planning requirements along the service territory boundaries. Horizon Utilities' distribution network is not highly interconnected with the neighbouring utilities and, as such, opportunities for the co-ordination of infrastructure planning and investment have been limited. Discussions have focused on the resolution of any remaining Long Term Load Transfer (“LTLT”) customers.

Horizon Utilities participates in the following working groups and committees in support of capital investment planning and implementation.

E8 Smart Grid Working Group

This group is made up of members from the eight largest LDCs plus Hydro One which includes high density urban distribution utilities with more than 100,000 customers. The utility members are Enersource Hydro Mississauga Inc., Hydro One Brampton Networks Inc., Hydro Ottawa Limited, London Hydro Inc., Powerstream Inc., Veridian Connections Inc., Toronto Hydro-Electric System Limited, Horizon Utilities, and Hydro One Networks Inc. The purpose of this group is to provide a forum for these utilities to meet on a routine basis to share with each other their experiences related to Smart Grid deployment, investigations and studies.

Some of the identified benefits are:

- Sharing vision, strategic thinking and development of key investment drivers;
- Validating technology requirements and specifications;
- Exploring approach and methodologies;
- Revealing challenges on developing technologies from both technical and business perspectives; and
- Seeking opportunities to share experiences with other LDCs outside of the group.

The group was formed in mid-2012. Meetings are hosted by each member on a rotating basis. The host utility is given an opportunity to highlight its own smart grid activities.

The discussions with this group are ongoing and continue to provide benefits in the understanding of Smart Grid technologies and how they can be employed by Horizon Utilities. Specific details of this consultation process are anticipated to benefit Horizon Utilities' future planning processes.

LDC Inter-Utility Standards Working Group

This group was formally created in February 2012 to serve as an opportunity for eight LDCs to share knowledge and experience in the area of distribution utility design standards, construction practices, and equipment and material standards.

The utility members are Enersource Hydro Mississauga Inc., London Hydro Inc., Powerstream Inc., Veridian Connections Inc., Toronto Hydro-Electric System Limited, Horizon Utilities Corporation, Peterborough Distribution Incorporated, and Whitby Hydro Electric Corporation.

Some of the identified benefits are:

- Enabling a forum for members to present a problem or issue for the group to provide advice and/or relate their experiences in solving a similar problem;
- To make others aware of equipment or material failures that a particular utility is experiencing in order to alert others or to identify common failures;
- To share experiences in use of new equipment or materials;
- To make others aware of new technologies or work practices that may benefit others;
- To share standards amongst those members interested in exchanging this information.

The discussions within this group are ongoing and continue to offer benefit in the understanding of asset management and capital expenditure procedures.

Hydro One - LDC Generation Working Group

The Hydro One – LDC Generation Working Group was originally created in 2011. The main focus was to provide a forum to update LDCs on Hydro One policies and practices relating to LDC Distributed Generation connections and to solicit input to enhance the customer experience related to processing and assessing Feed-In Tariff ("FIT") generation projects. The concept of establishing "Threshold Agreements" for allocating available blocks of transformer station capacity for generation use was developed and refined with input from the various committee members. The group has now been involved in generation issues that span beyond process and policy to the many operational challenges that we are now experiencing with generation as market penetration levels have increased. Some of the working group's current activities include:

- Discussing emerging issues around LDC Distributed Generation connections and sustainment;
- Presenting and gathering feedback on proposed enhancements to LDC Distributed Generation processes prior to implementation;
- Allowing LDC representatives to identify emerging issues from their perspective;
- Identifying emerging operational issues and determining the correct forum for addressing them; and
- Discussing operational issues related to Distributed Generation.

The Hydro One – LDC Generation Working Group is designed to play an advisory role rather than act as a decision making body. In this role, the Hydro One - LDC Generation Working Group will provide recommendations to Hydro One and the OPA. Feedback from the Hydro One - LDC Generation Working Group will be utilized in ongoing business decisions. The OPA now attends many meetings which provides an opportunity for LDCs to understand new OPA policies and processes related to generation connections.

There are many benefits for all members of the group. Some of these include:

- Aiding in the development of both OPA and Hydro One Distributed Generation connection processes;
- Providing input and feedback on OPA and Hydro One Distributed Generation connections and process sustainment; and
- Sharing and gaining knowledge and experience from other Hydro One - LDC Generation Working Group members.

Current committee representation includes Hydro One Networks Inc., Kingston Hydro Corporation, Horizon Utilities, Newmarket-Tay Power Distribution Ltd., Greater Sudbury Hydro Inc., Powerstream Inc., and Toronto Hydro-Electric System Limited.

The discussions within this group are ongoing and any tangible effect on the DSP has been through the development of common ideals in the distributor community. Specific details derived from this consultation process have not altered the development of the DSP as of yet. It is anticipated that future efforts with this contingent of LDCs and the OPA will influence future planning processes at Horizon Utilities.

Customer Engagement

Horizon Utilities conducted customer engagement activities regarding the DSP. These activities are outlined in Section 3.2.4.

1.2.3. Expected Deliverables and Impact on the DSP (5.2.2.b)

Deliverables and Status

Each of the coordinated efforts described in Section 1.2.2 above represents an ongoing process between Horizon Utilities and the various third parties. The consultations resulting from these coordinated efforts foster growth in understanding as well as strengthening ties to neighbouring distributors. If any of these ventures result in a formalized deliverable, that deliverable will be used to inform Horizon Utilitie's future planning process and reactive expenditure procedures as applicable. Horizon Utilities will continue its role in these discussions as a mid-level distributor with strategic goals based on providing customer value and economic efficiency. At this time, no current formal deliverables are scheduled and the status of all coordinated efforts can be described as ongoing.

Impact on the DSP

As identified in Section 1.2.1 above, Horizons Utilities endeavours to achieve the best possible value for its customers by interacting with other parties and participating in RPP. Currently, these initiatives are in preliminary stages and require further investigation for applicability to the processes identified within the DSP. It is anticipated that the impact of these interactions on the DSP will be minimal. Nevertheless, Horizon Utilities remains committed to the goals of the RPP and other consultation based programs to ensure it can continue to provide the best value for its customer base.

1.2.4. OPA Comment Letter (5.2.2.c)

Horizon Utilities filed Appendix E – Renewable Energy Generation (“REG”) Investment Plan with the OPA on February 12, 2014. The OPA reviewed Horizon Utilities’ Appendix E and issued its letter of comment supporting Horizon Utilities’ submission on March 14, 2014. No response was required with respect to this correspondence. A copy of the OPA correspondence is provided in Appendix E.

1.3. Performance Measurement for Continuous Improvement (5.2.3)

Horizon Utilities builds on internal strategies and high level goals to ensure a continuous level of improvement to its asset management and capital expenditure planning processes consistent with customer feedback and expectations. These strategies, goals and objectives allow a dynamic interaction of information and perspectives to ensure optimization in meeting both its objectives as well as needs of the region, province, and the customer base. The following sections provide: Horizon Utilities’ performance methodologies; measures (metrics); processes; frameworks; and trends.

1.3.1. Methods, Measures, and Metrics (5.2.3.a)

An organized reporting structure supports: information sharing; identification of key performance indicators (“KPI”); and allows management through measurement based on the corporate pillars of success. Value is extracted by identifying opportunities for improvement and productivity enhancements and allows for measurement to support business case development. The KPI pyramid, illustrated in Figure 2 below, is tiered between strategic, tactical and supporting metrics.

Figure 2 - KPI Pyramid

Horizon Utilities employs a number of KPIs at the strategic level to measure and manage:

- Customer oriented performance/satisfying the customer 'value proposition';
- Cost efficiency and effectiveness; and
- Asset and system operating performance.

Horizon Utilities' strategic KPIs, further described below, are supported by a number of tactical and supporting KPIs. The tactical and supporting KPIs provide Horizon Utilities' management with the ability to manage the daily operations to support the strategic goals.

<u>Customer Oriented Performance</u>

System Reliability metrics are customer focused, measuring the system performance as experienced and valued by customers. Horizon Utilities subscribes to the reliability definitions and metrics as defined by the Standards Management Committee ("SMC"), a subgroup of the

Canadian Electricity Association ("CEA"). The three metrics selected by Horizon Utilities to measure system performance are:

System Average Interruption Duration Index ("SAIDI")

- Measures the average annual *hours* of interruption experienced by all customers;

System Average Interruption Frequency Index ("SAIFI")

- Measures the average annual *number* of interruptions experienced by all customers; and

Customer Average Interruption ("CAIDI")

- Measures the average annual *outage duration* experienced by customers.

Horizon Utilities employs SAIDI as the metric for assessing reliability performance. Customer minutes of outage are used for more detailed outage analysis provided in Section 2.2.2. Customer minutes provides a better measure of total impact of each outage and the cause of each outage. The SAIDI metric provides a level of impact per customer but does provide insight into the number of customers affected when analyzing outages on a feeder or for a geographical area. For example, a SAIDI of 1.0 represents a lower overall impact to the system on a feeder with only 100 customers (6000 total customer minutes) than it would on a feeder with 4000 customers (240,000 total customer minutes). Utilizing customer minutes provides a more realistic view of the true impact of an outage during analysis. Horizon Utilities has selected SAIDI as the metric to determine the achievement of reliability targets. Horizon Utilities establishes the annual SAIDI target through comparison of system performance relative to a comparator set of 20 urban utilities in Southern Ontario. The five year average for each utility is determined from the results published annually in the Board's Yearbook of Electricity Distributors. Horizon Utilities' target for SAIDI performance is to maintain between the 50^{th} and 75^{th} percentile level of performance, relative to the most recent five year average for this comparator group.

Horizon Utilities chose to include a large number of utilities in the comparator group and to employ a five year average to reduce the impact of year over year volatility in the reliability results from the comparator utilities.

Horizon Utilities is implementing the following metrics to provide system reliability metrics at a customer specific, rather than system average, level. Horizon Utilities is participating in the OEB Reliability Data Working Group, (EB-2010-0249) which is currently reviewing customer specific reliability measures. The measures under review by the OEB Reliability Data Working Group and currently under consideration by Horizon Utilities are:

- Customers Experiencing Multiple Interruptions ("CEMI"); and
- Customers Experiencing Long Duration Interruptions ("CELDI").

The implementation of these two measures would require significant manual effort, at present. The implementation of an Outage Management System ("OMS"), scheduled for completion in 2015, will allow Horizon Utilities to report these metrics thereafter.

Cost Efficiency and Effectiveness

The measurement of cost efficiency and effectiveness is achieved through a number of metrics developed through the internal operational system called the Integrated Planning and Scheduling Solution ("iPass").

The iPass initiative was launched in 2012 to improve Horizon Utilities' planning and scheduling process. The iPass initiative improves productivity by: reducing manual processes; improving human resource utilization; improving actual deployment and tool time; as well as improving inventory availability. The initiative balances resources to work load across all work centres and, through a centralized approach, capitalizes on economies of scale. Further detail regarding Horizon Utilities' iPass initiative is provided in Exhibit 4, Tab 2, Schedule 2 and Exhibit 4, Tab 3, Schedule 4.

The iPass initiative defines and improves accountability while providing end to end reporting and visibility for all projects or work; whether in the planning process or in progress. This accountability and visibility allows Horizon Utilities to accurately measure its performance in meeting its capital and maintenance plans and identifying areas of improvement.

At a high level, the objective of iPass is to ensure that all distribution capital and maintenance work is completed on time and within budget. Several KPIs were introduced with the iPass initiative to measure this high level objective.

- Cost Performance Index

Cost Performance Index measures the ability to complete projects within budget. Actual project costs are measured as a ratio of estimated costs. It is a corporate objective that any corresponding variance is within 10% of estimated costs.

- Schedule Performance Index ("SPI")

  SPI measures the ability to complete projects within a specified amount of time. SPI is measured as the ratio of the actual number of days to build the project (construction only) to the planned number of days; with a target of a maximum 10% difference to the planned number of days. Where projects involve customer connections with an actual target date of completion, both the project duration and delivery relative to the target are measured. This metric was created in 2012 and utilized for first time in 2013.

- Request for Change ("RFC")

  The RFC metric measures the quality of job planning and estimation originating from the design technicians. This metric was created in 2012 and utilized for first time in 2013.

Asset and system operating performance

System reliability metrics, as identified above, provide a measurement system for operating performance. System reliability metrics are used to illustrate the performance history, performance concerns, and performance trends of Horizons Utilities assets over the historical period.

Horizon Utilities' utilizes a Health Index metric to assess the health of distribution assets. This metric is a leading measure that provides an indication for forward, or predicted risk of equipment failure. The Health Index assessment of Horizon Utilities' assets was performed Kinectrics and independently verified by KPMG.

Health Index

The asset Health Index provides a measure of the condition of an asset. The Health Index quantifies equipment condition based on numerous condition based parameters related to the long-term degradation factors that cumulatively lead to an asset's end-of-life. The Health Index is an indicator of the asset's overall health, relative to a brand new asset, and is given in terms of percentage, with 100% representing an asset in brand new condition. The Health Index measure is the evolution of the end-of-life (“EOL”) metric previously employed by Horizon Utilities in prior Cost of Service Applications.

The Health Index KPI is superior to EOL as EOL is purely based on asset age whereas Health Index incorporates many additional inputs such as: maintenance history; inspection records; failure history; and other condition parameters as available. KPMG, in its review of Kinectrics' ACA, stated that *“The probabilistic approach used by Kinectrics to calculate remaining asset life based on asset condition and asset age is consistent with similar models used in other utilities and in actuary science. The inclusion of asset condition in these calculations provides a more sophisticated approach than that of using chronological age alone*.”[2] Derivation of the Health Index was performed by Kinectrics. The results of the ACA performed by Kinectrics are provided in Section 2.2.3.

The Health Index is not a single KPI, rather it is a distribution derived for each major asset category and subcategory. This leading indicator provides a measure of the level of risk of equipment failure which would lead to service interruptions to Horizon Utilities' customers. Using this data in the development of this DSP allows Horizon Utilities to ensure it meets customer oriented performance objectives while maintaining a prudent level of capital investment.

1.3.2. Performance and Performance Trends (5.2.3.b)

<u>Health Index Forecast</u>

Horizon Utilities migrated to the Health Index distribution in 2013 and the Health Index distribution for previous years is not available. However, the Health Index results are consistent with the asset groups in poor health as identified by the EOL analysis performed in previous years.

The future health of system distribution assets can be forecasted based on the current health and replacement volumes associated with the proposed investment levels. This analysis allows for the creation of a Health Index forecast. The twenty year forecast, provided in five year increments, is illustrated below in Figure 3 through Figure 6 for selected, key asset categories, on the assumption that the 2013 capital investment levels are sustained through this period.

[2] Assurance Review of Kinectrics' Asset Condition Assessment Report, Page 1

The asset replacement costs were calculated using 2013 asset replacement costs for the twenty years and do not include inflation.

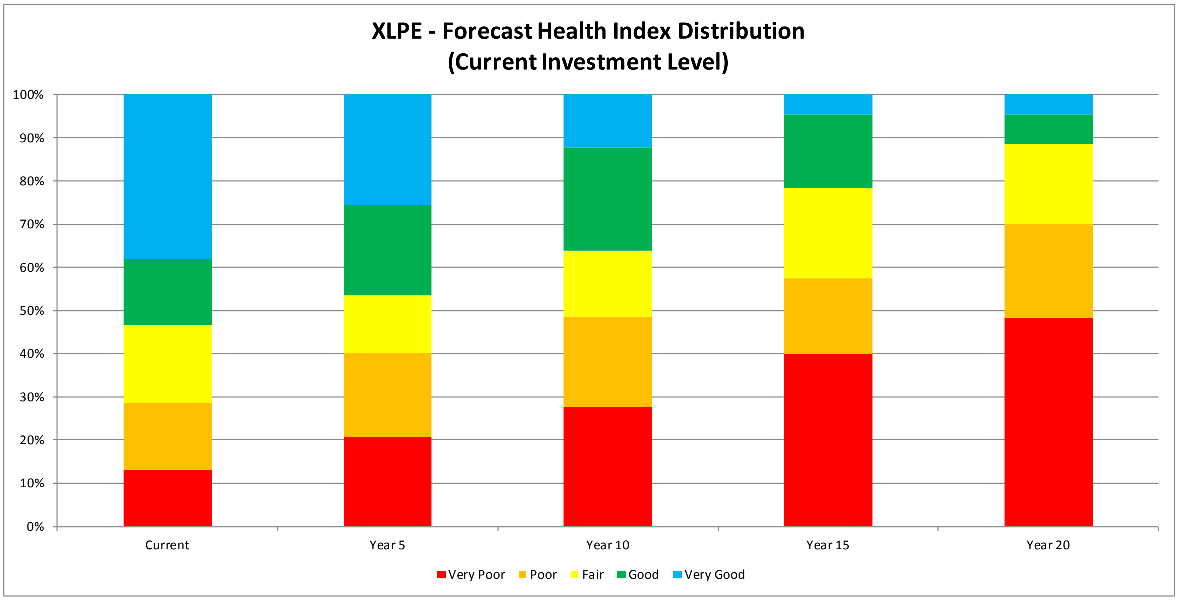

Figure 3 - XLPE Health Index Distribution Forecast at the Current Investment Level

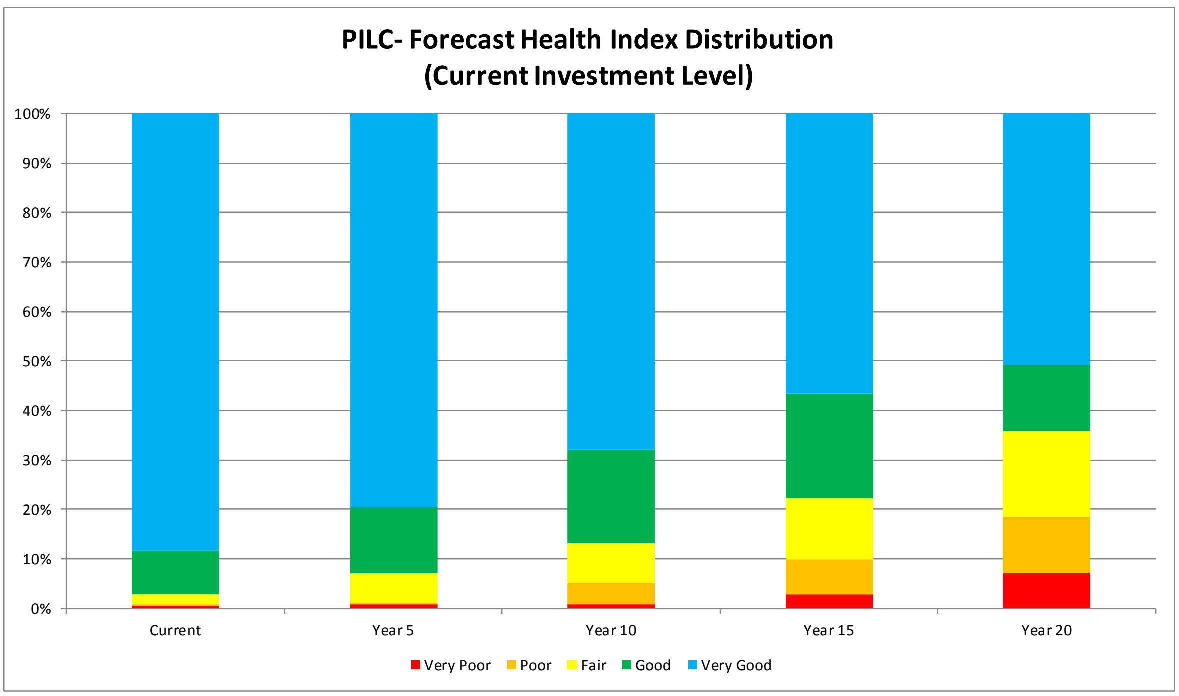

Figure 4 - Paper insulated lead covered ("PILC") Health Index Distribution at the Current Investment Level

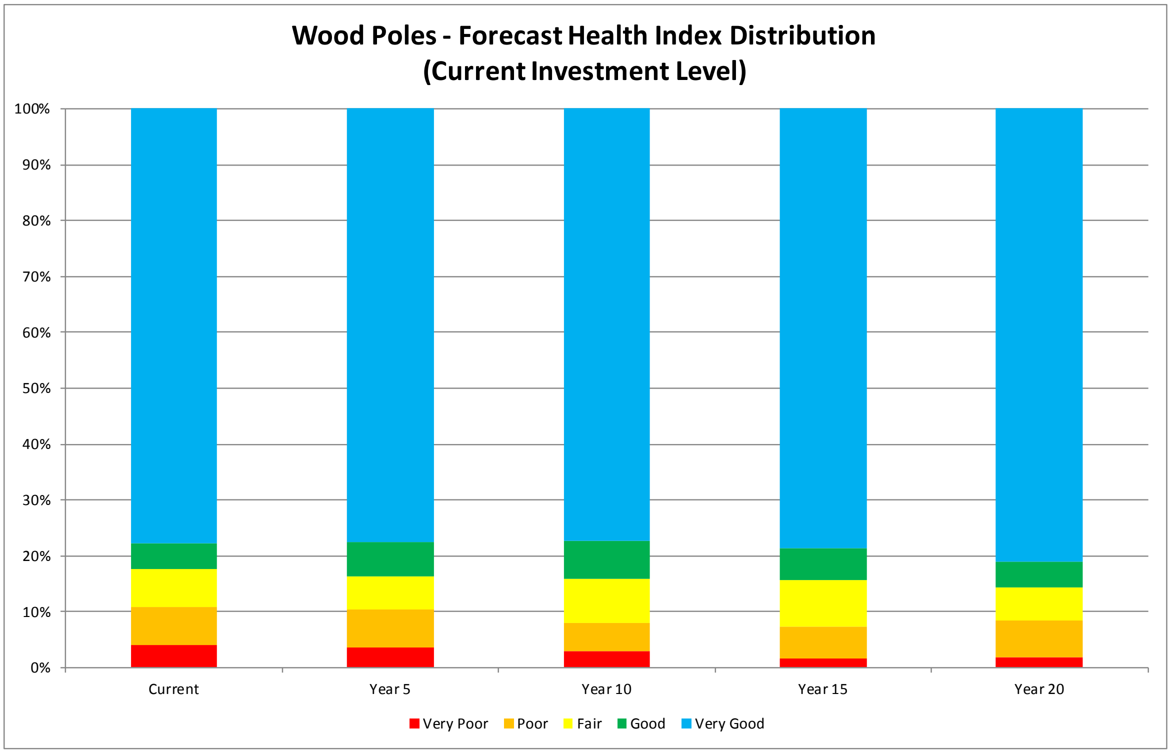

Figure 5 - Wood Pole Health Index Distribution at the Current Investment Level

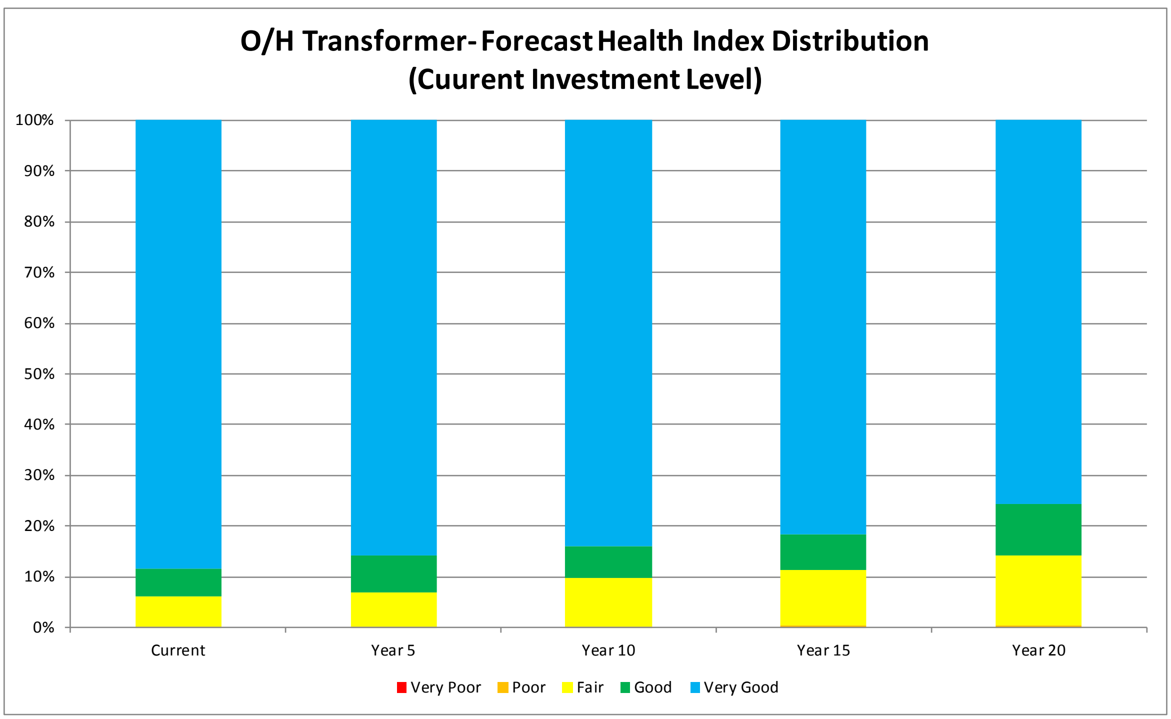

Figure 6 - O/H Transformer Health Index Distribution at the Current Investment Level

The Health Index distributions in Figure 3 and Figure 4 above show that the forward risk of the underground distribution system will increase in the future at the current investment level (using XLPE and PILC as a proxy).

By contrast, Figure 5 and Figure 6 above show that the forward risk for the overhead system will not increase dramatically in the future at the current investment level (using wood poles and overhead distribution transformers as a proxy).

These trends indicate a need for increased investment in underground cable replacements. These trends also support that investments in the wood poles and overhead distribution transformers can be sustained at current levels to maintain the current Health Index distribution.

System Reliability

SAIDI, SAIFI and CAIDI are lagging indicators that measure performance after events to assess outcomes and occurrences. Horizon Utilities' interruption metrics for SAIDI, SAIFI, and CAIDI are provided below in Figure 7, Figure 8, and Figure 9 respectively. Performance for all interruptions and all interruptions excluding loss of supply are provided.

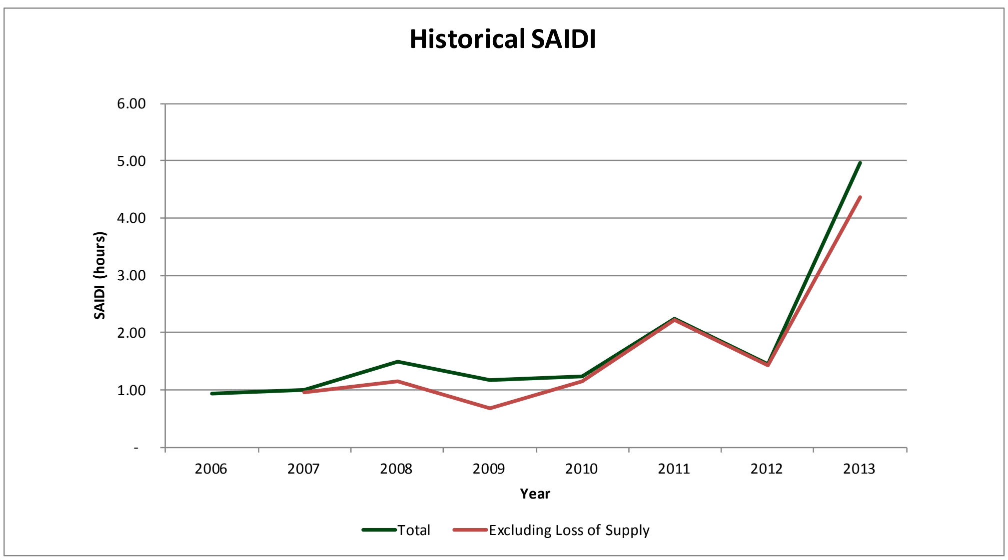

Figure 7 - Historical SAIDI

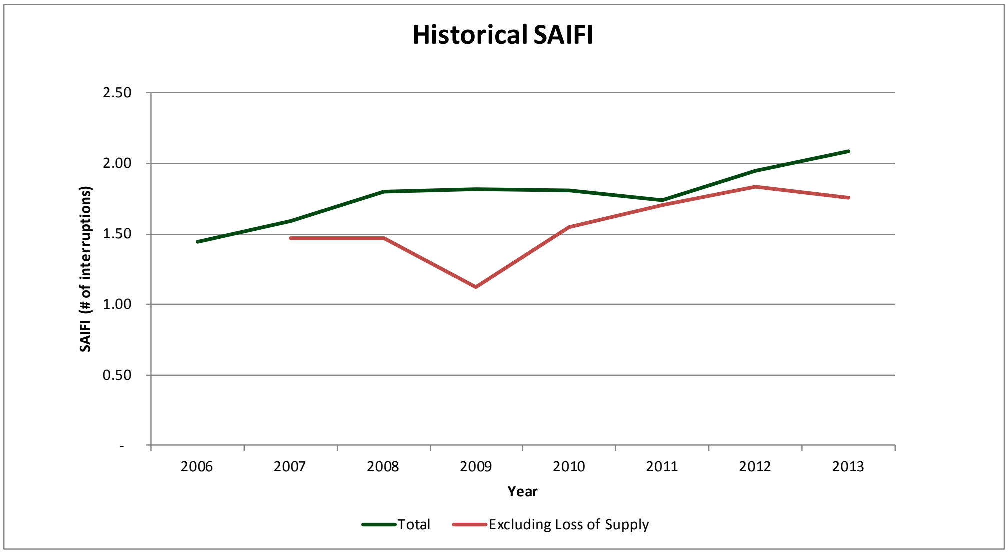

Figure 8 - Historical SAIFI

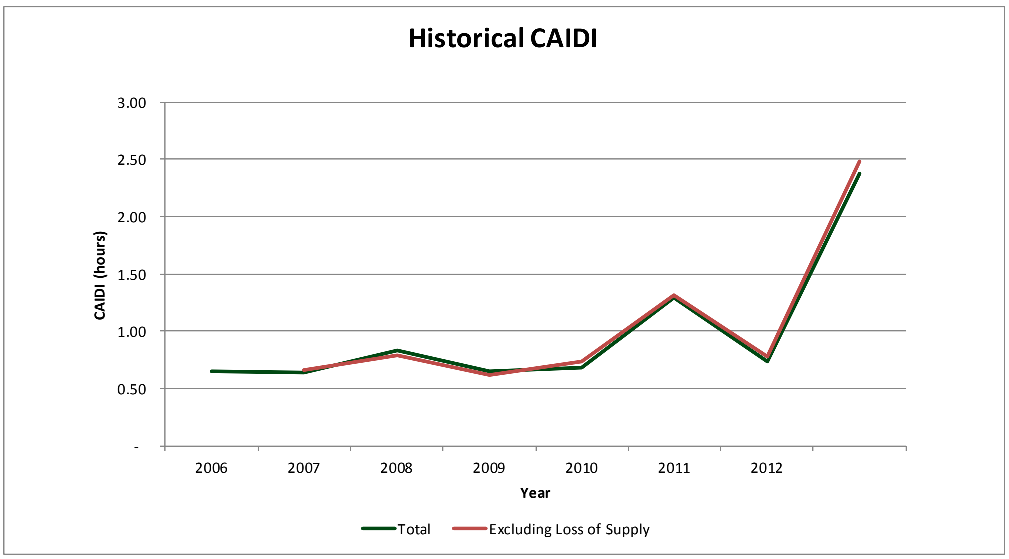

Figure 9 - Historical CAIDI

As illustrated in the figures above, all three of these metrics have steadily increased since 2006.

SAIDI and CAIDI increased by 430% and 265% in 2013 respectively compared to 2006. The 2013 results were impacted by the July 2013 windstorm and the December 2013 ice storm. Horizon Utilities' reliability has continued to decline since 2006 even when the impacts of major events are excluded. Horizon Utilities has not met its corporate reliability target (as identified in section 1.3.1), measured in SAIDI, in each of the past three years as illustrated in Table 2 below. Excluding the effect of these two storms in 2013, SAIDI and CAIDI increased 17% and 16% respectively in 2013 relative to 2006.

Year	Target (SAIDI)	Result (SAIDI)
2011	1.08 - 1.21	2.30
2012	0.99 - 1.12	1.45
2013	0.96 - 1.15	4.97

Table 2 - Historical Reliability Performance Against Target

Horizon Utilities has adopted the SMC classification of interruptions by cause. The primary cause of each service interruption is identified as one of the following:

- Unknown/Other;
- Scheduled Outage;
- Loss of Supply;
- Tree Contact;
- Adverse Weather;
- Adverse Environment;
- Human Element; or
- Foreign Interference.

Classification and analysis of outage causes is vital for efficient asset management and resource allocation, and encourages specifically targeted programs to increase system reliability.

Further analysis and classification of outages by the primary cause code reveals that outages caused by equipment failures, adverse weather, and foreign interference have caused 66% of the total customer minutes of outages over the previous four years. The contribution from each cause code is illustrated below in Figure 10.

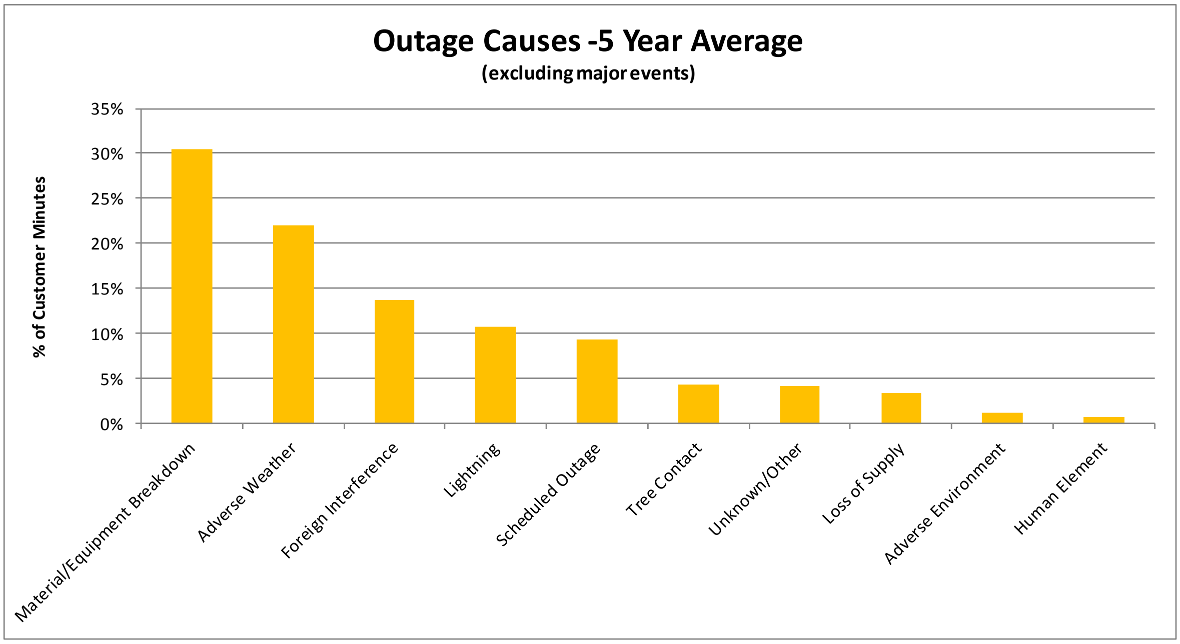

Figure 10 - Outage Cause Contributions for the years 2010 - 2013

The elements of the system become less resilient to adverse weather and foreign interference as they age. Horizon Utilities' distribution system has many asset groups with a high proportion of assets having a 'very poor' or 'poor' Health Index. The volume of assets with an unacceptable Health Index are contributing to a greater amount of equipment failures and service interruptions to customers. These service failures are further exacerbated as the aged/failed assets require longer repair times or outright replacement, extending the duration of the outage that the customer experiences. The negative trend in both SAIDI and SAIFI (and consequently CAIDI) corresponds to an increasing trend of quantity and impact of equipment failures and is symptomatic of an aging distribution system requiring investment in the renewal of assets to address the unacceptable level of system reliability.

1.3.3. Impact on the DSP (5.2.3.c)

Horizon Utilities leverages performance metrics and measures in an effort to continually improve the asset management and capital planning process.

The Health Index and System Reliability metrics are directly utilized in the asset management planning process. The Health Index distribution identifies the current level and future risk of equipment failure for the asset groups and corresponding level of risk in being able to provide a high level of service to customers.

The Health Index metric is also used to provide an indication of the level of investment required over a twenty year planning horizon per asset category allowing prioritization of investments in the various asset groups.

The System Reliability metrics, specifically SAIDI, are used to identify the customer impact of service interruptions. This customer impact is analyzed by geographic area and the cause of interruption. This information, when combined with the asset condition assessment information, is then used to develop Horizon Utilities' capital investment programs.

The cost efficiency and effectiveness metrics are utilized to measure and manage the implementation of the capital investment programs. These metrics provide an end to end reporting and visibility for all capital jobs, whether in the planning process or in progress. This accountability and visibility allows Horizon Utilities to accurately measure the company's performance in meeting the plan and identifying any areas for improvement on a continuous basis.

2. Asset Management Process (5.3)

2.1. Asset Management Process Overview (5.3.1)

2.1.1. Asset Management Framework - Goals and Objectives (5.3.1.a)

Since 2008, Horizon Utilities has adopted and implemented Asset Management practices based on those outlined in the British Standards Institution ("BSI") Publicly Available Specification No. 55 ("PAS-55"), which has been adopted by some utilities and companies in other industries who own and manage significant amounts of long lasting fixed assets and use asset management methodologies to ensure that their capital infrastructure investments are sustained in a cost-effective manner.

Horizon Utilities relies on the British Standards Institution definition of Asset Management ("AM") as:

> *"Systematic and coordinated activities and practices through which an organization optimally manages its assets, and their associated performance, risks, and expenditures over their life cycle for the purpose of achieving its organizational strategic plan."*[3]

Horizon Utilities' Asset Strategy is founded on the premise that effective management of the company's assets:

> *"enables an organization to maximize value and deliver its strategic objectives through managing its assets over their whole life spans."* [4]

Implementation of Horizon Utilities' vision to "be a leader in providing innovative energy solutions to the communities we serve" is achieved through its four corporate objectives: best performing utility; grow the business profitably; easy to do business with; and be a great place to work as illustrated in Figure 11 below.

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[3] From the British Standards Institution's PAS-55-1:2008 page v, developed by the UK Institute of Asset Management.
[4] PAS-55-1:2008 page v

Figure 11 - Horizon Utilities' Corporate Objectives

Horizon Utilities' asset management goals and objectives have been created to align with the corporate objectives as follows.

Financial Objectives

- Manage assets to minimize total lifecycle cost;
- Optimize operational and capital investments by utilizing best practice for the replacement, refurbishment, and maintenance of assets; and
- Ensure prudency of investment through balancing resources, and the interests of customers and shareholders.

Customer Focused Objectives

- Deliver save and reliable service to customers at reasonable cost;
- Satisfy customer expectations and delivering value for money;

- Manage reliability risks by monitoring outage causes with a goal that limits durations of outages on the distribution system to 4 hours, and durations of outages due to a substation failure to 12 hours; and

- Perform regular customer surveys to gauge customer satisfaction with operational effectiveness and reliability and power quality.

Operational

- Develop and utilize best in class processes for management of company assets;
- Manage risk to acceptable levels; and
- Incorporate and leverage benefits of new technology while assets are renewed.

These asset management objectives were leveraged to establish an asset management framework for the implementation of Horizon Utilities' asset management process and are presented in Figure 12 below. This framework outlines five core functions needed to build a strong asset management process while encouraging continuous improvement. Project selection and prioritization is an integral component of Horizon Utilities' asset management framework. The details pertaining to the implementation of the project selection and prioritization process are provided in Section 3.2.3 below.

Asset Management Framework

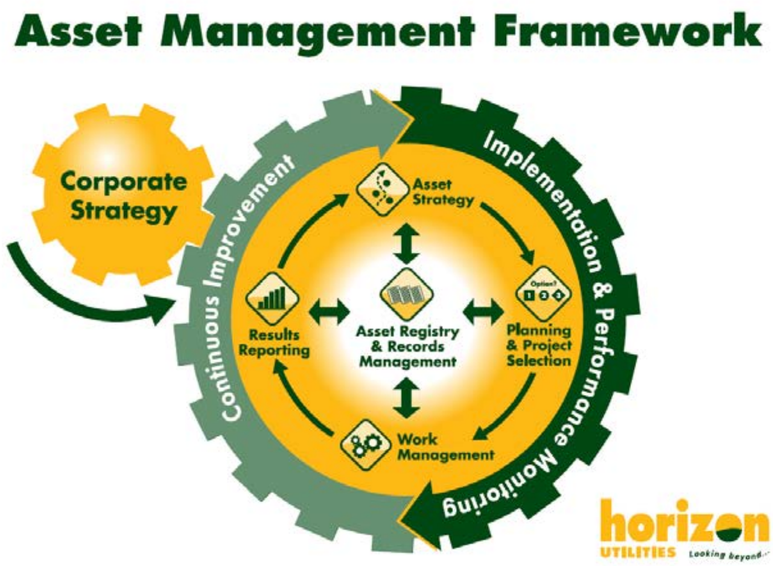

Figure 12 - Asset Management Framework

The AM Framework encourages equilibrium among proposed spending, performance objectives, customer satisfaction, risk factors, and goals. Continuous training and communication of AM policies and procedures is integral to this approach to ensure effective implementation and sustainable benefits.

Core Functions of the AM Framework

The five core functions are summarized below:

1. **Asset Strategy** – Overall AM strategy and performance objectives, investment strategy and Program Management roles and responsibilities including:

    - *Asset Management Policies*: Horizon Utilities' AM policies address capital management, equipment/system maintenance, reliability, and equipment protection. Additional policies (e.g., environmental, fleet, and facilities) are developed as required.
    - *KPI:* Horizon Utilities' KPIs combined with the AM program measure performance outcomes at strategic, operational and support levels.
    - *Asset Investment Strategy*: Horizon Utilities' investment decisions are based on a highly analytical approach that incorporates asset performance, condition, maintenance, and age based data acquired through its AM program.
    - *Continuous improvement*: Horizon Utilities incorporates on-going improvements to its AM capabilities.

2. **Asset Registry & Records Management** – A single electronic database of energy delivery asset data including:

    - *Data and Records Controls, Asset Knowledge and Records Management*: Horizon Utilities maintains a database of asset nameplate data and condition assessment data based on regularly performed equipment condition assessments, inspections, and testing programs.
    - *Joint Use Records Management*: Horizon Utilities establishes and maintains records of regular and on-going audits of joint use assets (e.g. Horizon Utilities' assets that are installed on a utility pole owned by an external party) to ensure accurate billings.
    - *Real Estate and Easements*: Horizon Utilities maintains all real estate and easement asset records, updates these records, and reviews agreements with parties on an on-going basis.

3. **Planning and Project Selection** – Development and acquisition of simulation tools, analytics, and evaluation methods including:

    - *System Planning:* System planning decisions are made based on data derived from regular system modelling and load forecasting activities.
    - *Design and Planning Criteria:* Horizon Utilities has developed and maintains planning criteria and design guidelines that will drive AM decisions.
    - *Construction and Material Standards:* Horizon Utilities has developed and maintains a detailed catalogue of construction and material standards that supports new build and maintenance activities.

4. **Work Management** – Establishment of consistent and documented procedures for execution of asset operation, maintenance and capital programs including:

    - *Operational Control and Execution of Maintenance and Capital Programs:* Horizon Utilities has implemented a consistent approach to the planning, scheduling and execution of capital and maintenance programs and will review/refine this approach on an on-going basis.
    - *Standard Processes:* Horizon Utilities employs standard processes to manage its work activities, including (at a minimum) a consistent approach to corrective and predictive maintenance, collecting equipment failure data comprehensively and consistently, and developing a standardized nomenclature for inventories.
    - *Inventory and Supplier Management:* Horizon Utilities maintains a single integrated inventory system and maintains inventories in a standard and consistent manner to allow for efficient replacement and procurement.

5. **Results Reporting** – Standardized and regular reporting of AM program results, both qualitative and quantitative to monitor and assess the quality of the planning process, the efficiency of implementation and the effectiveness in achieving the planning objectives.

2.1.2. Asset Management Implementation and Components (5.3.1.b)

Horizon Utilities' capital investment planning is achieved through the implementation of the AM Framework described above. The AM model ("AM Model"), illustrated in Figure 13 below, seeks to promote ongoing improvements involving each of the five core functions identified in the AM Framework. These activities encompass all aspects of managing the distribution system assets ranging from identifying long term system capacity requirements to determining needs of aging infrastructure based on the asset condition assessments to optimizing real time operational performance of the distribution system. The activities contained within each of the boxes in Figure 13 below create the inputs to the next step of the process, while the arrows within the diagram identify the process flow.

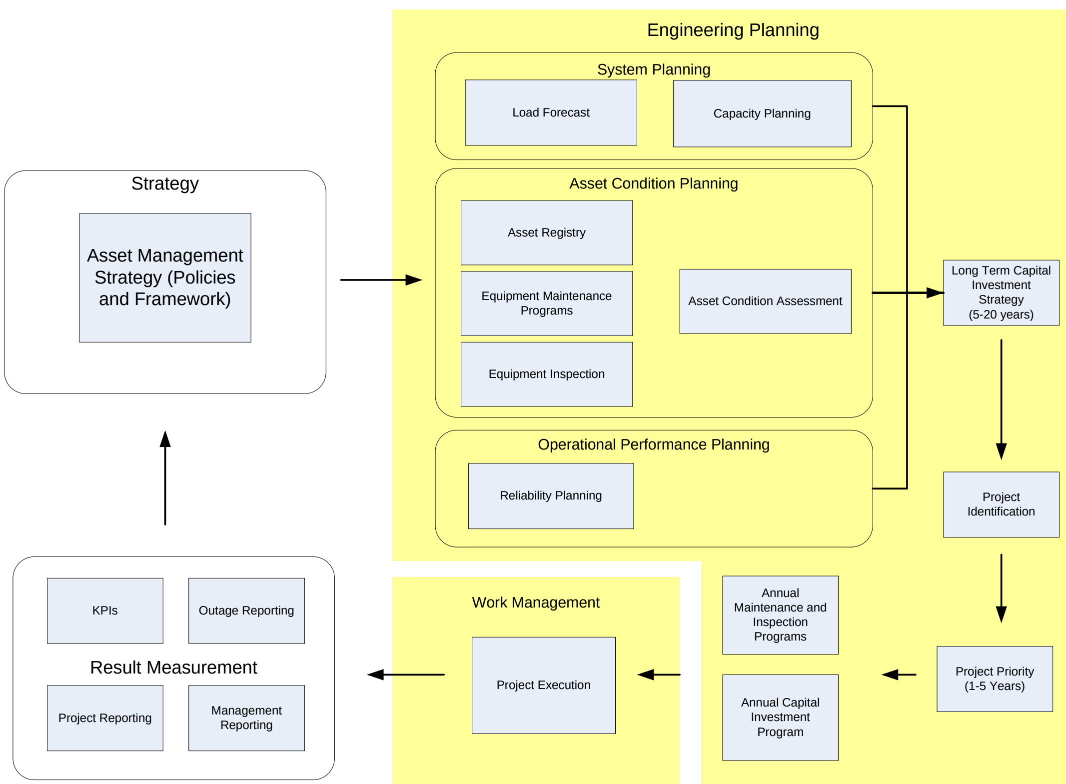

Figure 13 - Asset Management Model

Asset Strategy

Horizon Utilities identified the risk presented by its aging distribution infrastructure in both the Hamilton and St. Catharines service territories and moved to create and implement its AM Framework to address the risk of erosion of service to levels unacceptable to Horizon Utilities' customers. The fundamental principle of AM focuses on identification and justification for investment decisions related to the long term stewardship of the assets to provide an acceptable level of customer service and reliability consistent with customers' expectations at the lowest total life cycle cost possible.

The AM Framework balances short term operational needs with investments required for the long term sustainability of the distribution system. The framework enables long term system planning, identification of investment requirements and measurement of performance outcomes.

Asset Registry and Records Management

A thorough and unbiased assessment of asset condition is an essential component of effective asset management. All renewal decisions should be based on accurate and predictive assessments utilizing such data.

Horizon Utilities has centralized the distribution assets into a single asset registry contained in the Geospatial Information System ("GIS"). The GIS presents Horizon Utilities' distribution assets in graphical form with the asset attributes (such as - age, manufacturer, size/length, and installation date) with electrical connectivity. Horizon Utilities has collected records and inspection data to create an inventory of condition data for individual equipment. Horizon Utilities is in the process of renewing the GIS system and once complete, the maintenance and inspection data will be consolidated into the new GIS. The asset attributes as well as inspection and maintenance information are vital inputs into the asset condition assessment process.

The inventory and record of General Plant assets are managed outside of the GIS system within the business units that are responsible for the assets. This record system supports a parallel process to that performed on all other assets; with the exception of the use of the GIS system.

Planning and Project Selection

Engineering planning activities provide the foundational information and data upon which investment strategy is determined. The investment strategy, in combination with a project prioritization framework (described in the Project Identification and Selection segment below), ultimately produces the annual capital investment program and annual maintenance and inspection programs.

AM provides the foundation upon which the long term distribution capital investment strategy and annual capital investment programs can be developed and/or updated. The principal annual deliverables of the AM process include: review of the long term capital investment strategy; updating the AM inputs; development of the annual distribution capital investment program; and creation of the annual maintenance and inspection programs.

The planning activities of the AM Model include three major considerations:

- System Planning;
- Asset Condition Assessments; and
- Operational Performance Planning.

Horizon Utilities addresses asset capacity utilization through its System Planning and ACA analysis. Furthermore, the components related to equipment failure, worst performing feeders, and risk/consequence failure analysis are all addressed through the Operational Performance Planning process.

<u>System Planning</u>

Capacity and security planning play important roles in the way the distribution system and asset components are managed. The primary function of capacity planning is to ensure reliability of service for all existing customers as well as planning for future growth with the addition of new customers. Security planning focuses on the development of contingency plans to be used if a major asset should fail; thus allowing affected customers to be supplied from alternate power supplies. Ultimately, the final objective is to have adequate capacity and security for the entire distribution system in order to deliver a safe and reliable supply of electricity.

Long term system planning may include the coordination with third parties. This is further described in section 1.2.2 above.

Horizon Utilities' System Load Report

The System Load Report identifies electrical consumption by voltage level, service territory, Horizon Utilities-owned municipal substations, and Hydro One-owned transformer stations (at the TS bus and feeder level).

Long Term Load Forecast Report

The Long Term Load Forecast Report (found in Appendix H to this DSP) provides capacity analysis at all voltage levels of the distribution system. This analysis is performed at a station and feeder level. Feeders with peak loading exceeding 85% of capacity are identified so that new loads planned for these feeders can be analyzed. If the need for expansion or enhancement is identified, potential solutions and alternatives are reviewed in the annual planning cycle. The time period utilized for transformer station forecasts and feeder forecasts is twenty-five years.

Asset Condition Assessment

Distribution Assets

This ACA report summarizes the methodology used, outlines specific approaches used in the projects, and presents the resulting findings and recommendations.

For ease of reference, the Kinectrics ACA methodology, a summary of the data assessment criteria and the results of the ACA are summarized below:

Asset Condition Assessment Methodology

The Kinectrics ACA methodology involves the process of determining an asset Health Index, as well as developing a condition-based Flagged-For-Action Plan for each asset category. This data is then used to determine the appropriate course of action for assets in “very poor” or “poor” condition while also taking into account the criticality of the major assets, such as station transformers.

Health Index

Health Indexing quantifies equipment condition based on numerous condition parameters that are related to the long-term degradation factors that cumulatively lead to the end of life for a particular asset group. The Health Index is an indicator of the overall health of the assets and is typically given in terms of percentage, with 100% representing an asset in brand new condition.

The Health Index distribution given for each asset group illustrates the overall condition of the asset group. Further, the results are aggregated into five categories and the categorized distribution for each asset group is given.

The Health Index categories are as follows:

Very Poor	Health Index < 25%
Poor	25 <= Health Index < 50%
Fair	50 <= Health Index <70%
Good	70 <= Health Index <85%
Very Good	Health Index >= 85%

For critical asset groups, such as Station Transformers, the Health Index of each individual unit is given. For assets groups with a high volume of assets, the Health Index distribution deals with percentages of the total population.

Condition-based Flagged-For-Action Plan

Once the Health Index values were calculated, a Flagged-For-Action Plan based on asset condition was developed. The condition-based Flagged-For-Action Plan outlines the number of units that are expected to be replaced in the next twenty years.

The Kinectrics' models provide for two methods of calculating the Flagged-For-Action Plan volumes: i) reactive calculation; and ii) proactive calculation.

For assets with a relatively small consequence of failure, units are generally replaced *reactively* upon failure. The Flagged-For-Action Plan for such an approach is based on the asset group failure rate. This approach incorporates the possibility that assets may fail prematurely and prior to their expected typical end of lives.

For critical assets, a *proactive* approach is utilized such that units are replaced prior to failure. For asset groups that fall under this approach, a risk assessment study is conducted to determine the units eligible for replacement. This process establishes a relationship between the asset Health Index and the corresponding probability of failure for each individual asset within the asset group. The quantification of asset criticality was also involved through the assignment of weights and scores to factors that impact a decision for replacement. The combination of criticality and probability of failure determines risk and replacement priority for that unit. This approach was utilized for the substation transformers, switchgear, and circuit breaker asset groups.

ACA Conclusions and Recommendations

The Kinectrics ACA was conducted on 22 asset groups that were consolidated into fifteen asset categories. For each asset category, the Health Index distribution was determined and a condition-based Flagged-For-Action Plan was developed.

The results of the Kinectrics ACA are provided in Section 2.2.3.

<u>Operational Performance Planning</u>

The third major input into the planning process is Operational Performance Planning which relies on system reliability and equipment failure statistics to assess the operational performance of the distribution system.

SAIDI is used to measure the average annual hours of interruption experienced by all customers. Reliability reports provide for a very granular level of detail into system performance by classifying outages by cause, voltage, area and impact (number of customers and duration) and are used to identify areas requiring investment.

Additionally, outages caused by equipment failure are further investigated to determine the cause of the failure ("Failure Analysis"). Specifically, Horizon Utilities analyzes the performance of its worst feeders to ensure overall compliance and best practices in Asset Management. The Failure Analysis information is collated and analyzed in an attempt to improve equipment failure prediction and identify either geographical areas or asset groups requiring investment.

Collectively, SAIDI, reliability reports, and the Failure Analysis allow Horizon Utilities to identify and quantify the performance of various components. This analysis provides a measure of the risk or consequence of failure of an asset group. The analysis also includes a geographic analysis of system interruptions providing the identification of the worst performing feeders or areas of the service territory. All of this analysis provides Horizon Utilities with quantitative measures regarding distribution system performance and impacts on service which is used as a significant input into the capital investment planning process.

Ultimately, the entire AM planning process combines the output of the ACAs with the system performance, measured through system reliability, with capacity requirements to determine the areas, or projects, which require capital investment.

Candidate projects, identified through the system planning, asset condition assessment, and operational performance planning sections above, are then prioritized for inclusion in the annual capital investment programs. The prioritization process components are detailed immediately below with further and more detailed explanation in Section 3.2.3.

<u>Project Identification and Selection</u>

The output of the system, asset condition, and operational performance planning activities identified above are used in the development of long term capital investment strategy and subsequent project identification and prioritization. The steps, illustrated in the AM Model in Figure 13 above, are detailed below.

Long Term Capital Investment Strategy

System Renewal investment is primarily capital with a long term planning horizon. The output from the Long Term Capital Investment Strategy is provided below in Section 3.1.3.

The ACA performed by Kinectrics was the primary input and driver of the long term capital investment strategy ("LT Capital Strategy"). As previously discussed in Section 2.1.2, the Flagged-for-Action Plan identifies the number of units that are expected to be replaced in the next twenty years and provides a recommended renewal investment profile. This recommended profile is used to guide the twenty year capital investment requirements.

The Health Index distribution results identify the long term (20 year) investment requirements for the asset groups This information is used to identify long term capital investment programs which provide the overarching design for multi-year programs. The individual projects underlying the LT Capital Strategy are identified in the Project Identification step detailed below.

Kinectrics recommended a total twenty year investment level of approximately $693,000,000, detailed in Section 3.1.2 below, which warranted further validation given the materiality of the investment and related implications for long-term sustainable customer service reliability. Consequently, Horizon Utilities retained KPMG to conduct an independent assurance review and provide an opinion on Kinectrics' methodology and the resultant findings and recommendations contained in Kinectrics' report.

KPMG reviewed the methodology published by Kinectrics in its report and compared it with other methodologies used by utilities in order to test the validity of the selected methodology used by Kinectrics. The KPMG Report stated:

> *"Based on an independent assurance review of the methodology and analytics used in the Kinectrics report, it is KPMG's opinion that the approach used to arrive at the presented results is in line with industry practice and generally accepted methodologies. KPMG is of the opinion that the presented methodology has been appropriately and consistently applied against the Horizon supplied asset data in order to derive the final Flagged-for-Action plans for each of the asset classes. The interim and final results as presented in the Kinectrics report have been independently validated by KPMG to an acceptable margin of error for the intended purpose of projecting asset replacements or refurbishments over a twenty year period. When compared with accepted industry standards and practices for useful asset life, Kinectrics Flagged-for-Action plans appear to be reasonable and in line with industry expectations."*[5]

The KPMG Assurance Review of Kinectrics' ACA Report dated January 23, 2014 is provided as Appendix C to this DSP.

Project Identification

The long term needs identified by the LT Capital Strategy and short term needs identified through the planning processes are input into the Project Identification step. The LT Capital Strategy described above establishes a number of long-term, multi-year programs. Execution of these programs requires annual projects, completed sequentially, throughout the life of the program. Additional projects are identified through short term needs identified either from external parties, or from operational requirements of the distribution system.

The scope, justification and high level estimates are created for all candidate projects identified above and are submitted for project prioritization for scoring to determine the overall project effectiveness, value, and timing.

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[5] KPMG Report page 18[6] *The Conference Board of Canada, Adapting to Climate Change: Is Canada Ready*, March 2006 at page 8.

Project Prioritization

Candidate projects identified as a result of the Project Identification process are prioritized based on risk mitigation, asset renewal and other benefits.

Horizon Utilities prioritizes projects/activities to ensure that the most cost effective and necessary projects are executed first. Horizon Utilities' prioritization methodology assesses the effectiveness of projects based on their impact on the five defined categories with relative weights reflecting importance of each category. The highest scoring projects are given the highest priority. Necessity is determined by category and level of overall impact of a delay in action.

Proposed capital projects are ranked on the basis of a composite project priority score comprised of scores from each of the following categories:

1. Safety;
2. Security;
3. Customer Impact;
4. Regulatory/Statutory; and
5. Environmental.

The complete prioritization methodology is provided in Section 2.3.1 below.

<u>General Plant Assets</u>

Building Assets

Horizon Utilities has four main properties and 28 substations built between 1914 and the early 1980's within the cities of Hamilton and St. Catharines. In order to ensure capital investment in buildings is prudent and guided by proper AM principles, Horizon Utilities performed the following asset condition studies:

- Resource and Office Space Utilization Study Report ("Space Study") by PRISM Partners Inc provided in Appendix J;

- Building Condition Assessment 2013 (“BCA”) by Evans Consulting Services, provided in Appendix K;
- Horizon Utilities Physical Security Report by CAPSYS Integrated Technology Consultants provided in Appendix L;
- Horizon Utilities Head Office Window Assessment by MMM Group Limited provided in Appendix M; and
- Roof Inspection Review Fall 2013 for the John Street Head Office by Garland Canada Inc. provided in Appendix N.

The information collected during the asset condition studies provided Horizon Utilities with enhanced asset condition data and a refreshed view of long term capital expenditure requirements. This further informs the facilities planning process (“Facilities Planning”) undertaken by Horizon Utilities in the pursuit of efficient asset management. Figure 14 below demonstrates Horizon Utilities’ Asset Management decision tree that is used for Facilities Planning. This map is used in conjunction with objectives, goals and frameworks previously established through the DSP to ensure the most efficient management of building assets as well as ensuring effective capital expenditure planning. Through this process, Horizon Utilities strictly regulates its expenditure on these assets to adhere to priorities previously established in Section 2.1.1 above, while preventing undue degradation of building assets and negative consequence to operations and corporate functions.

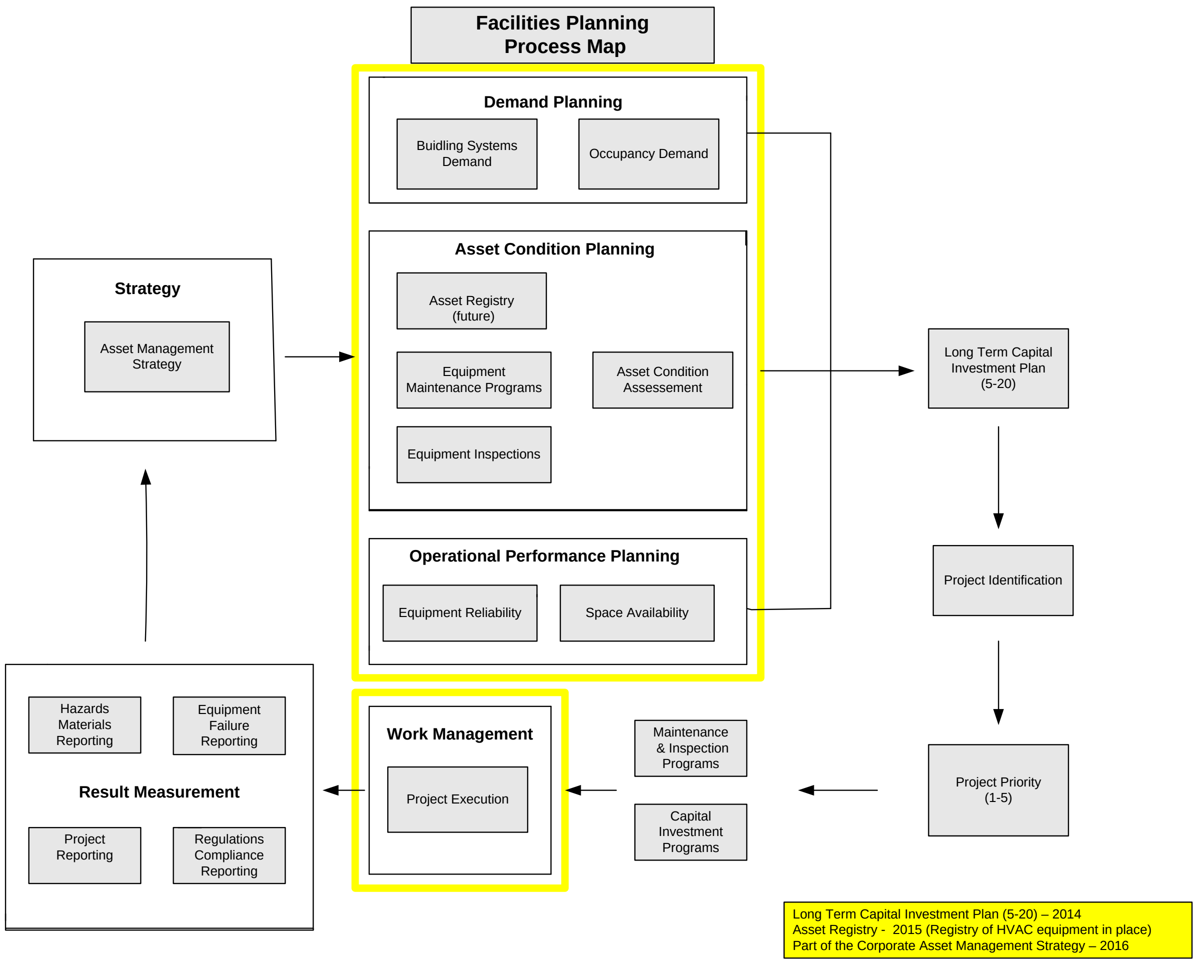

Figure 14 – Facility Planning Process Map

The following segments address the components of the Asset Management process as they relate to Facilities Planning identified above.

Asset Strategy

Horizon Utilities has identified the need for additional office space; the existence of poor work environments; and safety risks presented by aging building infrastructure and equipment. Horizon Utilities initiated a series of building asset condition studies, listed above, to identify the related investment needs. The findings from the asset condition studies are provided in Section 2.2.4.

Asset Registry

A thorough and detailed assessment of asset condition is an essential component of effective asset management. Repairs and renewal decisions should be based on accurate and predictive assessments utilizing such data. Horizon Utilities has created an inventory list of nearly all Heating, Ventilation and Air Conditioning ("HVAC") equipment and components. Horizon Utilities will complete a full inventory of all building related equipment and systems in 2014 and 2015. The facilities inventory of facilities related assets will be recorded in Horizon Utilities' Enterprise Resource Planning ("ERP") system. The findings and recommendations from the BCA will also be incorporated into the development of the facilities asset registry.

Planning and Project Selection

The buildings asset planning process provides the foundation for the long term capital investments required. Collectively, the Space Study, the BCA, and annual equipment maintenance and inspection programs determined the project prioritization.

The buildings renovation schedules from 2012 to 2019 were developed using: the recommendations from the Space Study; future departmental long term operational requirements; and user input. Each year, the planned renovation projects are reviewed and, if necessary, modified to reflect any changes to the operational requirements.

The planning activities of the Asset Management Model include the following major considerations:

- Building System Demand;
- Building Occupancy Demand;
- Increase in Employee Headcount and Office Equipment;
- Building Equipment & Systems Failure Reporting;
- Third party Asset Condition Assessments; and
- Operational Performance Planning.

Building Equipment & Occupancy Demand

Building equipment and office space capacity, availability, reliability, systems consumption and sustainability planning play important roles in the way those asset components are managed. The primary function of equipment and system demand planning is to ensure the adequate capacity and reliability of all building related equipment and systems, such as HVAC Units, building fire systems and building security systems, so as to maintain an acceptable work environment for Horizon Utilities employees while planning for future growth.

Building Asset Condition Assessment

The Space Study and BCA were primarily used to support the evaluation of the future buildings needs for Horizon Utilities.

The Spacy Study and BCA were conducted on the following categories of facilities:

- Office Space Environmental Conditions & Requirements
- Heating and Air Ventilation Conditions
- Interior and Exterior Architectural Conditions
- Building Code and Fire Act Compliance
- Building Regulation Requirements
- Early detection of possible failure to prevent deterioration and damage of existing and neighboring components or systems
- Forecast replacement costs for major components

Asset Condition Assessment Methodology

The objective of the BCA was to determine the condition of existing equipment, systems and infrastructure, and provide recommendations for improvement and forecast replacement costs for major building components based on their predictable life. The Life Cycle Analysis ("LCA") used is based on the premise that every component has a predictable life. Several organizations such Buildings Owners and Managers Association ("BOMA") and International Facility Management Association ("IFMA") publish lifecycle charts that forecast the expected service life of building components given their past performance. Building components include items such as roofing, architectural interior and exterior elements, heating ventilation and air conditioning components and so on.

Another driver that impacts the life of a building component is the effectiveness of the preventative maintenance program being applied. For purposes of the BCA, the consultants defined Preventative Maintenance ("PM") Program as planned actions undertaken to retain an item at a specified level of performance by providing repetitive scheduled tasks which prolong system operation and useful life and prevent premature failures. Typically PM Programs include inspection, lubrication, adjustment, cleaning, non-destructive testing, and periodic maintenance, usually including minor component replacement.

The balance of any successful PM Program is deciding the extent of maintenance that needs to be applied. Over maintaining a building is too expensive, while under maintaining can be catastrophic. The measure of the buildings' condition through a BCA is one way to measure the effectiveness of current maintenance programs and inform future maintenance requirements.. Maintenance programs are discussed further in Section 2.3.1.

Operational Performance Planning

One of the major inputs into the planning process is Operational Performance Planning which relies on system reliability, availability and equipment failure statistics to assess the operational performance of the facilities equipment and system.

Currently, Horizon Utilities tracks and reports on building equipment maintenance and repairs within facilities work orders. This is currently a manual process. Horizon Utilities anticipates automating and centralizing the collection and reporting of data to improve the visibility and accessibility of data during 2014 and 2015.

Planning and Scheduling Project Execution

Ultimately, the facilities Asset Management process combines the output of the ACAs (provided in the BCA, window assessment, equipment and system failure and repair data, roof assessment and security assessments) with the office space and occupancy demand (identified by the Space Study) to determine facility investment requirements. The process for project planning and scheduling is a manual exercise and is based on the highest risk areas, safety risks, operational requirements and affordability.

Results Reporting

Horizon Utilities' Asset Management process is driven by a continuous improvement focus. During 2014, Horizon Utilities will develop and implement key indicators to gauge the effectiveness of the Facilities Asset Management Planning process.

Information Technology

IST Planning Process

The Information Systems & Technology ("IST") capital investment program is a cyclical process with many inputs and variables. This process is demonstrated in Figure 15 below ("IST Planning Process").

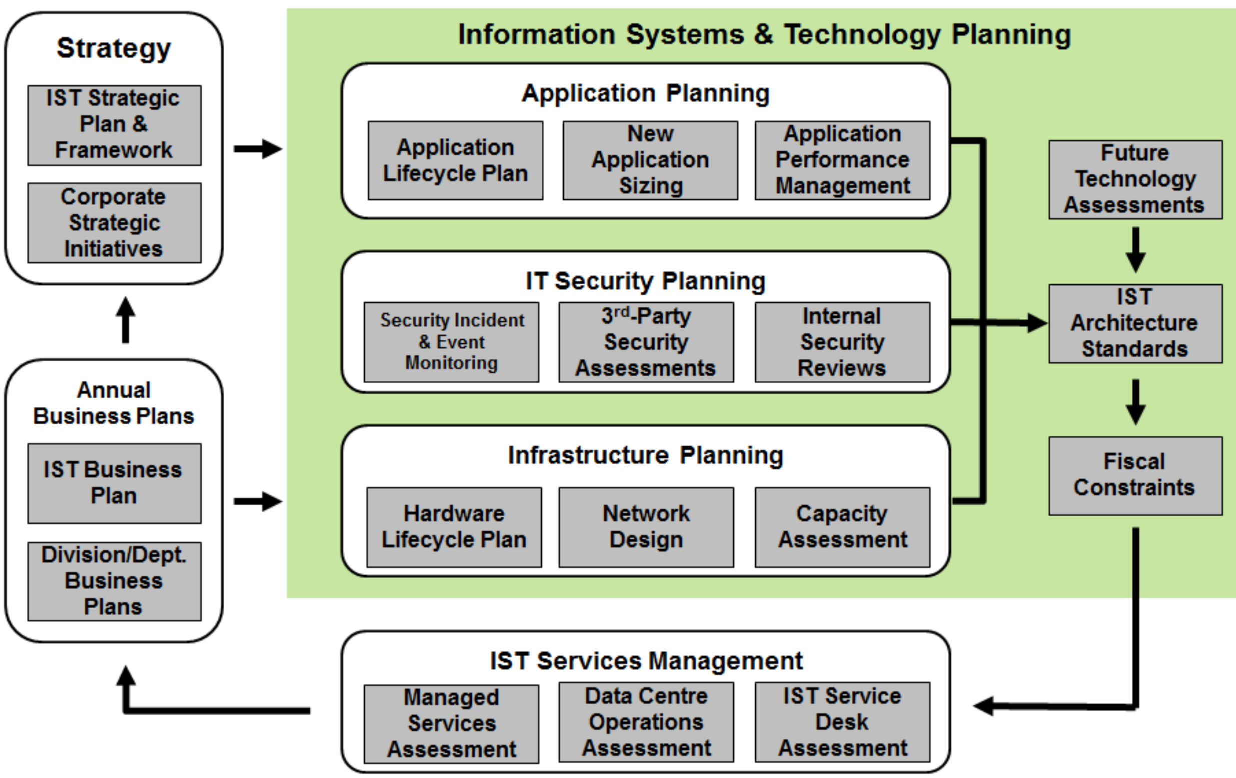

Figure 15 - IST Planning Process

The following is a description of each relevant component of the IST process.

IST Planning

The IST Planning Process focusses on three primary areas: Application Planning; IT Security Planning; and IT Infrastructure Planning.

The Application Planning process is a review and update of the Application Lifecycle Plan to determine business applications that should be upgraded or replaced. Any new applications approved during the business planning process or the IST strategic planning process is factored into application planning. Application performance is reviewed to determine investments required to keep applications running optimally so as to sustain and improve business operations.

The IT Security Planning process consists of a review of the security incident and event monitoring ("SIEM") system logs which identifies security incidents and potential threats. Periodic third-party security assessments are performed to identify potential security risks. Periodic internal security reviews of the IST infrastructure and applications are also performed to identify security changes required to maintain the security of infrastructure and data. Analysis of these processes assists in development of the capital expenditure program related to IT security.

The IT Infrastructure Planning process consists of a review and update of the Hardware Lifecycle Plan to determine which infrastructure items should be replaced or upgraded to maintain operations. The corporate network, advanced metering infrastructure ("AMI") network, and SCADA network design are reviewed to ensure that they have sufficient capacity to support ongoing business operations and approved new applications.

IST Architecture Standards are reviewed and updated based on output from Application Planning, IT Security Planning and IT Infrastructure Planning. Also factored into the IST standards are new and evolving future technologies as identified by leading IT technology research companies like Gartner, Inc. and Info-Tech Research Group.

IST Services Management

Based on the results of the IST Planning Process, IST services management is reviewed to determine the best option for IST resourcing to support the secure and optimal performance of the IST environment to maintain business operations. This consists of reviews of third-party managed services, data centre operations, and IST service desk capabilities.

Each division or department develops a five year business plan. These business plans are reviewed with IST to identify any requirements for enabling IT investments and resource support. The IST Business Plan is effectively informed by and developed in conjunction with department business plans. The IST business plan identifies the IST capital investment and IST operational changes to support business operations over a five year period. The five year financial plan is reviewed and approved by the Horizon Utilities Board of Directors, which results in specific approved IT projects.

Fleet Vehicles

Horizon Utilities' fleet inventory comprises 189 vehicles including 44 trailers. Horizon Utilities performs fleet assessments annually to determine the condition of each individual fleet unit. The assessment include: reviews of the mileage, engine hours, utilization, and power take off ("PTO") hours for each unit; and the identification of units that meet the following replacement criteria.

Fleet Class	Replacement Assessment Criteria
Light Duty Vehicles:	Assessed at six years and every year after, and/or high mileage (excess of 150,000 km) Replacement schedule: at 6 to 8 years
Heavy Duty Vehicles:	Assessed at 11 year service, and every year after, and/or high mileage (excess of 200,000 km) High engine hours (excess of 15,000 engine hours) Replacement schedule: at 16 to 19 years
Trailers:	Trailer replacement will follow the same core principles as the vehicle replacement criteria with the following differences: • When assessing trailer conditions, trailers will be refurbished rather than replaced. • Where trailers cannot be refurbished due to application change or condition, trailers will be flagged for replacement.

Table 3 - Fleet Replacement Criteria

Horizon Utilities' fleet replacement criteria was developed internally through experience gained in utility fleet operations regarding vehicle lifespan and operating costs. The fleet replacement criteria is periodically validated through comparison with other utilities and Horizon Utilities vehicle replacement criteria is consistent with the best practice for utilities in Ontario.

Horizon Utilities continues to use: data collected from GPS units on each vehicle; work order details on maintenance worked performed; manufacturer's standards; and related regulations policies to determine vehicle replacements to review and assess the fleet replacement criteria.

The fleet replacement assessment criteria was modified in 2011 to extend the service life for Light Duty and Heavy Duty vehicles. As a result of this change, the service life expectancy of Horizon Utilities' vehicles has increased by one year.

The results of the assessment, and the forecasted needs of the organization are evaluated to determine whether the vehicle should be retained, reallocated, or replaced.

Vehicles identified as requiring replacement are further assessed to determine the nature of replacement: replacement with the same class of vehicle or replacement with a different vehicle configuration, based upon the forecasted need of the workforce. Vehicle refurbishment is also considered, particularly for large and expensive vehicles such as bucket and digger derrick trucks.

The Fleet Replacement Plan (included as Appendix O) is updated annually to identify investment requirements over the next six years. The investment requirements for the 2015 to 2019 Test Years are summarized in Section 3.1.3.

Tools, Shop and Garage Equipment

This program includes capital expenditures pertaining to the replacement of tools, shop and garage equipment, which are either worn, have come to the end of their useful life, or the continued use of such creates health and safety risk. The asset management and lifecycle optimization of each of the programs above is further detailed below in Section 2.3.

Work Management Process

Work Management involves the complete lifecycle of distribution construction projects; commencing with project design and continuing through material procurement, construction, and financial closure. This process impacts several departments which adds a great deal of complexity through integration. Horizon Utilities has identified opportunities to improve work management processes through improved project planning, reduced inventory levels, increased crew utilization through improved crew scheduling, and improved construction job planning.

Planning and Scheduling Project Execution

As discussed in Section 1.3.1, the iPass initiative was launched in 2012 to improve productivity by reducing manual processes; more efficient human resource utilization, reducing actual deployment and tool time; as well as enhancing inventory availability. This initiative balances resources to work loads across all work centres and, through a centralized approach, capitalizes on economies of scale.

Prior to this implementation, the legacy process for planning and scheduling was a manual exercise that consisted of more than 15 processes and over 750 discrete activities. The legacy processes: were unproductive; impacted productivity; did not allow management visibility on the effective use of resources and inventory; and did not allow management to evaluate if the work planned was executed in the appropriate time frames.

Through the iPass initiative, responsibility for each step within the work management processes was clearly identified improving accountability while providing end to end reporting and visibility to all jobs; whether in the planning process or in construction. This accountability and visibility allows accurate measurement of performance in adhering to project timelines and milestones. Project variances, to either budget or schedule, are analyzed to identify the source of the problem. Problems common among multiple projects are reviewed to identify solutions in an attempt to prevent reoccurrence in future projects.

In addition to implementing best practices in utility management, iPass increases customer satisfaction through: the efficient identification of priority jobs, reduction of project lead times, and effective communication with the customer. Specifically, iPass improved the transparency to project dates and milestones allows Horizon Utilities' the ability to communicate deliverables and dates to the customer. The improved processes provide Horizon Utilities an improved ability to achieve these commitments without having to reschedule and disrupt the customer.

As illustrated in the Figure 16 below, the iPass Initiative is a continuous process that allows for constant adjustment and improvement to maximize Work Management.

Figure 16 - iPass Continuous Improvement Cycle

The objectives of iPass are to create a detailed centralized work schedule, integrating project scheduling, inventory management, and resource ability to respond to customer expectations, improve the predictability of planned work, and measure unplanned activities. Creating a centralized schedule allows stakeholders in the work management process access to as close to real time information as possible regarding the project through the entire life cycle. The resulting work schedule is visible to all construction, engineering, customer connections and supply chain personnel that have involvement with and accountability for various elements of the planning and execution of projects. The schedule displays the current status of current projects as well as key information on future scheduled work. The planning and scheduling group ("Planning and Scheduling") provides the data to measure productivity, which in turn enables the improvement of budgetary estimates and forecasting of project costs.

There are currently over 500 active projects that require hands-on management and visibility throughout the entire process. The detailed centralized work schedule is the key enabler for the effective planning, scheduling, and execution of these diverse projects.

Results Reporting

Horizon Utilities' Asset Management process is driven by the objective of continuous improvement. This improvement is only accomplished by accurate and timely reporting on the effectiveness of the process. The metrics used by Horizon Utilities are described above in Section 1.3.1.

2.2. Overview of Assets Managed (5.3.2)

2.2.1. Description and Explanation of Distribution System Features (5.3.2.a)

Horizon Utilities serves 338 square kilometres of urban area and 88 square kilometres of rural area in the cities of Hamilton and St. Catharines. With Decew Falls in St. Catharines being the one of the first generating stations in Ontario and its AC transmission line to Hamilton being the longest at the time when first constructed, Hamilton and St. Catharines evolved early around a heavy industrial base even before the creation of Ontario Hydro in 1905. Horizon Utilities' in-service distribution assets, in some cases, comprise among the oldest in the province. A significant portion of Horizon Utilities' asset infrastructure was installed during post-war expansion years of the 1950s, 1960s, and 1970s. This infrastructure is now largely due for renewal. Horizon Utilities has been able to extend the life of this equipment through careful management and prudent investments focused on the long-term stewardship of these assets. However, a significant portion of these assets is at, or nearing, EOL and must be replaced along a carefully managed timeframe in a manner that balances distribution system risks and customer rate impacts.

Hamilton and St. Catharines differ from the communities served by many other LDCs because they are large urban and industrial centres rather than primarily suburban or rural communities. This is reflected in Horizon Utilities' line density of 69 customers per kilometre, where the highest is 85, the average and median are 46 and the lowest is 6, and is area density of 426 customers per square kilometre, where the highest is 1168, the average is 302, the median is 276 and the lowest is 0.8. While these numbers are near the highest , they would be higher if only Horizon Utilities' urban service territory were considered.

The significance of this data for Horizon Utilities is that Hamilton and St. Catharines are largely built out urban communities with only infill development rather than greenfield development opportunities available in the future. While Horizon Utilities does have 88 square kilometres of rural service territory, these areas are greenbelt lands beyond the provincial government controlled "built boundary" for each city.

This service territory growth constraint is evident in Horizon Utilities' customer growth statistics. From the creation of Horizon Utilities in 2005 to 2012, the customer growth rate has been 0.42 percent, with the lowest year being (0.09%) and the highest being 0.79%.

	2005	2006	2007	2008	2009	2010	2011	2012
Horizon Customers	230,327	231,499	232,493	233,947	234,666	234,464	235,327	237,185
Horizon Customer Growth Rate/yr		0.51%	0.43%	0.63%	0.31%	-0.09%	0.37%	0.79%

Table 4 - Horizon Utilities Customer Growth Rate 2005 - 2012

Using population growth data as a proxy for customer growth, Statistics Canada data confirms the previous growth limitations and future growth prospects of a similar growth limitation. From 2001 to 2011, Hamilton's population growth averaged 0.31 percent per year and St. Catharines averaged negative 0.04 percent. From 2011 to 2016, population growth is expected to average 0.77 percent per year in Hamilton and 1.48 percent in St. Catharines. From 2016 to 2021, population growth is expected to average 1.85 percent per year in Hamilton and 0.20 percent in St. Catharines.

	2001-2011	2011-2016	2016-2021
Hamilton - increase per year	0.31%	0.77%	1.85%
St. Catharines - increase per year	-0.04%	1.48%	0.20%

Table 5 – Hamilton and St. Catharines Population Growth 2001-2012

Horizon Utilities has experienced an increase in severe weather over the past five years including significant storms, and corresponding significant service interruption to customers. This trend of increasing occurrences of severe weather is expected to continue.

- Mean temperatures in Great Lakes Basin could increase by 1.5° C to 2° C in the autumn and 4.5 – 5 °C in winter.[6]

- The number of days over 30° C in southern region is expected to more than double by 2050, with some studies indicating the frequency could increase three-fold.[7]

- Most areas will experience more precipitation, with most of the increase occurring as rain and less as snowfall and an increased risk of ice.

- Great Lakes water levels could decline by 0.5-1.6 metres,[8] despite the increase in precipitation, due to reduced ice cover and higher evaporation losses.

[6] *The Conference Board of Canada, Adapting to Climate Change: Is Canada Ready*, March 2006 at page 8.
[7] Chiotti, O. and Lavender, B., (2008), Ontario at page 239.

- Severe weather events **are** predicted to become more frequent. "**A 1990's 1-in-20 year annual maximum daily precipitation event is likely to become a 1-10 to 1-in-15 year event by 2050**"[9]. (emphasis added)

Horizon Utilities services the cities of Hamilton and St. Catharines as illustrated below in Figure 17 and Figure 18. The description of how these service territories are divided into eight distinct operating areas is provided in Section 2.2.2 below. The impact of the distribution system features described above and the resulting investment drivers are identified for each of the operating areas.

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[8] *Conference Board of Canada, Adapting to Climate Change*, at page 8. See also: Union of Concerned Scientists, Confronting Climate Change in the Great Lakes Region, April 2003, page 24.
[9] "*Extreme Weather: Big Picture*", Gordon McBean, University of Western Ontario – ICLR, presented at Ontario Regional Climate Change Consortium at slide 8.

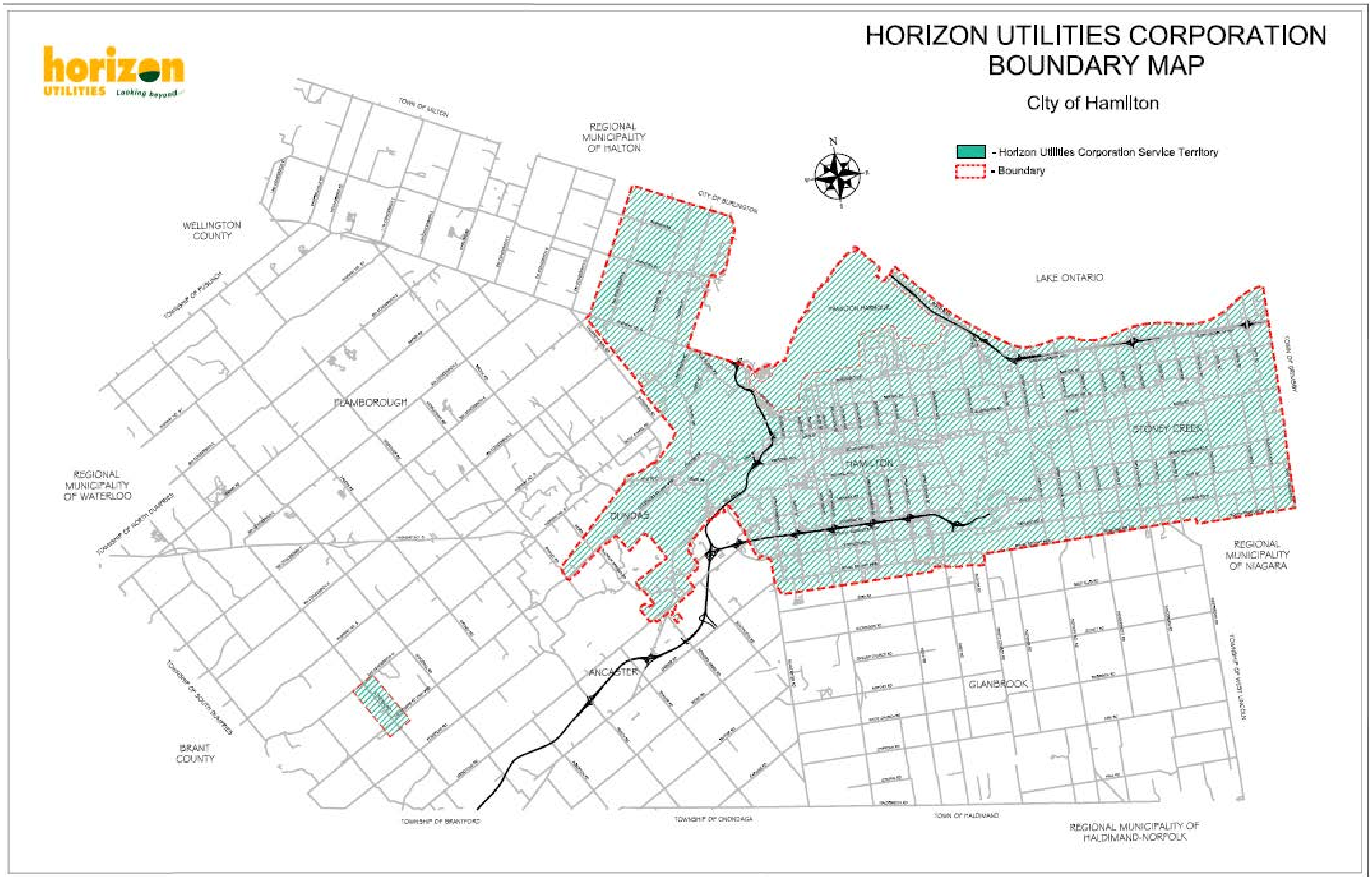

Figure 17 - Map of Horizon Utilities Boundary - Hamilton Service Territory

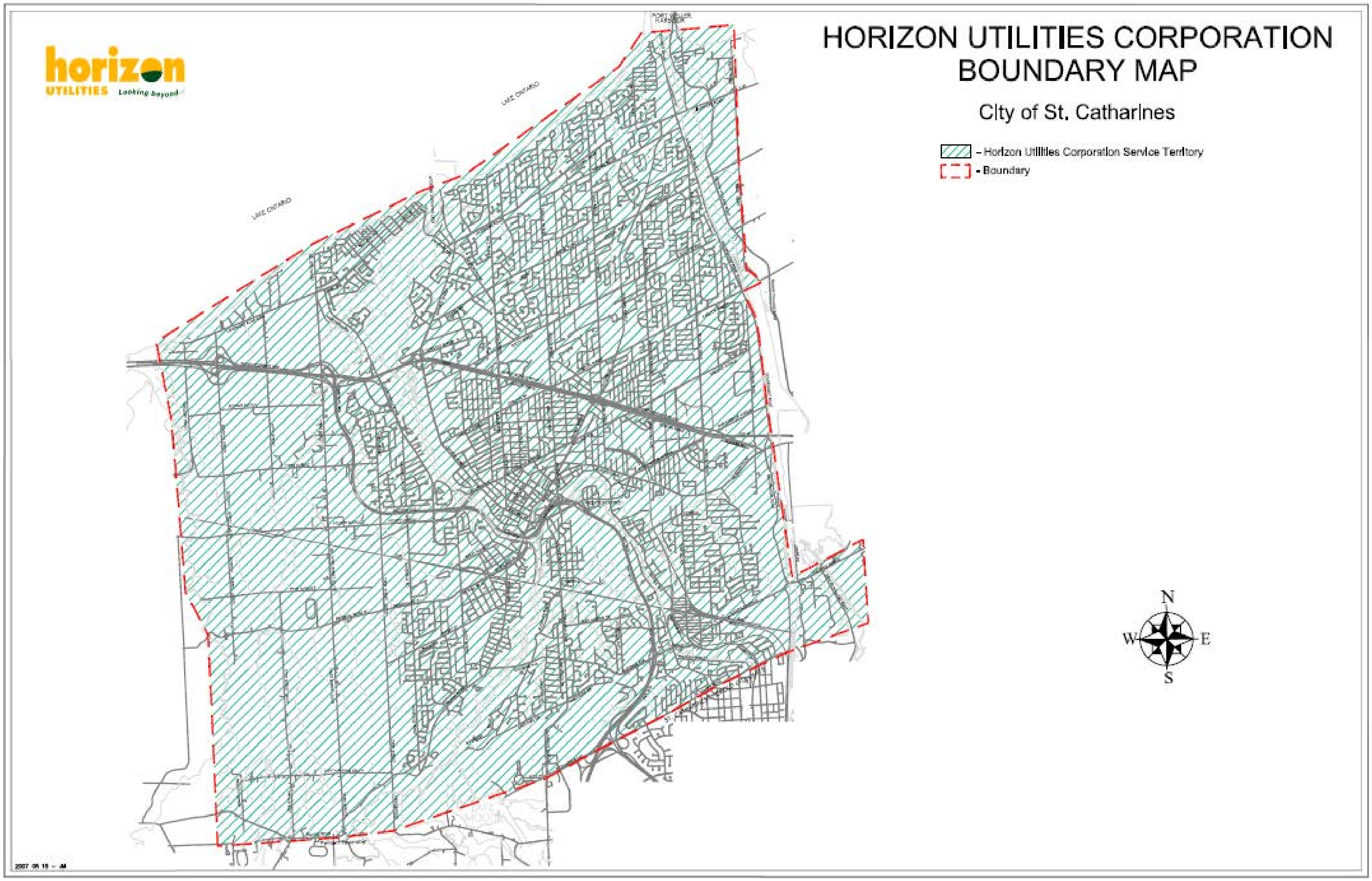

Figure 18 - Map of Horizon Utilities Boundary – St. Catharines Service Territory

2.2.2. Distribution System Description (5.3.2.b)

Horizon Utilities is supplied through the Hydro One transmission system at voltages of 13.8kV and 27.6kV. Electricity is then distributed over 1,904 km of underground ("U/G") cable and 1,524 km of overhead ("O/H") conductor. Horizon Utilities distributes electricity at four supply voltages: 27.6 kV, 13.8kV, 8.32 kV, and at 4.16kV delivered from 28 owned Municipal Substations.

Feeders

The number and length of circuits by voltage level is provided below in Table 6**.**

	Length of U/G in km	Length of O/H in km	Count of Feeders
4kV	98	397	164
8kV	22	25	9
13kV	1,409	784	403
27kV	375	318	17
	1,904	1,524	593

Table 6 - Number and Length of Circuits by Voltage

Transformer Stations

Horizon Utilities is serviced by seventeen Hydro One-owned Transformer Stations in the Hamilton service territory and four Hydro One-owned Transformer Stations in the St. Catharines service territory. Figure 19 and Figure 20 below illustrate where the Transformer Stations are located within the Hamilton and St. Catharines service territories.

Municipal Substations

Horizon Utilities owns and operates 28 Municipal Substations; 25 in the Hamilton service territory and three Substations in the St. Catharines service territory. Figure 21 and Figure 22 below illustrate the location of the Municipal Substations in the Hamilton and St. Catharines service territories, respectively.

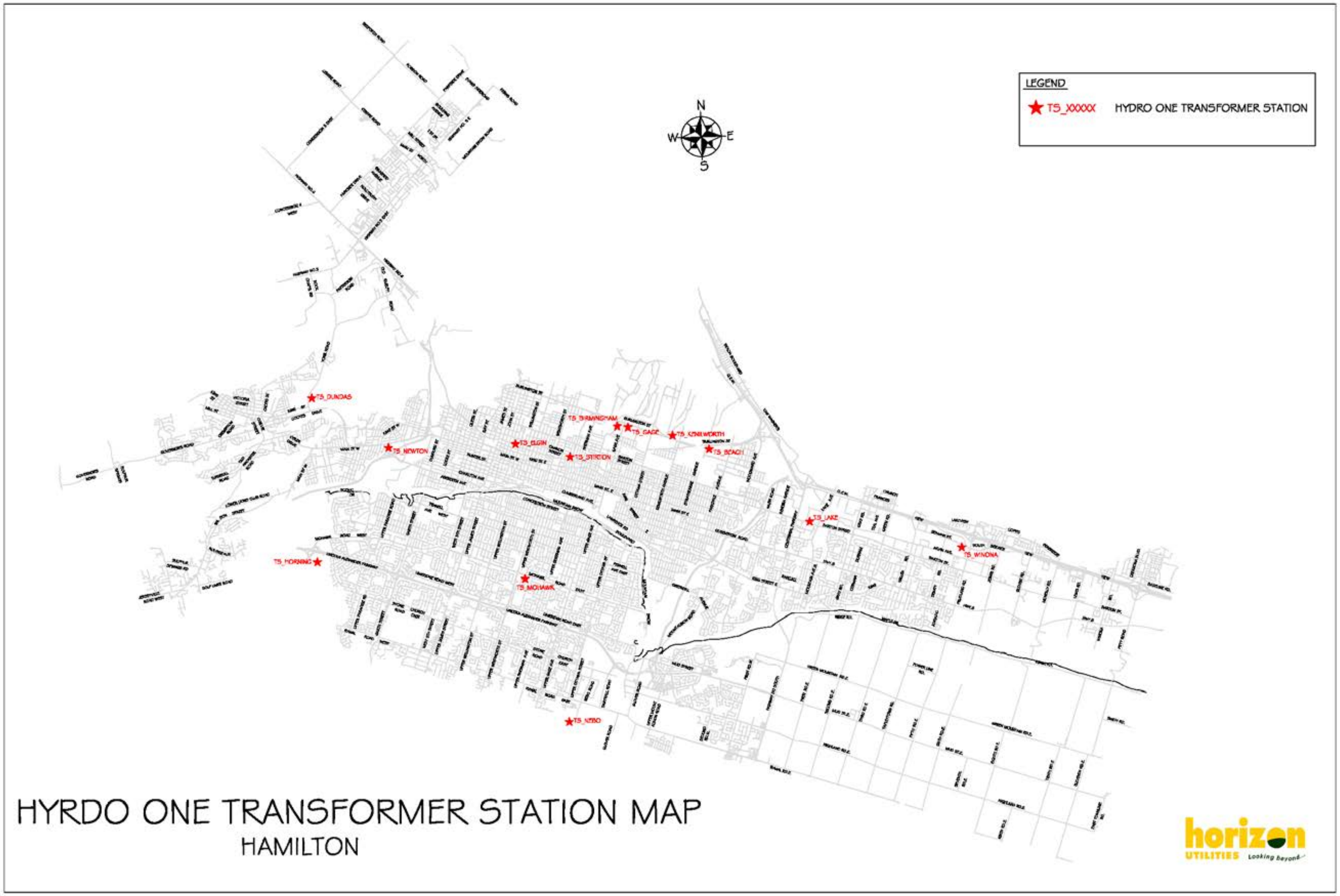

Figure 19 - Map of Transformer Stations Servicing the Hamilton Service Territory

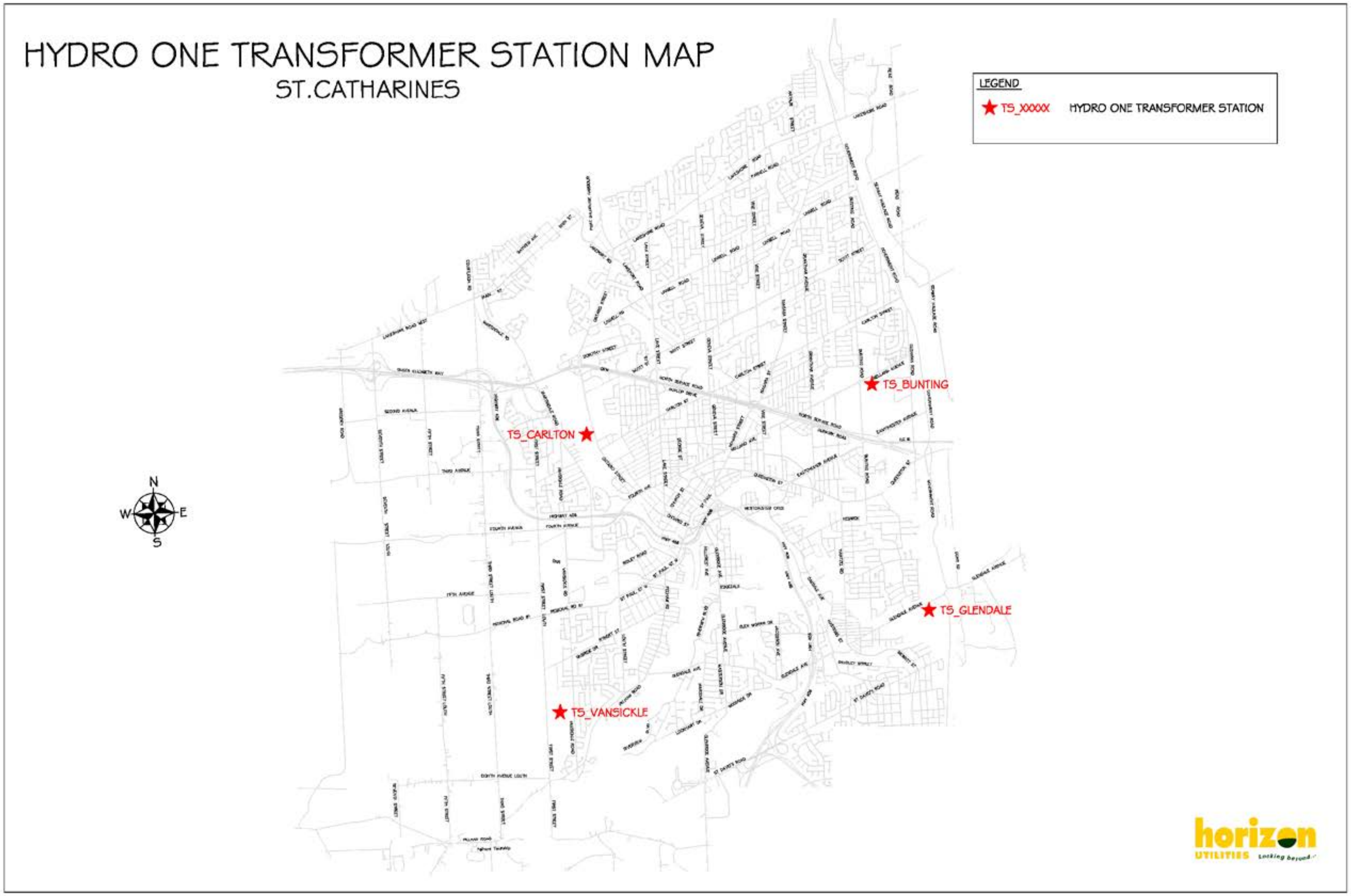

Figure 20 - Map of Transformer Stations Servicing the St. Catharines Service Territory

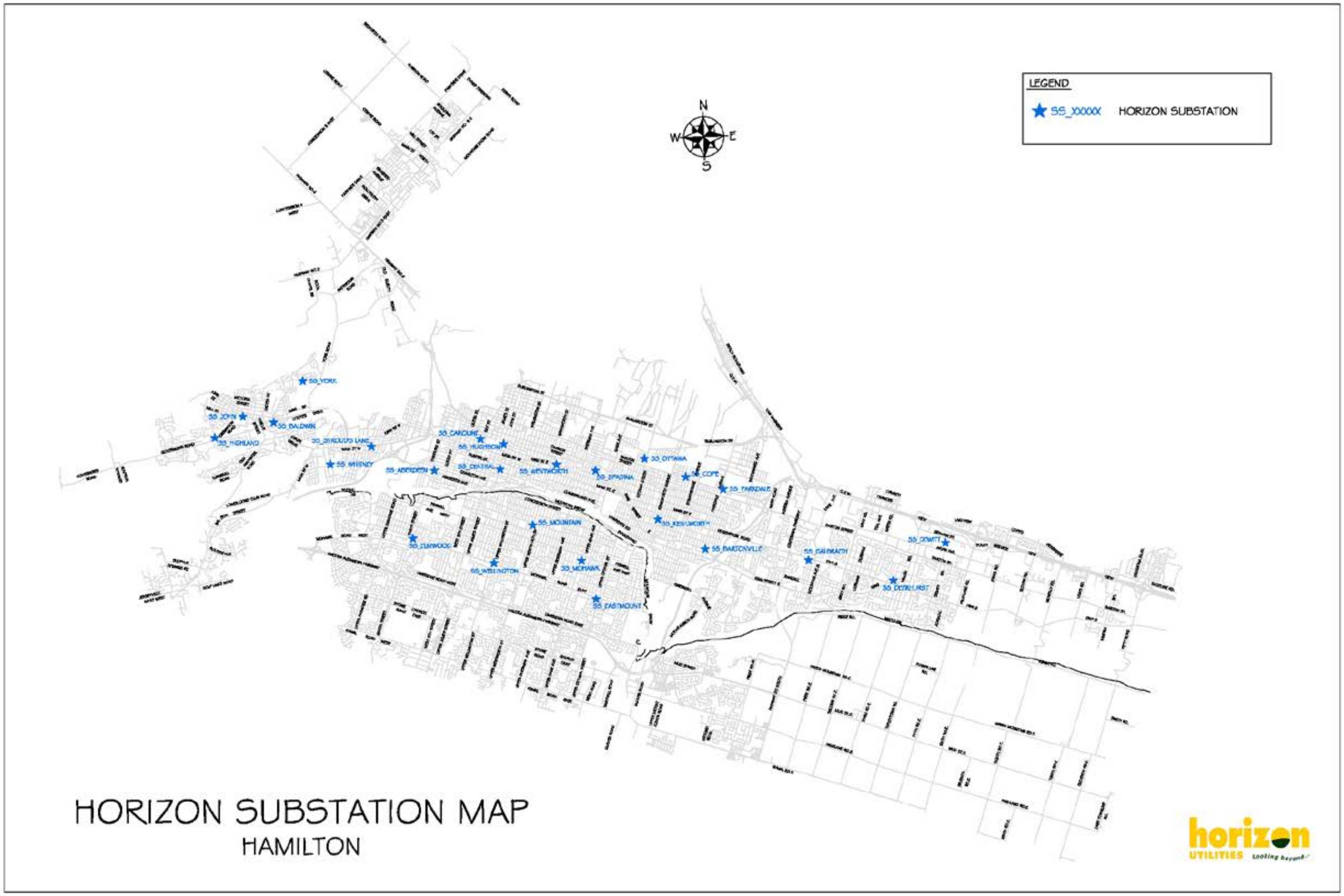

Figure 21 - Map of Municipal Substations Servicing the Hamilton Service Territory

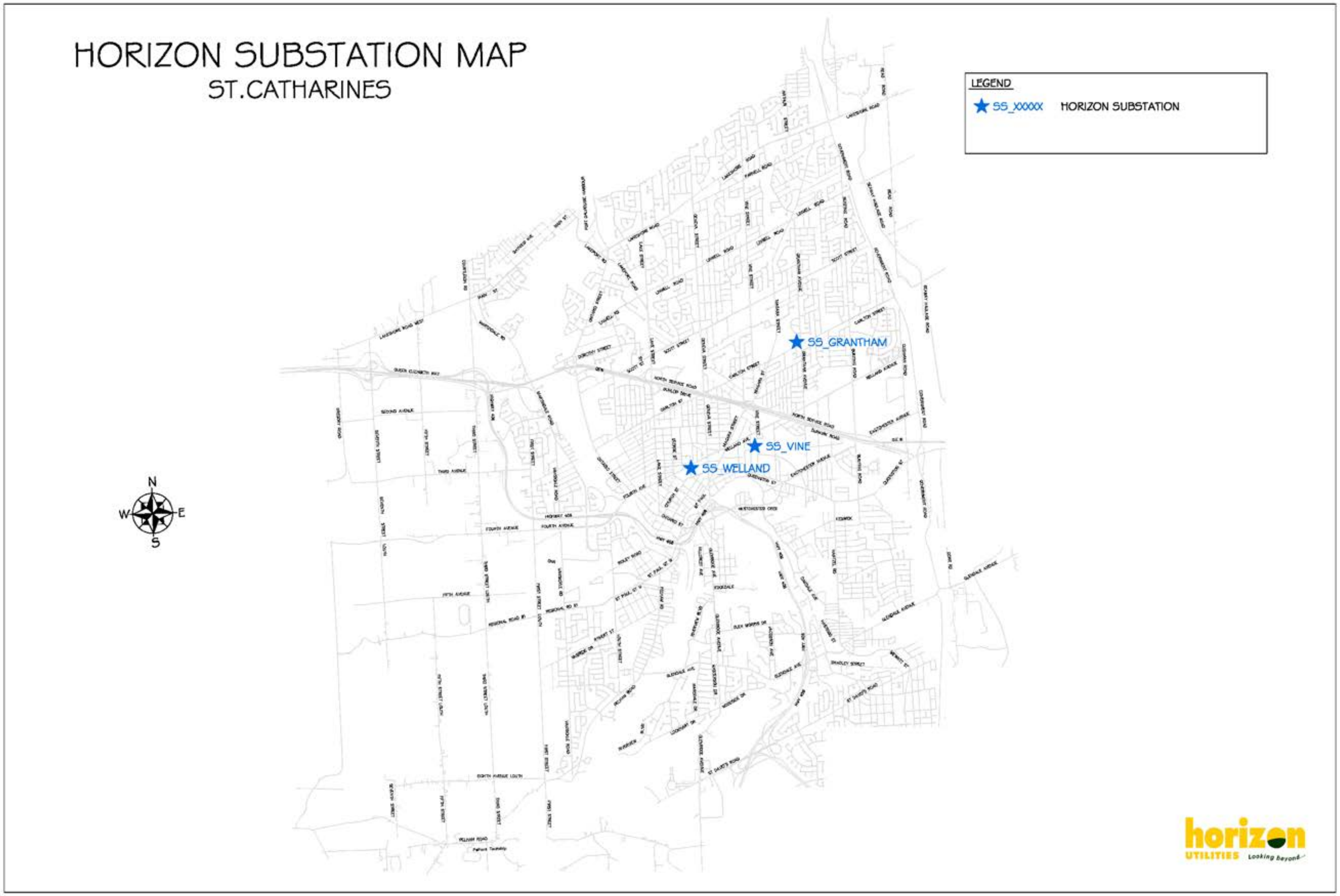

Figure 22 - Map of Municipal Substations Servicing the St. Catharines Service Territory

Operating Areas

The geography of the Hamilton and St. Catharines service territories in conjunction with the amalgamation of Hamilton Hydro, Stoney Creek Hydro, Dundas PUC, Ancaster Hydro, Flamborough Hydro and St. Catharines Hydro into Horizon Utilities has resulted in the formation of distinct operating areas. The operating areas in the Hamilton service territory are illustrated in Figure 23 and are further described below.

On the pages that follow, Horizon Utilities has provided descriptions of each of its operating areas, together with information on their features; on assets serving each of those areas; and on drivers of material investments included in Horizon Utilities' capital expenditure plan.

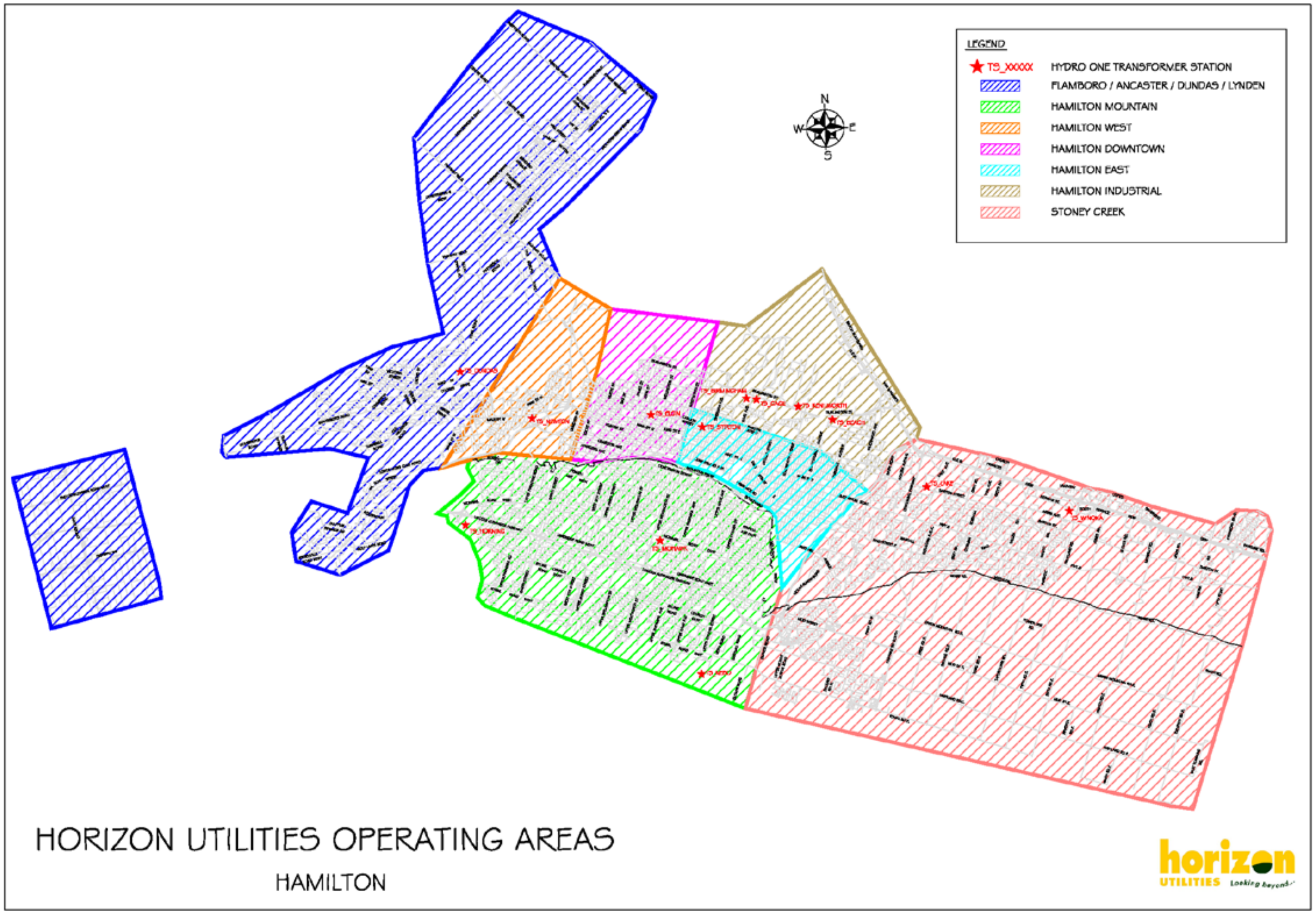

Figure 23 - Horizon Utilities Operating Areas in the Hamilton Service Territory

Flamborough/Ancaster/Dundas/Lynden

Description

The Flamborough/Ancaster/Dundas area incorporates approximately 19,000 residential and commercial customers in the Flamborough, Ancaster and Dundas areas of the Hamilton service territory.

Ancaster and Flamborough are serviced directly from Dundas TS at the 27.6kV voltage level. Dundas is serviced both directly by Dundas TS at 27.6kV and includes three Municipal Substations servicing customers at the 4.16kV voltage level. Lynden is serviced at the 8.32kV voltage level from the Hydro One-owned Troy Distribution Station.

The topography of the area serviced, in relation to the location of Dundas TS, results in the majority of customers in this area being effectively radially fed from the Transformer Station. The area is dispersed across the Niagara Escarpment, Dundas Valley, and the Cootes Paradise section of Burlington Bay, and is heavily forested.

Stations

Table 7 lists the Hydro One-owned Transformer Stations and Horizon Utilities-owned Municipal Substations and Feeders that service the Flamborough/Ancaster/Dundas operating area.

Transformer Station			
Station	Transformer	Capacity (MW)	Ratio of Peak Load to 10 Day Limited Time Rating (“LTR”)
Dundas TS	T3/T4	50 / 66.6 / 83.3	36%
	T5/T6	50 / 66.6 / 83.3	56%
Municipal Substations			
Station	Transformer	Capacity (MW)	% Loaded
Baldwin SS	T1	7.5	29%
Highland SS	T1	6.7	34%
John SS	T1	6.7	36%
York SS	T1	4.0	19%

Feeder Details					
Station	Primary Voltage (kV)	Secondary Voltage (kV)	Number of Feeders	Length of U/G (km)	Length of O/H (km)
Dundas TS	115	27.6	7	170.17	135.38
Baldwin SS	27.6	4.16	2	4.30	6.87
Highland SS	27.6	4.16	3	7.61	8.74
John SS	27.6	4.16	2	0.95	6.93
York SS	27.6	4.16	2	6.32	5.48

Table 7 - Flamborough/Ancaster/Dundas/Lynden Transformer and Municipal Substations

Operational History

The Flamborough/Ancaster/Dundas/Lynden area has experienced an average annual SAIDI for the past four years of 7.82 hours. This is significantly worse than the Horizon Utilities system average. Reliability in this operating area has decreased annually since 2010 with equipment failures and adverse weather being the primary cause codes for service interruptions. The topography of the area (heavy forestation, length of feeders, and large area serviced) accentuates the impact of outages due to equipment failures and adverse weather. This operating area has been significantly impacted by adverse weather in 2011, 2012 and 2013.

Automation will be the primary mechanism to improve the performance of the 27.6kV distribution system while asset renewal will address the reliability of the 4kV distribution system in Dundas. Figure 24 and Figure 25 below illustrate the reliability trend and cause of outages for this area over the previous four years.

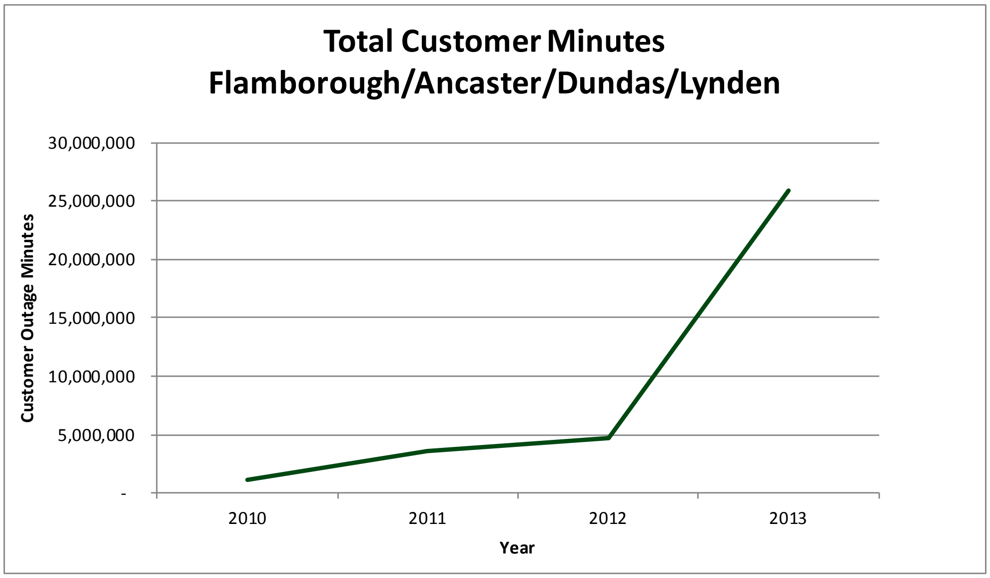

Figure 24 - Flamborough/Ancaster/Dundas/Lynden Operating Area - Historical Reliability

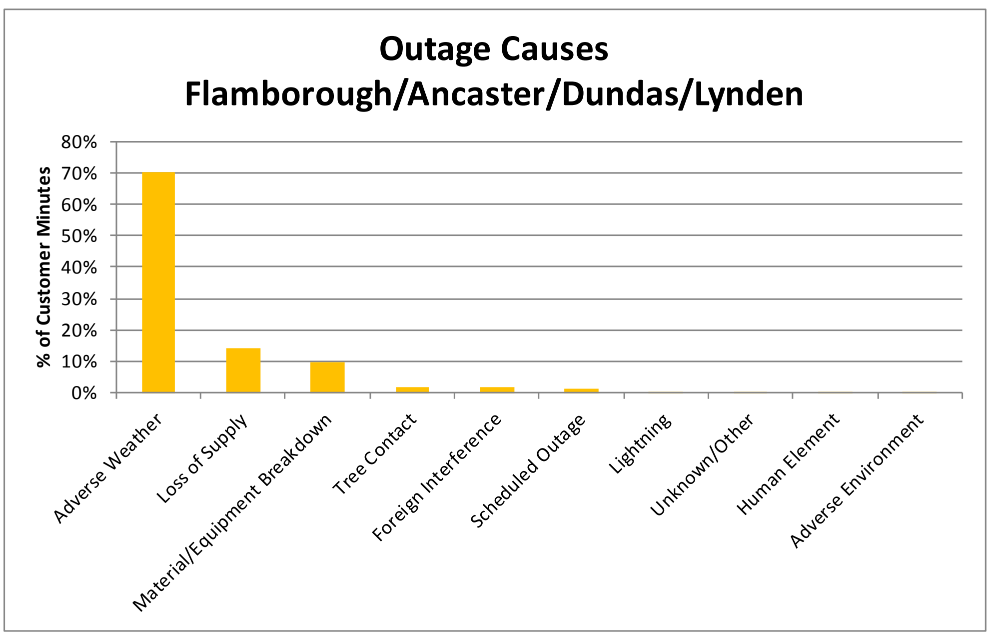

Figure 25 - Flamborough/Ancaster/Dundas/Lynden Operating Area - Cause of Outages

Investment Drivers

Investment in this area is largely driven by:

- System Access – the village of Waterdown in Flamborough is experiencing one of the highest rates of residential growth in Horizon Utilities service territory.
- System Renewal – Horizon Utilities' 4kV and 8kV Renewal Program requires the necessary conversion and decommissioning of the Baldwin, Highland, John and York Municipal Substations in the 2015 to 2019 timeframe.
- System Service – Automation investments are required to mitigate the impacts of equipment failures and adverse weather and improve system reliability for customers in this area. The lengthy feeders from Dundas to Ancaster are ideal candidates for automation.
- System Service – An alternate supply to the Flamborough area is required for security reasons. Currently, the entire village of Waterdown (approx. 6,600 customers) is supplied on a single pole line through a heavily forested area up the Niagara Escarpment. This project is required to be completed concurrently with the restructuring of the Highway #6 and Highway #5 intersection. Horizon Utilities will not be able to service the 6,600 customers in Waterdown without this third supply line as the restructuring of the Highway #6 and Highway #5 intersection will interrupt the existing two supply lines located on the same pole line into Waterdown.

<u>Hamilton Downtown</u>

Description

The Hamilton Downtown operating area is comprised of both residential and commercial customers as well as some larger critical load customers. The commercial customers consist of retail and office towers, Jackson Square shopping area and Copps Coliseum, resulting in a high level of energy density. Critical load customers include St. Joseph's and Hamilton General Hospitals. The downtown core is bordered to the north by residential customers and to the south by detached residential and multi-unit apartment buildings.

The commercial customers in the downtown core are primarily serviced by an underground 13.8kV distribution system using PILC and XLPE cables. The PILC cables in this area experience the same issues as the Hamilton Waterfront Industrial area (see below). The residential low rise customers north of the downtown core are serviced by an overhead 4.16kV system and residential low, medium, and high rise customers south of the downtown core are serviced by both the underground 13.8kV system (high rise) and the overhead 4.16kV system (medium and low rise).

The commercial core of Hamilton is congested with old infrastructure from multiple utilities: water, sewer, gas, electricity, and communication. The resources required for job planning and co-ordination with third parties in the Hamilton Downtown area are the highest of any area within Horizon Utilities' service territory.

The downtown core has recently begun to undergo a redevelopment commencing in its west end. The existing civil infrastructure in this area is at capacity (MW) and does not accommodate Horizon Utilities' construction standards, resulting in increased complexity and costs for expansion projects.

Stations

Table 8 lists the Hydro One-owned Transformer Stations and Horizon Utilities-owned Municipal Substations that service the Hamilton Downtown operating area.

Transformer Station			
Station	Transformer	Capacity (MW)	Ratio of Peak Load to 10 Day LTR
Elgin TS	T1/T2	45 / 60 / 75	74%
	T3/T4	20 / 27 / 33.3	49%

Municipal Substations			
Station	Transformer	Capacity (MW)	% Loaded
Aberdeen SS	T1	6.7	43%
	T2	6.7	36%
Caroline SS	T1	5	52%
	T2	5	7%
Central SS	T1	13.3	32%
	T2	13.3	22%
Hughson SS	T1	6.7	29%
	T3	6.7	0%
	T4	6.7	21%

Feeder Details					
Station	Primary Voltage (kV)	Secondary Voltage (kV)	Number of Feeders	Length of U/G (km)	Length of O/H (km)
Eglin TS	115	13.8	28	99.39	15.32
Aberdeen SS	13.8	4.16	4	1.41	12.86
Caroline SS	13.8	4.16	3	5.32	6.16
Central SS	13.8	4.16	10	9.88	10.65
Hughson SS	13.8	4.16	2	4.16	3.67

Table 8 - Hamilton Downtown Transformer and Municipal Substations

Operational History

The Hamilton Downtown area has experienced an average annual SAIDI for the past four years of 1.18 hours. This is marginally better than the Horizon Utilities system average and aligns with corporate targets for the system. Equipment failures are the predominant cause of outages in this area. The effect of adverse weather and foreign interference outages (defined by the CEA as “Customer interruptions beyond the control of the utility such as birds, animals, vehicles, dig-ins, vandalism, sabotage and foreign objects”) are magnified due to the operational constraints inherent with a PILC distribution system. Figure 26 and Figure 27 below identifies the reliability trend and outage causes experienced by this area over the previous three years.

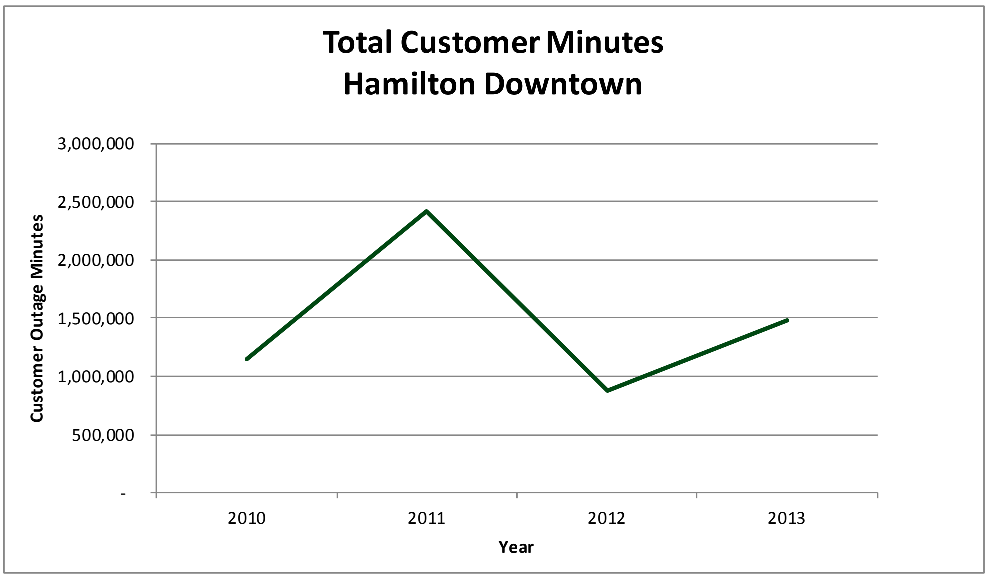

Figure 26 - Hamilton Downtown Operating Area - Historical Reliability

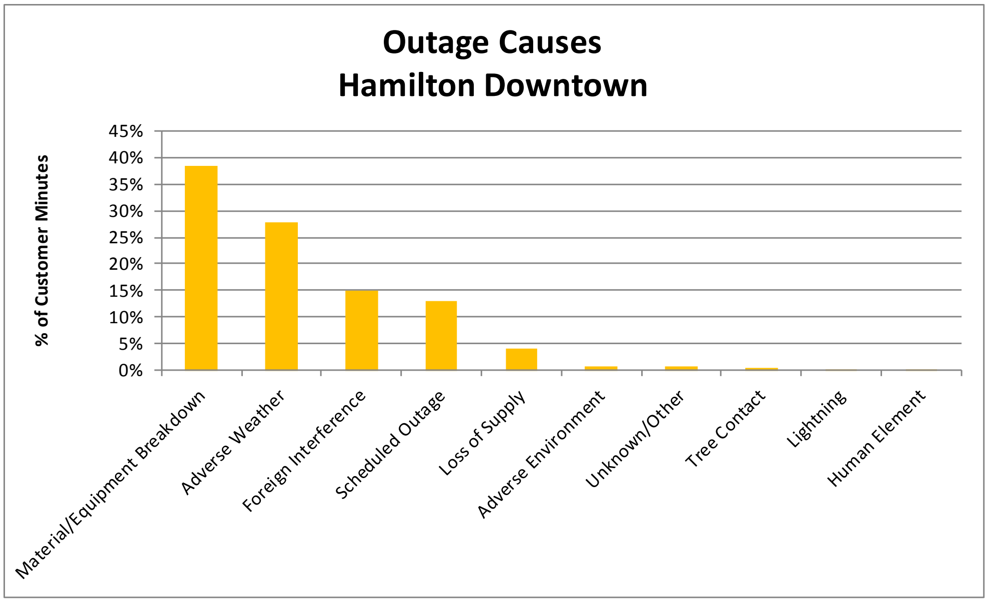

Figure 27 - Hamilton Downtown Operating Area - Cause of Outages

Investment Drivers

Investment in this area is largely driven by:

- System Access
  - Recent redevelopment of commercial properties in the downtown core has required expansion investment. Continued commercial redevelopment can be expected to require additional expansion investment.
  - The City of Hamilton is actively pursuing a Light Rapid Transit ("LRT") system. Should the City of Hamilton be successful in its pursuit of an LRT system, significant investment will be required to relocate existing civil and electrical infrastructure that is not provided for in this Application or the long term capital plan.
- System Renewal
  - Horizon Utilities' long-term strategic 4kV and 8kV Renewal Program includes the conversion and decommissioning of the Caroline Substation in 2015, followed by Central and Aberdeen conversions planned for completion by 2022. Further detail regarding the sequencing and justification of Horizon Utilities' 4kV and 8kV Renewal Program is provided in Appendix A.

- The civil and electrical infrastructure is nearing EOL in the downtown core. Due to the below grade congestion and co-ordination with third parties and migration to current construction standards the renewal of the downtown infrastructure will require significant investment. The high level strategic plan for this renewal is currently under development and the investment is expected to commence in the 2023 timeframe.

- The Hydro One-owned Elgin Transformer Station will require renewal in the medium (i.e. 10 year) term. Timing and design details have not been established by Hydro One at this time. Further details and justification for this project is provided in Appendix A.

Hamilton East

Description

The Hamilton East area encompasses the area east of the downtown core and north of the Niagara Escarpment and is bordered by the Red Hill Valley Expressway to the east. This area incorporates approximately 35,000 customers and includes a mix of residential, commercial, and industrial customers.

The industrial customers in this area are generally serviced from the 13.8kV underground distribution system. The commercial and residential customers are typically serviced from the 4.16kV overhead distribution system.

Horizon Utilities-owned municipal substations in this area have the highest overall Health Index ratings and as a result this area has no immediate plans for renewal by voltage conversion.

Stations

Table 9 below identifies the Hydro One-owned Transformer Stations and Horizon Utilities-owned Municipal Substations that service the Hamilton East operating area.

Transformer Station			
Station	Transformer	Capacity (MW)	Ratio of Peak Load to 10 Day LTR
Stirton	T3/T4	45 / 60 / 75	46%
Municipal Substations			
Station	Transformer	Capacity (MW)	% Loaded
Bartonville SS	T1	13.3	37%
Cope SS	T1	6.7	47%
	T2	6.7	32%
	T3	6.7	52%
Kenilworth SS	T1	6.7	51%
	T2	6.7	37%
Ottawa SS	T1	6.7	43%
	T2	6.7	40%
	T3	6.7	27%
Parkdale SS	T1	13.3	34%
	T2	13.3	19%
Spadina SS	T1	6.7	56%
	T3	6.7	58%
Wentworth SS	T1	6.7	68%
	T3	6.7	79%
	T4	6.7	30%
Feeder Details			

Station	Primary Voltage (kV)	Secondary Voltage (kV)	Number of Feeders	Length of U/G (km)	Length of O/H (km)
Stirton TS	115	13.8	20	50.31	26.78
Bartonville SS	13.8	4.16	5	2.01	14.52
Cope SS	13.8	4.16	9	4.13	18.98
Kenilworth SS	13.8	4.16	6	1.12	16.14
Ottawa SS	13.8	4.16	8	7.36	16.23
Spadina SS	13.8	4.16	6	1.07	16.81
Wentworth SS	13.8	4.16	11	7.22	20.68

Table 9 - Hamilton East Transformer and Municipal Stations

Operational History

Customers in the Hamilton East area have experienced an average annual SAIDI for the past three years of 2.16 hours. This is worse than Horizon Utilities' system average but, when the impact of the 2013 July windstorm and the 2013 December ice storms are excluded the performance, is better than both the Horizon Utilities system average and corporate system targets. Substation investments performed in 2011 through 2013 in the Hamilton East operating area have contributed to the higher level of reliability in this area. The health of the distribution system assets, combined with the recent investment in substation assets that were at the end of their useful life, have reduced the risk of outages in this area. As shown in Figure 29 below, outage in this area are primarily due to the adverse weather experienced in 2013.

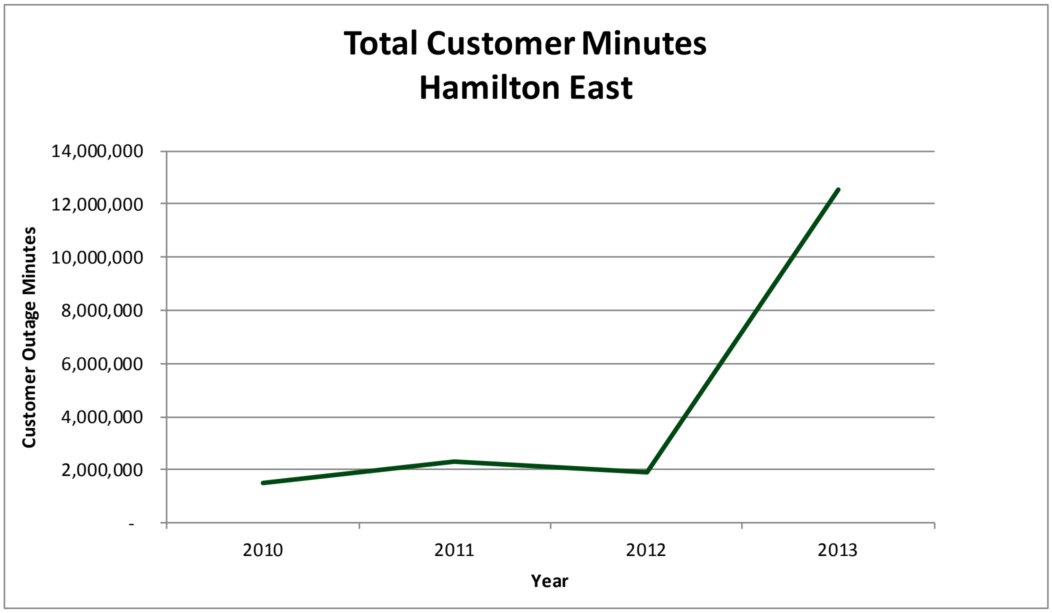

Figure 28 - Hamilton East Operating Area - Historical Reliability

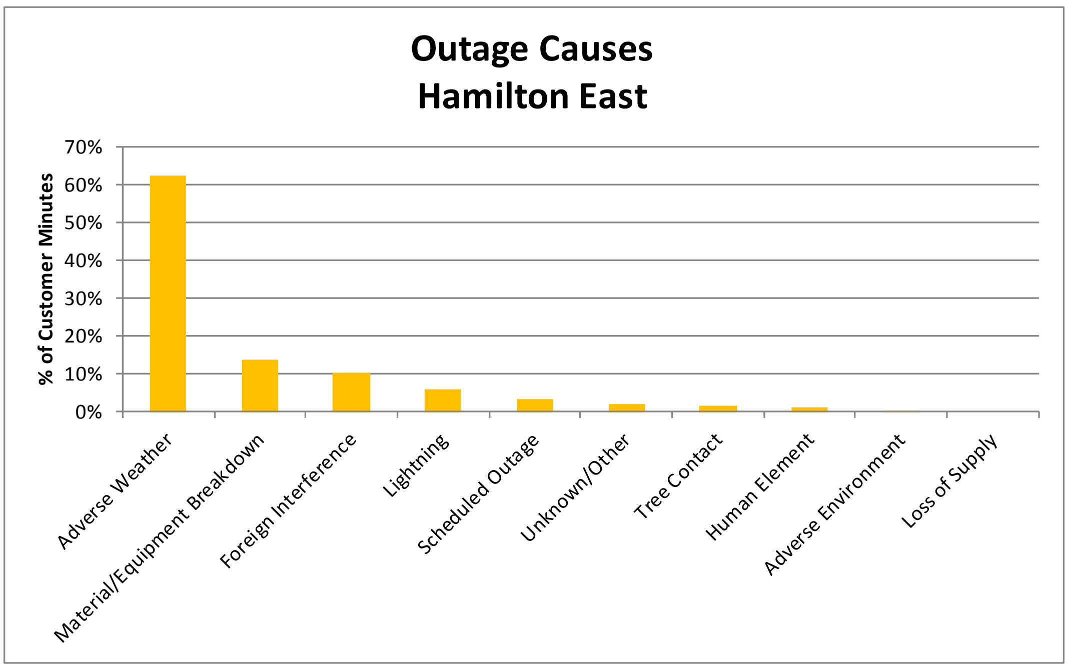

Figure 29 - Hamilton East Operating Area – Cause of Outages

Figure 28 and Figure 29 above illustrate the reliability history and outage causes experienced by customers in this area over the previous three years. Reliability has been relatively stable over the previous three years with the increase in 2011 attributable to an increase in service interruptions caused by lightning. The top three causes of outages are: foreign interference (animal contacts and vehicle accidents); lightning; and equipment failures, which is consistent with an old overhead distribution system such as exists in this area.

Investment Drivers

This area recently received significant substation renewal investment required to extend the life of the existing substations as required by the 4kV and 8kV Renewal Program. The investment in this area in 2015 through 2019 is largely driven by:

- System Service – As no significant renewal investments are identified for this area, automation will be deployed to mitigate the reliability impact of adverse weather and increasing equipment failures.

<u>Hamilton Waterfront Industrial</u>

Description

The Hamilton Waterfront Industrial area is the core industrial area of Hamilton. It contains a mix of light and heavy industry, historically associated with Hamilton's steel industry. Several large scale industrial customers operate and are located in this area.

Customers of this size are typically serviced from the Transformer Station breakers via dedicated underground PILC Cables. Horizon Utilities has an extensive inventory of PILC and has predominately used PILC in this area due to the heavy contamination levels, wet environment, and need for durability. These cables are nearing, but not yet at, end of life. There are, however, many concerns with the continued use of PILC cable not directly related to the end of life assets such as:

- Industry or government regulations abandoning its use due to environmental concerns related to lead and oil;
- Limited availability of PILC. There is currently only one supplier of PILC in North America remaining;
- High cost of PILC, cable accessories, and labour for splicing and terminating;
- Limited skilled tradesmen knowledgeable in splicing and maintaining this cable; and
- Worker health risk and precautions in the handling of lead.

Construction in this area is difficult and costly due to the combination of old civil infrastructure that is not compatible with current standards; heavy congestion below grade; the high water table; and the abundance of pollutants below grade.

Much of Horizon Utilities' infrastructure in this area was installed in the 1950's. The Hydro One-owned transformer stations are of similar vintage with Gage TS being one of the oldest transformer stations in Hydro One's inventory. Hydro One has identified the need to renew Gage TS within the 2015 to 2017 timeframe.

Stations

Table 10 below identifies the Hydro One-owned Transformer Stations and Horizon Utilities-owned Municipal Substations that service the Hamilton Industrial operating area.

Transformer Station			
Station	Transformer	Capacity (MW)	Ratio of Peak Load to 10 Day LTR
Beach TS	T3/T4	40 / 53.3 / 66.7	49%
	T5/T6	45 / 60 / 75	71%
Birmingham TS	T1/T2	45 / 60 / 75	65%
	T3/T4	48 / 54 / 80	60%
Gage TS	T3/T4	33.8 / 45 / 56	54%
	T5/T6	33.8 / 45 / 56	24%
	T8/T9	72 / 96 / 120	15%
Kenilworth TS	T1/T4	40 / 53.3 / 66.7	84%
	T2/T3	40 / 53.3 / 66.7	51%

Feeder Details					
Station	Primary Voltage (kV)	Secondary Voltage (kV)	Number of Feeders	Length of U/G (km)	Length of O/H (km)
Beach TS	115	13.8	32	95.44	39.28
Birmingham TS	115	13.8	17	22.37	7.99
Gage TS	115	13.8	26	35.05	0
Kenilworth TS	115	13.8	26	24.64	0

Table 10 - Hamilton Waterfront Industrial Transformer Stations

Operational History

The heavy industrial customers in this operating area require a very high level of reliability. Service interruptions may result in very costly impacts on production and, a sustained outage presents a significant environmental risk from unexpected production shut downs.

Customers in this area, supplied by the stations identified in Table 10 above, have experienced a high level of reliability. The average annual SAIDI for the past three years for this area is

1.57 hours. As illustrated in Figure 30 below, the reliability for this area deteriorated in 2012 and 2013 relative to 2011 and 2010.

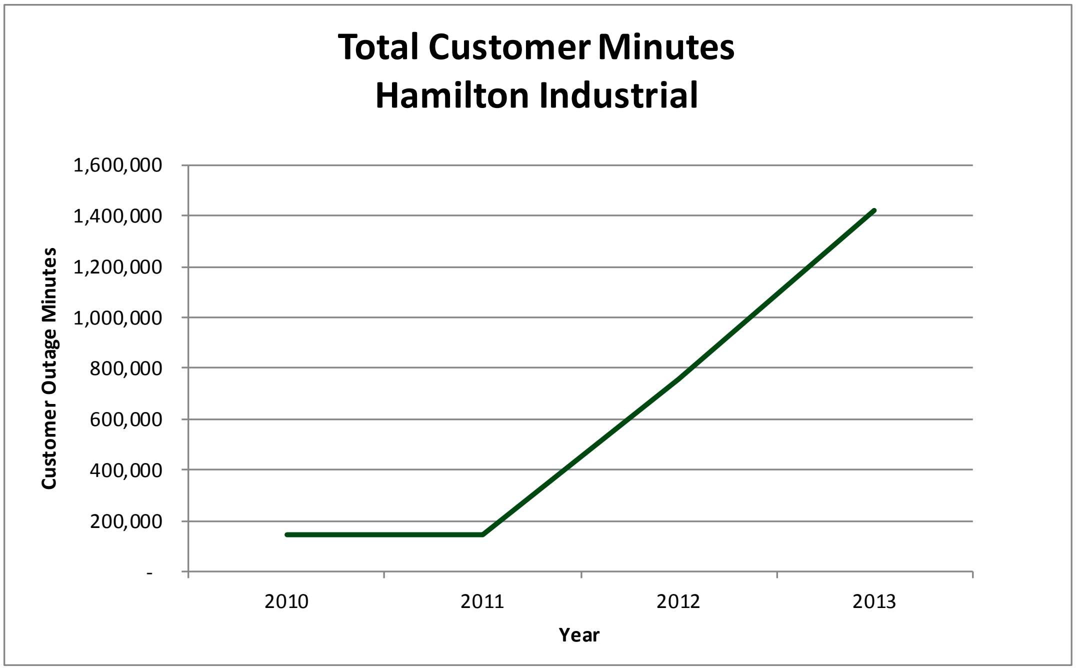

Figure 30 - Hamilton Waterfront Industrial Operating Area - Historical Reliability

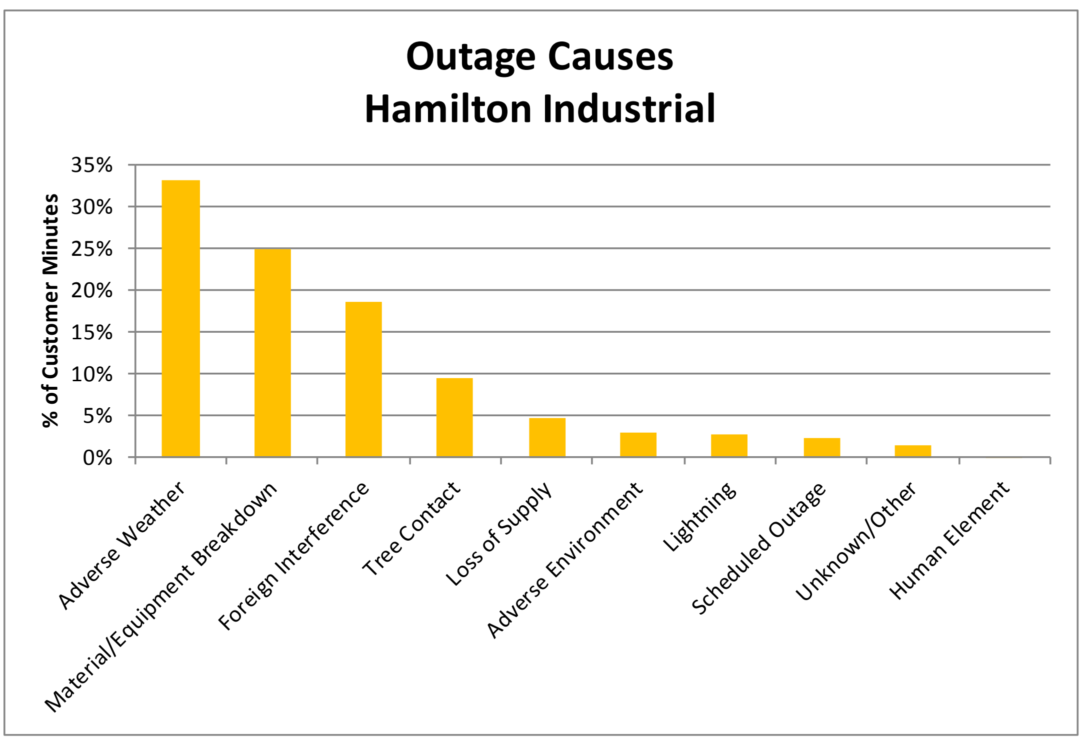

Figure 31 - Hamilton Waterfront Industrial Operating Area - Cause of Outages

Investment Drivers

Investment in this area is largely driven by:

- System Access – The Hamilton Port Authority is experiencing growth activity. There is unused capacity in the area in general, however due to the nature of the customers and the need for dedicated feeds to the customers in this area, expansion investment is often required to support the connection of new customers.
- System Renewal
  - Reactive system renewal required to mitigate equipment failures in this area.
  - Proactive system renewal required in co-ordination with Hydro One's renewal of Gage TS
  - Longer term renewal investment will be required to renew the PILC cable. PILC renewal investment is forecast to increase significantly in approximately 10 years, when the health of PILC begins to materially degrade and investment in the 4kV and 8kV Renewal Program begins to decrease.

<u>Hamilton Mountain</u>

Description

The Hamilton Mountain area consists of the area south of the Niagara Escarpment and west of Stoney Creek. This area incorporates approximately 55,000 customers and includes a mix of residential and commercial customers.

The area north of the Lincoln Alexander Parkway is generally serviced by a 4.16kV overhead distribution system while the area south of the Lincoln Alexander Parkway is serviced by a 13.8kV underground distribution system. The underground system utilizes PILC for transformer station egress feeders and transitions to XLPE cable. The system design is not consistent with current design standards. Radial un-fused sections with inadequate switching and contingency points exist throughout the area resulting in prolonged outages to identify and rectify service interruptions.

Stations

Table 11 below identifies the Hydro One-owned Transformer Stations and Horizon Utilities-owned Municipal Substations that service the Hamilton Mountain operating area.

Transformer Stations			
Station	Transformer	Capacity (MW)	Ratio of Peak Load to 10 Day LTR
Horning TS	T1/T2	30 / 40 / 50	65%
Mohawk TS	T1/T2	40 / 53.3 / 66.7	85%
Nebo TS	T3/T4	45 / 75 / 80	98%
Municipal Substations			
Station	Transformer	Capacity (MW)	% Loaded
Eastmount SS	T1	6.7	62%
	T2	6.7	22%
	T3	6.7	47%
	T4	6.7	28%
Elmwood SS	T1	6.7	37%
	T2	6.7	13%
	T3	6.7	43%
Mohawk SS	T1	13.3	36%
	T2	6.7	52%
Mountain SS	T1	13.3	45%
	T2	6.7	40%
	T3	6.7	0%
Wellington SS	T1	6.7	43%
	T2	6.7	33%
	T3	6.7	31%

	T4	6.7	23%

Feeder Details					
Station	Primary Voltage (kV)	Secondary Voltage (kV)	Number of Feeders	Length of U/G (km)	Length of O/H (km)
Horning TS	230	13.8	10	267.72	38.13
Mohawk TS	230	13.8	13	151.86	30.21
Nebo TS	230	13.8	8	209.70	19.36
Eastmount SS	13.8	4.16	10	3.99	37.08
Elmwood SS	13.8	4.16	7	1.62	28.40
Mohawk SS	13.8	4.16	8	3.95	26.63
Mountain SS	13.8	4.16	8	2.70	24.61
Wellington SS	13.8	4.16	10	4.18	31.48

Table 11 - Hamilton Mountain Transformer and Municipal Substations

Operational History

Customers in the Hamilton Mountain area have experienced an average annual SAIDI for the past three years of 2.31 hours. Reliability is trending negatively in this operating area with equipment failures dominating the cause of outages as illustrated in Figure 34 below. Reliability is materially different, however, between the 4.16kV overhead and 13.8kV underground system as illustrated in Figure 32 below.

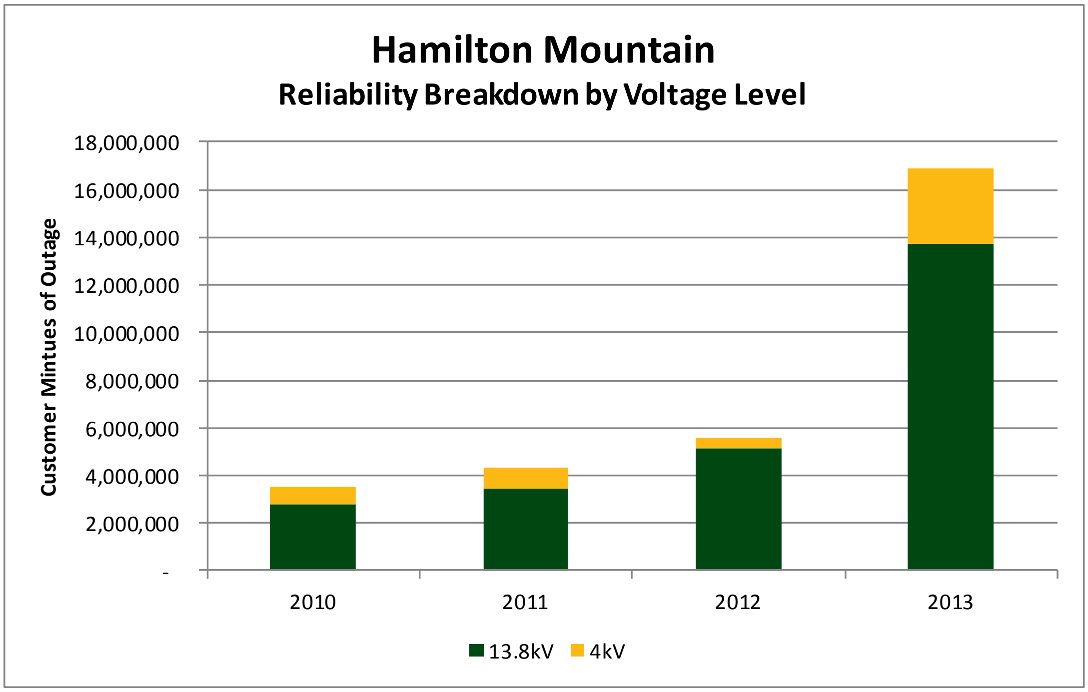

Figure 32 - Hamilton Mountain - Reliability Breakdown by Voltage Level

The 13.8kV underground system represented 83% of the total customer minutes of outage for the area resulting in a SAIDI of 2.90 hours. The SAIDI for the overhead system in comparison was 1.17 hours over the same period.

As identified in Figure 34 below, equipment failures are the driver for over 50% of the customer minutes of outage for the area. Equipment failures in the underground system represent 70% of the total outage minutes caused by equipment failure. Both the impact of equipment failures and percentage of equipment failures attributed to underground assets are significantly higher than Horizon Utilities system average.

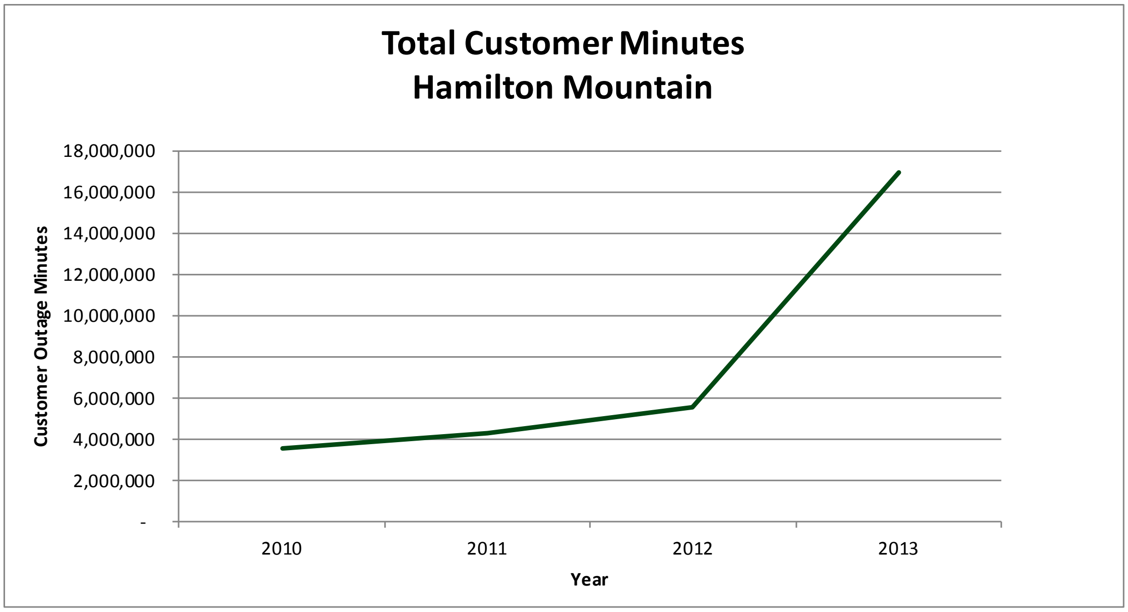

Figure 33 - Hamilton Mountain Operating Area - Historical Reliability

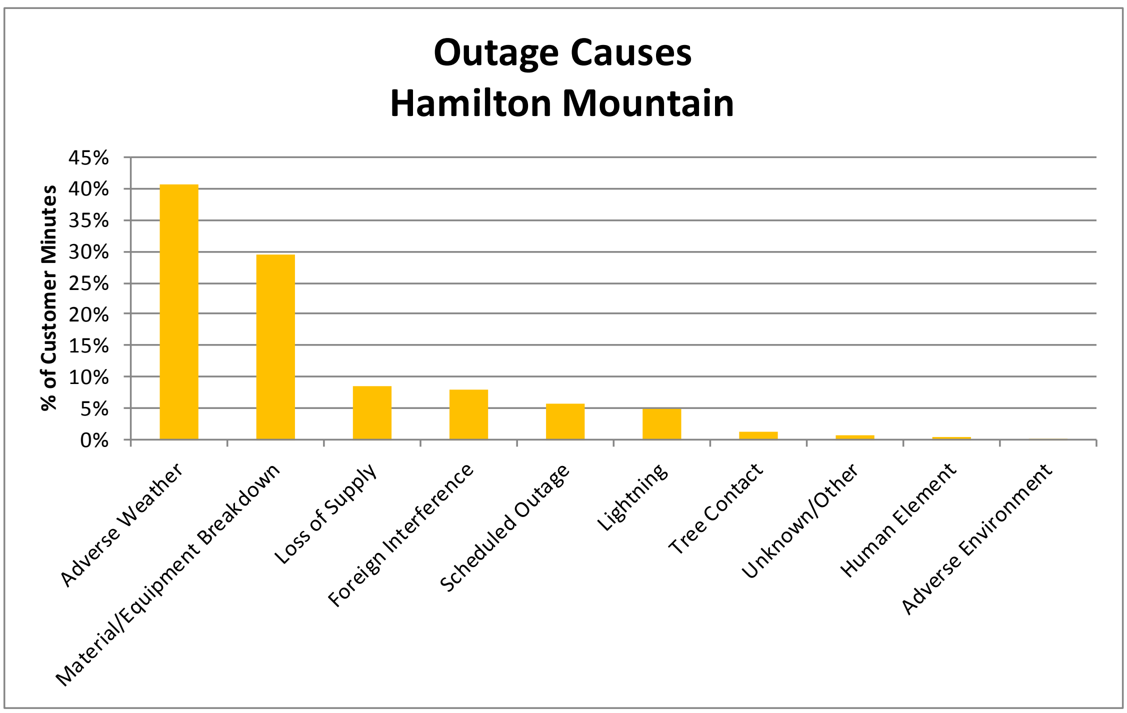

Figure 34 - Hamilton Mountain Operating Area – Cause of Outages

The Kinectrics ACA identified a high percentage of XLPE primary cable to have a ‘very poor’ Health Index and this percentage is forecast to increase significantly in the future unless renewal investment in this asset category is significantly increased. The Hamilton Mountain area is the primary area for this investment. The underground XLPE cable in this area comprises approximately 33% of the total installed XLPE and is the primary cause for 65% of the outages caused by failure of underground assets. This is a very serious issue that needs addressing. SAIDI for the underground system has more than quadrupled from 2010 to 2013. The failure experience is exponentially increasing as evident in Table 43. The exponential failure experience is a classic example of the often cited “bathtub” curve associated with failure analysis and reliability engineering more accurately described as the Weibull distribution in scientific literature.

Failure to invest in this area will result in the continued accelerated degradation of service to this area, reducing reliability and the service experienced by customers to an unacceptable level. An analysis of all service interruptions, caused by material or equipment failure from 2010 to 2013, revealed that 50% of service interruptions, measured by customer minutes of outage, were due to failures of underground cable and equipment. Over 30% of these outages exceeded four hours in duration, while 5% of these outages exceeded twelve hours in duration. These durations far exceed Horizon Utilities’ corporate target of one hour and nine minutes of outage on average per customer. Maintaining the XLPE cable renewal investment at 2013 levels would result in a continual decrease in the Health Index distribution and further increase the frequency and duration of service interruption to customers from the current levels.

Furthermore, due to the exponential nature of failures experienced as the 50+ year old cables experience material breakdown, the future cost of required investments will dramatically increase in the short term if not addressed in a systematic manner. Further detail and justification regarding Horizon Utilities’ renewal investment in the Hamilton Mountain Operating Area is provided in Section 3.5.3.

Investment Drivers

Investment in this area is largely driven by:

- System Renewal
    - Horizon Utilities’ 4kV and 8kV Renewal Program includes the conversion and decommissioning of Municipal Substations in this area. These stations are scheduled for conversion post 2024.
- Proactive underground cable renewal. The Hamilton Mountain has a significant volume of aged XLPE primary cable. Equipment failures, specifically those relating to the underground distribution system have been dramatically increasing at exponential rates

over the past three years resulting in declining reliability. Renewal of underground systems is costly and is best performed on a proactive basis. Reactive renewal of underground systems results in a much higher overall program cost, impedes the use of current design standards, and subjects the customers in the area to lengthy outages and unacceptable service levels. The customer impact of XLPE failures and the need for renewal is further detailed in Section 3.5.3.

<u>Hamilton West</u>

Description

The Hamilton West operating area encompasses the area of Hamilton west of the downtown core below the Niagara Escarpment neighbouring the McMaster University campus. The area serves approximately 12,000 residential and commercial customers. The residential neighborhoods in this area are mature and heavily forested. Many subdivisions which are adjacent to the escarpment were built utilizing rear lot construction which has proven difficult to repair/replace and maintain due to access issues.

Stations

Table 12 below identifies the Hydro One-owned Transformer Stations and Horizon Utilities-owned Municipal Substations that service the Hamilton West operating area.

Transformer Station			
Station	Transformer	Capacity (MW)	Ratio of Peak Load to 10 Day LTR
Newton TS	T1/T2	40 / 53.3 / 66.7	58%

Municipal Substations			
Station	Transformer	Capacity (MW)	% Loaded
Strouds SS	T1	6.7	44%
	T2	6.7	35%
Whitney SS	T1	6.7	51%
	T2	6.7	28%

Feeder Details					
Station	Primary Voltage (kV)	Secondary Voltage (kV)	Number of Feeders	Length of U/G (km)	Length of O/H (km)
Newton TS	115	13.8	10	56.91	30.60
Strouds SS	13.8	4.16	5	2.96	14.18
Whitney SS	13.8	4.16	6	4.21	15.34

Table 12 - Hamilton West Transformer and Municipal Stations

Operational History

Customers in the Hamilton West area have experienced an average annual SAIDI for the past three years of 1.26 hours. As illustrated in Figure 35 and Figure 36 below, the reliability is relatively stable (the 2013 increase is attributable to the July 2013 wind storm). Tree contact and foreign interference (animal contacts) are the largest cause of outages in this area when the impact of the July 2013 wind storm is excluded.

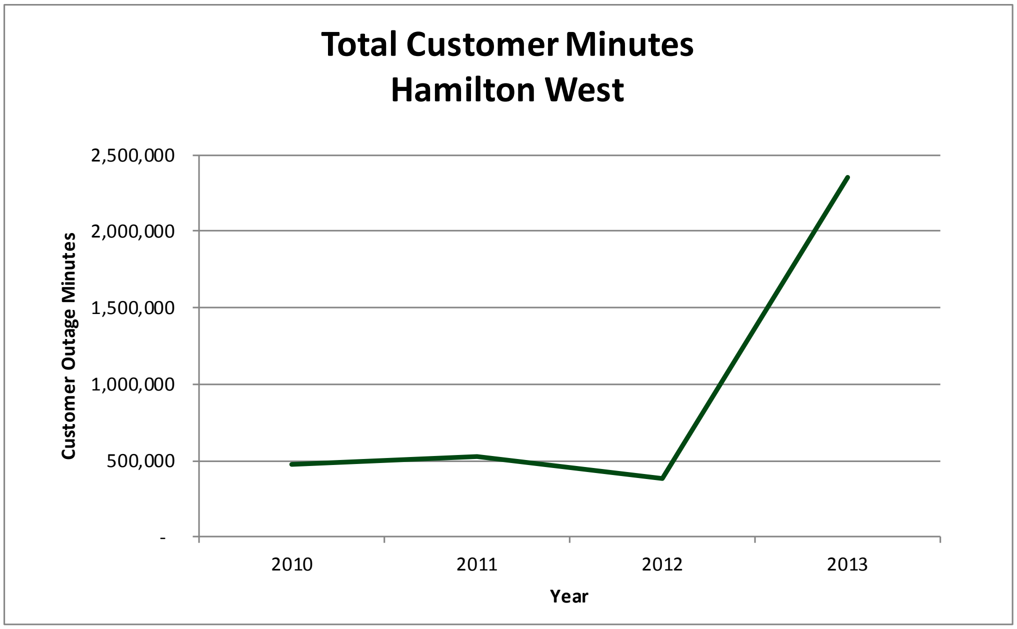

Figure 35 - Hamilton West Operating Area - Historical Reliability

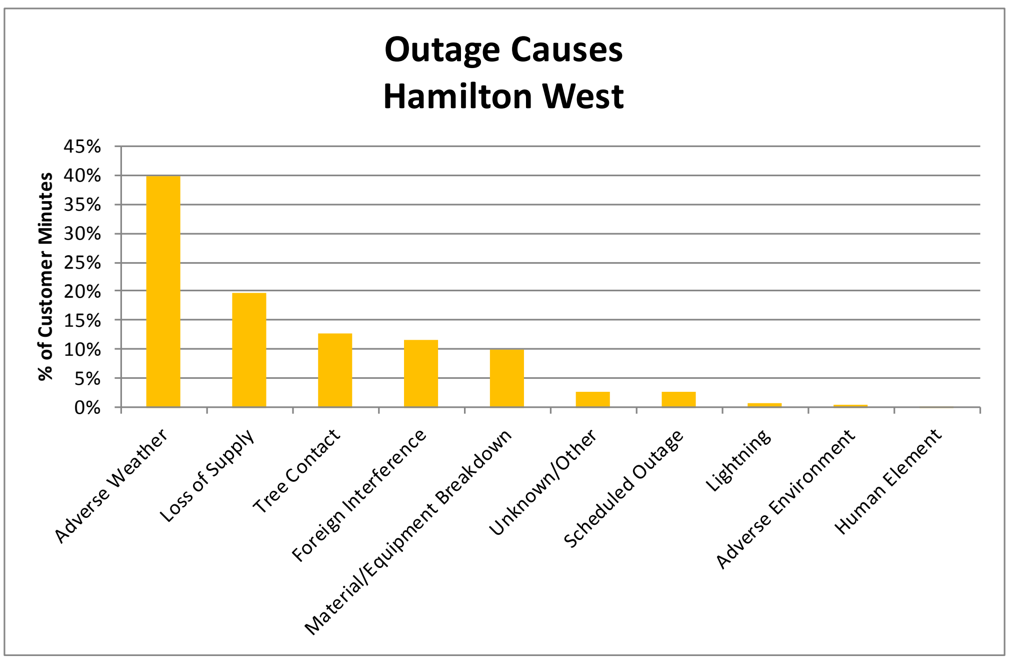

Figure 36 - Hamilton West Operating Area – Cause of Outages

Investment Drivers

Investment in this area is largely driven by:

- System Renewal – Horizon Utilities 4kV and 8kV Renewal Program includes the conversion and decommissioning of Municipal Substations in this area. These stations are scheduled for conversion in the 2014 to 2018 timeframe. This prioritization was based upon the overall poor condition of the Municipal Substations in this area as identified in the 4kV and 8kV Renewal Program. Lastly, due to the rear lot subdivisions many projects will incur higher costs to eliminate these in favour of front lot construction.

<u>Stoney Creek</u>

Description

The Stoney Creek area encompasses the area east of the Red Hill Valley Expressway in the Hamilton service territory. This area contains approximately 38,000 customers. The area below the Niagara Escarpment is comprised of approximately 30,000 residential and commercial customers and is serviced directly from the Hydro One transformer stations at the 27.6kV and through the Horizon Utilities-owned municipal substations at the 8.32kV voltage level.

The area above the Niagara Escarpment contains approximately 8,000 residential customers and has a significant rural footprint, all directly serviced from Nebo TS at the 27.6kV voltage level.

Stations

Table 13 below identifies the Hydro One-owned Transformer Stations and Horizon Utilities-owned substations that service the Stoney Creek operating area.

Transformer Stations			
Station	Transformer	Capacity (MW)	Ratio of Peak Load to 10 Day LTR
Lake TS	T1/T2	40 / 53.3 / 66.7	62%
	T3/T4	40 / 53.3 / 66.7	69%
Nebo TS	T1/T2	75 / 100 / 125	1.03%
Winona TS	T1/T2	50 / 66.6 / 83.3	51%

Municipal Substations			
Station	Transformer	Capacity (MW)	% Loaded
Deerhurst SS	T1	7.5	11%
Dewitt SS	T1	5.0	16%
Galbraith SS	T1	5.6	15%

Feeder Details					
Stations	Primary Voltage (kV)	Secondary Voltage (kV)	Number of Feeders	Length of U/G (km)	Length of O/H (km)
Lake TS	230 115	27.6 13.8	18	161.79	113.05
Nebo TS	230	27.6	2	114.03	115.01
Winona TS	115	27.6	6	85.32	67.70
Deerhurst SS	27.6	8.32	3	15.16	8.75
Dewitt SS	27.6	8.32	3	4.59	10.06
Galbraith SS	27.6	8.32	3	1.99	6.57

Table 13 - Stoney Creek Transformer and Municipal Substations

Operational History

Customers in the Stoney Creek area have experienced an average annual SAIDI for the past three years of 1.80 hours. Excluding the 2013 storm impacts, this is better than the system average and aligns with the corporate system targets. Reliability is materially different, however, between the rural area above the Niagara Escarpment and the area below the Niagara Escarpment. The 27.6kV overhead distribution system above the Niagara Escarpment experienced a SAIDI of 4.16 hours over the previous three years while the area below the Niagara Escarpment experienced a SAIDI of 1.13 hours over the same period. Figure 38 below illustrates the reliability history for the entire area over the previous three years and the ranking of the cause of outages.

The high impact of outages caused by adverse weather and lightning is a result of the exposure presented by the large rural area above the Niagara Escarpment. The two feeders servicing this large rural area also serve a large number (approximately 6,600) of urban customers. This results in the urban customers experiencing an unacceptable level of reliability.

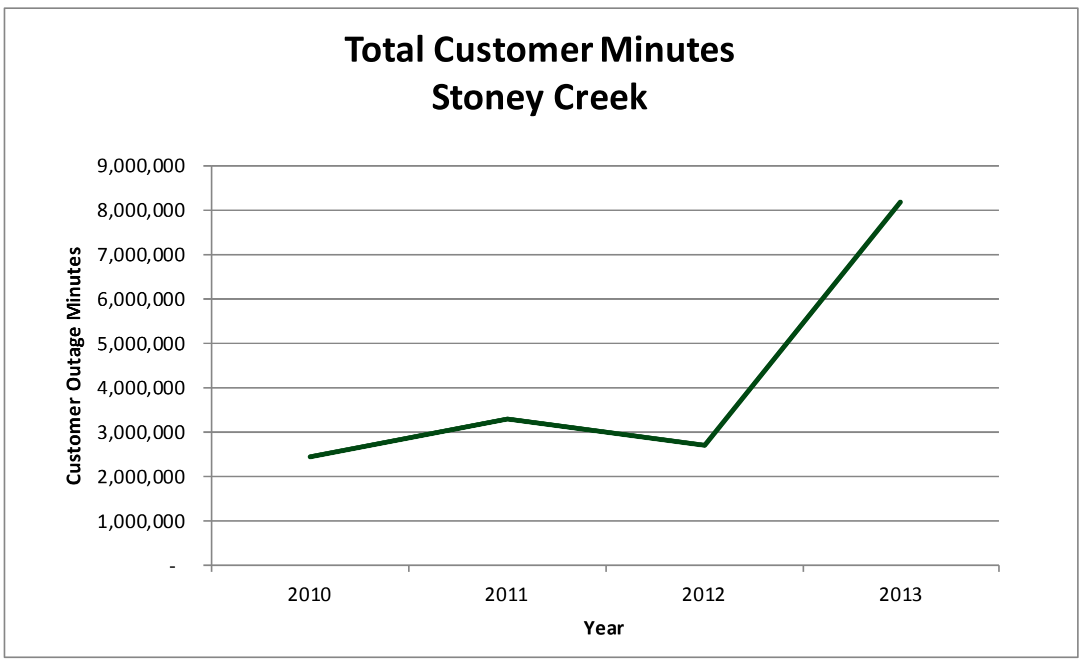

Figure 37 - Stoney Creek Operating Area - Historical Reliability

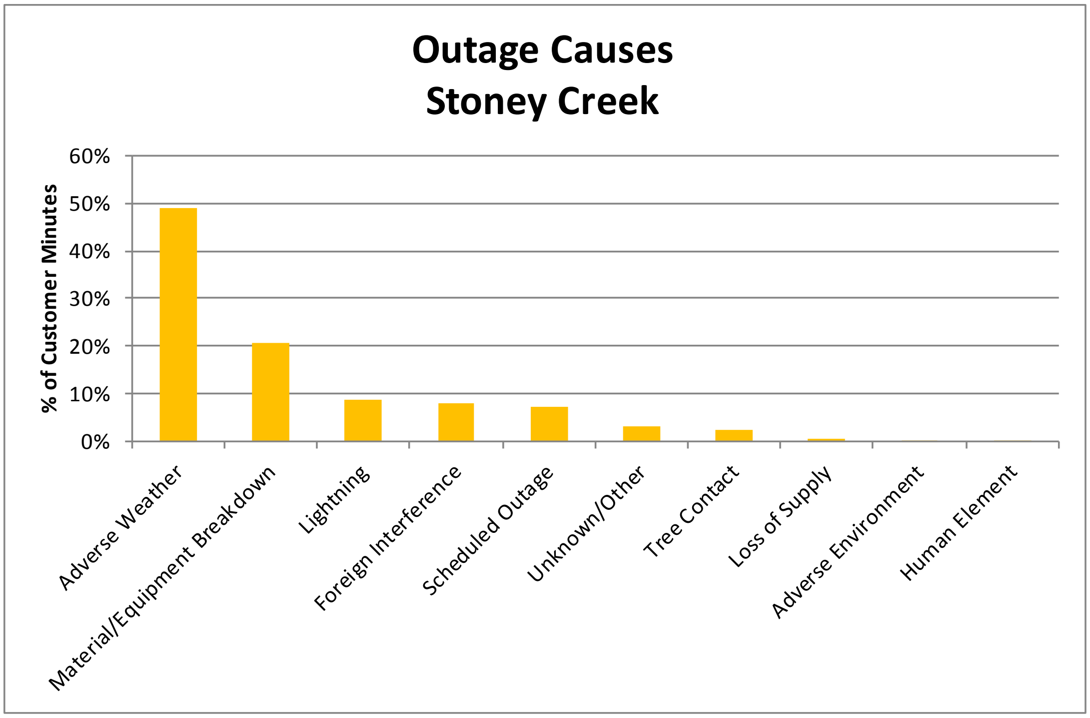

Figure 38 - Stoney Creek Operating Area – Cause of Outages

Investment Drivers

Investment in this area is largely driven by:

- System Renewal – The urban residential customers above the Niagara Escarpment are serviced by a 27.6kV underground distribution system. Development of this system dates back to the 1970s with the XLPE cable installed at that time nearing the end of its life. The SAIDI of 1.97 for this area is currently 72% worse than Horizon Utilities' corporate target of 1.15 hours and failure to proactively address this exposure will result in an exponential and rapid decrease in reliability in this area. The customer impact of XLPE failures and the need to renewal is further detailed in Section 3.5.3.

- System Service – The 27.6kV overhead distribution system above the Niagara Escarpment presents an ideal opportunity for the deployment of distribution automation. Distribution automation in this area will allow the isolation of the rural area from the urban area and protect the urban customers from the increased exposure to outages associated with lengthy rural lines and adverse weather impacts. Automation will also allow for decreased restoration times thereby offsetting the impact of increasing equipment failure rates expected as the assets continue to age. The justification for distribution automation, provided in further detail in Appendix A, is forecast to provide a reduction of customer minutes of outage by 10% annually.

St. Catharines

Description

The St. Catharines area is serviced directly from four Hydro One transformer stations at the 13.8kV voltage level. Customers in the area are also serviced at the 4.16kV voltage level from three Horizon Utilities-owned Municipal Substations. There are approximately 52,000 residential, commercial and industrial customers.

Stations

Table 14 below identifies the Hydro One-owned Transformer Stations and Horizon Utilities-owned Municipal Substations that service the St. Catharines operating area.

Transformer Stations						
Station	Transformer	Capacity (MW)	Ratio of Peak Load to 10 Day LTR	Primary Voltage (kV)	Secondary Voltage (kV)	Number of Feeders
Bunting TS	T3/T4	45 / 60 / 75	78%	115	13.8	10
Carlton TS	T1/T4	45 / 60 / 75	9%	115	13.8	4
	T2/T3	45 / 60 / 75	102.5%	115	13.8	14
Glendale TS	T1/T2	45 / 60 / 75	59%	115	13.8	8
	T3/T4	45 / 60 / 75	61%	115	13.8	4
Vansickle TS	T5/T6	45 / 60 / 75	55%	115	13.8	12

Municipal Substations						
Station	Transformer	Capacity (MW)	% Loaded	Primary Voltage (kV)	Secondary Voltage (kV)	Number of Feeders
Vine SS	T1	7.5	60%	13.8	4.16	4
Grantham SS	T1	6.0	55%	13.8	4.16	3
Welland SS	T1	9.6	37%	13.8	4.16	3

Feeder Details					
Stations	Primary Voltage (kV)	Secondary Voltage (kV)	Number of Feeders	Length of U/G (km)	Length of O/H (km)
Bunting TS	115	13.8	10	38.57	120.63
Carlton TS	115	13.8	18	110.46	11.21
Glendale TS	115	13.8	12	33.81	78.51
Vansickle TS	115	13.8	12	51.12	103.15
Vine SS	13.8	4.16	4	1.60	12.55
Grantham SS	13.8	4.16	3	2.24	11.60
Welland SS	13.8	4.16	3	0.36	3.22

Table 14 - St. Catharines Transformer and Municipal Substations

Operational History

Customers in St. Catharines have experienced an average annual SAIDI for the past three years of 2.82 hours. This level of reliability is 145% worse than Horizon Utilities' corporate 2014 target of 1.15 hours. The St. Catharines customers experienced, on average, a total of 2 hours and 49 minutes of outage duration annually compared to Horizon Utilities' corporate target of 1 hour and 9 minutes. As illustrated in Figure 40 below, reliability has improved year over year in the previous three years due to continued focus on the 4kV Renewal Program and the decommissioning of one substation. Adverse weather and equipment failures are the two leading causes of outages in this area which is consistent with the overall system.

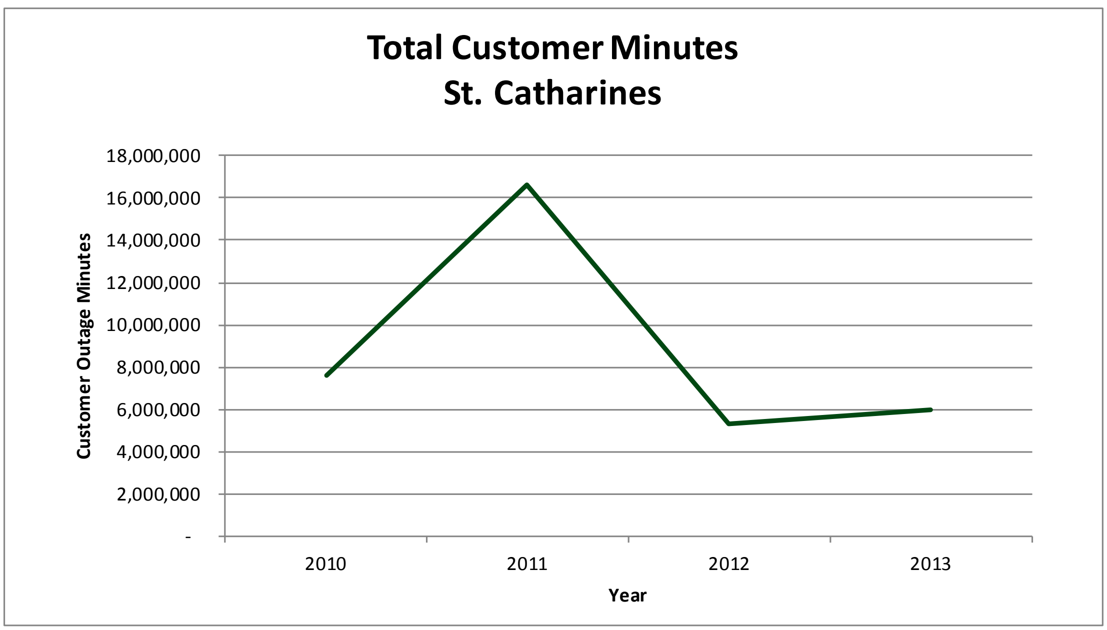

Figure 39 - St. Catharines Operating Area - Historical Reliability

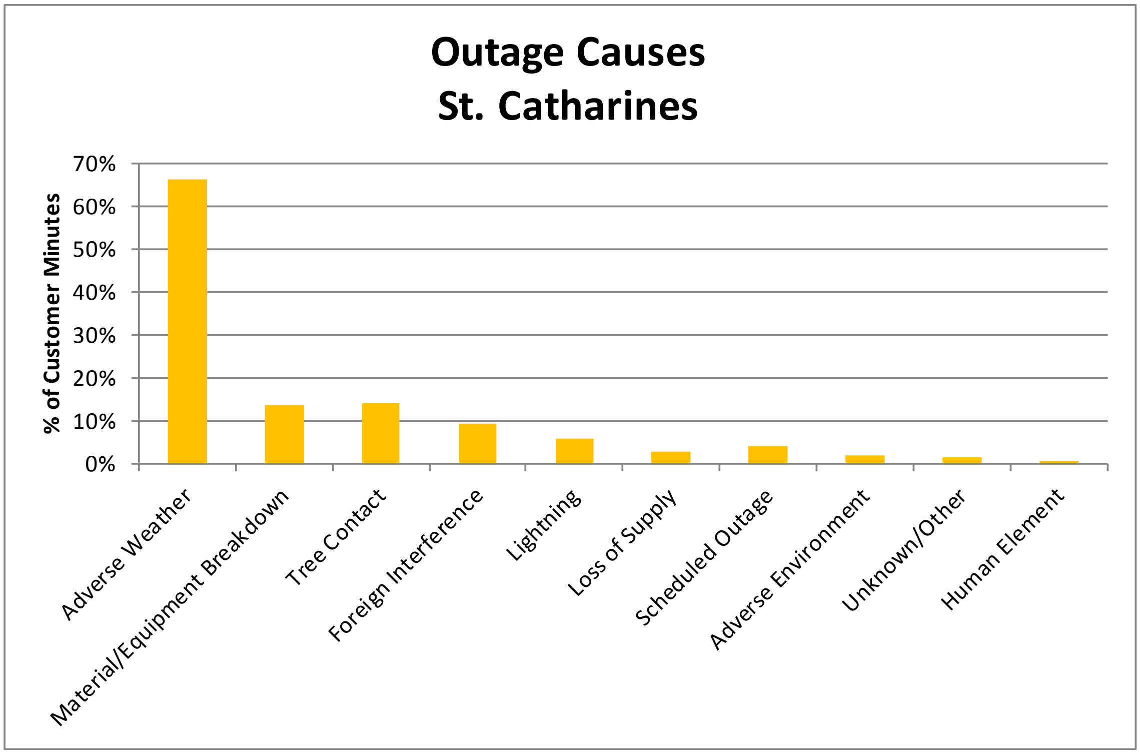

Figure 40 - St. Catharines Operating Area – Cause of Outages

Investment Drivers

Investment in this area is largely driven by:

- System Renewal – Horizon Utilities' 4kV and 8kV Renewal Program includes the conversion and decommissioning of municipal substations in this area. These stations are scheduled for conversion in the 2014 to 2017 timeframe.

- System Service – Deployment of distribution automation throughout the St. Catharines service territory will provide reliability improvements to align the reliability in this area with corporate targets.

2.2.3. Information on Distribution System Assets (5.3.2.c)

<u>Asset Condition Assessment Summary</u>

As identified in Section 2.1.2 above, Horizon Utilities maintains detailed records for a number of asset categories. Kinectrics performed a comprehensive asset condition assessment on the following major asset categories:

- Substation Transformers
- Substation Circuit Breakers

- Substation Switchgear
- Pole Mounted Transformers
- Overhead Conductors
- Overhead Line Switches
- Wood Poles
- Concrete Poles
- Underground Cables
- Pad Mounted Transformers
- Pad Mounted Switchgear
- Vault Transformers
- Utility Chambers
- Vaults
- Submersible Load Break Switches

The asset data provided to Kinectrics for the ACA was compiled on July 1, 2013 and is presented below in Table 15.

Asset		Sub-Category	Health Index Distribution (% of Sample Size)					Total of Poor and Very Poor (% of Sample Size)	Average Age
			Very Poor (< 25%)	Poor (25 - <50%)	Fair (50 - <70%)	Good (70 - <85%)	Very Good (≥85%)		
Substation Transformers		-	0%	0%	10%	31%	59%	0%	44
Substation Circuit Breakers		-	5%	18%	16%	22%	40%	23%	28
Substation Switchgear		-	0%	32%	49%	5%	14%	32%	44
Pole Mounted Transformers		-	5%	2%	4%	4%	85%	6%	24
Overhead Conductors		Primary	2%	3%	1%	5%	89%	5%	28
		Secondary	6%	3%	3%	12%	76%	9%	38
		Service	9%	3%	4%	13%	72%	11%	40
Overhead Line Switches		-	8%	13%	10%	16%	54%	20%	23
Wood Poles		-	4%	7%	7%	8%	74%	11%	32
Concrete Poles		-	2%	4%	2%	12%	80%	5%	27
Underground Cables	XLPE	Primary	13%	16%	18%	15%	38%	29%	22
	PILC		1%	0%	2%	9%	89%	1%	34
	DB	Secondary	11%	31%	22%	17%	18%	42%	29
	ID		14%	27%	18%	17%	23%	42%	29
	DB	Service	9%	54%	21%	6%	10%	63%	33
	ID		1%	4%	18%	18%	60%	4%	13
Pad Mounted Transformers		-	0%	0%	0%	1%	99%	0%	17
Pad Mounted Switchgear		-	0%	1%	3%	52%	44%	1%	20
Vault Transformers		-	23%	26%	40%	11%	0%	49%	25
Utility Chambers		-	0%	1%	2%	10%	87%	1%	39
Vaults			0%	0%	0%	0%	99%	0%	28
Submersible LBD Switches		-	21%	26%	23%	0%	31%	46%	30

Table 15 - Health Index Results Summary

A visual representation of the Health Index results is provided below in Figure 41.

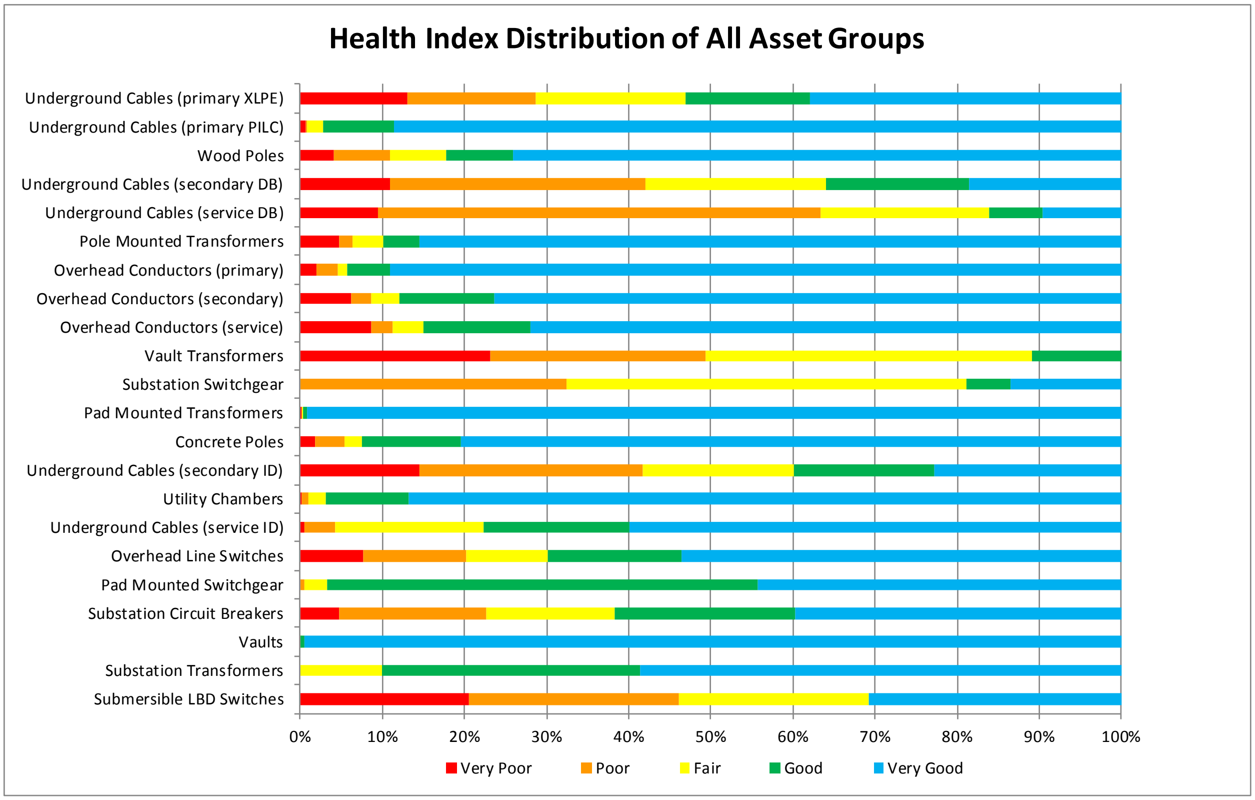

Figure 41 – Pictorial Summary of Health Index Results

The Kinectrics ACA Report provided the following conclusions and recommendations. The following is a summary of Kinectrics recommendations, and Horizon Utilities' actions for addressing each of the recommendations.

Conclusions and Recommendations[10]

An Asset Condition Assessment was conducted for fifteen of Horizon Utilities' distribution asset categories. For each asset category, the Health Index distribution was determined and a condition-based 20-year Flagged-For-Action Plan was developed. The following evidence (in italics) provides the recommendations from Kinectrics and Horizon Utilities' responses for action.

[10] Horizon Utilities 2013 Asset Condition Assessment, Kinectrics, page x

1. *In general, sufficient data and/or information were available for all the asset categories to develop a meaningful Health Index distribution. Horizon Utilities should continue to improve on existing data collection practices with some improvements as recommended in the Data Assessment section above.*

   <u>Horizon Utilities' Response:</u> In Horizon Utilities' asset management activities, it regularly reviews the data collected in support of asset condition assessments. The ability to migrate from an EOL to a Health Index metric was possible due to the increased asset maintenance and operational data collected. Kinectrics' recommendations regarding improved data collection processes will be incorporated into Horizon Utilities' existing processes.

2. *Horizon Utilities' investment in substation infrastructure in recent years has been effective in improving the overall health of the substation asset groups as compared to the previous asset condition assessments. Substation transformers are in good shape with substation circuit breakers and switchgear being in adequate condition. A small portion of breakers remain in poor condition.*

   <u>Horizon Utilities' Response:</u> Kinectrics' analysis substantiates the effectiveness of Horizon Utilities' recent substation renewal investments. The Health Index distribution of substation transformers and circuit breakers has markedly improved since the assessment performed in Horizon Utilities' 2010 AM Plan and the Health Index distribution is now at an acceptable level. Substation switchgear remains a risk with under 20% of the assets having a Health Index of either 'good' or 'very good'. Horizon Utilities will address the remaining substation assets in poor condition through decommissioning of the assets rather than through renewal investment. This decision was deemed the most prudent course of action due to the cost of renewal and the time remaining until these assets are retired. This decision however is predicated on maintaining the schedule identified in the 4kV and 8kV Renewal Program which requires an increase in investment from current levels. The retirement of these substation assets is directly linked to the 4kV and 8kV renewal programs. Any delays to the schedule created in the 4kV and 8kV Renewal Program increases the probability of requiring substation renewal investments that could otherwise be avoided. The impact of not executing the 4kV and 8kV Renewal Program as proposed in this DSP is provided below in Section 3.5.3.

3. *For overhead asset groups (including conductors, pole top transformers, switches and poles), even though their overall condition is fairly good, because they represent large populations, a significant number of units were still determined to be in "very poor" and "poor" condition and sustained investments will be required over the next 20 years to maintain overall condition at the existing level.*

<u>Horizon Utilities' Response</u>: Horizon Utilities' overhead distribution system has a healthier distribution than the underground assets. This can be attributed to past investments in renewing the 4kV and 8kV distribution systems as identified in Horizon Utilities' 4kV and 8kV Renewal Program. This plan was created by consolidating both distribution asset conditions and substation asset conditions to provide a complete picture for the localized service area and better information for the prioritized long term plan for renewal. The 4kV and 8kV distribution system represents the majority of Horizon Utilities' oldest distribution assets which are near or at the end or their useful life.

Sustained investments in the overhead distribution system are required to maintain the current level of health as stated by Kinectrics. Horizon Utilities will implement investment in overhead distribution renewal through the 4kV and 8kV Renewal Program. The reliability of service experienced by Horizon Utilities' customers is decreasing and Horizon Utilities' increased investment in the overhead distribution assets is required to address the decrease in system reliability and to allow the retirement of substation assets prior to end of life and preferably prior to failure. Horizon Utilities is proposing to increase investment in the 4kV and 8kV Renewal Program in the 2015 to 2019 Test Years to address the overhead renewal investments and to allow the decommissioning of the substation assets that are in poor health, as identified by Kinectrics. Horizon Utilities' 4kV and 8kV Renewal Program is further detailed and justified in Section 3.5.3.

4. *For asset groups associated with underground system, XLPE cables, direct buried cables, secondary in-duct cables and submersible LBD switches have a significant portion of population in "very poor" and "poor" condition and substantial investments will be required over the next 20 years to improve the overall condition of these asset categories. Even though the overall condition of PILC cables, service in-duct cables and pad mounted transformers is fairly good, a sustained investment over the next 20 years is required to maintain their overall condition at the existing level.*

Horizon Utilities' Repsonse: Primary XLPE cable is the asset category that poses the largest risk to the continued reliable operation of Horizon Utilities' distribution system. It has the largest investment requirement over the twenty year planning cycle. Due to the many kilometres of cable, purchasing lead time, distributed nature of the assets, and access issues requiring planned underground excavation and customer service interruptions this asset renewal category is a major concern due to its present and forecast Health Index. Horizon Utilities is proposing to increase renewal investment in the proactive replacement of XLPE primary cable. Further details and justification regarding Horizon Utilities' XLPE Renewal Program is provide in Section 3.5.3.

5. *The combination of health and installed population will require significant investment over the next 20 years in order to at least sustain the existing level of reliability in the following asset categories:*

- *pole mounted transformers*
- *overhead primary, secondary and service conductors*
- *wood poles*
- *underground primary XLPE cables*
- *underground PILC cables*
- *underground secondary/service direct buried cables*
- *vault transformers*

Horizon Utilities' Response: Kinectrics identified asset groups that require significant investment over the next twenty years to sustain existing reliability levels. Horizon Utilities' capital investment programs were determined to consider the renewal investment requirements for all asset groups with either a poor Health Index distribution (at least 20% of assets in either 'poor' or 'very poor' health) or a significant five year investment requirement (greater than $5,000,000). Table 107 in Section 3.1.3 below maps these asset groups against Horizon Utilities' capital investment programs.

6. *It is recommended to put in place asset specific program to not only address improving the overall condition of asset categories listed in point 4 above but also to maintain existing overall condition level for the remaining asset categories, particularly the ones listed in point 5 above. Not doing so will results in deteriorating reliability performance, taking unnecessary risks associated with failures of assets with significant consequence of failure (such as underground cables, substation breakers and overhead conductors)*

and bow wave of future investment needs that would be substantially higher than the historical levels.

Horizon Utilities' Response: Kinectrics identified the need to continue the maintenance and inspection programs to ensure the continued reliable operation of all of Horizon Utilities' distribution assets. Horizon Utilities conducts a comprehensive maintenance and inspection program, detailed in Section 2.3.1, to maximize the lifespan of the distribution assets and ensure the long-term viability of the distribution system. Horizon Utilities considers all asset categories when determining capital investment programs and changes to maintenance programs.

7. *It is important to note that the recommendations in this report are primarily condition-based. In putting in place a long-term asset strategy other factors, such as obsolescence, system growth, municipal initiatives, Regional Integrated Planning, etc. should be taken into account. Furthermore, the appropriate cost effective action for units flagged for action should be selected by considering options other than replacement, such as refurbishment, spare units strategy adjustment, intensified maintenance, real time monitoring or "doing nothing". This is particularly effective when dealing with proactively replaced assets.*

Horizon Utilities' Response: Kinectrics identified that external factors other than pure asset health need to be considered when planning for capital investment. Horizon Utilities' capital investment programs are created taking these external factors into consideration. These external factors can increase justification for renewal investment or provide options other than renewal to address asset health. For example, the renewal investment in the Dundas operating area is driven both by asset health and operating characteristics (e.g. lack of redundancy, obsolete equipment and system design standards) of the 4kV distribution system in the Dundas. Conversely, no further investment in the renewal of substation breakers and switchgear is planned. Horizon Utilities has chosen to decommission these assets, thereby avoiding the renewal investment requirements. Horizon Utilities considers options other than replacement as described further in Section 2.3.1.

The results of Kinectrics' asset analysis indicates that Horizon Utilities' distribution system requires significant renewal investment. As elements of the system age, they become less resilient to adverse weather and foreign interference. Horizon Utilities' distribution system has many components which have reached the end of their useful life and are contributing to a greater amount of equipment failures and service interruptions to customers. These service failures are further exaggerated as the aged assets require longer repair times or outright replacement, extending the duration of the outage experienced by the customer.

Asset Condition Assessment Details

The age and Health Index demographics for each individual asset category analyzed in the ACA are provided below.

<u>Substation Transformers</u>

Substation transformers are considered one of the most important and critical equipment types in a substation. Horizon Utilities' municipal substations have between one and four transformers supplying the switchgear depending on the stations. Failure of the substation transformer can result in the entire substation being removed from service (for substations with a single transformer), or part of a substation being removed from service (for substations with multiple transformers) for extended periods of time. Substation transformers are expensive and can have lead times for delivery in excess of twelve months. Consequently, substation transformers are a critical component of a distribution system.

The ACA performed by Kinectrics incorporated age, testing and inspection information to develop a Health Index rating for substation transformers.

As demonstrated in Figure 43 below, Horizon Utilities substation transformers are relatively old with an average age of 47 years and with only 1 unit being less than 20 years old. The Health Index however, as illustrated in Figure 43, indicates that Horizon Utilities fleet of substation transformers do not present a significant risk.

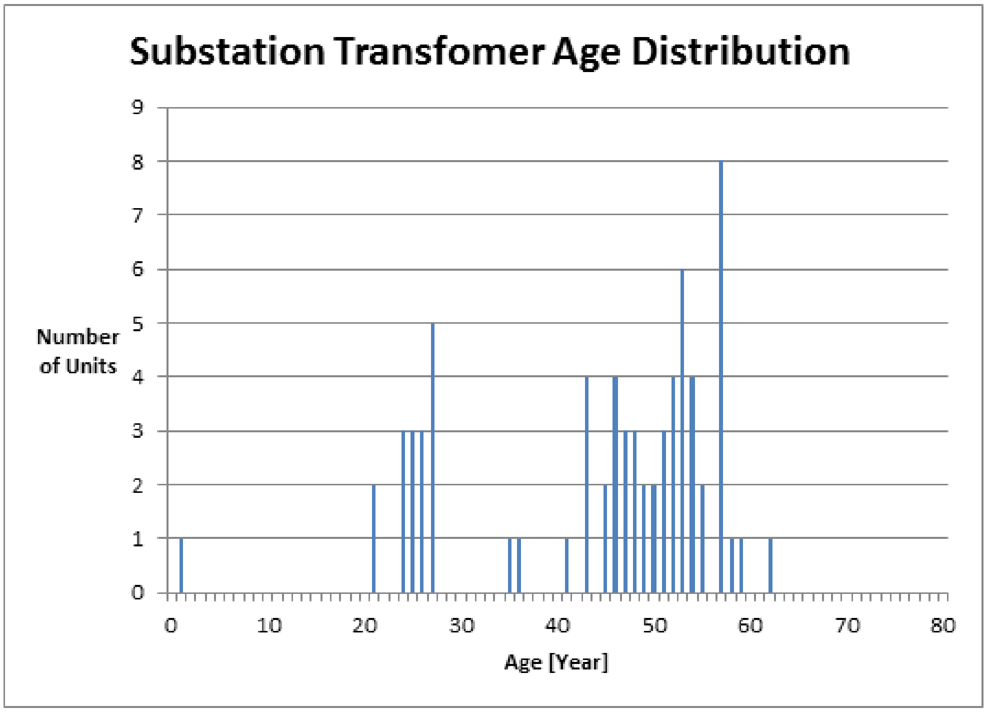

Figure 42 - Substation Transformers - Age Distribution

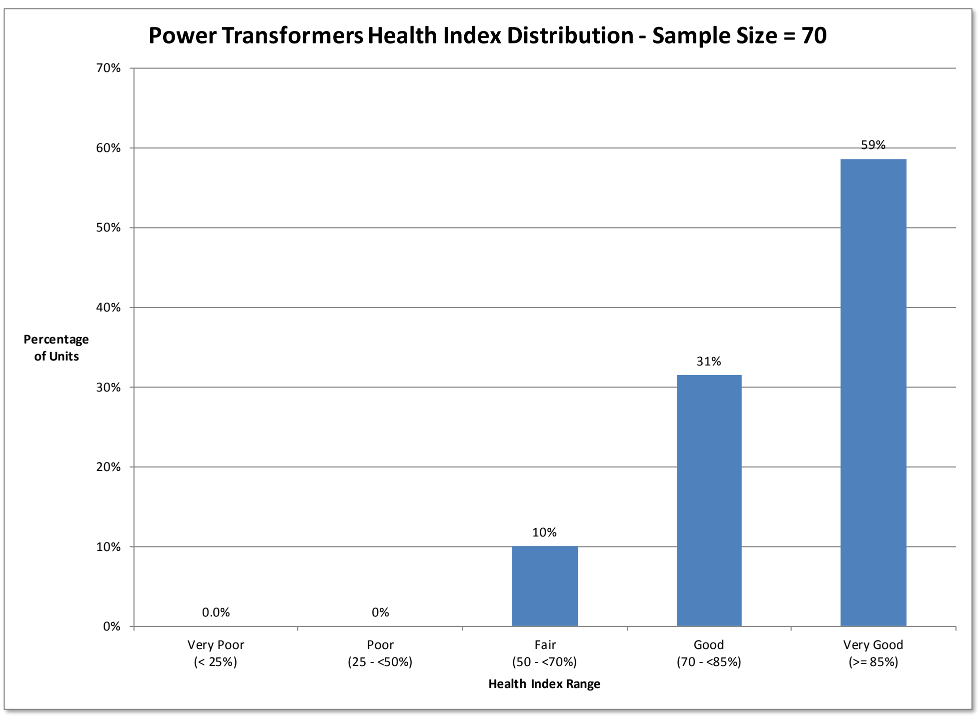

Figure 43 - Substation Transformer Health Index Distribution

Substation Circuit Breakers

As demonstrated in Figure 45 below, Horizon Utilities has a significant number of newer units (less than 5 years old). Previous ACAs identified the age and condition of the substation circuit breakers as significant risk. In co-ordination with Horizon Utilities' long term strategic 4KV and 8kV Renewal Program, a capital program was initiated and completed in 2012 and 2013 to renew a number of substation circuit breakers. The completion of this renewal investment has improved the age distribution and Health Index profile below to an acceptable level of risk. No further investments above Horizon Utilities' materiality threshold will be made in substation circuit breakers from 2015 through 2019.

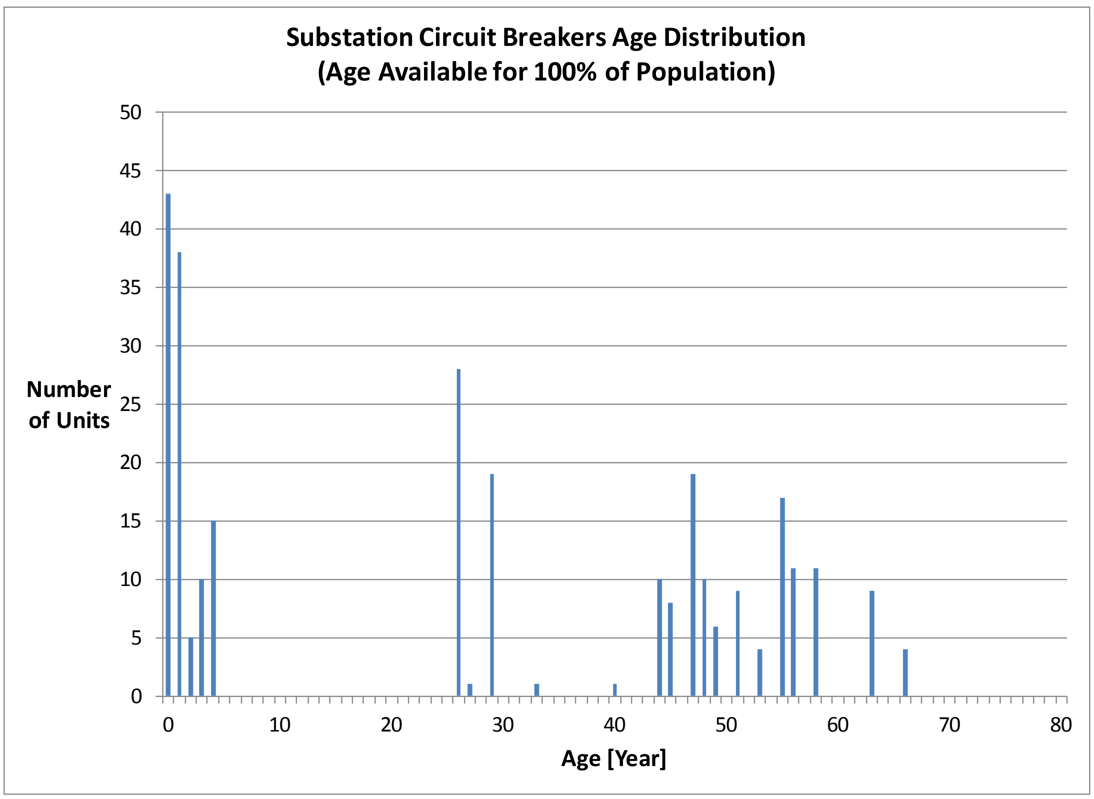

Figure 44 - Substation Circuit Breakers - Age Distribution

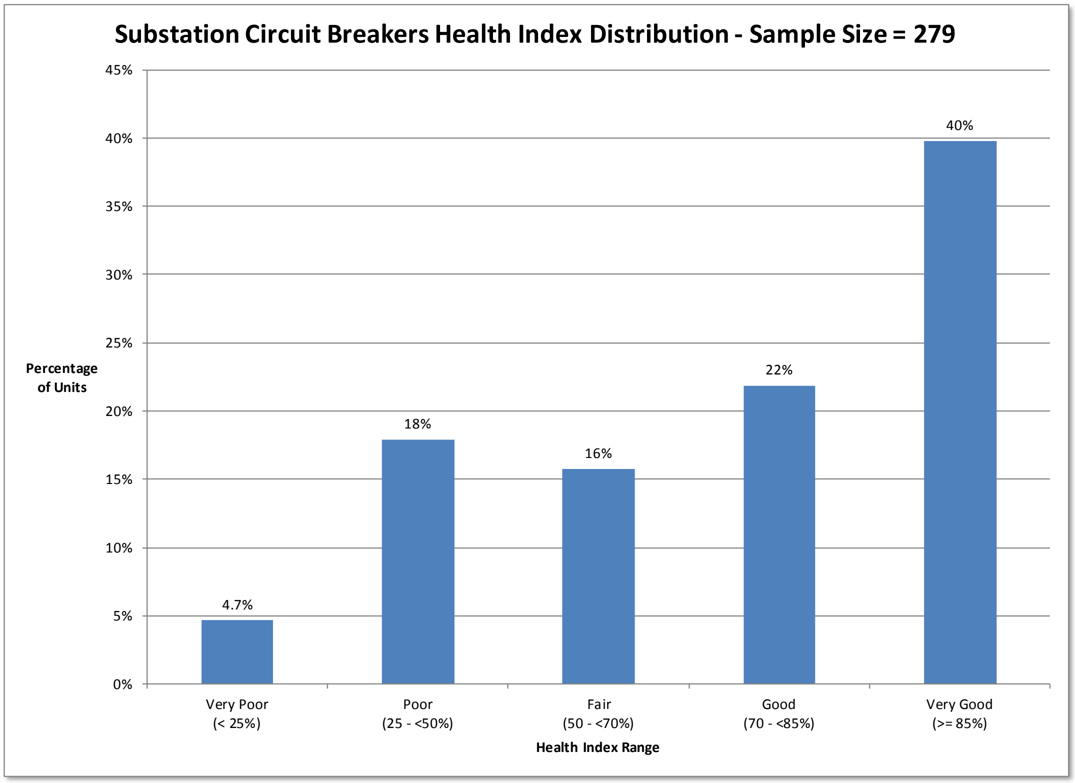

Figure 45 - Substation Circuit Breaker Health Index Distribution

Substation Switchgear

Substation switchgear consists of an assembly of retractable/racked switchgear devices that are totally enclosed in a metal envelop (metal-enclosed). The switchgear houses the circuit breakers and also contains disconnect switches, fuse gear, current transformers, potential transformers, metering, and protective relays. As illustrated in Figure 47 below, Horizon Utilities' switchgear are relatively old with many of the units exceeding 40 years of age. The remaining units with a Health Index of either poor or fair are planned to be managed through increased maintenance and inspection cycles until decommissioned.

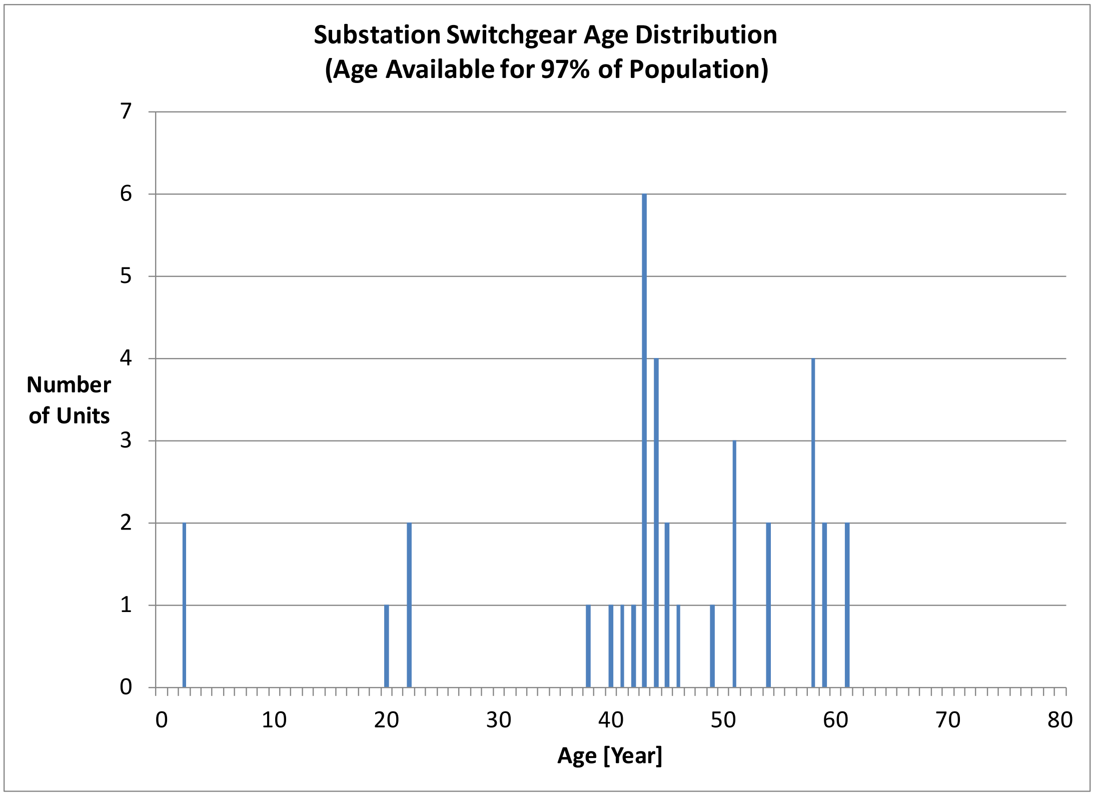

Figure 46 – Substation Switchgear – Age Distribution

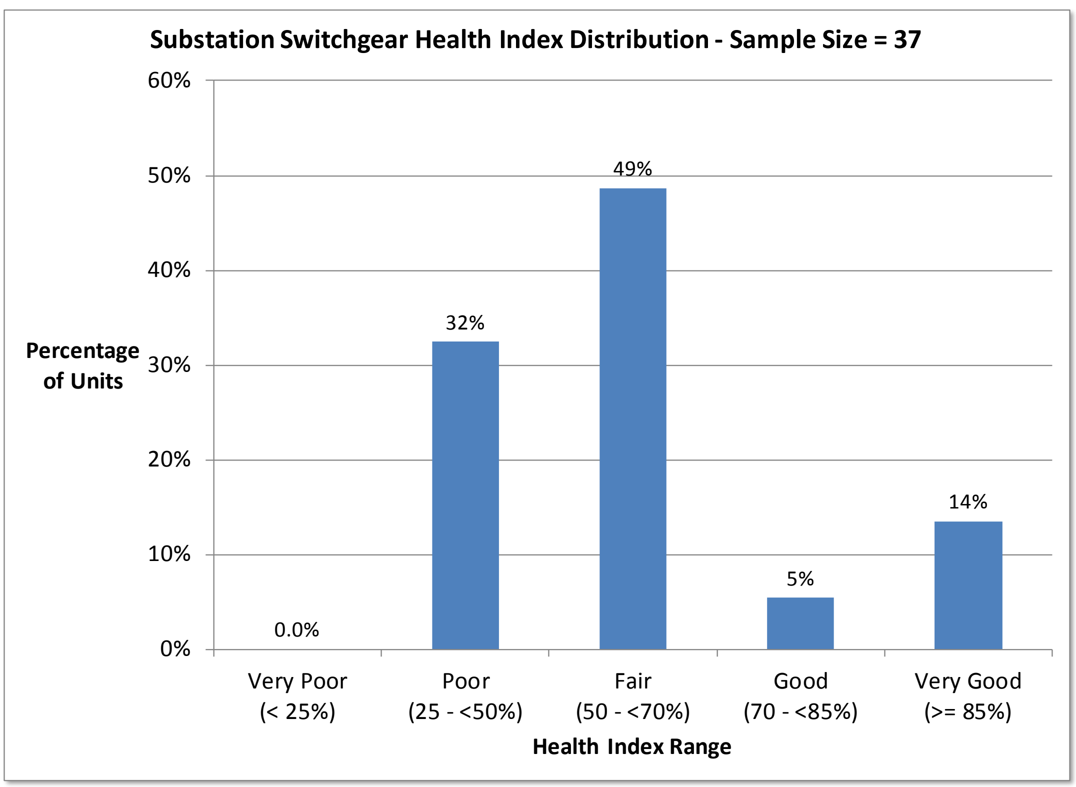

Figure 47 - Sub Station Switchgear Health Index Distribution

Transformers

Many customers cannot typically be serviced at Horizon Utilities' distribution voltages (27.6kV, 13.8kV, 8.32kv, and 4.16kV) and require step-down transformers to reduce the voltage to a useable service voltage of less than 750V. Horizon Utilities has approximately 24,000 distribution transformers which are categorized into the following categories:

- Overhead – All pole mounted distribution transformers are included in this category
- Padmount – All transformers supplied directly from an underground supply situated above grade are considered padmount transformers
- Vault - All transformers supplied directly from an underground supply situated below grade are considered vault transformers

The age and Health Index distribution for each transformer category is illustrated below in Figure 49 to Figure 53.

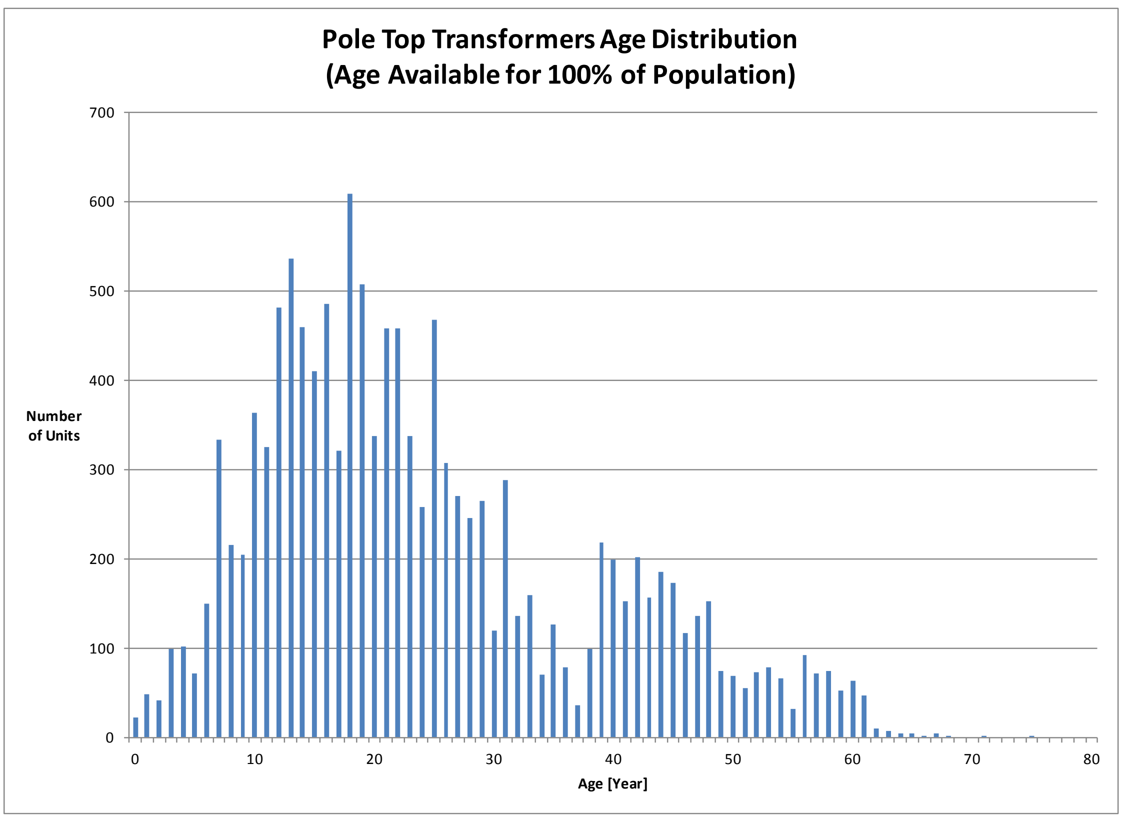

Figure 48 - Overhead Transformer - Age Distribution

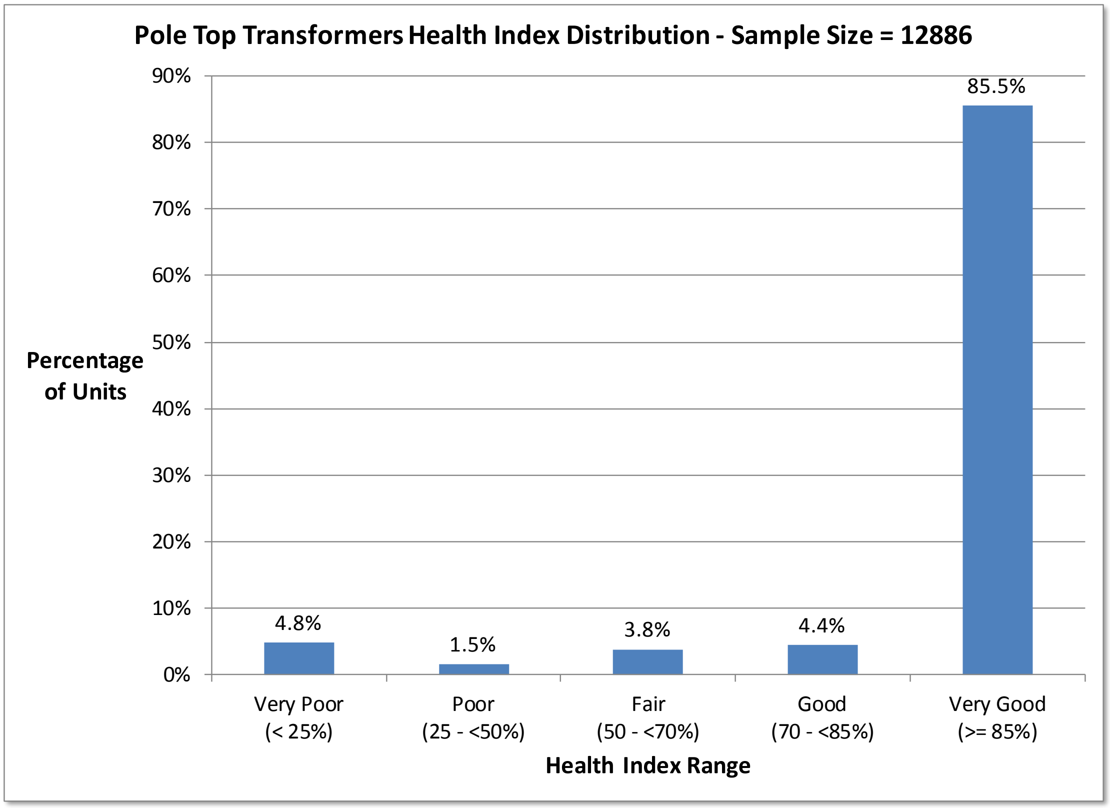

Figure 49 - Overhead Transformer Health Index Distribution

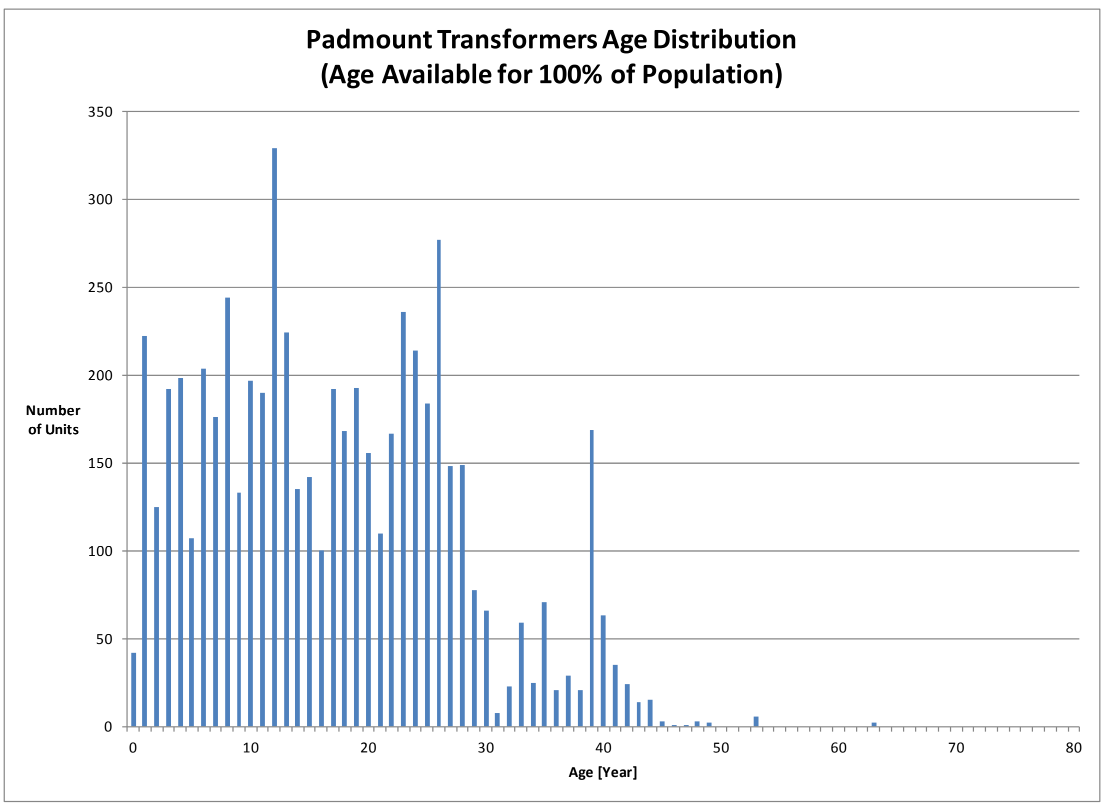

Figure 50 - Padmount Transformer - Age Distribution

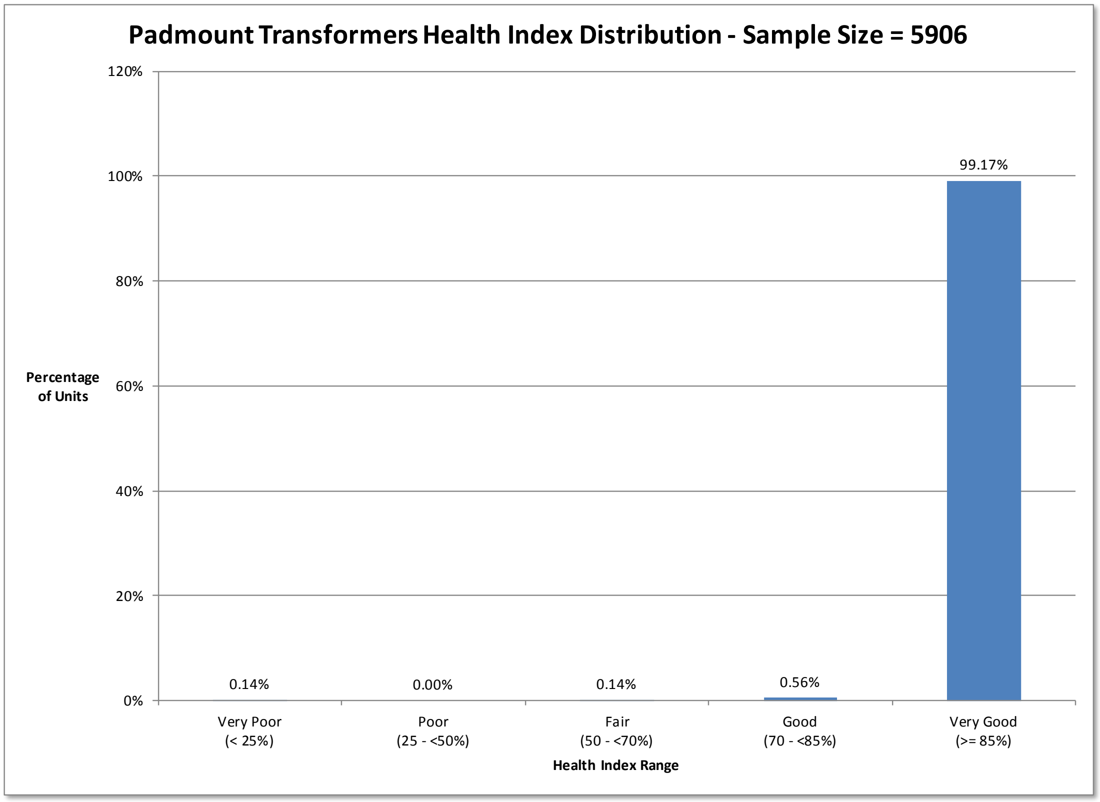

Figure 51 - Padmount Transformer Health Index Distribution

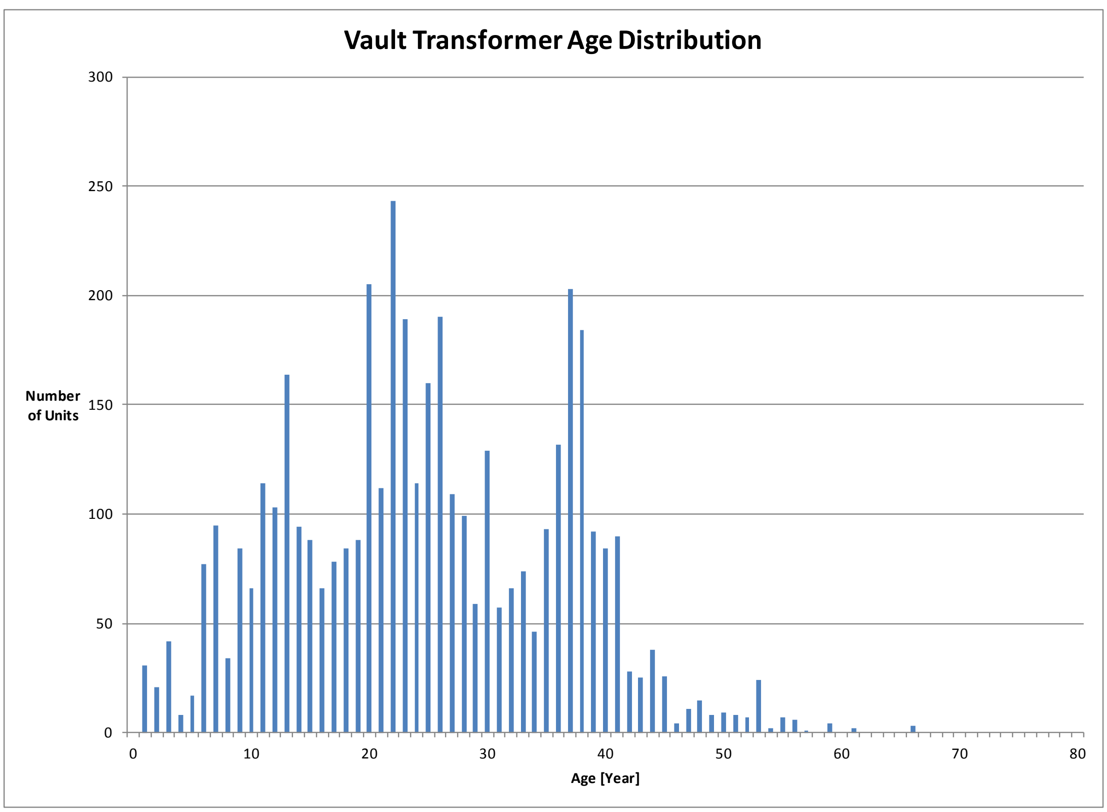

Figure 52 - Vault Transformer - Age Distribution

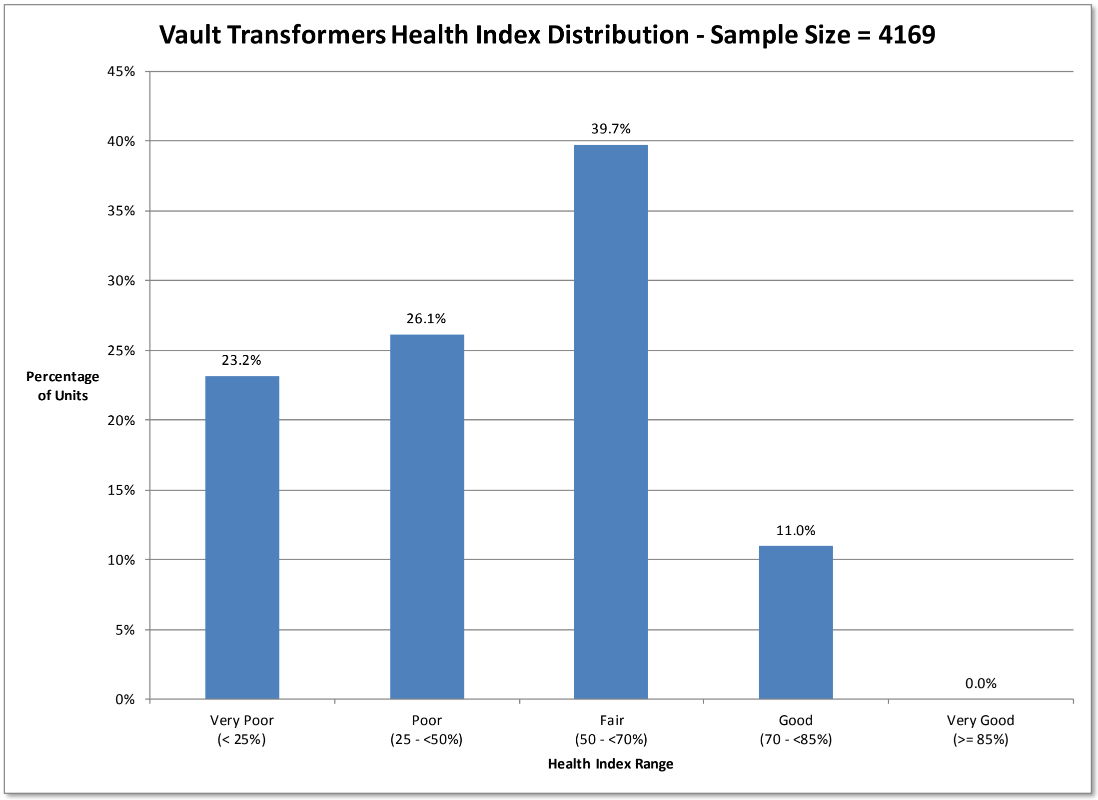

Figure 53 - Vault Transformer Health Index Distribution

As illustrated above, Padmount transformers have the lowest average age and best overall Health Index distribution. Overhead transformers and vault transformers have a higher average age and lower overall Health Index scores. The Health Index distribution reflects a change in Horizon Utilities' design standards over time to eliminate the practice, where possible, of installing vault transformers. Existing vault transformers are replaced when possible because:

- They are more susceptible to rusting as the underground vaults are prone to flooding with water;
- The primary and secondary transformer connections are more prone to failure because of immersion in water;
- Oil leaks are harder to detect with vault transformer resulting in a higher potential environmental impact;
- Restoration takes longer for vault transformers;
- They present a higher safety risk to staff when operating.

Overhead Primary Conductors

Overhead conductors comprise a critical component in Horizon Utilities' distribution system with over 3,300km of primary conductor in service.

The Kinectrics ACA identified 1.9% of the primary conductors having a Health Index of 'very poor' which represents 64km of conductor of which 58km (83%) is on the 4.16kV distribution system. The age distribution and Health Index distribution are illustrated below in Figure 54 and Figure 55.

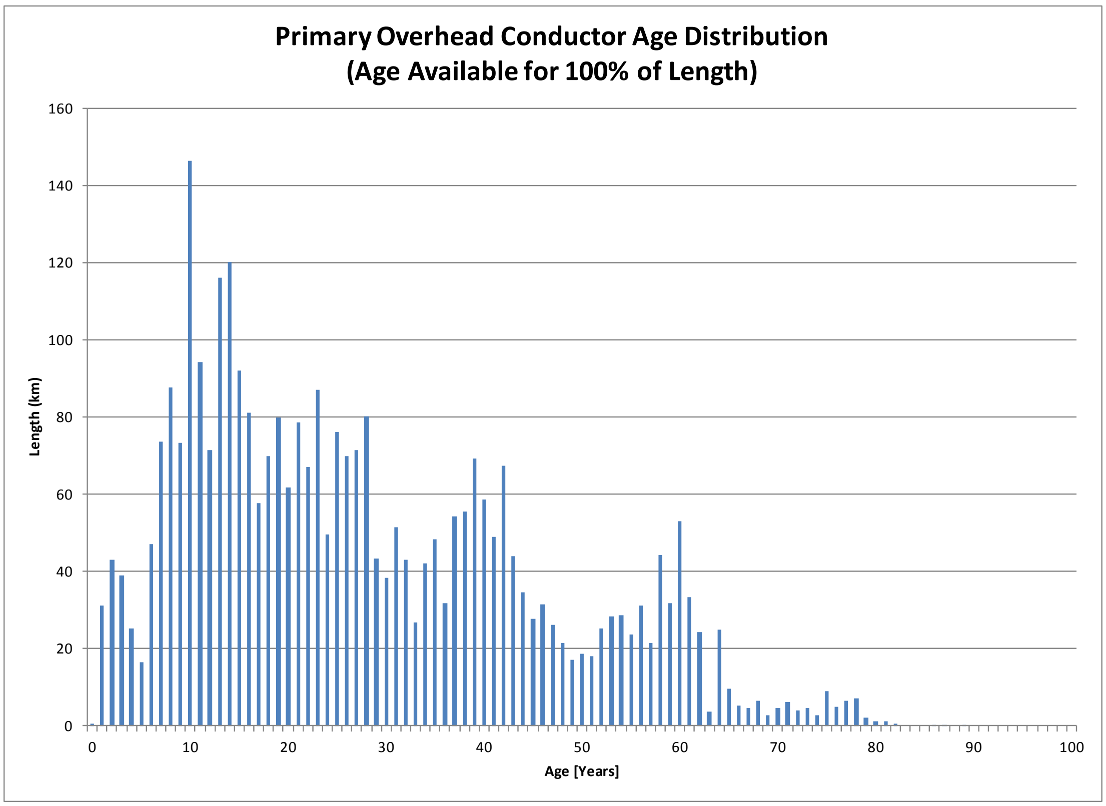

Figure 54 - Overhead Primary Conductor - Age Distribution

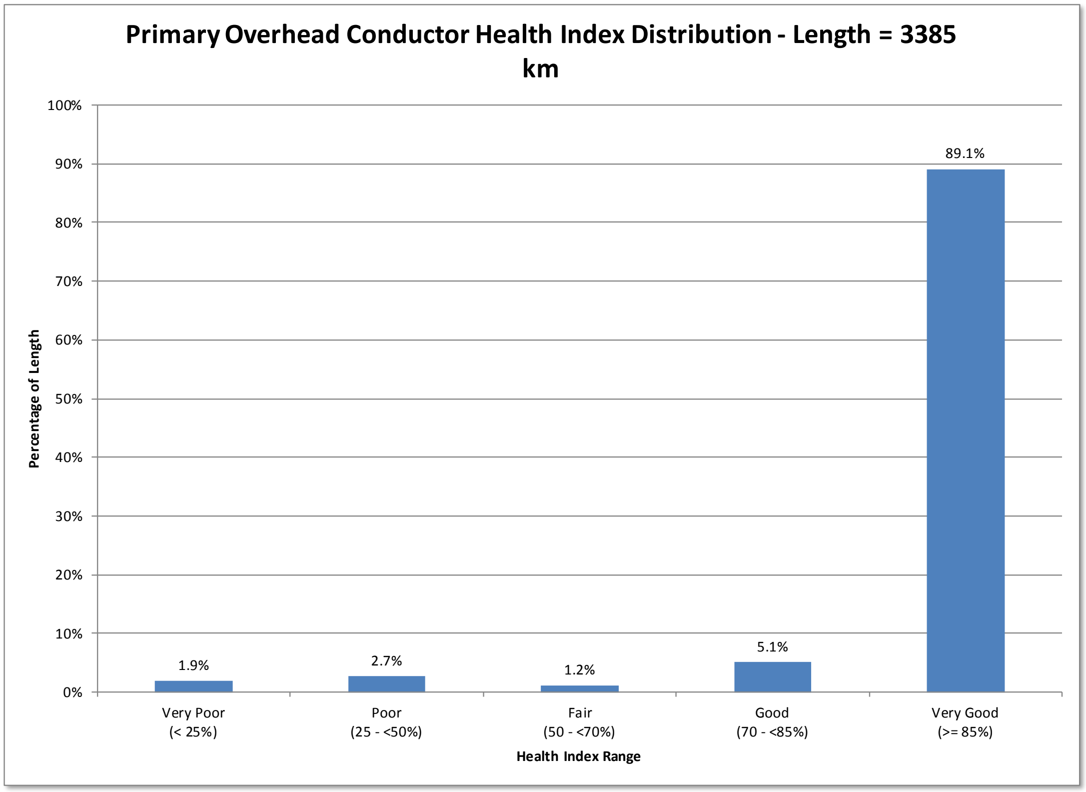

Figure 55 - Overhead Primary Conductor Health Index Distribution

Overhead conductors and poles provide a good proxy for the overall age of the overhead portion of the distribution system as the overhead backbone is typically the first component to be installed in an area. However, the Health Index of the actual conductor, is typically better than the associated overhead hardware (insulators, switches, lighting arrestors, connectors, fuses, etc.,.) as these components start to fail prior to the actual conductor failing.

A failure of an overhead conductor results in service interruptions to customers and represents a public safety concern through the risk of contact with an energized conductor. Having a conductor with a Health Index of ‘very poor’ presents a serious and very undesirable level of risk. The seriousness of impact is a result of:

- Significant customer impact when a conductor fails due to the number of customers impacted. Overhead conductors are the backbone of the distribution system. A failed conductor results in a service interruption to hundreds or thousands of customers and will result in road closures until the arrival of a field crew or multiple crews can render the site safe and until eventually to the restoration process.

- Restoration is more complex and time consuming due to the time, resources, and work procedures required to remedy the situation. Safe work procedures require multiple crews to repair failed conductors. The Utility Work Protection Code requires significant switching and associated work (checking open points, applying tags, and applying grounds) to establish a safe work zone prior to commencing the repair of the failed conductor.

- Failed conductors present a serious risk to public safety from the potential for electrical contact due to a failed primary conductor being within reach, or on the ground as well as the potential for damage or injury to life and private property due to the force/weight of the cable falling under tension. Post analysis of failed conductors when assessed against the results of Horizon Utilities visual and thermography inspection programs indicate that the conductor itself is not the point of failure but the conductor fails when another component in the system fails introducing a fault condition that stresses the conductor to the point of failure.

<u>Overhead Line Switches</u>

In order to increase the level of feeder automation, Horizon Utilities is phasing out air insulated, manually operated switches with remote operated, solid dielectric insulated reclosures. This new technology provides many advantages over the old, existing technology. Automated switches provide: remote control (open/close); telemetry (voltage and current); and alarms (status, fault indication) to the system control room ("System Control Room"). This functionality allows quicker fault location identification, isolation of faulted feeder sections and faster restoration of service in outage scenarios. This technology can also interrupt fault current and, therefore, can be programmed to: i) allow temporary faults to clear without interrupting the entire feeder; and ii) sectionalizing permanent faults thereby limiting the impact to a smaller number of customers. The contacts and insulating medium are internal to the switch eliminating the potential for flashovers and equipment failures resulting in service interruptions due to animal contacts or other foreign interference contacts.

The age and Health Index distribution for Horizon Utilities' line switches is provided below in Figure 56 and Figure 57.

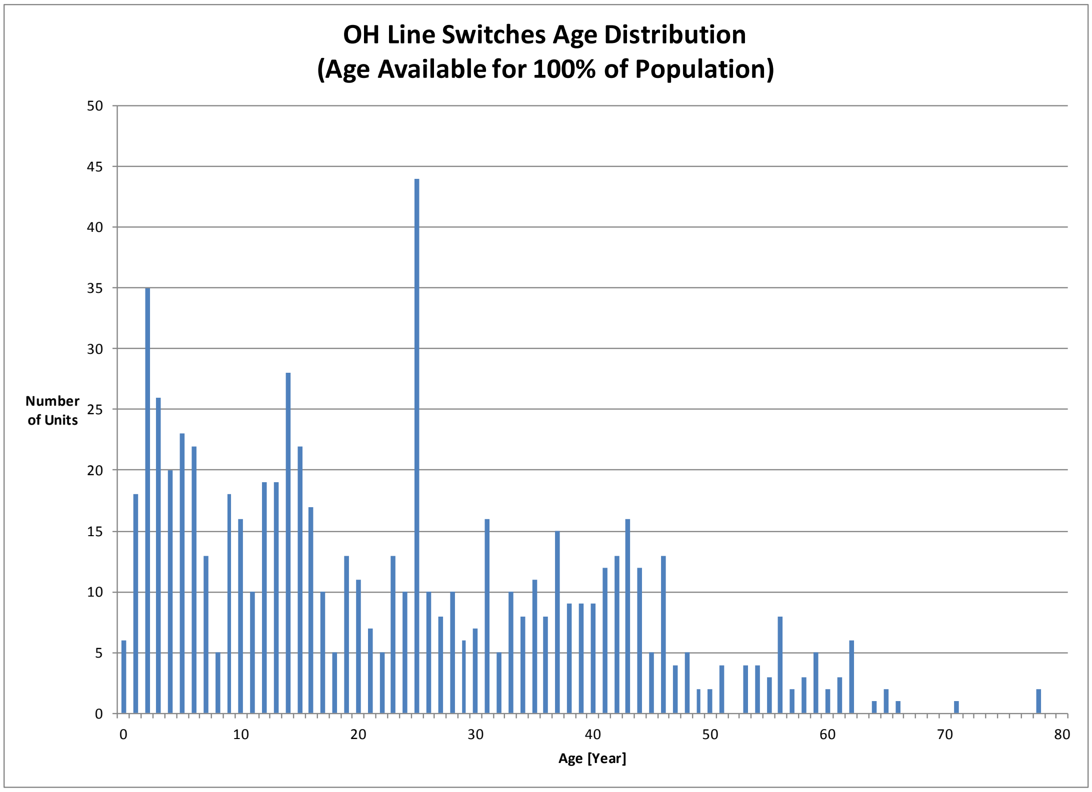

Figure 56 – Overhead Line Switch Age Distribution

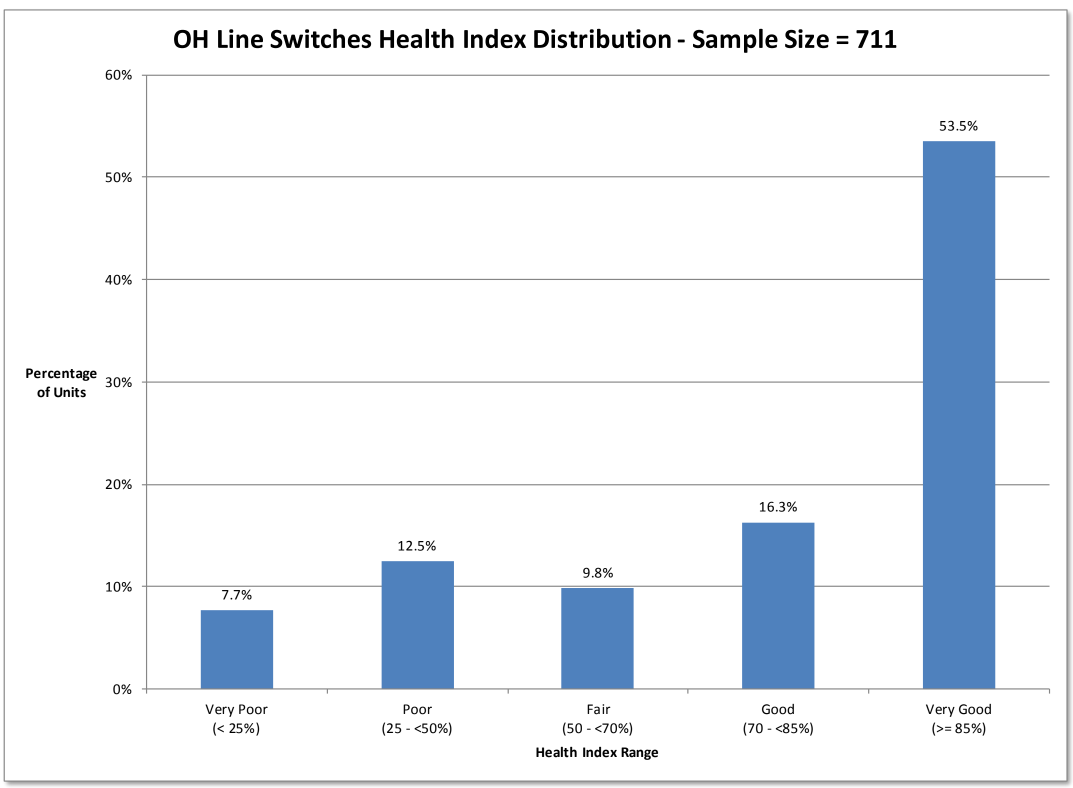

Figure 57 - Overhead Line Switch Health Index Distribution

Wood Poles

The age and Health Index distribution for wood poles is provided below in Figure 58 and Figure 59.

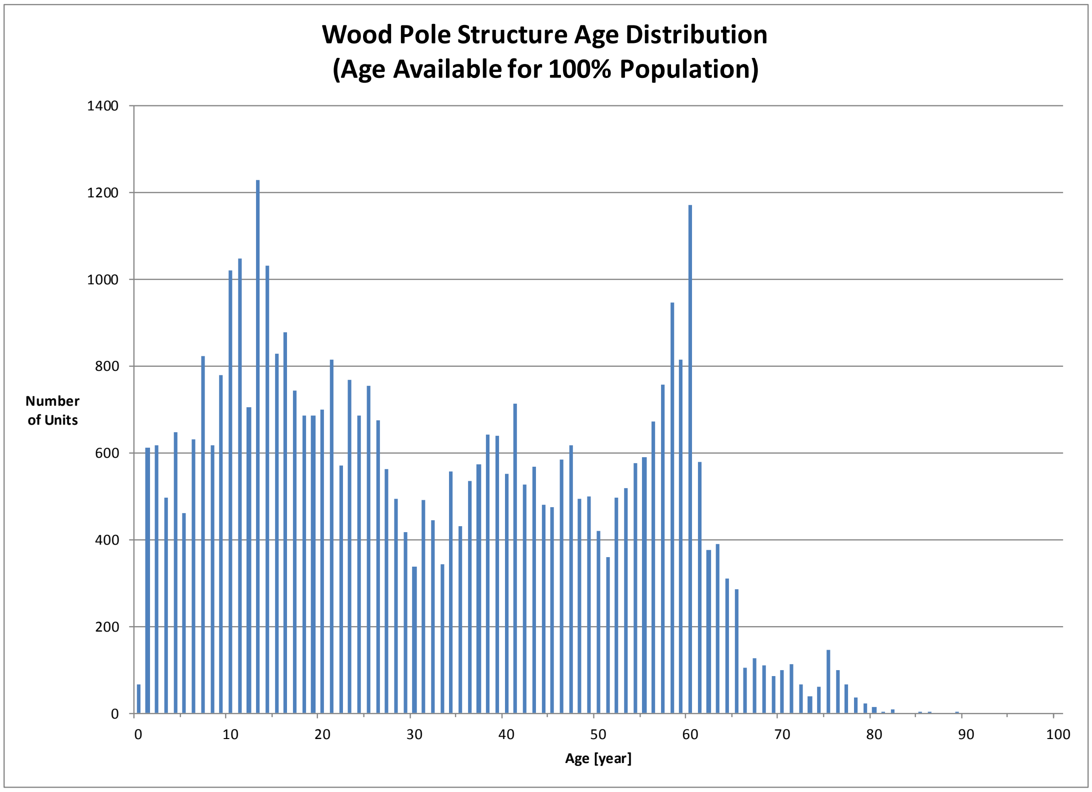

Figure 58 - Wood Pole - Age Distribution

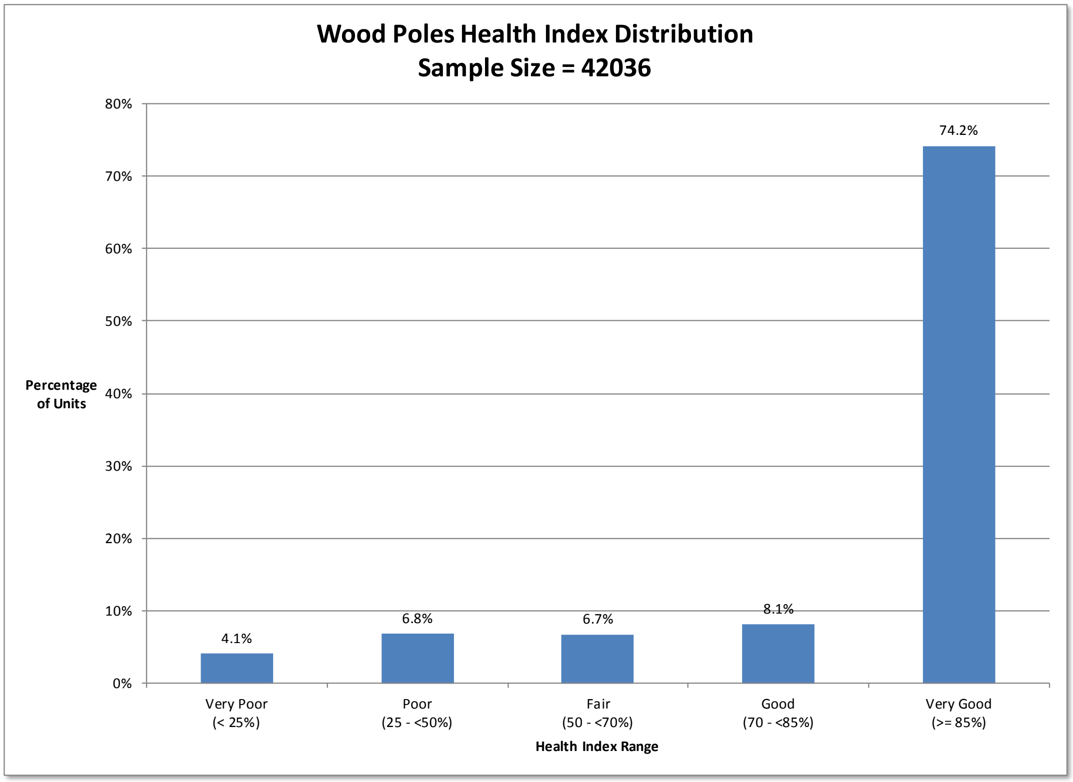

Figure 59 - Wood Pole Health Index Distribution

Concrete Poles

The age and Health Index distribution of concrete poles is provided below in Figure 61.

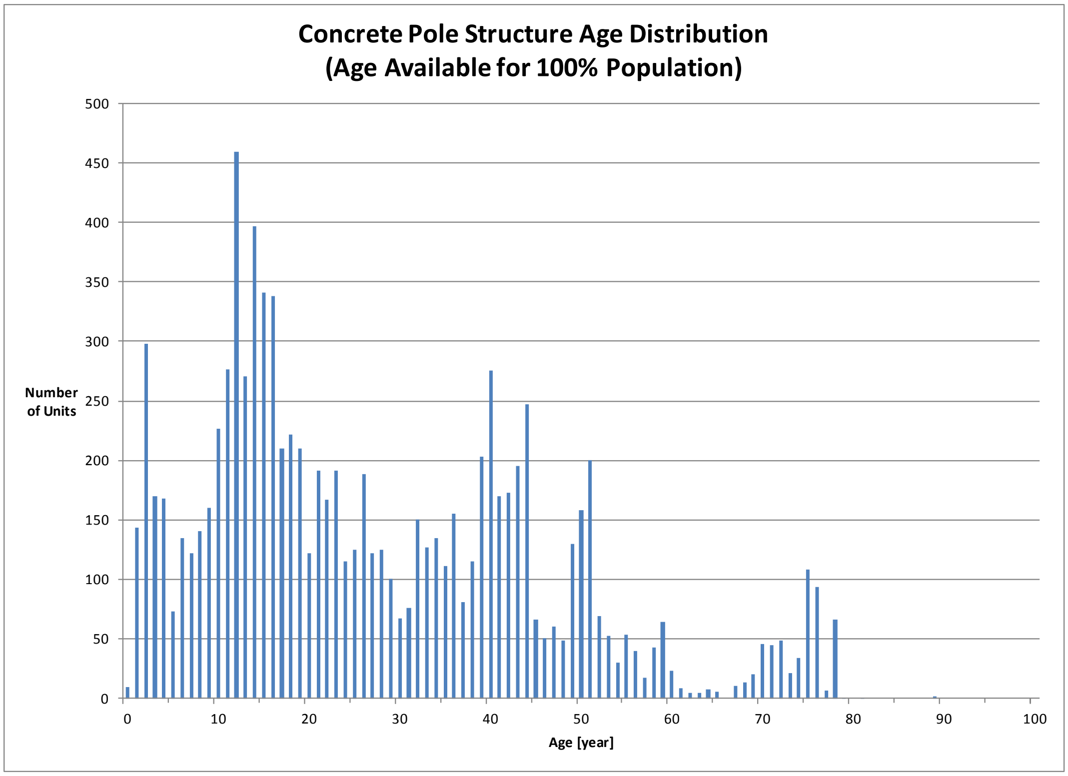

Figure 60 - Concrete Pole - Age Distribution

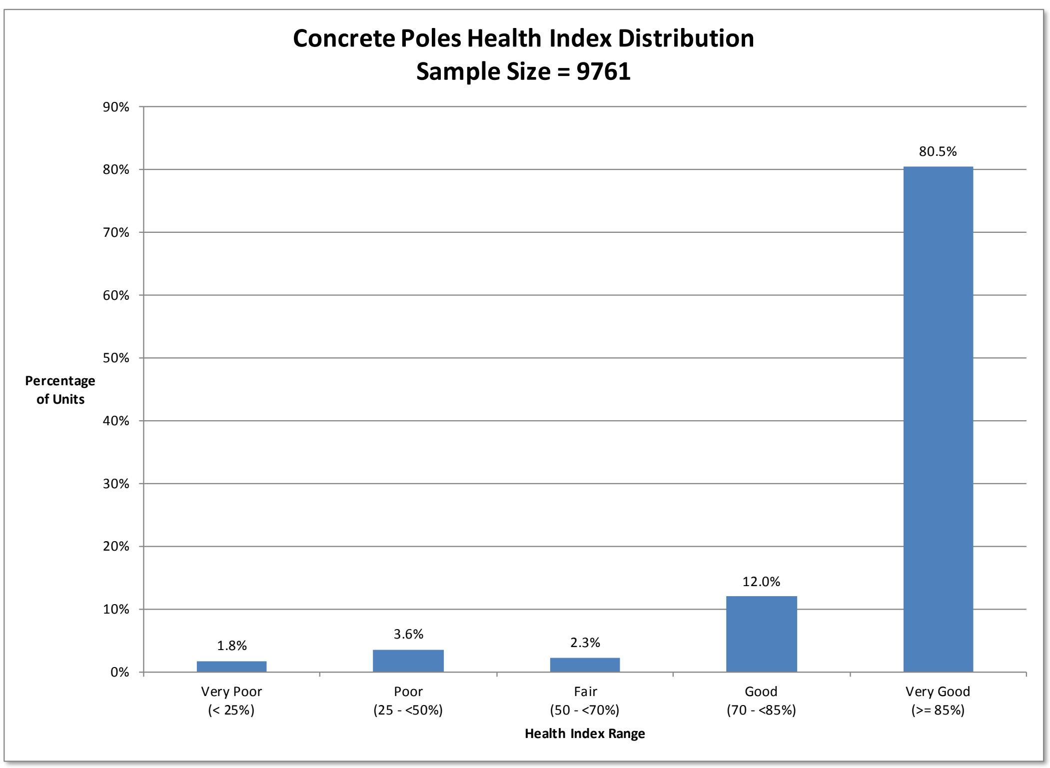

Figure 61 - Concrete Pole Health Index Distribution

Underground Primary Cable

The age and Health Index distribution for both XLPE and PILC primary cables are illustrated below in Figure 62 and Figure 63.

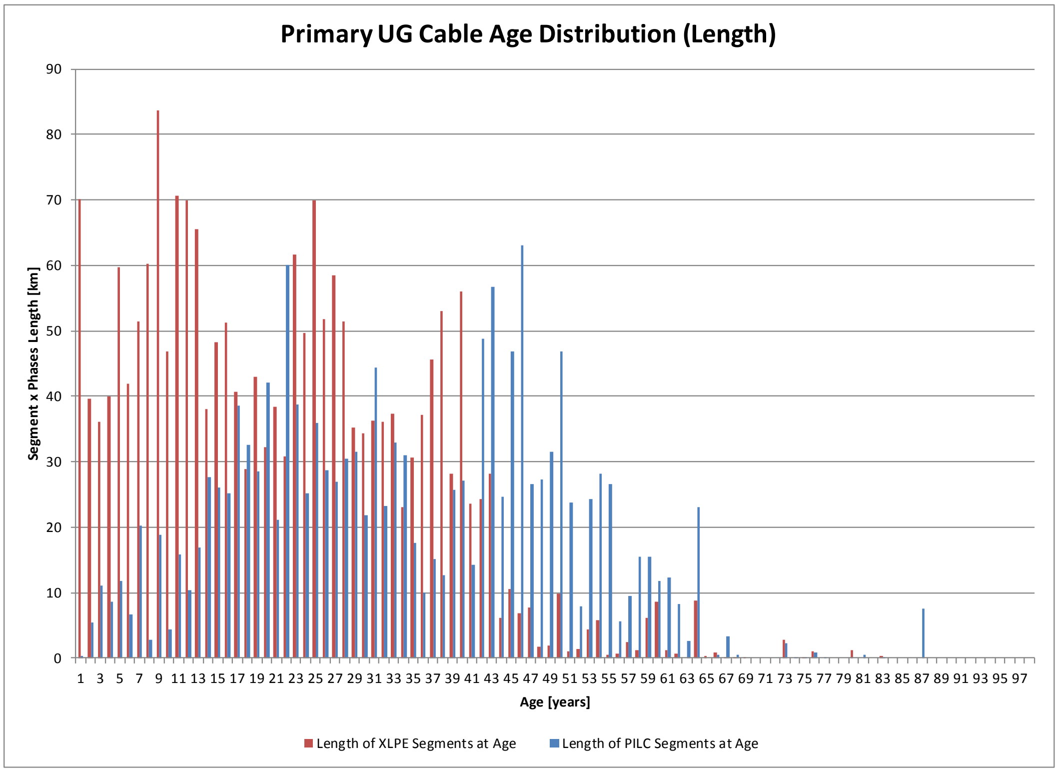

Figure 62 – Underground Primary Cable – Age Distribution

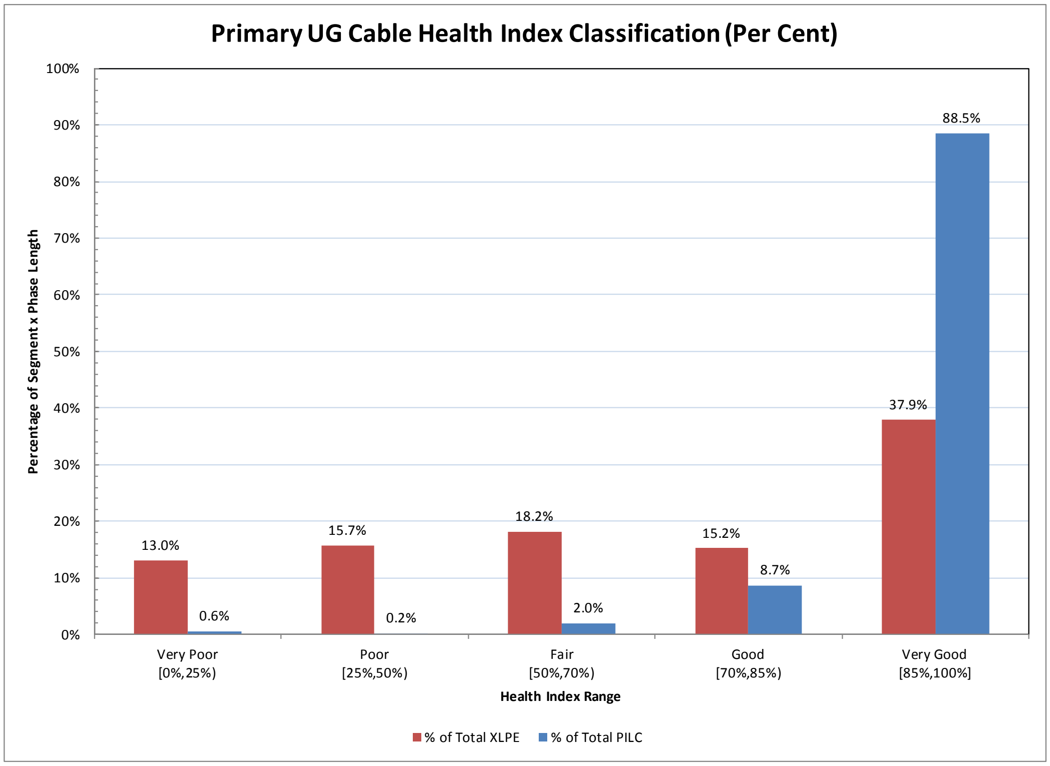

Figure 63 - Underground Primary Cable Health Index Distribution

The Health Index distribution in Figure 63 identifies a large future risk from the health of XLPE primary cable.

The Health Index distribution of the underground distribution system assets (cable and associated equipment) are at an unacceptable level and present the largest area of risk to Horizon Utilities ability to provide continued reliable service to customers. Specifically, the primary XLPE cable asset group represents the largest investment requirement over the twenty year planning cycle.

The unacceptability of the underground assets' Health Index distribution is demonstrated through analysis of system reliability – the measure of service received by Horizon Utility customers. From 2010 through 2012, material and equipment failures were the cause of 28% of the total customer minutes of outage. Of these outages, 50% were caused by a failure of material or equipment on the underground distribution system. Figure 64 below illustrates the breakdown in contribution between underground, overhead, transformer, and other material and equipment failures.

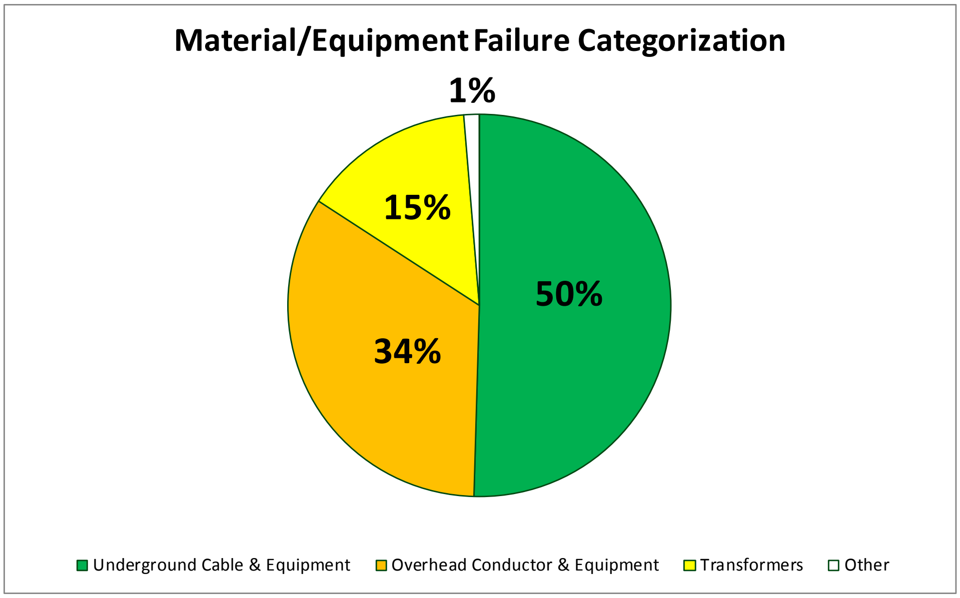

Figure 64 - Categorization of Equipment Failure Service Interruptions

Of the service interruptions caused by underground cable and equipment, 90% are caused by XLPE cable and associated equipment (splices, terminations) with the remaining 10% attributable to PILC cable and equipment (splices, potheads.)

Increasing the investment in underground renewal programs is a critical requirement for Horizon Utilities. Table 80 below shows a disturbing Health Index distribution forecast for primary XLPE cable over the 20 year planning cycle at 5 year increments at the current investment level.

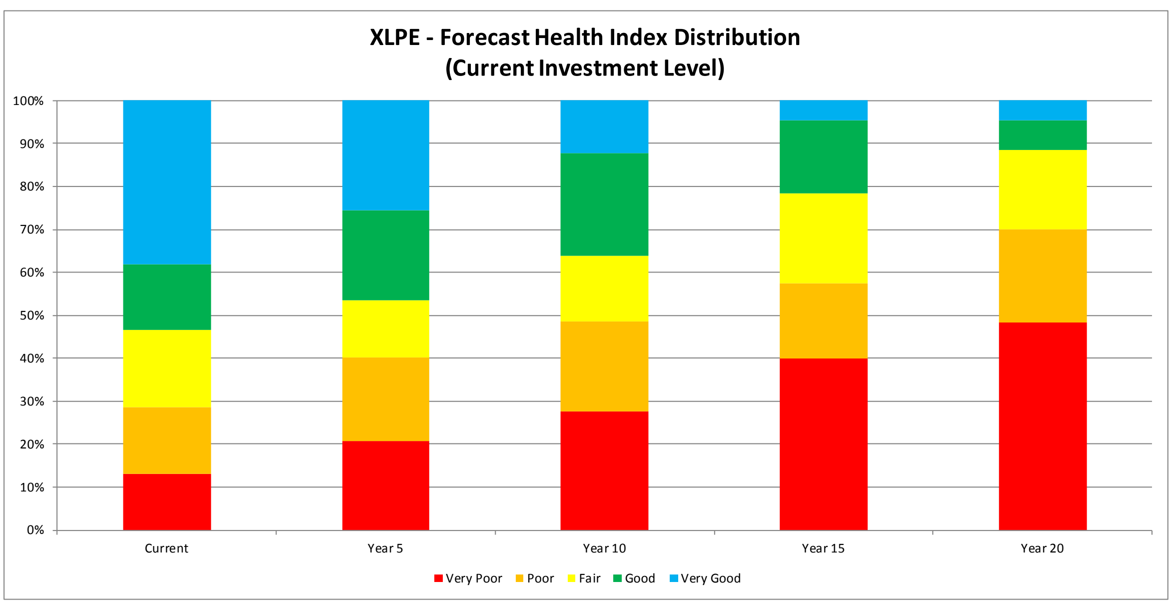

Figure 65 - XLPE Health Index Distribution Forecast at Current Investment Levels

Currently, 29% of primary XLPE cable has a Health Index of ‘very poor’ or ‘poor’. Underground distribution assets present the largest area of risk to the continued safe and reliable operation of Horizon Utilities’ distribution system. The XLPE asset group is the single asset group within the underground distribution assets with the largest investment requirement as identified by the Kinectrics ACA.

At the current investment level, the volume of assets with a Health Index of ‘poor’ or ‘very poor’ increases to 40% in 5 years, 49% in 10 years, 57% in 15 years and 70% in 20 years. Maintaining renewal investment at current levels is simply not sustainable. Reactive renewal of these assets would subject customers to an ever decreasing level of service and ultimately higher costs as reactive renewal of underground infrastructure is more costly than planned, proactive renewal. Service interruptions would involve prolonged outages affecting thousands of customers. At the forecast Health Index duration the failure rate, and resulting resources required to remedy could exceed Horizon Utilities’ capacity. Horizon Utilities cannot provide customers with continued, reliable service without a significant increase in underground renewal investment. Further justification for Horizon Utilities’ XLPE Renewal Program is provided in Section 3.5.3 below.

Both the Health Index (a measure of future risk) and System Reliability (the measure of current performance) indicate that underground cable, specifically XLPE primary cable, has a high volume of assets in poor health and is the cause of significant reliability issues. Failure to address the risk presented by this asset category will result in increased service interruptions, increased costs for repair under reactive replacement and is highly likely to result in a scenario where the cable fails at a rate higher than Horizon Utilities capability to repair and replace.

Further analysis, illustrated in Figure 66 below, demonstrates that the XLPE Plan and future XLPE programs should focus on the 13.8kV distribution system. This system has the largest total volume, and largest volume of ‘poor’ and ‘very poor’ XLPE primary cable.

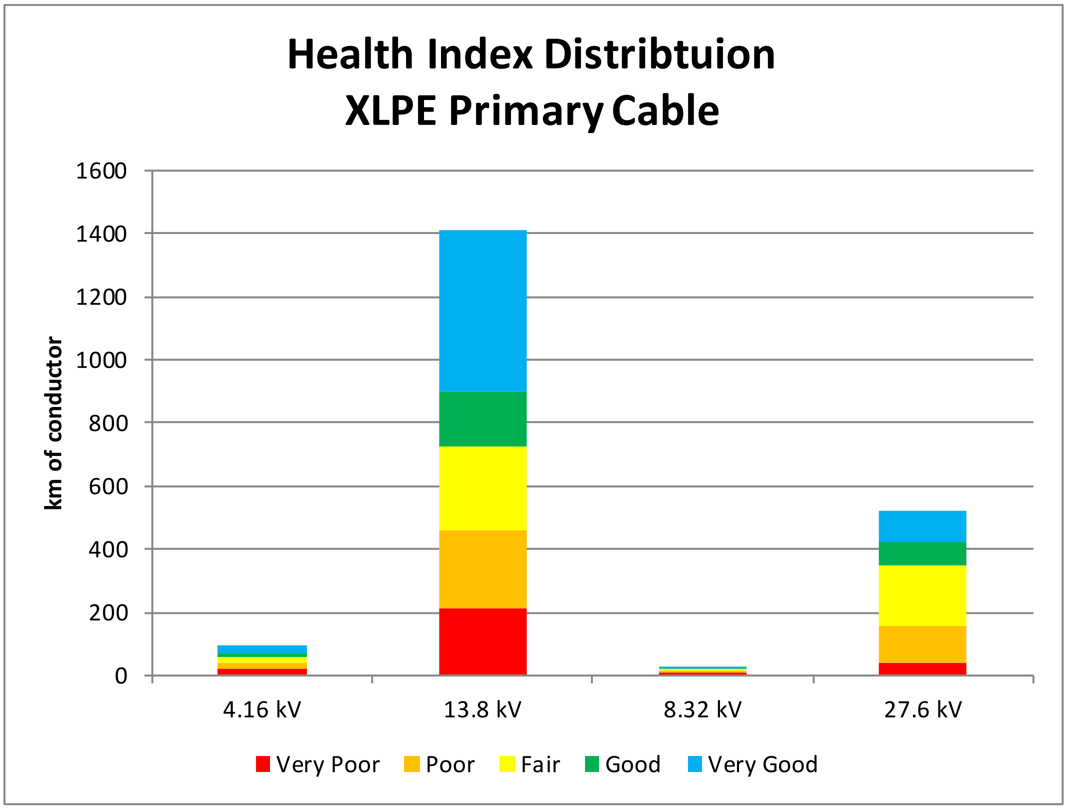

Figure 66 - XLPE Health Index Distribution by Voltage

The Hamilton Mountain and St. Catharines operating areas, both areas where the underground distribution system is primary operating at 13.8kV, have the highest volume of XLPE primary cable. The Stoney Creek operating area has the highest volume of XLPE primary cable operating at 27.6kV. The breakdown by operating area of XLPE primary cable is illustrated below in Figure 67. Further justification for Horizon Utilities' XLPE Renewal Program is provided in Section 3.5.3 and Appendix A.

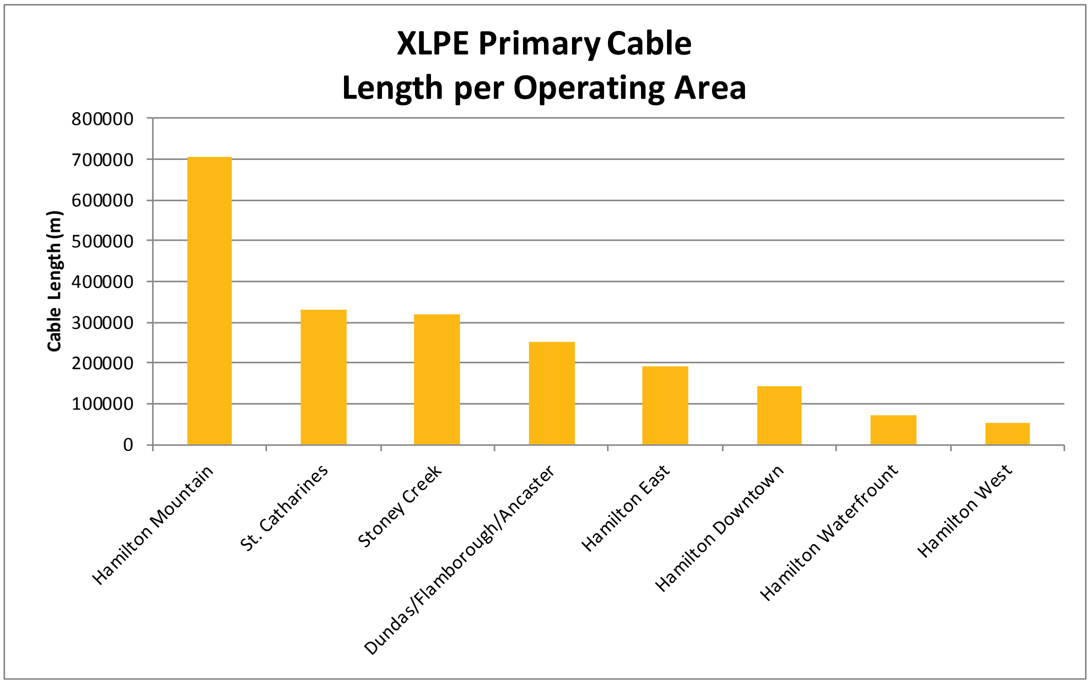

Figure 67 - XLPE Primary Cable per Operating Area

Neither the Health Index distribution nor reliability analysis indicates a need to proactively replace PILC cable at this point and renewal of this asset category will be limited to reactive replacement in the 2015 to 2019 timeframe. There are however many concerns with the continued use of PILC cable that is not directly related to end of life issues including:

- Environmental concerns relating to lead and oil;
- Limited availability of PILC and the risk of the sole North American manufacturer stopping production altogether;
- High cost of PILC cable, cable accessories and labour for splicing and terminating;
- Limited skilled tradesmen knowledgeable in splicing and maintaining this cable; and
- Worker health risk and precautions in handling of lead.

As illustrated below in Figure 68, the forecast PILC Health Index distribution starts to decrease in approximately 10 years. Horizon Utilities will need to increase investment in proactive replacement of PILC cable by that timeframe. PILC is the material used for station egress feeders and services Horizon Utilities large industrial customers. While the exact impact varies for each outage, generally a failure of a segment of PILC cable impacts a greater number of customers (over 500 customers), or impacts large industrial customers relative to a failure of a segment of XLPE cable.

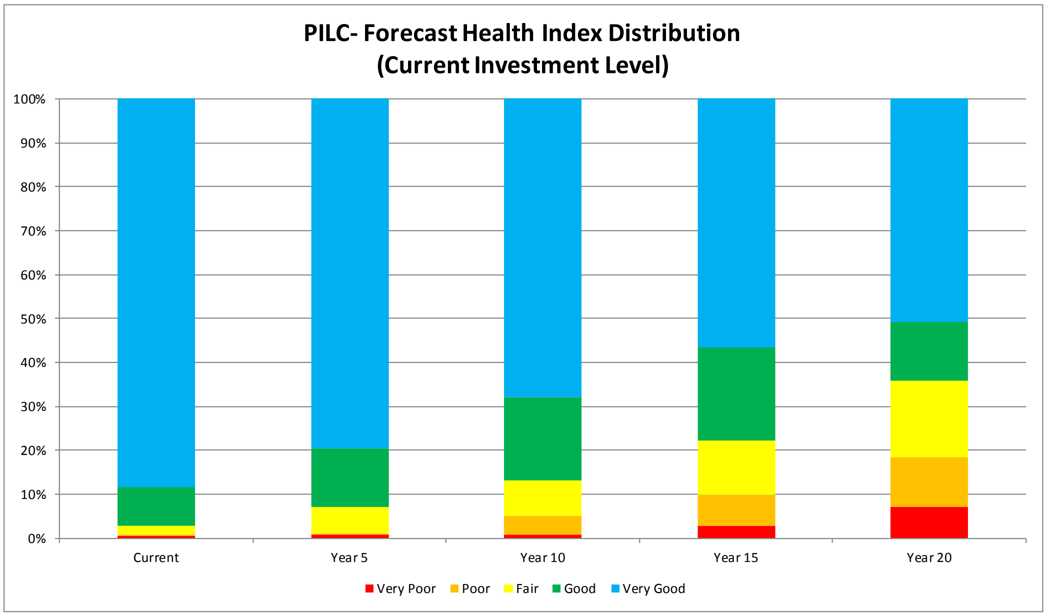

Figure 68 - PILC Forecasted Health Index Distribution at Current Investment Levels

Pad Mounted Switchgear

The age and Health Index distribution of pad mounted switchgear is provided below in Figure 69 and Figure 70.

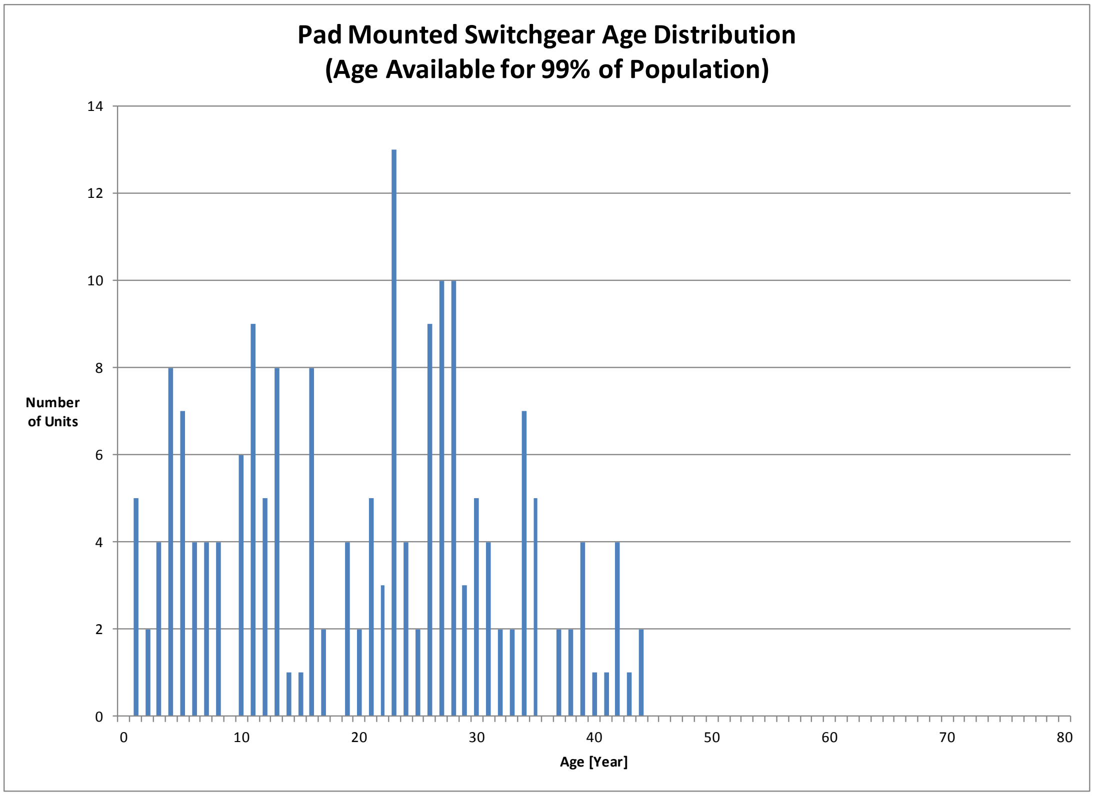

Figure 69 – Pad Mount Switchgear – Age Distribution

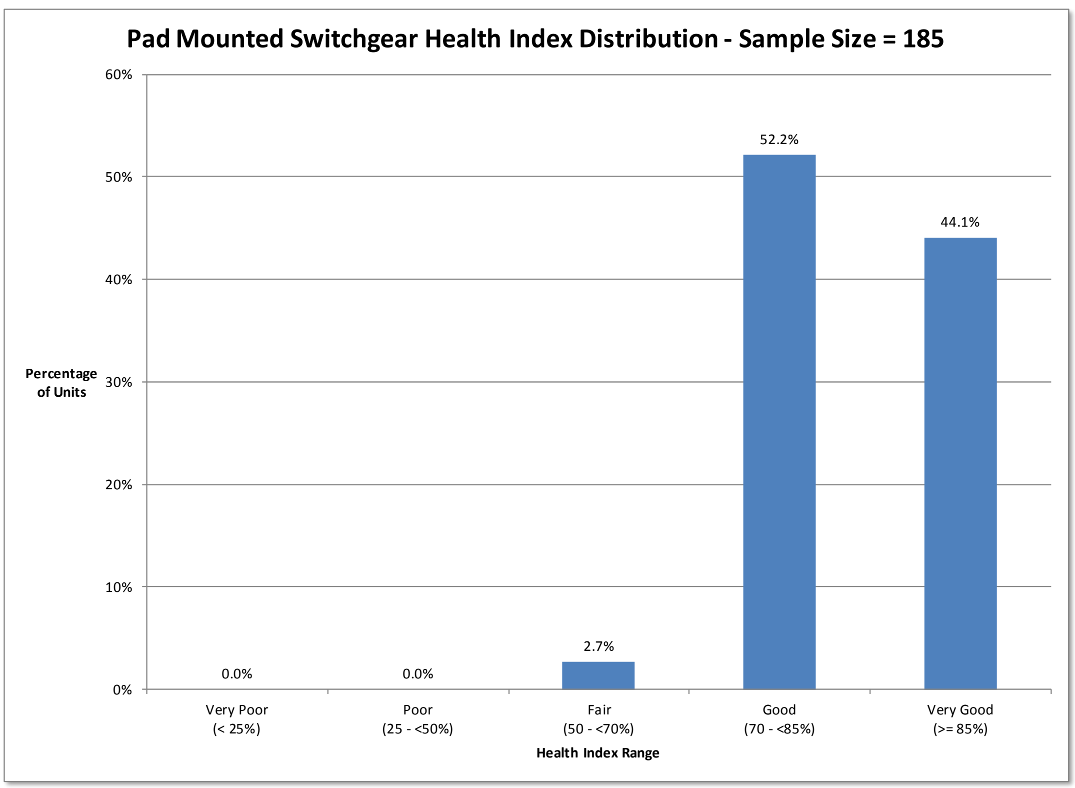

Figure 70 - Pad Mount Switchgear Health Index Distribution

Similar to overhead line switches, Horizon Utilities is moving to standardize on automated, remotely operated pad mounted switchgear. This technology provides many advantages over the older existing technology. Automated switches provide remote control (open/close), telemetry (voltage and current), and alarms (status, fault indication) to the System Control Room. This functionality allows quicker fault location identification, isolation of faulted feeder sections and faster restoration of service in outage scenarios. This technology can also interrupt fault current and therefore can be programmed to allow temporary faults to clear without interrupting the entire feeder by sectionalizing permanent faulted sections, without human intervention, thereby limiting the impact to a smaller number of customers.

<u>Vaults and Utility Chambers</u>

The age and Health Index distribution for vaults and utility chambers are provided below in Figure 71 to Figure 74.

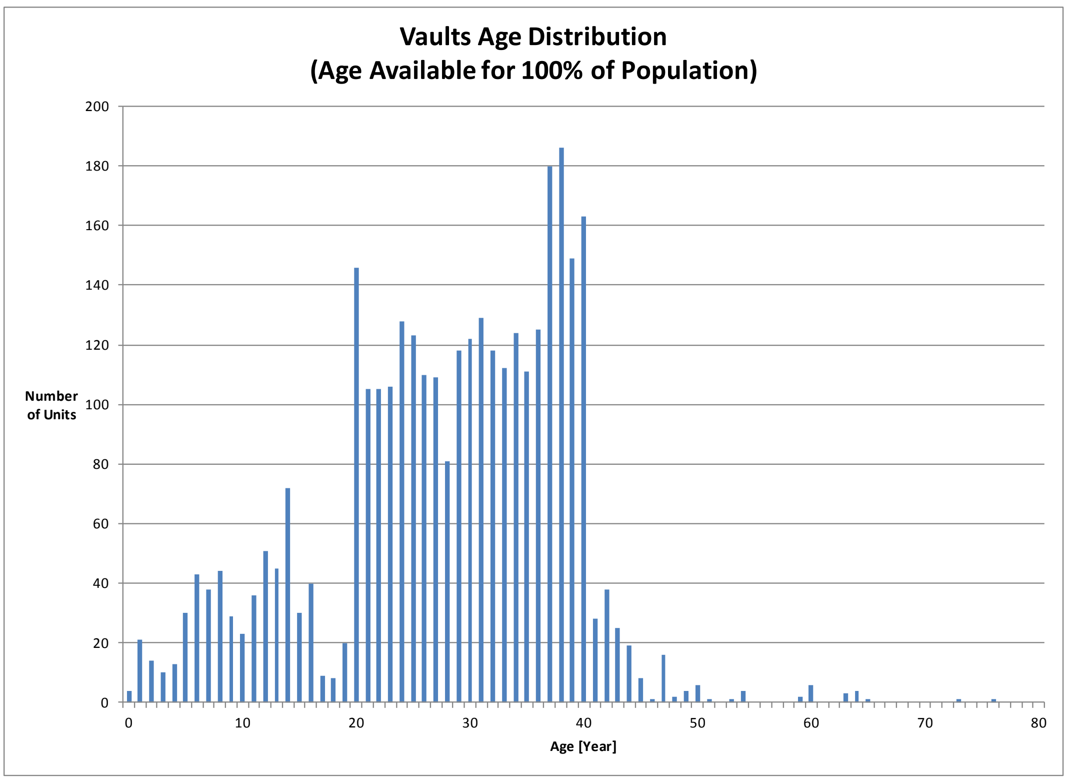

Figure 71 - Vault - Age Distribution

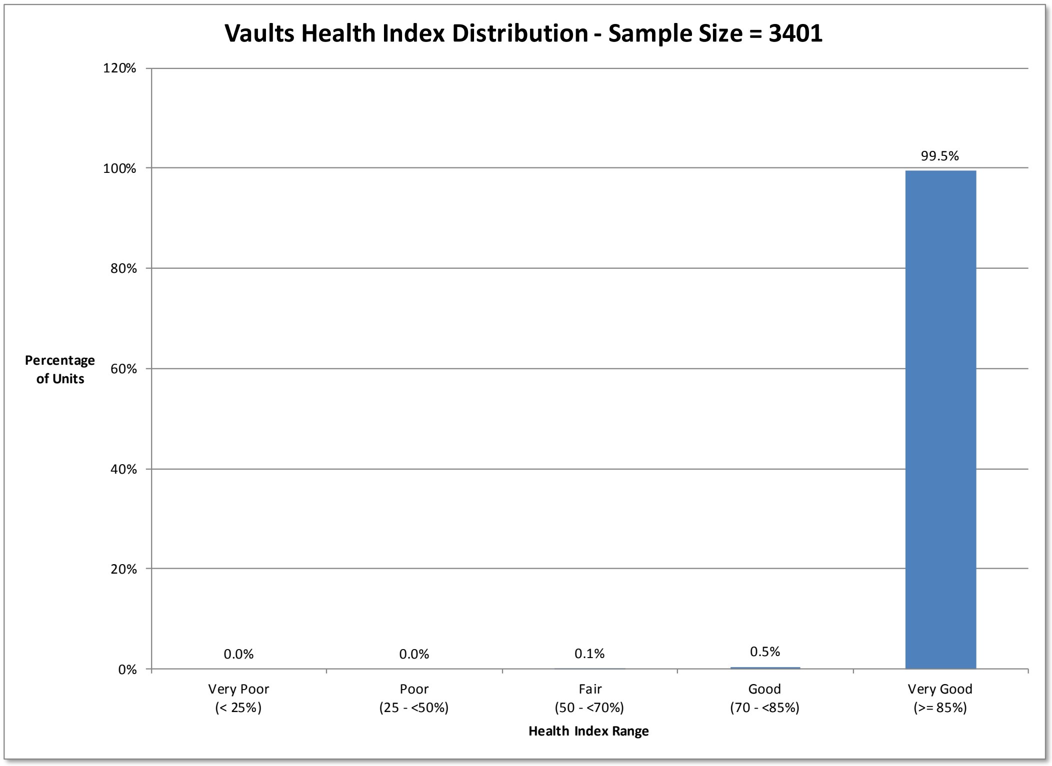

Figure 72 - Vault Health Index Distribution

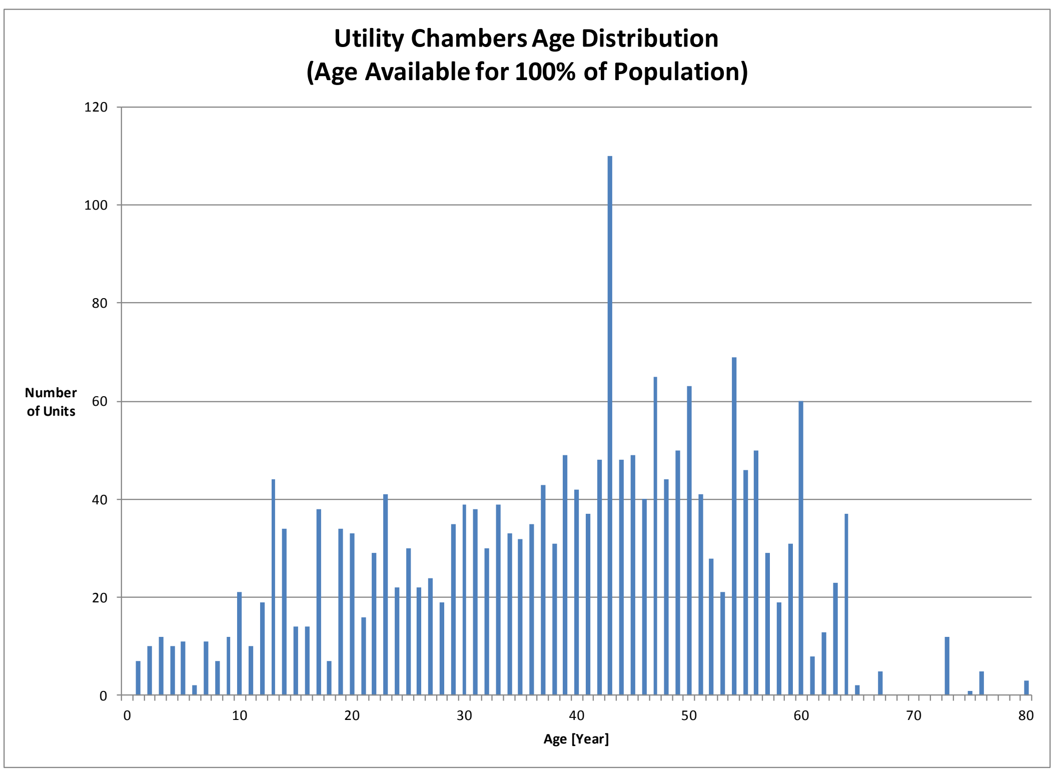

Figure 73 - Utility Chamber - Age Distribution

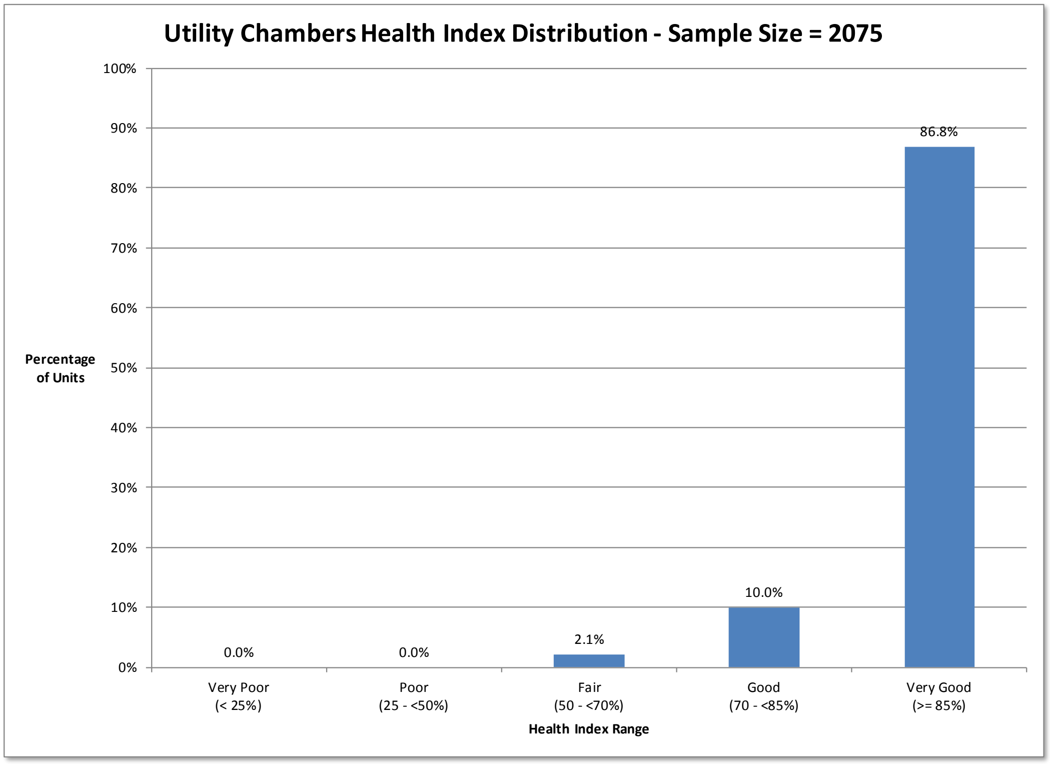

Figure 74 - Utility Chamber Health Index Distribution

Submersible Load Break Switches

As illustrated below in Figure 75 and Figure 76, a significant number of submersible load break switches have a Health Index of 'very poor' or 'poor' and this, combined with the failure rate of existing units, has led Horizon Utilities to develop a program for the proactive renewal of these assets.

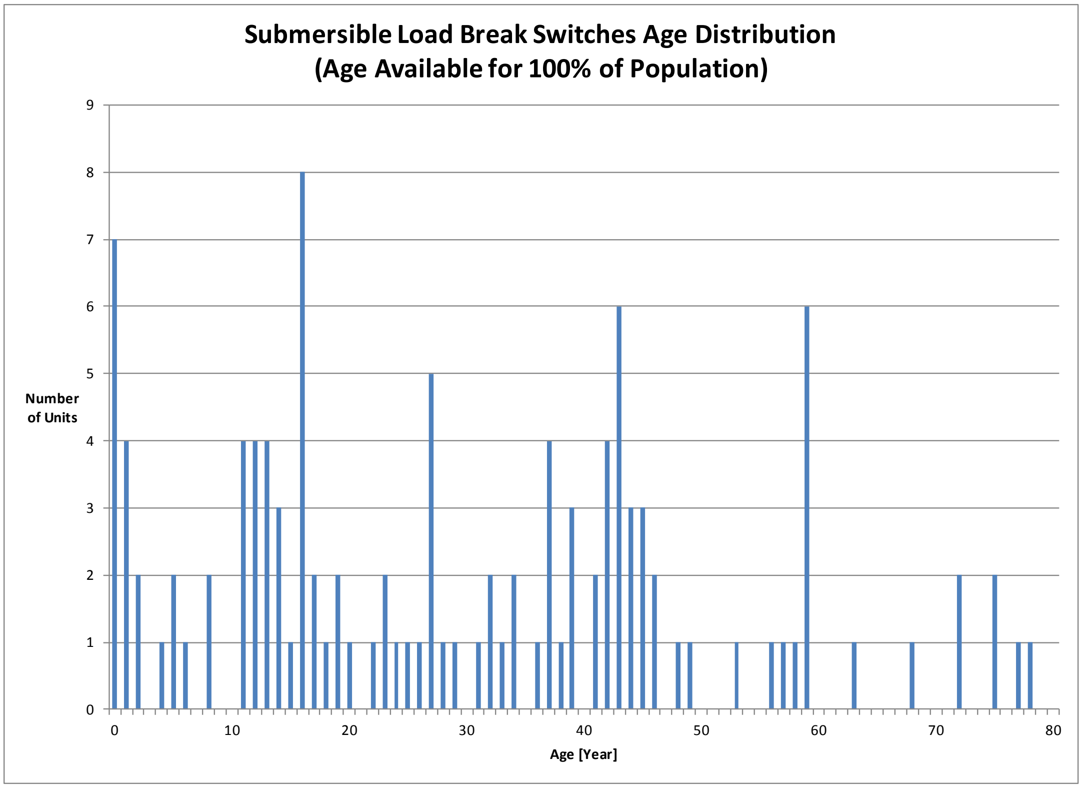

Figure 75 – Submersible Load Break – Age Distribution

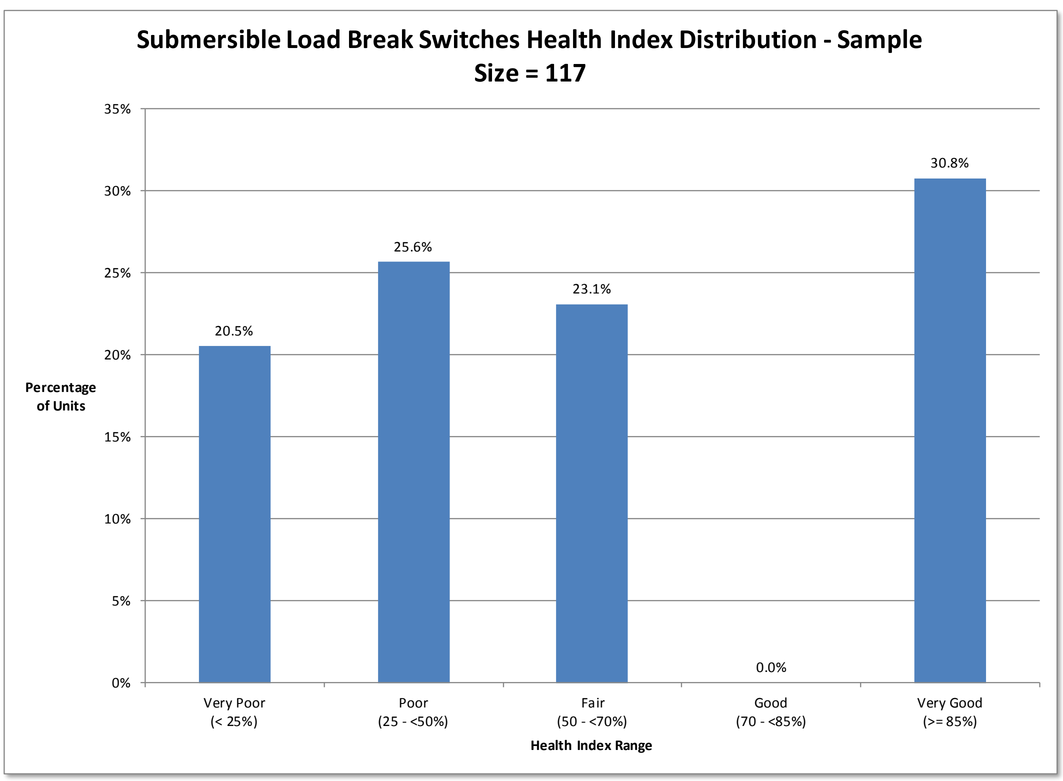

Figure 76 - Submersible Load Break Health Index Distribution

2.2.4. Information on General Plant Assets

Facilities

Horizon Utilities has five main buildings on four properties, comprised of two adjacent Head Office buildings and three Service Centres, as identified in Table 16 below. Horizon Utilities also has 28 substations, 23 of which are inside building enclosures in the cities of Hamilton and St. Catharines.

These buildings were constructed between 1914 and the early 1980s. The majority of the office space was largely as originally built prior to the renovations that commenced in 2012.

Location	Type	Vintage
John Street, Hamilton	Head Office	1950-1960
Hughson Street, Hamilton		1914
Nebo Road, Hamilton	Service Centre	1980
Vansickle Road, St. Catharines	Service Centre	1970
Hwy 8, Stoney Creek	Service Centre	1980

Table 16 - Vintage of Horizon Utilities' Main Buildings

Based on asset condition assessment studies, and with consideration for accommodating productivity within a growing workforce, significant renewal and refurbishment of buildings and related systems is required over the next several years as provided in this Application in order to sustain the office and operating environments and provide opportunity for productivity. Building infrastructure systems are at or nearing the end of their productive life, resulting in: inefficient equipment performance; increased risk of system failure; poor work environments for employees; and increased health and safety risks. Original floor layouts, building systems and structure do not meet the needs of the current workforce.

The buildings have not been renovated since their original construction and as such, the floor layout and design includes large offices and work areas which do not meet the needs of the current organization. This is creating a congested and unsafe work environment. Meeting rooms have been used as office space to house employees from the same function group, reducing the availability of meeting room space. Numerous workstations have been installed inside existing offices due to the lack of available open office space. The Space Study identifies opportunities to balance the space available to support the organization's current and future requirements by reducing congestion and creating appropriate work flows.

Horizon Utilities' buildings are comprised primarily of: office space; common areas that are available to all employees; and areas to support customer service, warehousing, fleet parking, and garage spaces.

The renovation projects allow Horizon Utilities to make more effective and efficient use of available space through:

- Rationalization of existing office spaces and creation of new office spaces to meet operational requirements;
- Creation of necessary common spaces, including meeting rooms, washrooms, and lunchrooms to accommodate the needs of 440 employees;
- Re-claiming under-utilized spaces; and
- Updating security to provide for controlled access to buildings and employees.

Horizon Utilities has taken a cost effective approach to refurbishment and renovations by maintaining the existing building footprint. The allocation of building space pre- and post-renovations is identified in Table 17, Table 18, and Table 19 below.

Description	Total	John Street	Hughson Street	Nebo Road	Vansickle Road	Hwy 8, Stoney Creek
Square Footage Consumed by Office Space [1]	33,663	24,728	1,740	3,373	3,494	328
Square Footage Consumed by Common Area [2]	66,597	38,172	660	11,387	8,606	7,772
Square Footage Allocated to Customers	2,900	2,700	0	0	200	0
Square Footage Allocated to Warehousing, Fleet, Parking and Garage [3]	154,200	24,900	2,400	73,500	35,100	18,300
Unusable Building Space [4]	4,500	0	4,500	0	0	0
Total Available Building Space	**261,860**	**90,500**	**9,300**	**88,260**	**47,400**	**26,400**
1. office space square footage excludes hallways, common areas, service areas, warehouses, garages and tenant space						
2. includes space utilized by all employees - e.g. hallways, meeting rooms, training rooms, lunch rooms, washrooms, first aid, lockers and showers, printing/photocopying						
3. includes Warehouse, Internal Parking & Fleet Shop Garage						
4. Unusable Building Space is a substation which will be converted into a meeting room						

Table 17 - Allocation of Building Space Prior to Renovations

Description	Prior to Renovations	Post Renovations	Net Change Decr/(Incr)
Square Footage Consumed by Office Space	33,663	26,968	6,695
Square Footage Consumed by Common Area	66,597	105,992	(39,395)
Square Footage Allocated to Customers	2,900	3,800	(900)
Square Footage Allocated to Warehousing, Fleet, Parking and Garage	154,200	125,100	29,100
Unusable Building Space	4,500	0	4,500
Total Usable Building Space	**261,860**	**261,860**	**0**

Table 18 - Summary of Building Space Allocation

Office Space

Horizon Utilities has developed standards for office space to ensure appropriate support of the operational needs of the business, which resulted in the necessary reallocation of space to common areas. Through the application of standards for office space, the average square footage per employee will decrease by 20 square feet as identified in Table 19 below. This will result in the reclamation of 6,695 square feet.

The number of employees indicated in Table 19 below represents employees who require office space on a regular basis, and therefore excludes field employees.

	Prior to Renovation			Post Renovation		
Location	Total Office Space Footage [1]	Number of Employees [2]	Average Square Footage per Employee	Total Office Space Footage [1]	Number of Employees [2]	Average Square Footage per Employee
John Street, Hamilton Hughson Street, Hamilton	26,468	244	108	20,988	244	86
Nebo Road, Hamilton	3,373	39	86	2,652	39	68
Vansickle Road, St. Catharines	3,494	51	69	3,096	51	61
Hwy 8, Stoney Creek	328	3	109	232	3	77
Total	**33,663**	**337**	**100**	**26,968**	**337**	**80**

1. office space square footage excludes common areas, service areas, warehouses, garages and tenant space
2. number of employees as at December 31, 2013, including contract staff and students; exclusive of field staff who do not require dedicated office space

Table 19 - Office Space Allocation per Employee

Common Areas

Horizon Utilities defines common areas as any space that may be utilized by all or a group of employees. The Office Space Study confirmed that common space resources were insufficient to support the Horizon Utilities workforce, and to meet existing Ontario Building Code ("OBC") regulations.

Post renovation will allow for the addition of 39,395 square feet of common space, reclaimed from warehouse, mechanical rooms, storage rooms, loading docks and office space, and consisting primarily of:

- Meeting rooms at the Head Office, Stoney Creek, Nebo Road, Vansickle Road, and Hughson Street locations;
- Dedicated training rooms located at the Head Office and Vansickle Road Service Centre locations;

- One lunch room or kitchenette per floor or building;
- One washroom for each gender per floor or building as per OBC;
- Locker and shower facilities at four of the buildings;
- Printing and photo-copying areas;
- A dedicated First Aid area at the Head Office location;
- Three Prayer/Meditation rooms, one located at Head Office, one located at the Vansickle Road Service Centre and one located at the Nebo Road Service Centre;
- Computing and data centres at the Head Office location and Vansickle Road Service Centre; and
- Hallways.

Customer Lobbies:

Horizon Utilities has dedicated lobbies for customer support where customers may submit customer service inquiries, meet with staff, or access their account information. The lobbies also serve as security checkpoints for the buildings and employees. Horizon Utilities will have customer support areas at the Vansickle Road and Nebo Road Service Centres and Head Office, totalling 3,800 square feet post renovation.

Warehousing, Fleet Parking, and Garage spaces:

Horizon Utilities' buildings are situated on four properties that are located at key vantage points across its service territory. The utilization of each as a service centre for field staff reduces the travel time of work crews to job sites as compared to a single operation centre.

The Nebo Road, Stoney Creek and Vansickle Road Service Centres have internal parking facilities which house approximately 70% of the vehicles and associated equipment in the Horizon Utilities fleet. Warehousing of inventory is primarily managed from the Nebo Road and Vansickle Road Service Centres with inventory staging areas located at Head Office and the Stoney Creek Service Centre. Maintenance of the Horizon Utilities fleet is performed in the garages of the Nebo Road and Vansickle Road Service Centres.

As a result of the planned renovations, warehousing, fleet parking and garage space, mechanical rooms, and storage room space will decrease by 29,100 square feet to 125,100 square feet as identified in the Table 20 below. This is possible through reductions of inventory levels, re-organization of inventory items and replacement of HVAC units with smaller more energy efficient units. Post renovation, project inventory staging will be primarily performed at the Stoney Creek Service Centre.

Location	Warehouse Square Footage	Inventory Items [1]	Internal Parking Garage Square Footage	Vehicles Inventory	Fleet Shop Garage Square Footage	Total Square Footage
John St. & Hughson St.	1,500	200	17,576	24	N/A	**19,300**
Nebo Road	22,600	1,661	24,666	73	6,500	**55,500**
Vansickle Road	14,503	1,460	13,200	37	2,800	**32,000**
Stoney Creek	5,500	710	12,080	10	N/A	**18,300**
Total	**44,103**	**4,031**	**67,522**	**144**	**9,300**	**125,100**

1. inventory items include bolts and nuts, switches, transformers and wire reels

Table 20 - Building Operational Expenditures 2011 - 2013

Overall expenditures for the maintenance and operations of the Horizon Utilities' buildings are increasing year-over-year as indicated in Table 21 below.

	2011 Actual	2012 Actual	2013 Actual
Building Equipment Repairs and Maintenance	$ 89,321	$ 69,668	$ 11,388
Building Utilities	$ 745,804	$ 720,988	$ 848,373
Building Repairs and Maintenance	$ 257,633	$ 569,104	$ 735,761
HVAC Maintenance	$ 63,402	$ 23,965	$ 86,850
Janitorial and Landscaping Service	$ 224,854	$ 226,431	$ 124,785
Building Security Service	$ 144,067	$ 149,024	$ 134,444
Building Maintenance Service Agreements	$ 340,864	$ 380,518	$ 559,934
Total	**$ 1,865,945**	**$ 2,139,698**	**$ 2,501,535**

Table 21 - Building Operational Expenditures 2011 - 2013

The increased expenditures are due to:

- increased maintenance on end-of-life systems;
- required structural repairs; and
- additional expense to procure replacement parts for obsolete systems.

As identified in Section 2.1.2 above, proper asset management principles were required to develop and guide the long-term building investment plan. The observations and recommendations from the completed studies are provided in Section 3.5.3 below.

2.2.5. Assessment of Existing System Capability (5.3.2.d)

The assessment of Horizon Utilities' distribution system assets and available capacity do not generally reveal a need for extensive investment to increase system capacity. Nebo TS, servicing the Stoney Creek mountain area, is the primary area requiring investment. This TS has exceeded the 10 day LTR[11] in recent years but this capacity constraint was recently relieved through the Hydro One construction project to increase capacity at the TS which was completed in 2013. Horizon Utilities' remaining investment for this service area involves the installation of a new egress feeder to access the capacity provided by the upgrade.

The Hamilton Mountain area is the next highest area of concern. The stations servicing this area are nearing their 10 day LTR and Horizon Utilities forecasts a need to increase the capacity of a station in this area in the 2019 to 2020 timeframe. Load growth in this area is comprised of small infill development of previously undeveloped areas. The investment drivers to address this for each asset group are provided below.

Investment Strategy

Substation Switchgear

No further investment in Substation switchgear replacements is forecast from 2015 through 2019. The risk of failure posed by existing units with a poor Health Index is expected to be managed through increased maintenance and inspection.

Transformers

The Kinectrics ACA identified a significant volume of overhead and vault transformers having a Health Index of Very Poor or Poor signifying a need to invest in transformer replacement (Figure 49 and Figure 53 above).

Horizon Utilities has adopted a 'run to failure' position for most distribution transformers to harvest the maximum amount of value for customers by ensuring that the maximum lifespans are realized from these assets and due to the lower customer impact upon failure. However,

[11] The capacity of a Hydro One transformer at a TS is determined by its ability to safely withstand a certain loading level for 10 continuous days without a perceptible impact in the expected life of the transformer. This is termed the "10 day long term rating" (10 day LTR). Loading a TS transformer above this 10 day LTR design limit will shorten its useful life expectancy. The 10 day LTR ratings are monitored closely and not exceeding this limit for any appreciable time limit is strictly desirable.

there are exceptions to this where distribution transformers are proactively replaced. Distribution transformers are replaced through identification via the maintenance and inspection programs; typically due to transformer rusting or oil leaks. A number of transformers are also replaced annually through the 4kV and 8kV Renewal Program and the XLPE Program. Vault transformers are replaced with padmount transformers when identified through maintenance and inspection programs and where reasonable to do so. Vault transformers are also replaced when required due to space and operational (i.e. safety) requirements and in conjunction with underground cable replacement programs.

Conductor Wire

The 4kV distribution system accounts for 40km of the 48km total of overhead conductor having a Health Index of 'very poor' (Figure 55 above). Horizon Utilities has two programs that incorporate the renewal of overhead conductor. The majority of conductor is renewed through the 4kV and 8kV Renewal Program; while a small volume of conductor is replaced through the #6 wire replacement program. The ACA provides validation that at present focusing on the 4kV system within overhead renewal is a prudent decision.

Switches

Investment in this asset category is accomplished through two means. The inspection and maintenance performed annually in the load break switch maintenance program identifies a number of switches beyond economic repair that require replacement. Commencing in 2015, automated, remotely operated reclosures will be used to replace the existing switches when replacement is required.

In select strategic locations, existing load break switches will be proactively replaced with automated switches, with reclosing capability, to proactively improve reliability of the distribution feeders.

Wood Poles

Wood pole renewal is accomplished through a number of projects and programs. The primary method for renewal is via the 4kV and 8kV Renewal Program. The execution of these projects will renew the entire 4kV and 8kV distribution systems; generally Horizon Utilities' oldest overhead distribution assets.

The criticality of wood poles, combined with the varying rate at which these assets decay, have led to the utility best practice of proactively testing wood poles. The pole residual testing program ("Pole Test") inspects and evaluates the structural integrity of wood poles through non-destructive testing procedures. Wood poles failing to meet the minimum standards are either replaced immediately or through the annual planned replacement program depending upon the test results.

Renewal of wood poles can also result from Customer Access projects where relocation of assets for roadway reconstruction is required.

Reactive renewal of wood poles is required annually in addition to the proactive replacement programs. Reactive replacements are generated from a number of causes including vehicle accidents, storm damage, structural failure, and tree damage.

Proactive replacement is preferred over reactive replacement as the overall cost is lower and ultimately provides the greatest benefit to the customer.

Concrete Poles

Concrete pole renewal is accomplished through a number of projects and programs. The primary method for renewal is via the 4kV and 8kV Renewal Program. The execution of these projects will renew the entire 4kV and 8kV distribution systems; generally Horizon Utilities' oldest assets.

XLPE

Renewal of underground primary cable will be completed through a number of programs.

Horizon Utilities is proposing to increase the investment directed at XLPE primary cable renewal programs. This program is further detailed in the Section 3.1.2 below.

PILC renewal will be performed reactively in the 2015 to 2019 planning cycle.

Renewal of XLPE and PILC on the 4kV and 8kV distribution systems will be proactively accomplished through the execution of the 4kV and 8kV Renewal Program.

Padmount

The Health Index distribution of pad mounted switchgear does not present a high level of risk to system operations and Horizon Utilities has not experienced a significant level of failures of this asset class. For these reasons, although the consequence of failure is high, Horizon Utilities has not invested materially in proactive replacement of these assets. Renewal investment for these assets is primarily reactive with the following exceptions:

- Replacement of units identified through inspection and maintenance activities. Replacement in this scenario is typically required for safety reasons due to the switch enclosure becoming compromised allowing access to live electrical components; and
- Pad mounted switchgear in strategic locations will be proactively replaced to allow for earlier identification and restoration of service, especially in outages caused by adverse weather.

Vaults and Chambers

Utility chambers and vaults have some of the longest lifespans of Horizon Utilities' distribution assets. Horizon Utilities engaged Kinectrics to perform a civil assessment on these assets in 2010 and the results of this assessment identified several manholes requiring repair. Location, especially in roadways with a high volume of traffic flow, is a higher contributor to degradation of the asset than age alone. Typically the roof of the chamber or vault degrades prior to the remainder of the asset. Horizon Utilities has planned to systematically replace the roofs of the worst rated manholes proactively to avoid a potentially catastrophic failure. This is an ongoing program.

Submersible Vaults

Submersible load break failures have a high customer impact and present a safety hazard to Horizon Utilities' staff that operates these devices due to the catastrophic nature of their failure. Failures to date have been limited to the older, 200A oil insulated switches and Horizon Utilities has established a program to replace these older units with 600A, SF6 insulated switches. The units with the highest risk of failure were replaced in 2012.

2.3. Asset Lifecycle Optimization Policies and Practice (5.3.3)

2.3.1. Asset Lifecycle Optimization (5.3.3.a)

Asset lifecycle optimization is achieved through Horizon Utilities' asset management programs which utilizes a data driven approach to optimize replacement strategies based on asset condition, risk, and life cycle management.

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

Regular review of maintenance programs, load forecasts, asset age and condition, equipment failures, and distribution system performance assist in the on-going prioritization of infrastructure investments in the short and long term.

Horizon Utilities operates with four broad approaches to managing assets:

- proactive replacement;
- reactive replacement;
- refurbishment; and
- maintenance.

Proactive Replacement

Proactive replacement strategies are typically deployed where the impact of failure can be significant in terms of public or employee safety, cost, system reliability, and customer service, or there is a regulatory or environmental driver. Proactive replacement of assets are planned and implemented through the execution of Horizon Utilities capital investment programs, detailed in Section 3.1.3. The capital investment programs provide a multi-year outline for renewal investments from which the specific projects are identified, developed and prioritized. The prioritization process allows for the ranking of projects for determination of the list of projects for inclusion in the annual budget. Project selection and prioritization to align with approved budget amounts is further detailed in Section 3.2.3.

For some LDCs, large portions of the distribution system may be obsolete and proactive conversion to more modern facilities, rather than refurbishment, improves reliability, maintainability, reduces maintenance costs associated with legacy assets, and offers conservation benefits from reduced system line losses. Such is the case for 4kV distribution at Horizon Utilities which is being proactively converted to 13.8kV distribution.

Underground XLPE cable is another example of an asset that is replaced on a proactive basis. Excavation, directional boring, and replacement of ducts and cables is a lengthy and expensive process, requiring considerable lead time and coordination with other stakeholders including the municipality and affected customers.

Reactive Replacement

Reactive replacement strategies include assets where unplanned failures represent a low risk to: public or employee safety; significant restoration cost, system reliability, and customer service. Replacement parts are readily available, generally small numbers of customers are impacted, and restoration is relatively quick and straightforward. For example, overhead and underground transformers typically service up to fourteen customers and replacement transformers are readily available in inventory. A "run to failure" or reactive replacement strategy for transformers is considered an asset management leading practice.

Reactive replacement can be more expensive than proactive replacement for some categories of assets. The timing of reactive replacements is outside the control of the utility and requires compensation of trades employees at overtime and premium rates when performed outside of normal business hours. Reactive replacements also do not provide for proper planning and scheduling and therefore the time required to coordinate and execute the replacement is longer than for an equivalent planned, proactive replacement. The extended duration of restoration increases costs and impact to customers. Underground primary cable failures, for example, result in: unplanned disruptions for customers; impact reliability to unacceptable levels in some cases; and cost up to three times more than proactive replacements.

Table 22 below summarizes the Asset Categories and replacement strategies for each.

Asset		Sub-Category	Primary Replacement Strategy	Secondary Replacement Strategy
Substation Transformers		-	Proactive	Reactive
Substation Circuit Breakers		-	Proactive	Reactive
Substation Switchgear		-	Proactive	Reactive
Pole Mounted Transformers		-	Reactive	Proactive
Overhead Conductors		Primary	Proactive	Reactive
		Secondary	Reactive	Proactive
		Service	Reactive	Proactive
Overhead Line Switches		-	Reactive	Proactive
Wood Poles		-	Proactive	Reactive
Concrete Poles		-	Reactive	Proactive
Underground Cables	XLPE	Primary	Proactive	Reactive
	PILC		Reactive	
	DB	Secondary	Reactive	Proactive
	ID		Reactive	Proactive
	DB	Service	Reactive	Proactive
	ID		Reactive	Proactive
Pad Mounted Transformers		-	Reactive	Proactive
Pad Mounted Switchgear		-	Reactive	
Vault Transformers		-	Reactive	Proactive
Utility Chambers		-	Reactive	
Vaults		-	Reactive	
Submersible LBD Switches		-	Reactive	Proactive

Table 22 - Asset Categories Replacement Strategy

Refurbishment

Replacement vs. Refurbishment Policies

Refurbishment of an asset to extend its useful life may be an alternative option to asset replacement and is considered within asset renewal decisions. The following factors are considered in evaluating this option:

- Obsolescence;

- Regulatory requirements;
- Rating limitations due to system additions, such as new load customers and distributed generation ("DG");
- Rating limitations due to the growth of existing loads; and
- Integration with system expansion.

Refurbishment of aged XLPE cable by cable injection has been used in a number of countries, including the USA and Europe, but has not been widely used in Ontario. Generally, the following represent barriers to effective refurbishment of XLPE cable in the distribution system: access to the cable; the presence of cable accessories that block the flow of injection fluids;; and customer impacts from lengthy interruptions due to worksite preparations.

In Horizon Utilities' case, most of the XLPE requiring replacement is either: i) associated with other legacy assets such as submersible transformers, which are also being replaced as part of proposed projects; or ii) is non-jacketed cable with compromised concentric neutrals in very poor condition and not a candidate for cable injection. For these reasons, Horizon Utilities is not considering cable injection as an alternative to replacement of its XLPE cable at this time.

As described above in Section 2.2.2, a number of substations were refurbished in 2012 and 2013 with new doors, relays, and breakers. Refurbishment investments of this type extend the useful life of the substation and are an economic alternative to switchgear replacements.

Substation Refurbishment

In 2010, a Station Asset Condition Assessment ("SACA") was performed which identified the need to invest in relatively old substation infrastructure. As a result, Horizon Utilities invested in the refurbishment of many 4kV substation assets.

The optimal replacement strategy was determined based upon this study with the following results:

- Re-prioritized the 4kV and 8kV Renewal Program. Timing for the conversion of some stations was adjusted in the schedule according to the criticality of the condition of station assets and the distribution assets. This new information on stations allowed for effective re-prioritization of work.

- A full switchgear replacement was performed at Parkdale Substation. This station is forecast to be in service at least until 2047 and the switchgear received a very low health score (two of four switchgear units at the station scored a 39%) . A full switchgear replacement ensured that Horizon Utilities will utilize this asset to its full potential. Other maintenance strategies were used on other station switchgear where just breakers were renewed.

- Substation assets (breakers/relays/transformers) at various stations were replaced/refurbished and prioritized based on stations that would remain in service the longest.

- When breakers were replaced, old breakers were returned to inventory to harvest and maintain parts that are obsolete (difficult to source) so that remaining vintage breakers of a similar type can be maintained for stations that are planned to be decommissioned in the short term.

- For station transformers, Horizon Utilities implemented a replacement strategy where two new and four refurbished transformers were used to replace transformers that were in very poor condition. This reduced the risk significantly by providing much needed spare transformers. Refurbished transformers offer an increased Return on Investment ("ROI") as refurbishment generally cost one-half of a new transformer. When overhead line switches require replacement, the old units, where possible, are harvested for parts for use in the future maintenance of the remaining units. This has allowed for in service units to be refurbished rather than replaced with a new unit.

<u>Load Break Switch Maintenance</u>

Each year, about 20% of overhead load break switches are subject to regularly planned maintenance and refurbishment. A preliminary visual inspection of the top portion of the pole and all attached equipment is performed as a first step in this process. This inspection includes a condition assessment of the pole, cross arms, insulators, pins, conductor, tie wires and braces. Any fiberglass rods used for clearance purposes are inspected to identify any deterioration due to ultra violet ("UV") rays. Examination for evidence of surface tracking is performed at the joints where the fiberglass meets the metal, as well as on the pole and cross arms at bolts or lag screws.

All switches targeted for maintenance will be maintained based on manufacturer instructions for specific switches. All normally closed switches will also have thermal scanning completed pre- and post- maintenance. The pre-maintenance thermal inspection will be reviewed before work begins to determine any apparent safety concern. The post-maintenance thermal inspection will also be reviewed to ensure that the maintenance was completed properly. Both images are reviewed by a supervisor and authorized prior to recording the switch as having been maintained.

Maintenance

Overview

Horizon Utilities' planned maintenance programs are primarily cyclical in nature. Planned maintenance and inspection expenditures are generally not influenced by capital investments. Unplanned maintenance expenditures, specifically reactive expenditures required to address equipment failures and service interruptions have increased proportionally with the increased level of service interruptions. Horizon Utilities' capital investments will address the decreasing reliability levels but it will take multiple years before material reductions in maintenance expenditures are realized. Renewal investments are initially below Kinectrics' recommended levels and the backlog of assets requiring renewal will continue to increase in the short term. Improved reliability resulting in a consistent, year over year, reduction in reactive maintenance expenditures will not be realized in the 2015 to 2019 Test Years.

Maintenance activities are divided into four categories; predictive, preventive, proactive, and corrective.

Predictive Maintenance

Predictive maintenance includes testing for potential failures so that action can be taken to prevent a failure or to avoid the consequences of a failure.

Preventive Maintenance

Preventive maintenance includes regularly scheduled programs conducted to service network components. These proactive programs are normally deployed at specific time intervals and are applied to network components regardless of their apparent condition at the time. They are conducted to prevent network components from failing.

Corrective Maintenance

Corrective maintenance includes the replacement of defective components, hardware, poles, lines, transformers and any other distribution assets found to be inoperable, failing, or have already failed.

Horizon Utilities uses its qualified tradespeople to perform visual inspections on all of its overhead, underground and substation assets. Inspection results are recorded in the Distribution Assets Reporting Tool ("D.A.R.T") and assessed as either "urgent", "timely", or "standard". Urgent repairs are either completed at the time of the inspection, or scheduled as soon after as practicable. Timely repairs are scheduled into the current year program, and standard repairs can be scheduled into the following year program.

Effective asset maintenance reduces unplanned outages by identifying and correcting deteriorating plant before a failure occurs while maximizing related equipment life span. It also contributes to improving reliability of service.

Age is a factor indicative of asset deterioration. However, condition assessments and analysis of field data are at the core of any leading Asset Management plan. Maintenance programs provide additional data to form a complete asset condition assessment. Horizon Utilities' contracted or in-house condition assessment programs target assets on a regular and as-needed basis to ensure the best information is utilized when performing capital planning.

The value of maintenance programs can be justified through: reduction in the frequency of unplanned outages; maximizing the equipment lifespan and value; and offering better service reliability.

Horizon Utilities has established maintenance programs for most of its assets on a cycle-basis, and each year it reviews asset performance to determine if the frequency of inspection and maintenance remains appropriate. The frequency of corrective maintenance on asset types, or equipment from a particular supplier, informs the capital plan, and allows Horizon Utilities to engage manufacturers for product solutions.

Maintenance Programs

Horizon Utilities' planned maintenance programs are described in the Construction and Maintenance Services overview in Exhibit 4, Tab 3, Schedule 2, and are summarized below.

Predictive Maintenance

Predictive maintenance includes:

- wood pole density testing by means of ultra-sonic equipment (referred to as "sounding") or wood core sampling;
- thermographic inspection to detect over-loaded components ("hot-spots");
- visual plant inspections; and,
- transformer oil analysis, power factor testing, partial discharge testing, vibro-acoustic testing, and internal battery resistance testing of substation equipment.

Residual Wood Pole Testing

Horizon Utilities performs residual wood pole testing each year. All poles are tested over a seven year period to determine asset condition as the pole ages. All poles requiring replacement within the subsequent five years will be replaced through an ongoing pole replacement program. Residual wood pole testing is considered a 'predictive' activity as it is used to anticipate whether a pole will fail within the next five years. In 2014, an estimated 6,000 wood poles will be tested in Hamilton and St. Catharines.

The Pole Test comprises inspection and evaluation of the structural integrity of wood poles through non-destructive testing procedures. A visual inspection of a pole will identify defects such as cracks, split tops, lightning strikes, shrinkage, discoloration, and pole feathering towards the top of the pole. Any defects found are recorded within a pole inspection report. Non-destructive tests follow visual inspection which comprise: ultra-sonic testing of pole strength at different heights to identify weak points at various pole heights.; recording strength readings at identified weak points; checking for decay below the ground line; and visually inspecting for any signs of surface decay or mechanical damage.

The final Pole Test report will contain the pole strength value (measured in percent strength remaining), specific characteristics about the pole (pole species and the type of treatment applied to the pole), as well as the overall mechanical and structural condition of the pole. Based upon these findings, the report also contains final recommendations concerning a particular pole asset.

Overhead and Underground Thermography Scanning

Each year, one-third of Horizon Utilities' overhead and underground distribution plant is scanned using thermography imaging technology. This scanning reveals temperature variances caused by excessive heat within distribution system plant which can indicate an overloading issue, a bad connection, or overheated equipment.

When components are inspected using the thermography equipment, the scanned temperature variation, compared to a particular reference point, will be used in determining the course of action as illustrated in Table 23[12]:

Temperature Rise	Impact
1 – 10 ºC	Possible deficiency – warrants investigation
11 – 20 ºC	Indicates probable deficiency – repair when time permits
21 – 40 ºC	Monitor continuously until corrective measures can be performed
> 40 ºC	Major discrepancy – repair immediately

Table 23 - Temperature Impact

These reference temperatures will vary based upon: type of asset; ambient temperature; and loading conditions on the particular asset. Should any of the preceding conditions (overloading, poor connection, or overheated equipment) be identified, these components will be flagged as assets requiring corrective action under this program.

Once an area of concern has been identified, the thermography inspector will take a thermographic picture of the area as well as a standard real life image from the same location, with date and time stamps indicated on the prints. The inspector will proceed to identify and flag the areas of concern on the image using a specialized thermography software package. These images will be included within a Thermography Report, which may also contain the following information:

[12] These reference temperatures are based upon N.E.T.A. Maintenance Testing Specifications for Electrical Equipment, developed by the International Electrical Testing Association.

- Inspection site information;
- Exact location of temperature variances;
- Description of the components and an assessment of the severity;
- Work recommendation;
- Degrees above ambient temperature;
- Potential hazards and physical conditions of the surroundings; and
- Date and time.

Thermography scanning and resulting load tests are considered ‘predictive’ activities as they are used to predict which assets will require repairs, upgrading, or replacement. Although all assets are scanned within the predetermined geographical area, only assets requiring attention are reported.

Visual Plant Inspections

Each year, one-third of the overhead and underground plant is visually inspected (the same one-third of the distribution plant that is subject to thermography scanning) and recorded in the Distribution Assets Reporting Tool (“D.A.R.T”). The visual plant inspection program is a series of detailed inspections carried out on all overhead and underground asset components, including: poles; transformers; overhead conductor; underground chambers; overhead (load break disconnect switches, fuses, etc.) and underground (Pad-mounted Switches) switchgear; insulators; arrestors; bushings and elbows; as well as hardware attachments and accessories such as guy wires, junctions (for cable), cross arms and ground wires. The visual inspection program also incorporates distribution system plant, such as transformer rooms and chambers, where elements such as the transformer room doors, chamber entry points, ceilings, drains, and internal lights will be closely examined and inspected.

The inspector will have the option to pass or fail each asset. When a particular asset fails an inspection, the inspector is required to indicate any and all deficiencies concerning that asset. Plant inspections are considered ‘predictive’ as they are used to determine if plant components need to be repaired or replaced.

Substation Testing and Inspections

Predictive substation testing and inspection is an integral task in the detection of potential equipment failure. The methods employed to monitor critical substation equipment are as follow:

- Inspections (Various Substation & Building Equipment);
- Transformer Oil Analysis (Power Transformers);
- Thermography (Various Substation & Building Equipment);
- Partial Discharge Testing (Substation Metalclad Switchgear);
- Vibro-Acoustic Testing (Power Transformers); and
- Internal Resistance Testing (Substation Storage Battery Sets).

Predictive testing provides the following results:

- Uncovers otherwise hidden deterioration of equipment condition or performance;
- The ability to predict the progress of component failure from its first detection to eventual failure; and
- Early detection of a pending equipment failure providing a longer timeframe for preventative action.

Predictive testing allows optimization of maintenance tactics and programs by developing and improving maintenance schedules and prioritizing the impact of equipment failure. The information gathered during predictive testing also serves as an input into asset condition assessments.

Substation Inspections

The most common inspection task is a visual inspection of a substation which is performed monthly by substation maintainers. This technique exercises human judgment in assessing the condition of a substation and its components and determining the severity and/or consequence of potential failures that may be discovered. Table 24 below identifies the frequency of inspections:

	SUBSTATIONS HAMILTON	INSPECTIONS
1	18 Indoor Substations (Buildings)	Monthly
2	6 Outdoor Substations (Tower/Structure)	Monthly

	SUBSTATIONS ST CATHARINES	INSPECTIONS
1	3 Indoor Substations (Buildings)	Monthly

Table 24 - Substation Inspections

Transformer Oil Analysis

Oil analysis is scheduled yearly on all active and spare transformers. A potential transformer failure can be determined by detecting the production or release of gases and other bi-products that occur during arcing within transformer windings. It can also determine the state of the paper insulation and the resilience of insulating oil to withstand electrical stress.

Thermography

Infrared scanning is also scheduled as a yearly activity on all substation buildings, equipment, and transformers. Thermography can capture the current temperature of equipment and, when compared with like components or the surrounding ambient temperature, an overloaded component may be detected; if not corrected, heat stress will eventually lead to component failure.

Storage Battery Testing

Batteries are used to provide back-up power for local and remote operation of various substation components, in the event of the loss of the normal station low voltage service.

Annual battery impedance testing is a condition-monitoring technique, which detects potential battery failure by measuring the chemical and electrical effects that would indicate deterioration of the battery blocks. Readings found outside of tolerated values would indicate a potential failure of a battery block(s), which would result in a loss of substation equipment control in the event of the loss of station service

Partial Discharge Testing

Partial Discharge Testing is a monitoring technique used to detect a breakdown in substation metalclad switchgear bus insulation. This procedure senses the magnitude of electrical field pulses that would occur in deteriorating switchgear insulation. The failure of bus insulation would be catastrophic, possibly destroying the switchgear, other equipment in the vicinity, and causing wide-spread system outages for a prolonged period of time. Partial discharge testing is scheduled on a 5-year cycle on all substations that contain metalclad switchgear.

Vibro-Acoustic Testing

Vibro-acoustic emission testing is a dynamic monitoring technique that detects potential transformer failures by measuring the energy emitted in the form of vibration pulses and audible stress waves produced from energized transformers. Measured deviations from the norm for a power transformer may indicate a loose winding or a loose core element, which, through fatigue, stress, and wear may result in compromised insulation levels and could result in catastrophic failure of the transformer including an oil fire if the tank is compromised, threatening the entire station. This test procedure is scheduled on a 5-year cycle for all energized substation power transformers.

Preventive Maintenance

Preventive maintenance includes:

- dry ice (CO_2) cleaning of switching devices;
- transformer rooms, vaults and chamber inspection and cleaning;
- load break switch maintenance;
- vegetation management (“tree trimming”);
- insulator washing; and,
- substation equipment (breakers and relays).

Dry Ice Cleaning and Inspection

Contaminants such as dust, salt spray, silt, ash, and dirt can greatly reduce the dielectric strength of electrical equipment. These contaminants can lead to increased levels of leakage current conducting on the surface of the dielectric materials and result in leaving behind marks or tracking of the surface. These conditions compromise the insulating qualities of the material and can result in flash-overs that can damage electrical equipment and cause service outages as well as safety concerns.

Dry ice cleaning is a term used to describe the use of carbon dioxide to clean electrical equipment, without requiring an outage. Compressed non-conductive CO_2 is a gas that is directed at electrical components to lift contaminants from surfaces without damaging the underlying material. The buildup of dust, salt, dirt, and other contaminants on electrical equipment can reduce the dielectric strength of materials, leading to damaged equipment and unplanned outages. Because dry-ice cleaning enable the safe cleaning of energized equipment, the cleaning and maintenance of electrical equipment is practical. Certain other types of equipment, such as padmounted switches, can also be safely cleaned in this way.

Padmounted switches are enclosed in cabinets, and are situated where three-phase switching capability is required throughout the underground system. These switches are subject to regularly planned maintenance, including a detailed inspection of the fiberglass panels and terminators to ensure that there are no contaminants that could lead to arcing, potential discharge, tracking, or corona discharge. Any concerns related to physical alignment of barriers or components and clearances between phases and clearances to ground components are recorded and addressed. The overall enclosure is inspected and cleaned to eliminate dirt, weeds, and insect or rodent intrusions.   The switch blades are inspected for signs of galling or arc interruption. The switches are also opened and closed to ensure optimum interrupting performance.

Based on their condition, these switches are scheduled for dry ice cleaning. Approximately ten switches are cleaned in Hamilton and five in St. Catharines every year.

Transformer Rooms, Vaults and Cable Chambers

Horizon Utilities maintains an infrastructure of over 4,000 concrete vaults and cable chambers in the road allowance; and 200 transformer rooms in various customer sites in its service territory. These facilities are inspected and cleaned on a three year cycle.

Vaults are typically below grade and contain transformers and elbow connectors; cable chambers contain cables and in many locations contain a transformer; transformer rooms are typically on customer premises and contain transformers, cabling and switches. Crews perform the following tasks: check for general housekeeping, electrical and mechanical integrity, remove dirt and debris; and connections and components are thermographically scanned for hot spots.

Load Break Switches

Load break switch maintenance includes a visual assessment of components and supporting structures including the pole, cross arms, insulators, pins, conductor, tie wires and braces, and application of lubrication, operation of the switch, tightening of all mechanical connections, and thermographic inspection.

Vegetation Management

Tree trimming and clearing is an integral part of preventative line maintenance program. The intent of the program is to: maintain operating clearances between tree limbs and overhead conductor and equipment; remove dangerous trees and overhangs that could become energized and present a public safety hazard; and reduce the frequency of tree contact with overhead lines during storms or windy conditions, which cause momentary and sometimes sustained outages. The tree trimming program ensures that the utility services will not be interrupted as a result of interference between overhead conductor/equipment and surrounding vegetation. This maintenance is performed on a three year cycle. In order to ensure public safety, it is important to maintain clearances between energized conductor and tree branches.

Tree trimming maintenance comprises:

- Removal of dangerous trees and overhangs;
- Trimming to clear conductors; and
- Clearing distribution right-of-way.

Fault events caused by tree contact generally arise from the following three conditions:

- Falling trees knock down poles or break pole line hardware;
- A branch (or set of branches) rubbing across conductors; and

- A branch falls across one or several conductors and forms a path to ground under certain conditions or a short between two or more conductors.

Insulator Washing

Horizon Utilities conducts an insulator washing program in both Hamilton and St. Catharines. Targeted service areas are within heavy industrial areas and along highways were the salt contamination levels are high. Regular insulator washing eliminates contaminants that could reduce the insulation properties of these particular assets and lead to flashovers, pole fires, and further damage to surrounding and connected plant.

Substation Equipment

Station breakers and relays are tested and their operating parameters are re-set every six years or more frequently based on a risk assessment of the impact of component malfunction.

Corrective Maintenance Activities

The Visual Plant Inspection program will identify asset repairs as Standard, Timely, or Urgent. Urgent repairs identified during predictive maintenance activities are completed as soon as practical during the inspection year. Standard and timely repairs are planned for and completed during the following year. Urgent repairs represent serious problems within the distribution system plant that can impact the reliability of the distribution system or public safety.

Corrective Substation Maintenance

When deficiencies or imminent component failures are detected, repairs are prioritized and scheduled reactively. Analysis of the potential cause of the imminent failure will be undertaken and any additional maintenance needs will be identified; with corresponding costs recorded in the ERP system. Costs are tracked in this financial management program to help identify assets that have recurring maintenance costs, and to assist engineering staff to target certain components for in-depth analysis. Failure modes and causes can be established with the objective of improving maintenance programs to improve asset performance. Horizon Utilities can then determine whether to repair, replace, or eliminate a component.

2.3.2. Asset Lifecycle Risk Management (5.3.3.b)

Asset lifecycle risk management is an integral component in Horizon Utilities' overall AM process. Identifying, quantifying and managing risk is critical for achieving the AM objectives identified in Section 2.1.1 above. Asset lifecycle risk is managed through the methods that follow below.

System Loading

Horizon Utilities monitors and manages system loading to prevent overloading conditions that lead to a premature aging of assets. Load forecasts and co-ordination with Hydro One Networks provide a long-term view of the distribution system load. This provides the ability to identify and take actions to remedy potential problems prior to occurrence. Feeder capacity analysis, performed on each feeder, allows the appropriate limits to be established and alarm settings created in the SCADA system to identify overloading scenarios in real time.

Asset Health

Horizon Utilities monitors the health of assets to assess the level of risk presented to system operations from the health of the distribution assets. Assets in poor health, that result in service interruptions, and that exceed Horizon Utilities' ability to address, pose a high level of risk to the continued, reliable operation of the distribution system. The ACA performed by Kinectrics provided a detailed health analysis for 22 asset groups. This analysis provides feedback regarding the current asset health and identifies the long-term investment requirements for each asset group.

Horizon Utilities also assesses asset health through analysis of service interruptions and failed equipment. This analysis provide feedback regarding the current operational health of the distribution system. Analysis on the cause of service interruptions is performed to identify the which cause codes have the largest impact on system operations. Analysis on failed equipment is leveraged in the asset condition assessments.

Horizon Utilities' inspection programs provide another mechanism to identify and address risks on the distribution system. Inspection programs allow for the early identification of potential issues allowing mitigation steps to be taken prior to the issue escalating into a service interruption.

Asset Replacement Criteria

Asset replacement criteria is to ensure that assets are replaced and/or refurbished at the optimum time. Premature investment in the renewal or refurbishment of assets is economically inefficient as the full value of the asset is not utilized. Deferral of renewal or refurbishment investment however, can result in service interruptions due to failure or can lead to unnecessary increases in operating and maintenance costs. Horizon Utilities has assessed each asset group identified in the ACA and determined, based on: asset health; volume of assets; and impact of failure, whether to implement a proactive or reactive replacement philosophy. Assets in good health, or assets having a low impact upon failure are generally replaced on a reactive basis. Assets having a large installed volume, and/or that are in poor health with a high impact upon failure are considered for inclusion in a capital investment program and replaced in a proactive manner.

3. Capital Expenditure Plan (5.4)

3.1. Summary (5.4.1)

3.1.1. Load Connection Capability (5.4.1.a)

Horizon Utilities services a mature territory with limited areas of greenfield development. There are pockets of growth in both Hamilton and St. Catharines. Growth in both service areas is primarily driven by the redevelopment of existing brownfield (i.e., previously developed) areas or small pockets of undeveloped 'infill' within existing developed areas.

Horizon Utilities produces a Long Term Load Forecast Report bi-annually to perform a capacity analysis at all voltage levels of the Horizon Utilities distribution system. Horizon Utilities' capacity and ability to connect new customers, as identified by this report, is summarized by operating area below. Horizon Utilities' 2013 Long Term Load Forecast is provided in Appendix H.

Flamborough/Ancaster/Dundas

The village of Waterdown in Flamborough is experiencing one of the highest rates of residential growth in Horizon Utilities service territory. This area is supplied by two feeders originating from Dundas TS. Currently, sufficient bus capacity exists at Dundas TS. One of the feeders servicing this area operated at a peak exceeding 85% of available capacity indicating the conductors are approaching their operating limits. New loads planned for this feeder require additional analysis so that the feeder will not exceed operating limits at peak times. The full load of Waterdown cannot be serviced by a single feeder upon loss of one of the two feeders supplying Waterdown. A third feeder to service this area is planned in 2015 to improve security and accommodate expected future growth.

Hamilton Downtown

The Hamilton Downtown area is supplied from Elgin TS. Load growth in this area of Hamilton is expected from the redevelopment of underutilized land in the Hamilton Downtown core. The Elgin TS has sufficient capacity to service this load growth. Investment may be required in the construction of additional feeders or the modification of existing feeders to service these redevelopment projects.

Hamilton East

The Hamilton East operating area is serviced from Stirton TS. This area of the city has not experienced load growth in recent years and sufficient capacity exists at Stirton TS to accommodate projected load growth.

Hamilton Waterfront Industrial

The Hamilton Waterfront Industrial area is served by Beach TS, Birmingham TS, Gage TS, and Kenilworth TS. This area is the core industrial area of Hamilton and is not experiencing load growth at this time. The existing Hydro One stations servicing this area have sufficient capacity to accommodate the forecasted redevelopment of this area. Investment may be required in the construction of additional feeders or the modification of existing feeders to service redevelopment in this area.

Hamilton Mountain

The Hamilton Mountain area is serviced by Horning TS, Mohawk TS, and Nebo TS. Development in this area is centred on small infill projects that had not been previously developed. The stations in this area are nearing capacity and investment is forecast to be required in 2019 to increase the capacity of TS servicing this area.

Hamilton West

The Hamilton West area is serviced by Newton TS. Load growth is forecast to be limited in this area and the TS has sufficient capacity to supply the forecasted growth.

Stoney Creek

The Stoney Creek area is serviced by Lake TS and Winona TS north of the Niagara Escarpment, and Nebo TS south of the Niagara Escarpment. The Stoney Creek area south of the escarpment is an area of Horizon Utilities' service area experiencing growth. Nebo TS was at capacity and Horizon Utilities entered into a Connection and Cost Recovery Agreement ("CCRA") with Hydro One to increase the capacity at Nebo TS. This expansion, completed in 2013, provides the required capacity to service load growth in this area.

St. Catharines

The St. Catharines service territory is serviced by Bunting TS, Carlton TS, Glendale TS and Vansickle TS. Load growth in St. Catharines is primarily located on the west side of the city.

Horizon Utilities entered into a CCRA with Hydro One to increase the capacity of Vansickle TS. This expansion, completed in 2010, provides the required capacity to service the forecasted load growth in St. Catharines.

A brief description for each investment category, with annual capital expenditure, is provided below.

3.1.2. Total Annual Capital Expenditures by Category (5.4.1.b)

Horizon Utilities' total capital expenditure by category is provided in Table 25 below.

Category	2015 Test Year	2016 Test Year	2017 Test Year	2018 Test Year	2019 Test Year
System Access	$8,242,598	$8,471,952	$7,896,202	$8,091,602	$8,273,338
System Renewal	$18,070,415	$28,293,649	$33,167,877	$33,208,155	$34,706,031
System Service	$4,139,747	$294,732	$535,135	$2,031,847	$2,057,209
General Plant	$9,487,208	$5,887,200	$5,826,900	$5,610,900	$6,235,900
Total	**$39,939,967**	**$42,947,533**	**$47,426,114**	**$48,942,504**	**$51,272,477**

Table 25 - Total Capital Expenditures

3.1.3. Capital Expenditures Description by Category (5.4.1.c)

This section will provide a brief description of capital expenditures within each category and how such investments, correspond to the outcomes of the Horizon Utilities' asset management process. This justification for the scope and level of investment for the capital expenditures identified below is provided in Section 3.5.3 at a program level and in Table 1 of Appendix A at a more detailed project level.

<u>System Access</u>

The annual investment required for System Access projects, net of capital contributions, from 2015 through 2019 is provided in Table 26 below.

Category	2015 Test Year	2016 Test Year	2017 Test Year	2018 Test Year	2019 Test Year
System Access	$8,242,598	$8,471,952	$7,896,202	$8,091,602	$8,273,338

Table 26 - System Access Investment

System Access projects are investments required to meet customer service obligations in accordance with the DSC and Horizon Utilities' Conditions of Service. These projects, typically numbering over 300 annually, include: connecting new customers; building new subdivisions; and relocating system plant for roadway reconstruction work. Horizon Utilities uses an economic evaluation methodology prescribed by the DSC to determine the level, if any, of capital contributions for each project; with such levels incorporated into the annual capital budget. The output of the capital planning process has minimal effect on System Access investments as these investments cannot be deferred and must proceed as planned.

The total investment required to support the connection of new customers is projected to increase at a rate of approximately 3% annually over the 2015 – 2019 time period; which is consistent with historical growth trends. Capital contributions are expected to remain stable in 2015 through 2019.

System Renewal

Horizon Utilities' System Renewal investment requirements for the 2015 to 2019 planning cycle are provided in Table 27 below.

Category	2015 Test Year	2016 Test Year	2017 Test Year	2018 Test Year	2019 Test Year
System Renewal	$18,070,415	$28,293,649	$33,167,877	$33,208,155	$34,706,031

Table 27 - System Renewal Investment

System Renewal investments are driven by long-term plans to replace assets that are at the end, or nearing the end, of their useful lives. Replacement strategies are prioritized based on both age and condition of assets, as well as the impact on system reliability.

System Renewal projects and investment levels are determined from the output of the AM planning process. Specifically, the Kinectrics ACA was used as the basis for determining the investment requirements.

Asset Condition Assessment Investment Requirements

Table 28 below illustrates the forecasted number of assets flagged-for-action, having a high probability of failure, by asset class, identified by Kinectrics over a twenty year planning cycle. This forecast and the asset Health Index distribution were the key outputs of the ACA process detailed in the Planning and Project Section of the capital investment planning process as described in Section 2.1.2 above. The timing of replacements, as identified by Kinectrics, represents the optimum timing for asset renewal and, as such, the year 1 values are substantially higher than subsequent years due to the high percentage of Horizon Utilities' distribution system with a Health Index of either 'very poor' or 'poor' and recommended for immediate replacement.

The product of the volume of Flagged-for-Action Plan assets identified by the Kinectrics ACA and the per unit replacement costs for each asset category provides the required system renewal investment requirements over the twenty year planning cycle. During the detailed design of each project, opportunities for refurbishment or re-use of existing assets are examined.

An overview of annual investment required to replace the forecasted flagged-for-action assets, identified by Kinectrics, based on the optimal replacement strategy for the twenty year planning cycle, is provided below in Table 29 and Table 30 below.

Asset	Sub-Category	Total Population	Flagged for Action Year																			
			1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Substation Transformers	-	70	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	1	0	1	0	2
Substation Circuit Breakers	-	279	16	0	10	0	11	0	9	0	17	0	7	0	0	0	0	9	1	0	0	9
Substation Switchgear	-	37	1	0	1	1	4	0	0	4	2	4	0	4	1	4	0	0	0	0	0	0
Pole Mounted Transformers	-	12886	593	277	232	218	215	217	220	223	226	228	229	229	230	230	231	234	238	244	252	262
Overhead Conductors	Primary	3386	53	45	40	37	34	32	31	30	29	30	30	31	32	32	32	33	33	33	33	34
	Secondar	2196	86	63	52	44	40	38	38	38	39	39	39	39	39	39	38	37	36	34	33	32
	Service	1897	97	69	54	44	39	36	35	36	36	36	36	36	36	35	34	33	32	30	28	27
Overhead Line Switches	-	711	31	26	23	22	20	20	19	18	19	18	18	18	17	17	17	17	16	17	17	17
Wood Poles	-	42037	1509	1103	1011	967	935	905	876	845	814	782	752	724	699	678	662	648	637	627	619	611
Concrete Poles	-	9761	97	98	100	101	103	104	105	107	108	109	110	111	112	114	115	118	119	121	123	126
Underground Cables	Prim. XLPE	2060	126	103	96	91	88	85	83	80	78	76	74	72	71	70	69	68	67	66	66	66
	Prim. PILC	1532	11	11	12	12	12	13	14	14	15	16	17	18	19	20	20	21	22	23	24	25
	Sec. DB	757	28	28	28	27	27	27	27	27	26	26	26	26	25	25	25	25	24	24	24	24
	Sec. ID	533	21	21	21	20	20	19	19	19	18	18	18	18	17	17	17	17	17	16	16	16
	Serv. DB	446	20	20	20	19	19	19	19	18	18	18	18	17	17	17	16	16	16	15	15	15
	Serv. ID	588	10	11	11	11	11	12	12	12	13	13	13	13	14	14	14	14	14	15	15	15
Pad Mounted Transformers	-	5893	17	17	20	23	27	31	36	41	47	53	59	65	70	75	79	83	87	92	98	105
Pad Mounted Switchgear	-	186	3	3	3	3	3	3	3	3	3	3	3	4	4	4	4	4	4	4	4	5
Vault Transformers	-	4169	309	294	282	270	260	250	240	230	221	212	203	194	186	178	170	162	156	150	144	139
Utility Chambers	-	2075	12	13	13	14	15	15	16	17	17	18	19	20	20	21	22	23	23	24	25	26
Vaults	-	3413	6	7	7	7	8	8	9	10	10	11	12	12	13	14	15	16	17	18	19	20
Submersible LBD Switches	-	117	14	8	7	6	5	5	5	4	4	4	3	3	3	3	2	2	2	2	2	3

Table 28 - 20 Year Flagged-for-Action Plan

Asset	Sub-Category	Avg Annual Replacement	Flagged For Action Year									
			1	2	3	4	5	6	7	8	9	10
Substation Transformers	-	$ 37,500	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Substation Circuit Breakers	-	$ 200,250	$ 720,000	$ -	$ 450,000	$ -	$ 495,000	$ -	$ 405,000	$ -	$ 765,000	$ -
Substation Switchgear	-	$ 975,000	$ 750,000	$ -	$ 750,000	$ 750,000	$ 3,000,000	$ -	$ -	$ 3,000,000	$ 1,500,000	$ 3,000,000
Pole Mounted Transformers	-	$ 1,939,207	$ 4,574,183	$ 2,136,676	$ 1,789,562	$ 1,681,571	$ 1,658,430	$ 1,673,858	$ 1,696,999	$ 1,720,139	$ 1,743,280	$ 1,758,708
Overhead Conductors	Primary	$ 1,480,860	$ 2,294,900	$ 1,948,500	$ 1,732,000	$ 1,602,100	$ 1,472,200	$ 1,385,600	$ 1,342,300	$ 1,299,000	$ 1,255,700	$ 1,299,000
	Secondary	$ 1,747,961	$ 3,566,420	$ 2,612,610	$ 2,156,440	$ 1,824,680	$ 1,658,800	$ 1,575,860	$ 1,575,860	$ 1,575,860	$ 1,617,330	$ 1,617,330
	Service	$ 1,677,462	$ 4,022,590	$ 2,861,430	$ 2,239,380	$ 1,824,680	$ 1,617,330	$ 1,492,920	$ 1,451,450	$ 1,492,920	$ 1,492,920	$ 1,492,920
Overhead Line Switches	-	$ 262,309	$ 420,236	$ 352,456	$ 311,788	$ 298,232	$ 271,120	$ 271,120	$ 257,564	$ 244,008	$ 257,564	$ 244,008
Wood Poles	-	$ 3,628,762	$ 6,676,178	$ 4,879,937	$ 4,472,907	$ 4,278,240	$ 4,136,664	$ 4,003,937	$ 3,875,634	$ 3,738,483	$ 3,601,331	$ 3,459,756
Concrete Poles	-	$ 550,250	$ 485,000	$ 490,000	$ 500,000	$ 505,000	$ 515,000	$ 520,000	$ 525,000	$ 535,000	$ 540,000	$ 545,000
Underground Cables	Prim. XLPE	$ 8,637,102	$ 13,676,203	$ 11,197,024	$ 10,377,440	$ 9,896,729	$ 9,536,760	$ 9,231,188	$ 8,954,335	$ 8,696,947	$ 8,456,651	$ 8,233,733
	Prim. PILC	$ 4,190,477	$ 2,746,641	$ 2,801,654	$ 2,874,567	$ 2,967,548	$ 3,081,796	$ 3,217,424	$ 3,373,465	$ 3,548,000	$ 3,738,402	$ 3,941,651
	Sec. DB	$ 3,240,928	$ 3,495,176	$ 3,475,469	$ 3,454,447	$ 3,432,087	$ 3,408,382	$ 3,383,340	$ 3,356,987	$ 3,329,369	$ 3,300,552	$ 3,270,624
	Sec. ID	$ 454,186	$ 532,315	$ 521,036	$ 510,413	$ 500,418	$ 491,016	$ 482,171	$ 473,842	$ 465,988	$ 458,568	$ 451,545
	Serv. DB	$ 2,192,029	$ 2,494,556	$ 2,474,732	$ 2,452,272	$ 2,427,369	$ 2,400,039	$ 2,370,406	$ 2,338,612	$ 2,304,816	$ 2,269,195	$ 2,231,942
	Serv. ID	$ 319,594	$ 259,287	$ 265,857	$ 272,433	$ 279,006	$ 285,567	$ 292,105	$ 298,610	$ 305,071	$ 311,478	$ 317,820
Pad Mounted Transformers	-	$ 937,526	$ 283,341	$ 283,341	$ 333,342	$ 383,344	$ 450,012	$ 516,681	$ 600,016	$ 683,352	$ 783,355	$ 883,357
Pad Mounted Switchgear	-	$ 192,500	$ 165,000	$ 165,000	$ 165,000	$ 165,000	$ 165,000	$ 165,000	$ 165,000	$ 165,000	$ 165,000	$ 165,000
Vault Transformers	-	$ 1,448,217	$ 2,105,878	$ 2,003,651	$ 1,921,869	$ 1,840,088	$ 1,771,936	$ 1,703,785	$ 1,635,634	$ 1,567,482	$ 1,506,146	$ 1,444,810
Utility Chambers	-	$ 389,599	$ 250,680	$ 271,570	$ 271,570	$ 292,460	$ 313,350	$ 313,350	$ 334,240	$ 355,130	$ 355,130	$ 376,020
Vaults		$ 97,906	$ 49,158	$ 57,351	$ 57,351	$ 57,351	$ 65,544	$ 65,544	$ 73,737	$ 81,930	$ 81,930	$ 90,123
Submersible LBD Switches	-	$ 33,599	$ 108,136	$ 61,792	$ 54,068	$ 46,344	$ 38,620	$ 38,620	$ 38,620	$ 30,896	$ 30,896	$ 30,896
Kinectrics Total			**$ 49,675,877**	**$ 38,860,085**	**$ 37,146,850**	**$ 35,052,247**	**$ 36,832,568**	**$ 32,702,909**	**$ 32,772,905**	**$ 35,139,391**	**$ 34,230,428**	**$ 34,854,241**

Table 29 - Optimal Year 1 to Year 10 Renewal Investment Detail

Asset	Sub-Category		Avg Annual Replacement	Flagged For Action Year 11	12	13	14	15	16	17	18	19	20	20 year total
Substation Transformers	-		$ 37,500	$ -	$ 150,000	$ -	$ -	$ -	$ 150,000	$ -	$ 150,000	$ -	$ 300,000	$ 750,000
Substation Circuit Breakers	-		$ 200,250	$ 315,000	$ -	$ -	$ -	$ -	$ 405,000	$ 45,000	$ -	$ -	$ 405,000	$ 4,005,000
Substation Switchgear	-		$ 975,000	$ -	$ 3,000,000	$ 750,000	$ 3,000,000	$ -	$ -	$ -	$ -	$ -	$ -	$ 19,500,000
Pole Mounted Transformers	-		$ 1,939,207	$ 1,766,421	$ 1,766,421	$ 1,774,135	$ 1,774,135	$ 1,781,849	$ 1,804,989	$ 1,835,844	$ 1,882,126	$ 1,943,835	$ 2,020,971	$ 38,784,132
Overhead Conductors	Primary		$ 1,480,860	$ 1,299,000	$ 1,342,300	$ 1,385,600	$ 1,385,600	$ 1,385,600	$ 1,428,900	$ 1,428,900	$ 1,428,900	$ 1,428,900	$ 1,472,200	$ 29,617,200
	Secondary		$ 1,747,961	$ 1,617,330	$ 1,617,330	$ 1,617,330	$ 1,617,330	$ 1,575,860	$ 1,534,390	$ 1,492,920	$ 1,409,980	$ 1,368,510	$ 1,327,040	$ 34,959,210
	Service		$ 1,677,462	$ 1,492,920	$ 1,492,920	$ 1,492,920	$ 1,451,450	$ 1,409,980	$ 1,368,510	$ 1,327,040	$ 1,244,100	$ 1,161,160	$ 1,119,690	$ 33,549,230
Overhead Line Switches	-		$ 262,309	$ 244,008	$ 244,008	$ 230,452	$ 230,452	$ 230,452	$ 230,452	$ 216,896	$ 230,452	$ 230,452	$ 230,452	$ 5,246,172
Wood Poles	-		$ 3,628,762	$ 3,327,028	$ 3,203,150	$ 3,092,544	$ 2,999,635	$ 2,928,847	$ 2,866,908	$ 2,818,241	$ 2,773,998	$ 2,738,605	$ 2,703,211	$ 72,575,233
Concrete Poles	-		$ 550,250	$ 550,000	$ 555,000	$ 560,000	$ 570,000	$ 575,000	$ 590,000	$ 595,000	$ 605,000	$ 615,000	$ 630,000	$ 11,005,000
Underground Cables	Prim.	XLPE	$ 8,637,102	$ 8,029,420	$ 7,845,109	$ 7,681,907	$ 7,540,357	$ 7,420,306	$ 7,320,918	$ 7,240,785	$ 7,178,109	$ 7,130,906	$ 7,097,209	$ 172,742,036
		PILC	$ 4,190,477	$ 4,154,642	$ 4,374,448	$ 4,598,460	$ 4,824,418	$ 5,050,319	$ 5,274,431	$ 5,494,953	$ 5,710,192	$ 5,918,455	$ 6,118,084	$ 83,809,549
	Sec.	DB	$ 3,240,928	$ 3,239,691	$ 3,207,879	$ 3,175,329	$ 3,142,199	$ 3,108,657	$ 3,074,879	$ 3,041,050	$ 3,007,356	$ 2,973,972	$ 2,941,108	$ 64,818,554
		ID	$ 454,186	$ 444,882	$ 438,547	$ 432,515	$ 426,761	$ 421,269	$ 416,025	$ 411,022	$ 406,253	$ 401,716	$ 397,417	$ 9,083,718
	Serv.	DB	$ 2,192,029	$ 2,193,267	$ 2,153,394	$ 2,112,559	$ 2,071,010	$ 2,029,001	$ 1,986,800	$ 1,944,669	$ 1,902,879	$ 1,861,693	$ 1,821,375	$ 43,840,585
		ID	$ 319,594	$ 324,085	$ 330,262	$ 336,341	$ 342,309	$ 348,157	$ 353,872	$ 359,444	$ 364,862	$ 370,116	$ 375,195	$ 6,391,878
Pad Mounted Transformers	-		$ 937,526	$ 983,360	$ 1,083,363	$ 1,166,698	$ 1,250,034	$ 1,316,702	$ 1,383,371	$ 1,450,039	$ 1,533,375	$ 1,633,378	$ 1,750,048	$ 18,750,510
Pad Mounted Switchgear	-		$ 192,500	$ 165,000	$ 220,000	$ 220,000	$ 220,000	$ 220,000	$ 220,000	$ 220,000	$ 220,000	$ 220,000	$ 275,000	$ 3,850,000
Vault Transformers	-		$ 1,448,217	$ 1,383,473	$ 1,322,137	$ 1,267,616	$ 1,213,095	$ 1,158,574	$ 1,104,053	$ 1,063,162	$ 1,022,271	$ 981,380	$ 947,304	$ 28,964,345
Utility Chambers	-		$ 389,599	$ 396,910	$ 417,800	$ 417,800	$ 438,690	$ 459,580	$ 480,470	$ 480,470	$ 501,360	$ 522,250	$ 543,140	$ 7,791,970
Vaults			$ 97,906	$ 98,316	$ 98,316	$ 106,509	$ 114,702	$ 122,895	$ 131,088	$ 139,281	$ 147,474	$ 155,667	$ 163,860	$ 1,958,127
Submersible LBD Switches	-		$ 33,599	$ 23,172	$ 23,172	$ 23,172	$ 23,172	$ 15,448	$ 15,448	$ 15,448	$ 15,448	$ 15,448	$ 23,172	$ 671,988
Kinectrics Total				**$ 32,047,926**	**$ 34,885,556**	**$ 32,441,887**	**$ 34,635,349**	**$ 31,558,496**	**$ 32,140,503**	**$ 31,620,164**	**$ 31,734,135**	**$ 31,671,442**	**$ 32,661,476**	**$ 692,664,436**

Table 30 - Optimal Year 11 to Year 20 Renewal Investment Detail

Analytical Findings from AM and Capital Expenditure Planning Outputs

Kinectrics identified a 20 year investment requirement of $692,664,000 using 2013 asset replacements costs without inflation (i.e., values stated in 2013 dollars). The Kinectrics analysis provides clear corroboration for the assertion that, based on sound engineering principles and best asset management practices, the health of Horizon Utilities' distribution system is degrading and increased investment is required to halt further system health degradation to increasingly unacceptable levels. As illustrated in Figure 77, Kinectrics' recommended investment profile is highest in year 1 due to the high number of assets having a Health Index of either "very poor" or "poor" and then decreases annually through the remainder of the twenty year planning cycle. The front loading of investment identified by Kinectrics is consistent with a backlog of assets requiring renewal and overdue for replacement. The operation of the distribution system in this state involves an elevated level of risk of equipment failure and interruption of service to customers. The increased risk of equipment failure will result in higher reactive renewal investment requirements which is inherently less efficient than renewing assets using a proactive, planned approach.

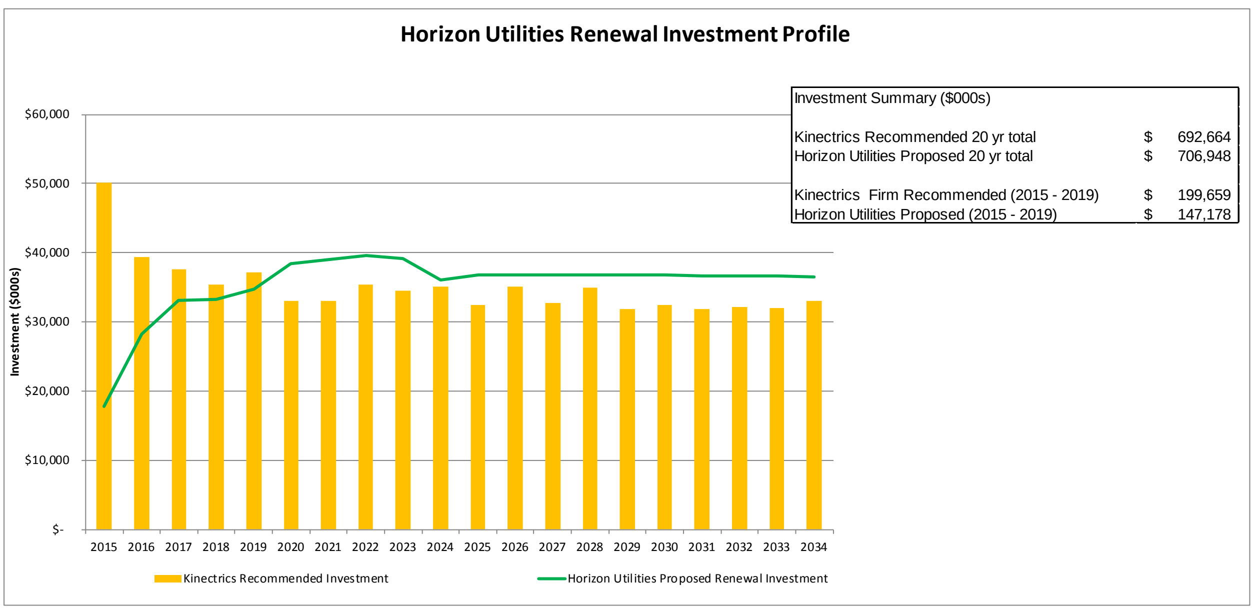

Figure 77 - Horizon Utilities Renewal Investment Profile

Horizon Utilities' initial AM efforts in 2008 identified the need to increase renewal investment. In order to ensure the continued operational viability of the distribution system, Horizon Utilities began increasing its system renewal expenditures at a graduated rate from $8,452,500 (CGAAP) in 2008 to $22,474,931 (CGAAP) by 2011.

Kinectrics' recommended System Renewal investment for 2015 in comparison is $49,675,877. Horizon Utilities' assessment of the investment level and profile recommended by Kinectrics determined that this investment profile would result in an unfair rate impact on the customer base within such a short period of time. Additionally, a sharp increase in investment to this level without supporting customer rates would not be affordable for Horizon Utilities.

In order to balance ratepayer and utility affordability, Horizon Utilities proposes increasing annual renewal investment at a graduated rate from $18,070,000 in 2015 to $34,706,000 by 2019 and peaking at $39,661,000 in 2022. Horizon Utilities' proposed 20 year renewal investment profile is provided above in Figure 77 and denoted by the green line. Horizon Utilities' investment profile incorporates inflation for the 2015 to 2019 Test Years but investments beyond the 2019 Test Year do not incorporate inflation.

The total 20 year investment proposed by Horizon Utilities is equivalent to Kinectrics total 20 year recommended investment but is $52,481,000 lower than the Kinectrics recommended investment level for the period from 2015 to 2019. Horizon Utilities' proposed investment profile, illustrated in Figure 77, represents the minimum renewal investment required to prevent the continued degradation of the Health Index distribution of Horizon Utilities major asset categories through to 2019. Failure to invest at this level will result in Horizon Utilities' customers experiencing a persisting cumulative decline in service through more frequent outages of increasing duration. Outages could impact thousands of customers and continue for several days. The potential impact on customers is further described in Section 3.5.3 below.

Capital Investment Programs

Kinectrics recommended implementing asset specific programs not only to address improving the overall condition of the asset categories listed above, but also to maintain the existing overall condition level for the remaining asset categories. The failure to do so could result in: deteriorating reliability performance; taking unnecessary risks associated with failures of assets with significant consequence of failure (such as underground cables, substation breakers and overhead conductors); and creating future investment needs that would be substantially higher than historical levels.

The capital investment program outlined in Table 31 below addresses the investment renewal requirements identified by Horizon Utilities' asset management analysis. These programs existed prior to Kinectrics' ACA and the results of Kinectrics' ACA validated that Horizon Utilities' capital investment program identified the assets with the highest priority for investment. The level of investment proposed for each program is guided by the level of investment recommended by Kinectrics ACA.

Table 31 below maps assets with either a poor Health Index distribution (at least 20% of assets in either 'poor' or 'very poor' health) or a significant five year investment requirement (greater than $5,000,000) against Horizon Utilities' capital investment programs.

Asset Group	Kinectrics Recommended 5 Year Replacement Value	Percentage of Assets with 'Poor' or 'Very Poor' Health Index	4kV and 8kV Renewal Program	XLPE Cable Renewal Program	Pole Residual Program	Proactive Transformer Replacement	LBDS Maintenance	Reactive Replacement
Underground Cables (primary XLPE)	$ 54,684,156	29%		X				X
Wood Poles	$ 24,443,926	11%	X		X			
Underground Cables (secondary DB)	$ 17,265,561	42%		X				X
Underground Cables (primary PILC)	$ 14,472,205	1%						X
Overhead Conductors (service)	$ 12,565,410	11%	X					X
Underground Cables (service DB)	$ 12,248,968	63%		X				X
Pole Mounted Transformers	$ 11,840,422	6%	X			X		X
Overhead Conductors (secondary)	$ 11,818,950	9%	X					X
Vault Transformers	$ 9,643,423	49%		X				X
Overhead Conductors (primary)	$ 9,049,700	5%	X					
Substation Switchgear	$ 5,250,000	32%	X					
Underground Cables (secondary ID)	$ 2,555,198	42%		X				X
Substation Circuit Breakers	$ 1,665,000	23%	X					
Overhead Line Switches	$ 1,653,832	20%					X	
Submersible LBD Switches	$ 308,960	46%						

Table 31 - Capital Investment Programs

4kV and 8kV Renewal Program

Horizon Utilities' 4kV and 8kV distribution system services approximately 75,000 customers representing 34% of the total customer base. The 40-year 4kV and 8kV Renewal Program, provided in Appendix F consolidates both distribution asset conditions and substation asset conditions to provide a prioritized long term plan for renewal. The 4kV and 8kV distribution system represents the majority of Horizon Utilities' oldest distribution assets, constructed in the 1950's which are at or near EOL. Furthermore, conversion to a higher voltage level will provide greater security as higher voltage systems are designed with more redundancy and better interoperability.

The Kinectrics' ACA provided the Health Index for 22 asset groups. Fifteen of these asset groups have an unacceptable Health Index distribution. Horizon Utilities has established that an unacceptable Health Index distribution occurs when:

- at least 20% of the assets within the group have a Health Index of either "very poor" or "poor"; or

- the assets within the group, which have a “very poor” or “poor” health index, require a significant five year investment (greater than $5,000,000).

Horizon Utilities’ 4kV and 8kV Renewal Program addresses the renewal of assets in seven of the fifteen asset groups. The seven asset groups are:

- Wood poles;
- Overhead conductors (primary);
- Overhead conductors (secondary);
- Overhead conductors (service);
- Pole mounted transformers;
- Substation switchgear; and
- Substation circuit breakers.

For these reasons, Horizon Utilities prioritized the renewal of these voltage systems in the capital expenditure plan. These project are designated as the primary vehicle for renewal of the overhead distribution system and the decommissioning of Substation assets.

XLPE Cable Renewal Program – XLPE Plan

The high risk profile of this asset group results from the high percentage of assets with a ‘very poor’ and ‘poor’ Health Index, indicating a high risk of failure, combined with the large volume of XLPE installed in the distribution system. Kinectrics’ analysis and recommended replacement volume, combined with the high customer impact upon failure, resulted in Horizon Utilities increasing its investment in XLPE replacement in 2015 to 2019 relative to 2011 to 2014 values. Horizon Utilities has determined that primary XLPE cable is the asset category with the largest risk to the continued safe, reliable and economic operation of Horizon Utilities’ distribution system.

The XLPE Cable Renewal Program is the primary vehicle to renew Horizon Utilities’ underground distribution assets. Horizon Utilities’ XLPE Renewal Program addresses the renewal of assets in six of the fifteen asset groups having an unacceptable Health Index distribution. These six asset groups are:

- XLPE Cables (Primary);
- Underground Cables (Secondary Direct Buried);
- Underground Cables (Secondary In Duct);
- Underground Cables (Service Direct Buried);
- Underground Cables (Service In Duct); and
- Vault Transformers.

The total length of XLPE primary cable, with an unacceptable Health Index distribution is 597km or 29% of Horizon Utilities' total XLPE cable. XLPE cable, as illustrated in Table 29 and Table 30, has the highest investment requirement of the 22 asset groups due to the high percentage of cable with an unacceptable Health Index distribution and the high volume of installed cable. The Kinectrics ACA identified a requirement for a $172,742,000 investment over the next 20 years for this category; with $54,684,000 of this amount required within the first five years.

This current backlog of XLPE cable requiring renewal cannot be addressed in a single year and requires an investment strategy spanning several years. The optimal level of renewal for XLPE cable, based on a 40-year useful life replacement cycle, is 50km/year. Horizon Utilities' proposed aggregate investment for the 2015 to 2019 Test Years is $36,014,000, which provides for the replacement of 180km of cable over the 2015 to 2019 Test Years. This represents a managed, gradual increase in investment in order to balance rate payer and utility affordability. This proposed investment is below the minimum investment required to maintain the current Health Index in 2015 to 2019, as identified in previously in Figure 65. The backlog of XLPE cable with a "very poor" or "poor" health index continues to grow until 2019. It will take Horizon Utilities until 2017 to reach the optimal level of renewal, due to long lead times required to address planning and municipal consent processes and customer stakeholdering.

Pole Residual Program – Pole Test

The Pole Residual Program is the vehicle for replacing wood poles identified as requiring replacement through inspection and maintenance program. All wood poles are tested on a seven year interval to determine asset condition as the pole ages.

Wood poles identified as having an imminent risk of failure are replaced immediately as reactive replacements. Wood poles predicted to fail within a five year timespan are reviewed and if not scheduled to be replaced in the five year time span through the 4kV and 8kV Renewable Program, are scheduled for proactive replacement the following year through the Pole Test Program.

Proactive Transformer Replacement

In 2007, a proactive transformer renewal program was initiated based on the distribution transformer Health Index developed within Horizon Utilities. In 2008, a study conducted jointly by Horizon Utilities' AM team and Navigant Consulting studied the benefits of this program and its alignment with industry best practices.

From this study, it was recommended that although the Health Index for transformers is based on sound AM principles and provides a good means of monitoring the condition of all transformers in the system, proactively replacing transformers based on these Health Index scores is not the most cost effective strategy from an AM perspective. Industry best practices indicate replacing transformers of the following categories:

- Transformers that have failed;
- Transformers that have visibly deteriorated and will fail imminently;
- Transformers that are unique with no adequate backup available; and
- Transformers that will be difficult to restore with possibility of long outages in case of failure.

This is commonly referred to as a "Run to Failure" strategy. Horizon Utilities has adopted this strategy since 2009. The system reliability impact based on transformer failure is monitored throughout the year to assess the adequacy of this strategy.

System Service

System Service investment expenditures recommendations are provided in Table 32 below.

Category	2015 Test Year	2016 Test Year	2017 Test Year	2018 Test Year	2019 Test Year
System Service	$4,139,747	$294,732	$535,135	$2,031,847	$2,057,209

Table 32 - System Service Investment

System Service investments, formerly referred to by Horizon Utilities as non-renewal investments, are required to support the expansion, operation and reliability of the distribution system. System Service investment requirements are primarily identified through the outcomes of the system planning and operational performance planning activities within the asset management activities. System Service projects typically score lower than System Access and System Renewal projects resulting in a significantly lower investment requirement than the System Renewal category. The System Service sub-categories used by Horizon Utilities are described below.

Capacity

Although overall load growth in Horizon Utilities' service territory is low, there are specific areas within the service territory that require capacity investments to accommodate growth.

Security

The primary driver for security investments is to prevent interruptions due to an inability to supply a load through an alternate route because of insufficient redundant capability. The lack of redundancy could be caused by either the lack of an available back-up system or overloading of supply line. This will lead to premature failure of equipment by unduly overloading and/or causing harm to other parts of the distribution system.

Reliability

System reliability investments are focused on either reducing the frequency of interruptions to the distribution system or reducing the duration of interruptions upon occurrence. Distribution automation will be the primary mechanism to improve overall system reliability metrics. However, there are also requirements for specific projects in targeted areas of the system.

Safety

Safety investments are required to correct an unacceptable level of public and worker safety as determined by statutory/regulatory requirements. This is also done in accordance with good utility practice.

Feeder Automation

The automation of the distribution system (i.e. the ability to remotely identify faulted areas and remotely restore service through the use of remotely controlled switches) is fundamental towards reversing the recent trend of declining reliability and increased service interruptions. Distribution automation will provide the ability to decrease the duration of service interruptions to offset the impact on the customer of an increasing volume of interruptions due to equipment failures associated with the declining health of the distribution system. Distribution automation will also mitigate the impact of service interruptions resulting from significant weather events (i.e. the high volume of outages resulting from wind and ice storms).

The higher level of investment in 2015 is necessary to implement projects requiring: coordination with external parties; implementation of automation as identified in the GEA Plan; or to address critical loads in downtown Hamilton that would be operating without adequate backup capabilities. The investment levels in 2018 and 2019 are necessary to address reliability and operational issues that have been present for several years and where further deferral is not recommended. Notably, 2016 and 2017 investment levels are below historical values and further deferrals in these years are not possible.

The list of System Service projects exceeding Horizon Utilities' materiality threshold with justifications can be found in Appendix A.

General Plant

The General Plant investment requirements are provided in Table 33 below.

Description	2015 Test Year	2016 Test Year	2017 Test Year	2018 Test Year	2019 Test Year
Fleet	$778,000	$780,000	$775,000	$785,000	$785,000
Building and Facilities [1]	$4,000,000	$2,195,000	$2,495,000	$1,595,000	$1,595,000
Computer Hardware & Software	$3,707,347	$2,181,000	$1,886,700	$2,532,700	$3,107,700
Communication Equipment	$245,000	$5,000	$5,000	$5,000	$5,000
Tools, Shop, Garage and Measurement Equipment	$687,860	$657,200	$596,200	$620,200	$670,200
Office Furniture and Equipment	$69,000	$69,000	$69,000	$73,000	$73,000
Total General Plant	**$9,487,208**	**$5,887,200**	**$5,826,900**	**$5,610,900**	**$6,235,900**

1 Buildings and Facilities includes building security

Table 33 - General Plant Investment

General Plant investments apply to assets that are not part of the distribution system. Horizon Utilities categorized capital investments in General Plant are grouped in the following categories:

- Fleet;
- Buildings and facilities;
- Information technology; and
- Tools, shop and garage equipment.

Fleet

The process to develop Horizon Utilities' Fleet Replacement Plan, which provides the annual investment requirement for a six year planning horizon, was provided in detail in Section 2.1.2 above. Using the processes described in that section, Horizon Utilities has identified 23 light and heavy duty vehicles that require replacement in the 2015 and 2019 Test Years as identified below in Table 34.

Vehicle	Model Year	Replacement Year
Unit 246 – Heavy Duty Pickup	1998	2015
Unit 220 – Double Bucket	1997	2015
Unit 296 – Passenger Vehicle/Cargo Van	2002	2015
Unit 292 – Low Duty Pickup	2002	2015
Unit 380 – Low Duty Pickup	2001	2015
Unit 234 – Passenger Vehicle/Cargo Van	1999	2015
Unit 213 – Heavy Duty Pickup	2000	2015
Unit 298 – Heavy Duty Pickup	2000	2016
Unit 241 – Passenger Vehicle/Cargo Van	1998	2016
Unit 248 – Knuckle Crane Truck	1997	2016
Unit 217 – Single Bucket	2000	2016
Unit 277 – Single Bucket	2000	2017
Unit 267 – Heavy Duty Pickup	1999	2017
Unit 330 – Cable Pulling/Digger Derrick Truck	2003	2017
Unit 293 – Heavy Duty Pickup	2000	2017
Unit 279 – Step Van	2001	2017
Unit 327 – Passenger Vehicle/Cargo Van	2002	2017
Unit 286 – Single Bucket	2002	2018
Unit 287 – Single Bucket	2002	2018
Unit 295 – Heavy Duty Pickup	2003	2018
Unit 291 – Heavy Duty Pickup	2003	2018
Unit 257 – Single Bucket	1999	2019
Unit 285 – Single Bucket	2002	2019
Unit 281 – Step Van	2001	2019

Table 34 - Vehicle Replacement Schedule

Facility Renewal

Horizon Utilities' facility renewal investments are determined through the facilities planning process illustrated in Figure 14 and described in Section 2.1.2. above. The facility asset studies identified in Section 2.1.2 resulted in the creation of a multi-year investment plan which commenced in 2012.

Facility investments for the 2015 to 2019 Test Years, totalling $10,700,000 are provided in Table 35 below.

Buildings - Capital Expenditures $	2015 Test Year	2016 Test Year	2017 Test Year	2018 Test Year	2019 Test Year
Reporting Basis	*MIFRS*	*MIFRS*	*MIFRS*	*MIFRS*	*MIFRS*
Building Renovations - Vansickle Road	$ -	$ -	$ -	$ -	$ -
Building Renovations - John and Hughson Street	$ 2,000,000	$ 1,600,000	$ 2,200,000	$ 1,200,000	$ -
Building Renovations - Nebo Road	$ -	$ -	$ -	$ -	$ -
Building Renovations - Stoney Creek	$ -	$ -	$ -	$ -	$ 1,200,000
Total Building Renovations	**$ 2,000,000**	**$ 1,600,000**	**$ 2,200,000**	**$ 1,200,000**	**$ 1,200,000**
Additional Building Investments					
Building Security Replacement	$ 300,000	$ 200,000	$ -	$ -	$ -
John Street Roof Replacement	$ 900,000	$ -	$ -	$ -	$ -
John Street Window Replacement	$ 300,000	$ 300,000	$ 200,000	$ -	$ -
Nebo Road Emergency Backup Generator	$ 300,000	$ -	$ -	$ -	$ -
Total Buildings Capital Expenditures	**$ 3,800,000**	**$ 2,100,000**	**$ 2,400,000**	**$ 1,200,000**	**$ 1,200,000**

Table 35 - Facilities Capital Expenditures

Building Renovations

2015 Planned Building Renovations - $2,000,000

There are two main projects that are planned for 2015 to address: congestion; consolidate work groups in order to improve organizational work flows; and to comply with current fire codes and the OBC. These are: Fifth Floor – John Street building; and Hughson Substation – Phase 2.

Fifth Floor – John Street building

This project will consolidate IST staff that are currently housed in three different locations, and provide sufficient space for the Human Resources, Health and Safety, and Corporate Communications departments.

Hughson Substation – Phase 2

The project will include the reclamation of Hughson Substation building, which was an active distribution station prior to its planned decommissioning scheduled for 2014. This industrial space is more than 100 years old, and requires a full restoration including:

- the removal of hazardous materials such as asbestos and mould;
- the installation of HVAC systems;
- the installation of life and safety support systems; and
- lighting.

The space will be converted into a large training room which will become the main corporate training room for John Street employees.. This will reduce travel time for John Street employees who currently travel approximately 30 minutes or 20 km from John Street to the Stoney Creek Service Centre Training Room.

Reclamation of the industrial space is anticipated to be a capital expenditure of $1,500,000.

2016 Planned Building Renovations - Capital $1,600,000

The project planned for 2016 will focus on the second floor of the John Street building, which remains in similar condition to that originally constructed in 1950. The project will address: employee security; safety and deficiencies related to fire and OBC codes; air quality; and lighting.

Second Floor – John Street Building

The second floor of the John Street building will be renovated to consolidate Customer Service and CDM employees into contiguous workgroups for organizational efficiency and to improve employee security and safety by relocating certain Customer Service staff from the area adjacent to the customer lobby on the first floor.

The fire and life safety and electrical systems will be updated to comply with current fire codes and the OBC. All HVAC components will be replaced and redirected as required to ensure air quality meets appropriate standards.

2017 Planned Building Renovations - Capital $2,200,000

The renovation of the sixth floor of the John Street building is planned for 2017. This floor is virtually unchanged from its time of construction in the 1960s, with limited updates approximately twelve years ago.

The Space Study conducted in 2010 concluded that additional space was required at the John Street building to reduce the congestion and improve the work environment. Horizon Utilities reclaimed part of the 6^{th} floor from the City of Hamilton Water Division to provide the additional space required. This space has been used, and will continue to be used, as “swing space” to support building renovation and renewals projects from 2012 to 2016. The swing space will be renovated to replace much of the electrical, mechanical, lighting systems when the building projects are complete. Building systems engineered and installed in the 1960s, are at end-of-life and cannot support the current occupancy demand. Renovations will also include removal of all existing walls, the remediation of hazard materials and expansion of the floor foot print to current space requirements .

Sixth Floor – John Street building

The renovation of the sixth floor, which presently hosts certain members of the Executive Management Team and includes temporary swing space for re-located departments as renovation projects occur, will include:

- the creation of additional office space to address organizational congestion;
- the installation of HVAC and fire and life safety systems that are at end-of-life;
- the anticipated disposal of hazardous materials including asbestos and mould; and
- the creation of necessary meeting room space.

2018 Planned Building Renovations - Capital $1,200,000

The project planned for 2018 is the renovation of the basement and lobby of the John Street building, which is largely original to the 1950s building.

Basement / Lobby – John Street building

The project will include the following:

- renovation of the locker, washroom, and shower space which is relatively unchanged from those originally constructed the 1950's building. These facilities have leaking plumbing and are unable to accommodate the size and needs of the current workforce;
- the removal of anticipated hazardous materials and the replacement of end-of-life HVAC and fire and life safety systems; and
- renovations to the public and customer entrance to improve the utilization of space and to address concerns regarding employee and public security.

2019 Planned Building Renovations - Capital $1,200,000

One project is planned for 2019; primarily to address employee and public safety concerns at the Stoney Creek Service Centre and replace end-of-life systems.

Stoney Creek Service Centre

The Stoney Creek Service Centre is utilized as an outdoor trades training facility and is a service centre for the east end of Horizon Utilities' service territory.

The project will include:

- the renovation of the locker, washroom, and shower space to replace end-of life assets;
- the replacement of end-of-life plumbing, lighting, and HVAC;
- the replacement of fire and life support systems;
- the addition of building automation systems to provide monitoring and remote access control of the systems. Currently the Stoney Creek location is the only building that is not monitored; and
- The creation of a centralized storage location for records retention and storage of furniture and assets. This would address improper storage of equipment at the John Street building and resolve compliance issues with fire codes and building codes for the John Street building and the Stoney Creek locations.

These renovations will support the needs of the current and future workforces, and improve employee safety due to the renewal of fire and life support systems.

Additional Buildings Projects

The BCA, security studies and window and roof assessments identified a number of major systems and assets that are at end-of-life and require replacements or upgrades including: building security; exterior structure repairs, the roof at the John Street and Hughson Street buildings; the John Street building windows; and a back-up emergency generator at the Nebo Road Service Centre.

All suppliers and contractors involved in the additional projects will be procured using the activities, practices and processes defined within Horizon Utilities' Corporate Procurement and Corporate Expenditure Approval Policies. The Corporate Procurement and Corporate Expenditure Approval Policies are provided in Exhibit 4, Tab 4, Appendix 4-7, and Exhibit 4, Tab 4, Appendix 4-8, respectively. Horizon Utilities has provided a description of its procurement of services and materials at Exhibit 2, Tab 6, Schedule 1.

Building Security Replacement

[redacted]

[redacted]

[redacted]

Exterior Structural Repairs

The 2013 BCA identified a number of exterior walls of the John Street and Hughson Street buildings and some substation buildings that have structural deficiencies due to their age. Elaboration of the exterior structure repairs are provided in the BCA provided in Appendix K.

The BCA recommends that the walls be re-bricked in the next two to five years to reduce the risk of future structural damage. Horizon Utilities has deferred this investment to 2018 as a result of its project priority selection process. The project is forecasted at $300,000 in capital expenditures.

Roof Replacement

The roofs at the John Street and Hughson Street buildings have surpassed end-of-life, as per the Roof Inspection Review provided as Appendix N, and requires replacement. The roof was last replaced in 1999 and, despite annual maintenance, leaks have caused damage to the floors below.

The replacement of the roof is planned for 2015 at a capital expenditure of $900,000. The capital expenditure includes repair damage to surrounding walls, and the cost of replacement and expansion of the roof railing to ensure compliance with the OBC. The forecast is based on $18 per square foot, which is consistent with industry comparators. Horizon Utilities will issue an RFP to obtain competitive pricing in accordance with Horizon Utilities' procurement practices as defined within its Procurement Policy.

Head Office Window Replacements

The windows at the John Street building, that were installed in 1994, were assessed by the MMM Group Limited ("MMM Group") in 2013. MMM Group is one of the largest building services firms in Canada, a recognized expert in community planning and infrastructure design, a leader in the transportation industry, and a best-in-class sustainability consultant. The Windown Assessment from MMM Group is provided as Appendix M.

The windows are reaching end-of-life, and have been identified to be in very poor condition and in need of replacement. The condition of the windows is discussed in further detail in Exhibit 2, Tab 6, Schedule 1.

The replacement of the windows is forecasted at $800,000 in capital expenditures between 2015 and 2017.

Nebo Road Emergency Back-up Generator

Nebo Road, Horizon Utilities' largest Service Centre, supports all customers in the Central and West Hamilton service area and is the Emergency Control Centre for the outside operations during emergencies. Horizon Utilities has experienced outages at the Nebo Service Centre during large scale outages, with the result that the dispatching of emergency crews and contractors was impaired. Portable generators did supply partial power to the building for lights and gas pumps, but major electrical equipment such as overhead cranes and fleet hoists were not in service. The use of portable generators is no longer an option due to their non-conformance with safety regulations.

The Nebo Road electrical service was evaluated in 2013 by T. Lloyd Electric, a leading full service electrical contractor, which concluded that, in order to safely connect a generator to power up the Service Centre in the event of a power failure, Horizon Utilities would need to install new switch gear and an automatic transfer switch. The mobile generator unit was not manufactured to safely support this type of service connection.

The report issued by T. Lloyd Electric recommended the installation of a 300kW generator to provide permanent back up power to the facility.

The cost to replace the generator is forecasted at $300,000 in 2015.

Information Technology

Horizon Utilities' capital investment in Information Technology is focused on the delivery of processes, technology, and systems that support five key strategic areas:

- **Friction Attrition**: The reduction of the operating cost base through replacement of inefficient paper-bound and electronic processes and activities through broad adoption of technology;

- **Enterprise Telecommunications Management:** Use of robust, scalable, enterprise-wide telecommunications standards, processes and tools to cost-effectively and securely drive business and operations processes. This includes the pervasive use of mobile technologies;

- **Enterprise Information Management:** Use of advanced information management techniques and technologies to effectively manage ever increasing and larger volumes of data in order to provide business and operational analytics that improve integration and management of key business processes;

- **Lifecycle Upgrades of Major Enterprise Business System:** Planned upgrade of major business systems (IFS Enterprise Resource Planning ("ERP") system and Daffron Customer Information System ("CIS") to mitigate risks related to age of systems and ongoing vendor support; and

- **Lifecycle Upgrades and/or New Implementations of Enterprise Operations Systems:** Planned upgrade of key operations systems (GIS, SCADA) to mitigate risks related to the age of systems, ongoing vendor support, and to provide new or improved modern capabilities for key operations processes such as Outage Management.

Capital investments must be made to ensure a robust, scalable and secure information technology foundation. These investments are grouped into the following two areas:

- **eFrastructure -** Providing an integrated, cost-effective infrastructure in terms of:
    - Technology components;
    - Core business and operations applications;
    - Common, interchangeable, navigable and reusable data; and
    - Flawless infrastructure operations.
- **IST Capability - Development and/or restructuring of the IST function through:**
    - Implementation of new tools and development of new competencies required to support new technologies;
    - Standardized and integrated services;
    - More efficiently utilization outside services, such as, managed services and cloud computing;
    - Streamlined decision processes; and
    - Simplified IST administrative processes.

The two significant upgrades to enterprise-wide systems are identified below.

IFS ERP Upgrade 2013-2015

This is an enterprise-wide project commencing in 2013 through to 2015 to upgrade Horizon Utilities' ERP system from IFS version 7.3 to version 8.1. This is a major upgrade to the Horizon Utilities ERP system installed in 2007-2008. This project was required to eliminate operational risks due to software, database and operating systems that will not be supported by respective vendors beyond 2014. The upgrade is also required to provide an updated application for the implementation of redesigned, optimized and/or new business processes that will allow Horizon Utilities to deliver planned productivity improvements as identified in Exhibit 4, Tab 3, Schedule 4.

This project was planned in three phases in order to effectively manage the internal resources requirements and impact on the business:

- Phase 1 - Upgrade from IFS 7.3 to IFS 8.1 (Go Live was September 2013);
- Phase 2 - Remove customizations that are now part of core functionality (Go Live phased throughout 2014); and
- Phase 3 - Process redesign / optimization (Go Live phased by process throughout 2015).

The costs associated with each phase of the project are identified in Table 36 below:

Phase	Year	$
1	2013	$1,224,564
2	2014	$980,260
3	2015	$1,693,000
Total ERP Upgrade		**$3,897,824**

Table 36 - ERP Upgrade Capital Expenditures

The justification for this project by phase is provided below in Section 3.5.3 below.

Tools, Shop and Garage Equipment

Tools, shop and garage equipment includes expenditures pertaining to the replacement of tools and equipment, which are either: worn; beyond repair; or where the continued use of such creates health and safety risk. This equipment is used by various trades employees at Horizon Utilities including: Distribution System Line Trades (Line persons, Cable Splicers, Substation Maintainers, and Labourers); Meter Technicians; Vehicle Mechanics; Facility Maintainers; and engineering related positions.

Equipment can be categorized into the following groups:

- Safety Equipment - includes traffic control equipment; dielectric tools and cover up; rescue devices and personal protective equipment;
- Storage Systems – includes warehouse shelving and storage systems and equipment;

- Rigging and Grounding – includes grips, hoists, conductor stringing equipment and cable pulling equipment, and grounding devices;
- Tools and Equipment – includes battery-operated equipment; and hydraulic and mechanical tools;
- Measurement/Test/Computing Equipment – includes volt meters, gas detectors, mobile computing accessories and GPS units.

Each year a condition assessment is conducted on the inventory of tools and equipment in use, to determine a forecast for expected replacements. Feedback from the crews that use the tools and equipment, together with feedback from the Fleet Mechanics who maintain the tools and equipment on each vehicle, is used to establish the annual budgets. It becomes unsafe, costly and inefficient to use or maintain this type of equipment which has reached the end of its useful life.

New tools become available on the market, on a periodic basis, that offer improved safety, ergonomics and productivity features which Horizon Utilities evaluates for use. Changes in regulations, which require a different standard of equipment, may necessitate a replacement of tools and equipment. Fall arrest equipment for example, needs to be exchanged when new standards come into effect, and any required new equipment is included in the budget.

3.1.4. Total Capital Cost (5.4.1.d)

A list and brief description of material capital expenditure projects/activities (sorted by category) is included in Appendix A - Material Capital Projects.

3.1.5. Regional Planning Process or Regional Infrastructure Plan Impact (5.4.1.e)

Horizon Utilities is actively participating in the RPP as described in Section 1.2.1 above. The formal RPP for the Burlington to Nanticoke region was initiated in December 2013 and is in the needs assessment stage within this process. The process has not proceeded to the stage of identifying projects and, as such, no material investments under this category have been identified by Horizon Utilities at this time for this Application's Test Year period. Horizon Utilities will continue to support and actively participate in the RPP initiative.

3.1.6. Customer Engagement Activities (5.4.1.f)

The Report of the Board: Renewed Regulatory Framework for Electricity – An Outcomes Based Approach (the "RRFE Report") contemplates enhanced engagement between distributors and their customers to provide better alignment between distributor operational plans and customer needs and expectations. Horizon Utilities has endeavoured to maintain a consumer-centric approach to AM and capital planning pursuant to the RRFE Report and the Board's Filing Requirements.

In section 5.0.4 of the Chapter 5 Requirements (p.4 of Chapter 5), the Board states that "*A DS Plan filing must demonstrate that distribution services are provided in a manner that responds to identified customer preferences*." The Chapter 5 Requirements also state (in section 5.4.1(f), at page 14 of the Chapter 5 Requirements) that distributors should provide "*a brief description of customer engagement activities to obtain information on their preferences and how the results of assessing this information are reflected in the [DS] plan*".

The informal facets of Horizon Utilities' customer engagement procedure have typically guided decision making in the AM and capital expenditure programs. Through the AM process, Horizon Utilities addresses customer needs on a case-by-case basis and is responsive to customer preferences. This form of engagement, which has included key account meetings and discussions with customers following events such as storms and other unplanned outages, has historically allowed for efficient planning at both the macro and micro levels of the distribution system. For example, an upgrade to the Gage Transformer Station planned for 2016 is a direct result of Horizon Utilities' historical ongoing engagement with its customers. Horizon Utilities has been able to gauge customer preference through these reactive mechanisms and directly apply it such to inform this DSP.

Following the Board's issuance of the Chapter 5 Requirements in March of 2013, Horizon Utilities undertook a formal customer engagement process related to asset management and capital planning, and that process has contributed to the final form of the Horizon Utilities DSP.

More specifically, in response to these requirements, Horizon Utilities engaged an independent third party, Innovative Research Group Inc. ("Innovative"), a national research and strategy firm that works with government, associations, not-for-profits, and private companies, to assist Horizon Utilities with the design of its customer consultation process in reference to the DSP; the collection of customer feedback; and the documentation of customer engagement results.

Horizon Utilities worked with Innovative to design a multi-faceted customer engagement program that combined traditional consultation elements and qualitative and quantitative research elements.

Traditional Consultation Elements

The traditional consultation elements included an online workbook (the “DSP Workbook”) that summarized Horizon Utilities’ DSP in a customer-friendly format and a related survey to which customers could respond.

The DSP Workbook was divided into key sections that explained Horizon Utilities’ electric system, the challenges confronting the system, and Horizon Utilities’ plans to meet those challenges over time.

The DSP Workbook had seven distinct chapters:

1. What is this about?
2. Electricity Grid 101
3. Horizon Utilities’ Distribution System Today
4. Challenges Facing Our Distribution System
5. Controlling Costs
6. What Our Plan Means For You
7. About Horizon Utilities Corporation

The DSP Workbook specified the level of investment that Horizon Utilities requires over the 2015-2019 Test Years; provided the investment levels for each of the OEB’s four investment categories, i.e., system renewal, system access, system service and general plant; and identified the related customer bill impacts estimated based on information existing at that time. Horizon Utilities has included its DSP Workbook as an appendix within the Innovative Customer Consultation Report in Appendix D.

Opinion Research Elements

The opinion research elements included:

- Quantitative research through telephone survey of residential customers;
- DSP Workbook-based facilitated discussions with commercial customers (GS<50kW and GS>50kW) as well as with community stakeholders; and,
- One-on-one meetings with key customer accounts led by Horizon Utilities, followed by a validation survey conducted by Innovative.

Horizon Utilities' DSP-related outreach involved all customer classes and was designed to allow any customer to participate in the process. Horizon Utilities' broader customer engagement activities are discussed in Exhibit 1, Tab 4, Schedule 1. Horizon Utilities has provided further details of its customer outreach initiatives, in support of the DSP, in Section 3.2.4.

Table 37 below identifies Horizon Utilities' customer outreach efforts by customer class.

Customer Class	Medium for Outreach	Dates
All customer classes	Online Distribution System Plan Workbook – www.horizonutilitiesworkbook.com	December 11, 2013 – January 13, 2014
	Media release; Social media: Twitter, Facebook	Launch on December 11, 2013
	Advertisement supporting online workbook campaign in Hamilton Spectator and St. Catharines Standard	Hamilton Spectator: December 14 and 18, 2013 St. Catharines Standard: December 14 and 19, 2013
Large Use class (GS>5MW)	One-on-one customer meetings facilitated by Horizon Utilities Management	November 27, 2013 – February 4, 2014
	Follow Up Telephone Survey by Innovative	November, 2013 - February 2014
GS<50kW class	Class-specific Focus Groups	January 14, 2014 – St. Catharines January 15, 2014 - Hamilton
GS>50kW class	Class-specific Focus Groups	
Community stakeholders	Focus Groups	
Residential class	Random Telephone Survey	January 17-24, 2014

Table 37 - Customer Outreach Programs

As discussed below, the approach adopted in Horizon Utilities' DSP, with its emphasis on system renewal over the 2015-2019 Test Year period, is consistent with the customer preferences expressed through the customer engagement process, in which a majority of customers supported Horizon Utilities' investment plans.

3.1.7. System Development Expectations (5.4.1.g)

Horizon Utilities' Hamilton and St. Catharines service territories are largely built out urban communities. Small greenfield development opportunities exist in the Waterdown area within the Dundas/Ancaster/Flamborough/Lynden operating area and in the Stoney Creek operating area. Development within the remainder of the service territory will be limited to infill and brownfield redevelopment opportunities. While Horizon does have 88 square kilometres of rural service territory, these areas are greenbelt lands beyond the provincial government controlled "built boundary" for each city. Horizon Utilities ability to service these development needs is detailed in Section 3.1.1.

This service territory growth constraint is evident in Horizon Utilities' customer growth statistics. As identified in Section 2.2.1, from the creation of Horizon Utilities in 2005 through to 2012, the customer growth rate has been 0.42 percent, with the lowest being year being -0.09 percent and the highest being 0.79 percent. Using population growth data as a proxy for customer growth, Statistics Canada data confirms the previous growth limitations and future growth prospects of a similar growth limitation. From 2001 to 2011, Hamilton's population growth averaged 0.31 percent per year and St. Catharines averaged negative 0.04 percent. From 2011 to 2016, population growth is expected to average 0.77 percent per year in Hamilton and 1.48 percent in St. Catharines. From 2016 to 2021, population growth is expected to average 1.85 percent per year in Hamilton and 0.20 percent in St. Catharines.

Horizon Utilities' deployment of technology throughout the distribution system will continue in the 2015 to 2019 Test Years. Technology focused on improving Horizon Utilities' distribution system operating capabilities will focus on the continued deployment of automation throughout the distribution system. Automation provides real time operational data and improves the ability to respond to service interruptions and reduces the duration of service interruptions. Technology focused on providing customer benefits will be guided through continued customer engagement. The customer engagement effort was initiated in 2013 and will continue through the 2015 to 2019 Test Years.

Horizon Utilities has sufficient of capacity to support REG connections in both Hamilton and St. Catharines. Horizon Utilities identifies that some feeders are constrained due to the presence of existing generation. These generators cause a minimum loading constraint on these feeders. More load would have to be added to the feeders by the addition of new customers, to resolve this issue. To date, any constraints related to the connection of renewable generation caused directly by Horizon Utilities' distribution system have been due to minimal loading on feeders.

Constraints on the host transmitter, Hydro One vary; the most common of these is thermal or short circuit loading. The substations in St. Catharines will be relieved when Allanburg TS breaker upgrades are completed in 2014 by Hydro One. Additional capacity for renewable generation will be available in Hamilton/Stoney Creek when the short circuit values are recalculated and the results reported on March 1, 2014 for Nebo TS (27.6kV) by Hydro One. Further information regarding REG deployment in Horizon Utilities' service territory is provided in Appendix E.

3.1.8. Conditional Impact on Total Capital Cost (5.4.1 h)

Horizon Utilities is focused on the development of projects and initiatives that create value for customers and promote the safe and reliable delivery of electricity through innovative energy solutions.

Horizon Utilities' projects can be categorized as: responsive to customer preferences; leveraging technology-based opportunities; and investigating innovative processes and technologies as detailed in Table 38 below.

Projects	2014 Bridge Year	2015 Test Year	2016 Test Year	2017 Test Year	2018 Test Year	2019 Test Year	Driver: Customer / Technology / Innovation
Reporting Basis	*MIFRS*	*MIFRS*	*MIFRS*	*MIFRS*	*MIFRS*	*MIFRS*	
IFS ERP Upgrade	$ 980,260	$ 1,382,600	$ -	$ -	$ 1,225,000	$ -	Technology / Innovation
Enterprise Phone System Upgrade	$ -	$ 400,000	$ -	$ -	$ -	$ -	Technology / Innovation
GIS Renewal	$ 1,869,308	$ 205,276	$ -	$ -	$ -	$ -	Technology / Innovation
CIS Upgrade / Replacement	$ -	$ 150,000	$ -	$ -		$ 200,000	Technology / Innovation
OMS Enhancements			$ 250,000	$ 250,000	$ 50,000	$ 50,000	Customer / Technology / Innovation
Website Enhancements - Customer Tools		$ 50,000	$ 50,000	$ 50,000	$ 50,000	$ 50,000	Customer
Total	**$ 2,849,568**	**$ 2,187,876**	**$ 300,000**	**$ 300,000**	**$ 1,325,000**	**$ 300,000**	

Table 38 - Projects Addressing Customer Preference, Technology, and Innovation

Customer Preference

Customers' expectations for transparency of information are increasing. Horizon Utilities plans to increase customer education opportunities and provide multi-channel customer communications and accessibility through enhancements to the OMS, continued investments in self-service options and website improvements, and the implementation of Smart Grid components.

Horizon Utilities is planning enhancements to the OMS system which is scheduled for implementation in 2015. Enhancements anticipated in 2016 and beyond include the integration of the AMI Smart Meter data as an input channel in order to proactively provide customers with information about power outages. The integration of Smart Meter data will also enable the automated verification of power restoration. Outage notification services will be expanded to incorporate customer text-based messaging and to include on-going communication of restoration efforts. An enhanced communication service is also planned for vulnerable customers through the ability to notify secondary contacts of power outages and estimated restoration times.

Horizon Utilities is integrating the GIS, OMS, and AMI operational systems with customer interfaces which will enable increased accessibility of information to customers to the utility. System integration will provide visibility of the status of field assets and systems, providing valuable information to assist in power restoration and decreasing the length of customer outages.

Horizon Utilities has planned investments to address customer preferences for 24/7 accessibility to account information and services and consumption and cost management tools through continued investment in the corporate website. Projects include website functionality improvements to provide the ability for customers to register for pre-authorized payments on-line, enhanced customer tool offerings to manage consumption and costs, and to enable customer selection of preferred communication channels for outage notifications and on-going restoration communications. In addition to providing additional tools and services to customers, web investments are a cost effective way to meet customers increasing expectations for information and accessibility.

Horizon Utilities conducted a customer engagement effort, launched in July 2013, to identify customer preference and requirements with respect to investment in Smart Grid components. Horizon Utilities conducted a Smart Grid Survey captioned “Plug in to Win” to acquire this information. This program consisted of a survey designed to educate customers about Smart Grid technology and to gauge customer preferences and priorities for Smart Grid investment planning. Feedback categories on the survey included:

- System automation;
- Connectivity of renewable generation;
- Investments to further support electric vehicles;
- Two-way meter communication;
- Battery storage;

- Enhanced time-of-use pricing strategies; and
- Customer tools for cost management.

To increase customer engagement in the Smart Grid survey, the survey was promoted through a contest opportunity for customers and a multi-channel advertising strategy. More than 800 customers responded to the survey before it concluded on November 30, 2013. Horizon Utilities is currently analyzing the feedback received from customers through this survey to inform future Smart Grid investments.

Technology-Based Opportunities

Horizon Utilities has a number of projects and system lifecycle upgrades of enterprise operations systems planned to take advantage of emerging and affordable technology improvements. These initiatives are necessary as part of the evolution and modernization of the distribution system, to deliver productivity improvements and reduce risk to the organization.

Horizon Utilities has identified a 2014 and 2015 Distribution Automation project specifically directed at the deployment of automated switches throughout the Hamilton and St. Catharines service territories. An investment of $1,250,000 is forecast in each of 2014 and 2015 for this project. This project is further detailed in Appendix A of this document.

The Customer Information System is nearing end-of-life and planning for the upgrade or replacement of this critical corporate system will begin in 2017 as detailed in Exhibit 2, Tab 6, Schedule 1. As compared to the current CIS, the upgraded or replaced CIS will have enhanced technology capabilities which are anticipated to provide productivity efficiencies through streamlined processes, decreased training time due to intuitive browser options, and decreased internal maintenance and system support requirements.

Lifecycle upgrades which will introduce enhanced technology are also scheduled for the GIS, SCADA, OMS, ERP, AMI, and MV90 systems between 2015 and 2019. In addition to the provision of new technology, the ERP system in particular is anticipated to result in productivity improvements as detailed in Exhibit 4, Tab 3, Schedule 4.

Innovative Processes and Technologies

Horizon Utilities studies and assesses technologies and processes through a number of forums. Horizon Utilities’ participation in the E8 Smart Grid Working Group, described in Section 1.2.2 above is an example of its commitment to understanding and assessment of innovative processes and technologies.

3.2. Capital Expenditure Planning Process Overview (5.4.2)

3.2.1. Objectives (5.4.2.a)

Horizon Utilities' capital expenditure planning objectives align with the AM Planning Objectives. AM Objectives guide the selection and prioritization of projects and ensure projects brought forward for review and approval align with Horizon Utilities' Financial, Customer, Operational, and People corporate objectives.

The capital planning process ("Capital Planning Process") balances AM needs against the financial impact of the investments. AM determines the level and area of capital investment whereas the capital planning process determines the affordability for both the company and customers.

Horizon Utilities' Capital Planning Process objectives are:

- Ensuring capital investments are affordable and support long-term financial viability;
- Providing the investment required for Horizon Utilities to meet obligations for enabling customer and 3rd party initiated projects;
- Reviewing investment plans for rate impact and affordability for customers;
- Variance in the investment requirements from year-to-year identified and justified; and
- Ensuring Horizon Utilities has sufficient financial and human resources required to execute the required investments prior to approval.

The Capital Planning Process is undertaken annually as a component of the annual financial and business planning process of Horizon Utilities. The process includes the development and detailed departmental business plans. Investment requirements and implementation plans to achieve identified objectives are included in the business plans. Objectives requiring significant (greater than $100,000) investment or requiring cross departmental resources are specifically identified and supported by a business case.

The capital and operational expenditure requests identified in the business plans are compiled and assessed against Horizon Utilities' capital planning objectives identified above. The quantity and timing of resources (e.g. internal labour) required to execute the prioritized list of projects are assessed for resource availability.

Affordability is a factor that Horizon Utilities considers a precursory necessity to meeting its asset management objectives. During the development of a capital expenditure plan, Horizon Utilities analyzes its long-term ability to sustain required investments in its distribution system. These investments are contingent on an outlook of Horizon Utilities for sufficiency and sustainability of regulated cash flow that, generally speaking, meets the Fair Return Standard; thus supporting financial integrity and ongoing capital attraction based on returns on invested capital that are comparable to other enterprises of like risk. This standard supports the interests of investors (debt and/ or equity) and customers in the long-term viability of the utility.

As a practical matter, government-owned utility investments are financed by a combination of debt and regulated cash flow to service debt. The amount that can be borrowed by a regulated utility is a function of its risk profile and regulated level of cash flow. The rate-making policies of the OEB, including those that govern the rate recoverable amount of cost of financial capital, create practical constraints on regulated utility borrowings and cash flow. Additionally, the tax regime governing government-owned regulated utilities is a practical constraint on the issuance of shares as a source of financing. Consequently, debt management is a central element of the overall financial management of a regulated utility including the retention of debt liquidity to support contingencies (e.g., changes in government policies; legal; etc.,.).

Based on the above factors, Horizon Utilities manages its debt levels within a long-term range of 50% to 60% of total financial capitalization on the presumption of an outlook for supporting cash flow sufficiency as previously described.

Horizon Utilities has prepared financial projections based on the approval of this Application as filed, including the full recovery of all OM&A and depreciation expenses resulting from continued investment as proposed herein. These projections support the maintenance of key financial ratios within a range that, under present market conditions, would allow for continued efficient access to financing from the capital markets.

Integrating financial objectives (such as project affordability) into the overall DSP allows Horizon Utilities to maintain an efficient capital expenditure process. Each step of the Capital Planning Process is directly linked to the objectives stated above; each of which informs this DSP.

3.2.2. Policies, Regional Planning and Non-Distribution System Alternatives (5.4.2.b)

Horizon Utilities actively pursues Conservation and Demand Management ("CDM") initiatives providing a non-distribution means of reducing capacity demands on the distribution system. Horizon Utilities' Long Term Load Forecast report produced in 2013 identified a decrease in peak loading across the service territory when compared to the previous report generated in in 2011. The decrease varied by station and bus and Horizon Utilities believes that some of the decrease could be attributable to the success of CDM programs.

Subsequent to the production of the 2013 report, the OPA identified 8.2MW in distributed generation contracts awarded within Horizon Utilities service territory. A 2% reduction in load in 2015 rising to 5% in 2019 was projected by the OPA for Horizon Utilities' service territory through the RPP.

Horizon Utilities' investment proposed in the 2015 to 2019 Test Years is focused on System Renewal investments with minimal investments required for capacity projects. An investment to Hydro One for increasing the TS capacity in the Hamilton Mountain area is forecast in the 2019 Test Year and Horizon Utilities will continue to monitor the CDM results to assess their impact on this forecast investment. The CDM results will be incorporated into the next Long Term Load Forecast scheduled for 2015.

3.2.3. Prioritization and Pacing of Investments (5.4.2.c)

Horizon Utilities combines a top down and bottom up iterative approach in resolving the prioritization and pace of capital investment requirements in the context of balancing objectives of long term operational and financial sustainability including the balancing of related risks. In this regard:

- Operational sustainability corresponds to the continuous delivery of customer service obligations with respect to the adequacy, reliability and quality of electricity distribution service. The achievement of operational sustainability is dependent on the delivery of necessary investment and operating costs articulated in this Application;

- Financial sustainability aligns to the ongoing ability to generate cash flows that are reasonably sufficient to achieve the objectives of the Fair Return Standard (EB-2009-0084), including the maintenance of financial integrity and capital attraction on reasonably competitive terms and conditions as compared to other enterprises of a like risk. Financial sustainability also incorporates customer affordability of service as this is the ultimate source of regulated cash flow. In this regard, and in the context of regulated rate making policy, Horizon Utilities is committed to continuous improvement and the delivery of productivity as a core component of supporting customer affordability. Financial sustainability is particularly important in the context of this Application as the Long Term Capital Investment Strategy will require significant amounts of incremental financial capital over the investment horizon. The achievement of financial sustainability is dependent upon cash flow that is supportive of the necessary investment and operating costs articulated in this application including a reasonable return on capital consistent with the Fair Return Standard.

These sustainability objectives underlie the corporate strategies and asset management strategies that are foundational elements of: i) the AM Framework and Asset Management Model that are deterministic of System Capital (i.e., System Access, System Renewal, and System Service) project identification as elaborated in Section 2.1.2; and ii) the assessment and identification of General Plant capital projects as further described below.

Specifically, the AM Framework (Section 2.1.2, Figure 12) is designed to achieve equilibrium among proposed Distribution System Capital investments, performance objectives (including operational and financial), customer satisfaction, risk factors, and energy policy and regulation. The fundamental principle of Asset Management Strategy within the AM Model (Section 2.1.2, Figure 13) focuses on identification of and justification for System Capital investment decisions related to the long term stewardship of electricity assets to provide a high level of customer service and reliability at the lowest total life cycle cost possible.

General Plant Capital projects are principally undertaken to provide for: i) the sustainment of assets supporting electricity distribution service such as facilities, fleet, tools, and information technology assets; and ii) the enhancement of electricity distribution service through investments that support productivity and more effective customer service delivery.

General Plant Capital projects that support sustainability are generally identified as a result of:

- condition studies and statutory compliance (e.g building refurbishments);
- the application of best practices with respect to routine replacements (e.g., fleet, tool and computer replacement programs); and

- a need to replace assets that are otherwise at the end of their productive life or the continued use thereof represents an unacceptable risk to business continuity (e.g., major upgrades of computer systems such as Customer Information Systems, etc., that are no longer supported by software and/or hardware vendors).

General Plant Capital expenditures that support productivity are generally identified as a result of process improvement or process optimization investigations (e.g., changes to planning and scheduling, process optimization through new or upgraded systems, etc.).

General Plant Capital expenditures that provide more efficient and effective customer service delivery are generally identified as a result of evolving customer trends and supporting technology (e.g., web-based self-service technologies, outage management systems and processes, etc.).

The pacing and prioritization of all capital investment is ultimately resolved through: i) a balancing of these sustainability objectives underlying corporate and asset management strategies; and ii) delivery through the output of the system, asset condition, and operational performance planning activity components of the AM Framework, Asset Management Model, and General Plant project assessment and identification processes. These activities are elaborated further below.

Long Term Capital Investment Strategy

The Long Term Capital Investment Strategy is used to determine discrete annual investment envelopes required for the aggregate of investment requirements for: i) the continued renewal of the distribution system within the twenty year planning horizon; as identified by the Kinectrics' ACA; System Access and System Service; and iii) System Renewal. System Renewal investment is the primary capital investment driver with a long term planning horizon. The output from the Long Term Capital Investment Strategy is provided above in Section 3.1.3.

As previously discussed in Section 2.1.2, the ACA identifies the number of units categorized under System Renewal that are expected to be flagged-for-action in the next twenty years and provides a recommended and prioritized renewal investment profile. This recommended profile is used to guide the twenty year capital investment requirements.

Project Identification

Based on the Long Term Capital Investment Strategy, candidate projects are selected for development, analysis, and prioritization within discrete years covered by the business and financial planning cycle as described under the Annual Capital Investment Program heading below. The initial screening criteria for the selection of projects for development within a particular year are prioritized in the following order:

1. System Access – These projects take priority because these investments are required to meet customer service obligations in accordance with the DSC or to remain compliant with regulatory or legal requirements.
2. System Renewal – The long term capital investment strategy identifies the investment profile over a 20 year planning horizon. The investment profile is identified for each asset group assessed in the ACA. The Project Identification step identifies the asset groups requiring renewal prioritization. The high volume of assets in poor health and level of investment required to address these assets cannot be addressed in a single year and requires a multi-year investment plan. Capital investment programs are developed to provide this multi-year plan for the renewal of the prioritized assets. The capital investment programs form the basis from which candidate renewal projects are selected and developed for inclusion in the annual budget process.
3. System Service – These Investments are non-renewal in nature and support the expansion, operation and reliability of the distribution system. The level of expenditure in the short term is also prioritized based on resource requirements to execute on proposed plans.
4. General Plant – These investments address the sustainment and enhancement of electricity distribution service, as described above, in the following areas:
    - (a) IT Investments:
        - (i) Regulatory Requirements.
        - (ii) Business sustainment continuity and risk mitigation.
        - (iii) Hardware and software to support corporate productivity and customer value initiatives.

(b) Facilities:

(i) Building renewal and renovation projects driven by requirements from asset condition studies.

(ii) Business continuity and risk mitigation.

(c) Fleet:

The scope, justification and high level estimates are created for the portfolio of candidate System Capital projects identified above are submitted for project prioritization for scoring to determine overall project effectiveness, value, and timing.

General Plant expenditures are identified based on, as applicable: i) recommendations and results of asset condition studies with emphasis on the urgency of investment and pacing investment to balance customer and utility affordability; ii) statutory compliance requirements; iii) experience embedded within best practices for replacement or incremental investment to support System Capital growth; iv) the time that incumbent assets will be at the end of their productive life; iv) opportunities to harvest productivity; v) customer preferences and trends with respect to electricity distribution service.

Project Prioritization

The project prioritization process related to the annual business planning cycle assesses the portfolio of candidate projects to identify the final list of projects for inclusion in the budget for the next year.

Distribution System Capital

The prioritization methodology for Distribution System Capital results in a weighted average score for each project that is based on an assessment of how each project contributes to, or the level of importance for, each of the five defined categories. The highest scoring projects are given the highest priority.

The prioritization methodology will apply to all proposed System Capital projects with the exception of projects determined to be mandatory. Projects deemed to be mandatory include:

- Projects identified as a result of customer demand;

- Projects where there is an immediate risk to worker or public safety;
- Highway or roadway relocations, and upgrades needed to accommodate municipal, federal or provincial infrastructure improvements;
- Projects required to become or remain compliant with applicable legislation and/or regulation;
- Projects required to address immediate environmental concerns; and
- Replacement of equipment that has failed or become damaged and is needed to maintain continuity of service.

All other proposed capital projects are otherwise ranked and prioritized. The relative weights of the five identified categories used in the prioritization process are shown in Table 39 below. The categories and weights, further elaborated below, were determined in conjunction with Navigant Consulting as part of Horizon Utilities' efforts in 2009 to continue to improve the AM model.

Category	Description	Weighting
Safety	Employee and Public	20%
Security	Outage Impact	30%
Customer Impact	Commercial, Industrial & Residential Impacts	25%
Regulatory/Statutory	Regulatory and Statutory	15%
Environmental	Impact to and from the Environment	10%
Total Score		100%

Table 39 - Total Prioritization Score

The project prioritization categories, including a description of each of the components used to derive project scores is provided as follows:

Safety Risk Score

The safety risk score measures the impact or importance to either employee or public safety of the investment.

Horizon Utilities' objectives with respect to safety are:

- The operation of the distribution system, under normal operating conditions, presents no risk to public safety;

- The risk of failure of the distribution system resulting in a risk to public safety is minimized; and

- The risk to employee safety during the maintenance and operation of the distribution system can me managed to acceptable levels through approved work procedures and using approved personal protective equipment.

The safety risk score, measured using a five point scale, quantifies the impact of the proposed project on the ability to address one of the objectives listed above. The minimum score of zero corresponds to projects having no impact on safety related issues while the maximum score of five corresponds to projects addressing issues where the continued operation of equipment cannot be performed within the acceptable limits identified by a Horizon Utilities' Risk Assessment.

Security Score

The security score provides a measure for the increase in reliability resulting from the corresponding investment. Increased reliability is measured through identification of potential service interruptions to be mitigated through completion of the investment.

The security score, measured using a five point scale, measures the reliability impact through combining the probability of a service interruption with the impact of the outage upon occurrence.

The minimum score of zero corresponds to projects having no impact on reliability while the maximum score of five corresponds to projects providing a significant ability to either reduce the risk of a service interruption or reduce the duration (i.e. impact) of the interruption upon occurrence.

Customer Impact Score

The customer impact score measures the financial or inconvenience impact to customers relative to the investment required to address the risk of the service interruption. The customer impact score is derived by dividing the financial impact to customers by the project cost. The financial impact to customers is calculated by multiplying a Value of Service ("VOS") value (measured in $/kw) by the quantity of load impacted by a service interruption (measured in kw). The VOS is a derived value that represents a proxy for: the customer's lost production and/or sales; or inconvenience due to a service interruption. The mix of affected residential, commercial and industrial customers and the duration of the outage are used to determine the VOS value. Horizon Utilities utilizes VOS values based on metrics developed by Dr. Roy Billinton[13] of the University of Saskatchewan.

The customer impact score, measured using a five point scale, quantifies the ratio of the financial impact to customers relative to the investment required to address the risk.

The minimum score of zero corresponds to projects with a low ratio of financial impact to customers versus project costs while the maximum score of five corresponds to projects with a high ratio of financial impact to customer versus project costs.

Regulatory/Statutory Risk Score

The Regulatory/Statutory risk score quantifies the risk of non-compliance with statues and/ or regulations should a project not be completed. Projects required to comply with the DSC or the OHSA as identified above are deemed mandatory and do not require scoring.

Compliance risk is assessed by: identifying the risk associated with the non-compliance; the cost to address the risk; and the impact on customers/shareholders/external parties associated with the non-compliance.

The minimum score of zero corresponds to projects having no impact on regulatory or legal compliance while the maximum score of five corresponds to projects addressing a significant risk of legal or regulatory non-compliance.

Environmental Risk Score

The environmental risk score measures the mitigation of environmental risk or impact provided by the investment. Environmental risks or impacts result from:

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[13] Dr. Billinton has provided consulting services to major Canadian electric power utilities and to many other organizations around the world. Over 100 individual utility courses dealing with power system reliability evaluation have been presented. Dr. Billinton has authored or co-authored eight books on reliability evaluation and over 775 papers on power system reliability evaluation, economic system operation and power system analysis. Dr. Billinton is a Fellow of the IEEE, the EIC, the United Kingdom Safety and Reliability Society and the Royal Society of Canada. He is also Chairman of the Canadian Electrical Association, Consultative Committee in Outage Statistics and a Professional Engineer in the Province of Saskatchewan

- Equipment failures creating a hazard to the environment (e.g. waterway or soil contamination);

- Impact on the environment from business operations;

- Presence of hazardous or selected material within distribution assets. (e.g. PCBs)

Environmental risk is assessed by identifying the risk mitigated through the completion of the investment. The minimum score of zero corresponds to projects providing no mitigation on environmental risks or impacts while the maximum score of five corresponds to projects providing significant mitigation to environmental risks or impacts.

The scores from each category are combined, using the weighting factors identified in Table 39 above, to provide a single weighted average composite score. Interpretation of the total score is provided in Table 40.

Total Score	Description
5	Mandatory project – Deferral of project will result in: - Negative impact on customer - Inability to address an imminent safety concern
4	Required project – Deferral of project not recommended and will impact the schedule for multi-year programs.
3	Required project – Deferral of project not recommended. Project required to proceed and will displace projects in future years.
2	Desired project – Deferral of project can be accommodated and may not impact or displace projects in future years.
1	Optional project – Deferral of project does not have material impact on system operations or asset health.

Table 40 - Score Interpretation Guide

General Plant Capital

The general criteria underlying the prioritization of System Capital overlap with those underlying the prioritization of General Plant Capital. However, certain System Capital prioritization criteria are less relevant to General Plant Capital prioritization (e.g., customer demand, road relocations). Additionally, there is no formulaic scoring mechanism for the General Plant class of capital. The prioritization within this class and integration within the overall annual and long-term capital program is performed more judgmentally.

General Plant Projects deemed to be mandatory would include:

- Projects where there is an immediate risk to worker or public safety;
- Projects required to become or remain compliant with applicable legislation and/ or regulation;
- Projects required to address immediate environmental concerns; and
- Replacement of equipment that has failed or become damaged and is needed to maintain continuity of service.

Similar to System Capital, the prioritization of General Plant Capital otherwise is based on objectives of: Safety; Security; Customer Impact; Regulatory/ Statutory Compliance; and Environmental Risk. Generally speaking, the objectives between the two categories are similar but with the following notable differences:

- The Security criterion is considered in the context of business continuity, and physical and cyber security;
- The Customer Impact criterion is considered in the context of delivering customer service with regard for productivity and service enhancement.

The timing of projects is also relevant to prioritization. Such timing is generally specified on the same basis as described under the Project Identification section with respect to General Plant Capital.

Annual Capital Investment Program

The period of coverage for the annual business and financial planning process of Horizon Utilities is five years ("5-Year Plan"). The period of coverage for the 2014 plan was expanded to six years in order to cover the 2014 Bridge Year and the 2015 through 2019 Test Years.

Annual capital investment programs are specified in each year of the 5-Year Plan and derived from the AM Framework and implementation components of the AM Model as previously described including the project identification and prioritization processes.

Ultimately, the magnitude of annual capital investment is limited through the balancing of the financial and operational sustainability objectives as previously described. This balancing sets the pace of overall capital investment across and within discrete years covered by the 5-Yr Plan. The prioritization of annual capital investment is then determined by adding capital projects from highest to lowest priority until the cumulative total equals the magnitude set for the corresponding year. Projects that do not qualify for execution in the most current budget year are reviewed once again to ensure that the consequence of project deferral to the next year is not an unacceptable level of operational risk. Thereafter, the final list of projects for the annual capital investment program is approved within the 5-Year.

Customer Engagement (5.4.2.d)

Horizon Utilities undertook a multi-faceted approach to customer outreach for the DSP, as identified above. Details of the key elements of the outreach are provided as follows:

a) **Online Workbook** – As identified above, Horizon Utilities and Innovative created a Distribution System Plan Workbook to articulate the key elements of Horizon Utilities' preliminary work on the DSP in a customer-friendly manner. The Online Workbook was used as an engagement tool to: educate customers; assess customer preferences and priorities; gauge customer reaction to rate increases; and inform subsequent phases of the consultation. Horizon Utilities posted the DSP Workbook online at www.horizonutilitiesworkbook.com for 34 days, between December 11, 2013 and January 13, 2014. Horizon Utilities promoted the Online Workbook through: traditional print advertising (i.e., the Hamilton Spectator and the St. Catharines Standard); Horizon Utilities' website and Horizon Utilities' social media accounts, including Facebook and Twitter.

   As respondents went through the Online Workbook, they were prompted with questions related to system reliability, system challenges, and what the DSP means to them. In total, the Online Workbook contained fifteen questions, with opportunities for open-ended responses and additional comments. All responses were anonymous and kept strictly confidential.

This was the opportunity for customers to learn more about Horizon Utilities' operational plans and share their feedback. The ultimate goal was to understand the level of alignment between Horizon Utilities' operational plans and customers' preferences and priorities.

The Innovative Customer Consultation Report, that includes all aspects of the consultation as well as the results, is included in Appendix D.

Results

- 1,049 unique visitors came to the Online Workbook's landing page;
- 333 unique visitors continued beyond the landing page;
- 151 customers completed at least the profiling section of the Online Workbook (140 residential/11 business customers); and
- 111 customers completed the entire Online Workbook by answering all questions (103 residential/8 business customers).

The results of the Online Workbook were based on completed answers to the Online Workbook questions by residential customers. More than 60% of respondents indicated that they were prepared to accept the proposed rate increase. That is, they either thought the proposed rate increase was reasonable and supported it or indicated that, while they did not like it, they thought it is necessary. Of the remaining residential respondents, 32% were opposed to the rate increase, while 6% indicated that they did not know or did not have an opinion. In advising of their acceptance of the proposed rate increase, customers identified that they understood that investments in system renewal made now could avoid more costly reactive renewal investment later.

b) **DSP Workbook-based Facilitated Discussions** – Innovative conducted a series of stakeholder and General Service customer consultation sessions using the DSP Workbook as the foundation of the facilitated discussions. The consultation sessions were designed to identify the needs and preferences of customers as they related to the proposed 5-Year DSP. The consultation sessions were held in St. Catharines on January 14, 2014 and in Hamilton on January 15, 2014. A total of 43 stakeholders and General Service customers participated in these consultation sessions.

Community and industry stakeholders were recruited from a list provided by Horizon Utilities. Invited stakeholders represented a diverse range of interests from a cross section of industry, business, environmental and social advocacy groups from both St. Catharines and Hamilton.

General Service customers in the < 50kW and > 50kW rate classes were randomly selected by telephone from customer lists and screened for appropriateness as session participants. General Service customers qualified for the consultation if their representative employees managed or had oversight of their electricity bill in order to ensure they were somewhat knowledgeable of their electricity costs and could have an informed discussion on the impact of the proposed rate increases. Horizon Utilities randomly generated the customer lists and provided them to Innovative. All General Service customers who participated in the consultation sessions were given a $100 incentive. Community and industry stakeholders did not receive an incentive to participate in the consultation sessions.

The consultation sessions were structured around the themes contained in the DSP Workbook. All consultation participants were sent electronic copies of the workbook via email as part of a pre-read package in advance of the 2.5 hour sessions. At the start of the sessions, the facilitator gave an overview explaining the purpose of the consultation and why Horizon Utilities was seeking feedback from stakeholder groups and customers.

After explaining the purpose of the consultation, hard copy workbooks were distributed to act as a session guide for participants to record their answers to the question contained within. The facilitator then led the participants through the workbook, section by section, to ensure they understood the information and to answer any questions they had about the content.

Participants completed the questions in the Workbook independently. The facilitator then led a group discussion on the participants' answers and what this meant for their businesses or constituents.

Results

A total of 43 stakeholders and General Service customers participated in the January 14th and 15th consultation sessions.

- **St. Catharines: January 14, 2014**

Community and Industry Stakeholders: 5 participants

General Service over 50 kW Rate Class: 8 participants

General Service under 50 kW Rate Class: 8 participants

- **Hamilton: January 15, 2014**

Community and Industry Stakeholders: 8 participants

General Service over 50 kW Rate Class: 7 participants

General Service under 50 kW Rate Class: 7 participants

Most participants (32 of 43) in the consultation groups were prepared to accept the proposed customer rate increases, with 8 of 43 indicating their support for the proposed rate increase and 24 of 43 indicating that while they did not like it, they believed it was necessary. The remaining eight participants indicated that the rate increase was unreasonable and that they opposed it.

c) **Residential Survey** – Innovative conducted a telephone survey among 1,011 of Horizon Utilities residential customers, who were randomly selected from a Horizon Utilities-provided list between January 22nd and 29th, 2014. A sample of this size is considered accurate to within ±3.1 percentage points, 19 times out of 20. The questionnaire was designed to simulate the process that respondents in the Online Workbook and Workbook-led Consultation Sessions experienced. This included a combination of: educating the customers; having them reflect on their personal experience with their distribution system; and having them make value judgments on trade-offs between system reliability and bill impact.

The questionnaire was informed by and incorporated feedback from the previous phases of Horizon Utilities' customer engagement. This included sharing both supportive and non-supportive feedback in the survey from previous phases of Horizon Utilities' customer consultation, as such related to Horizon Utilities' proposed rate increase. The average survey completion was just under 11 minutes. The survey instrument and further details regarding the survey can be found in Appendix D.

Results

Almost three-quarters of respondents (73%) in the residential customer survey indicated that they were prepared to accept the proposed rate increase. That is, they either thought the proposed rate increase was reasonable and supported it or indicated that, while they did not like it, they thought it is necessary. Approximately one quarter of the respondents (24%) thought the proposed rate increase was unreasonable and opposed it. The remaining respondents did not know or refused to answer.

d) **Key Account Meetings and Validation Interviews** – Horizon Utilities facilitated one-on-one customer meetings with key account customers between November 27, 2013 and February 4, 2014. Innovative conducted follow up interviews with nine of the twelve key account customers who participated in one-on-one consultation sessions with Horizon Utilities' management. The interviews were designed to validate the process and to verify that Horizon Utilities had provided these customers with the information they needed to provide informed feedback on the proposed DSP. Horizon Utilities identifies that, of the nine key account customers interviewed by Innovative, six are members of Horizon Utilities' Large Use customer class and three are classified as General Service > 50 kW customers – each of these three customers has multiple facilities and multiple accounts that, if aggregated, would be equivalent to a Large Use load.

Results

Most participants (6 of 9) in the key account group indicated that they were prepared to accept the proposed rate change. Among the key account customers, 5 of 9 indicated their support for the proposed rate change and 1 of 9 indicated that, while they did not like it, they thought it was necessary.

Stages of the Planning Process at which Customer Feedback was Used

Horizon Utilities used the feedback from its customer outreach mechanisms for the purpose of identifying its customers' needs, priorities and preferences, and the final version of the DSP is consistent with customer preferences for system renewal notwithstanding a resulting increase in distribution rates.

Aspects of the DSP Affected by Customer Consultation

Through its DSP-related customer engagement processes, Horizon Utilities educated customers on the major issues facing its distribution system and the matters that Horizon Utilities needs to address over the next five years and beyond. More particularly, Horizon Utilities identified System Renewal projects such as the 4kV and 8 kV Renewal Program, distribution station decommissioning, and proactive XLPE replacement as key elements of its renewal plan. The majority of Horizon Utilities' customers accepted the need for system renewal, notwithstanding that this may involve increased distribution rates. The DSP's focus is consistent with these findings. System Renewal projects over the 2015-2019 Test Years represent 64% of Horizon Utilities' capital expenditure.

3.3. System Capability Assessment for Renewable Energy Generation (5.4.3)

Information regarding Horizon Utilities' capability to accommodate Renewal Energy Generation ("REG") can be found in Appendix E.

3.4. Capital Expenditure Summary (5.4.4)

The following section is designed to provide a summary of Horizon Utilities' capital expenditures over a 10 year period. This includes five historical years and five forecast years. As this is Horizon Utilities' first Application with a DSP, pursuant to the Chapter 5 Requirements, there is no data provided as to the 'Plan' values for the historical period. Only actual data was provided for the purpose of this summary.

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

First year of Forecast Period: *2014*

CATEGORY	Historical Period (previous plan[1] & actual)																		Forecast Period (planned)				
	2010 (CGAAP)			2011 (CGAAP)			2011 (MIFRS)			2012 (MIFRS)			2013 (MIFRS)			2014 (MIFRS)			2014	2015	2016	2017	2018
	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		13,558	--		8,914	--		5,629	--		6,602	--		6,369	--	7,540			8,243	8,472	7,896	8,092	8,273
System Renewal		14,082	--		22,475	--		17,171	--		14,091	--		18,425	--	15,372			18,070	28,294	33,168	33,208	34,706
System Service		3,583	--		3,125	--		2,374	--		2,885	--		2,151	--	4,101			4,140	295	535	2,032	2,057
General Plant		6,208	--		4,584	--		4,584	--		8,748	--		12,559	--	10,760			9,487	5,887	5,827	5,611	6,236
TOTAL EXPENDITURE BEFORE SMART METERS	**-**	**37,432**	**--**	**-**	**39,098**	**--**	**-**	**29,758**	**--**	**-**	**32,326**	**--**	**-**	**39,505**	**--**	**37,773**			**39,940**	**42,948**	**47,426**	**48,943**	**51,272**
Smart Meter Implementation		-			-			-			23,278			-		-			-	-	-	-	-
TOTAL EXPENDITURE INLCUDING SMART METERS	**-**	**37,432**	**--**	**-**	**39,098**	**--**	**-**	**29,758**	**--**	**-**	**55,604**	**--**	**-**	**39,505**	**--**	**37,773**	**-**		**39,940**	**42,948**	**47,426**	**48,943**	**51,272**
Hydro One Contribution		-			-			-			10,000			-		-			-	-	-	-	-
TOTAL EXPENDITURES	**-**	**37,432**	**--**	**-**	**39,098**	**--**	**-**	**29,758**	**--**	**-**	**65,604**	**--**	**-**	**39,505**	**--**	**37,773**	**-**		**39,940**	**42,948**	**47,426**	**48,943**	**51,272**
Change in WIP		- 2,841			743			743			4,654			- 1,597		2,019			175	-	-	-	-
TOTAL ADDITIONS	**-**	**34,590**	**--**	**-**	**39,841**	**--**	**-**	**30,501**	**--**	**-**	**70,258**	**--**	**-**	**37,908**	**--**	**39,792**	**-**		**40,115**	**42,948**	**47,426**	**48,943**	**51,272**
System O&M		18,742			19,654			n/a			27,755			29,928		33,776			34,571	35,504	36,355	37,337	38,084

Notes:
1. 2013 values include 12 months of actuals
2. 2014 values include 12 months of forecast

Notes to the Table:
1. Historical "previous plan" data is not required unless a plan has previously been filed
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. histrical budgets by category
n/a
Notes on year over year Plan vs. Actual variances for Total Expenditures
n/a
Notes on Plan vs. Actual variance trends for individual expenditure categories
n/a

3.4.1. Explanatory Notes on Variances in Capital Expenditure Summary

Horizon Utilities has completed Appendix 2-AB in compliance with the Chapter 2 Filing Requirements and Chapter 5 Requirements. Historical prior plan data has not been provided since a DSP has not previously been filed with the Board. Horizon Utilities has provided a summary of Appendix 2-AB by category below.

<u>System Access</u>

System Access investments are comprised of projects outside of Horizon Utilities' control that are required to meet customer service obligations in accordance with the Distribution System Code ("DSC") and Horizon Utilities' Conditions of Service.

These projects include: connecting new customers; metering; building new subdivisions; and relocating system plant for roadway reconstruction work. Horizon Utilities uses an economic evaluation methodology prescribed in the DSC to determine the level, if any, of capital contributions for each project; with such levels incorporated into the annual capital budget. These investments are typically: a high priority; cannot be deferred; and must proceed as planned.

Historical year over year variances in 2011, 2012 and 2013 are primarily due to increased road relocations for municipalities and the connection of Municipalities, Universities, Schools and Hospitals ("MUSH") sector customers in Hamilton and St. Catharines.

The level of system access expenditures in each of 2010 to 2013 historical years was as follows:

- 2010 actuals (CGAAP) were $13,558,204, net of capital contributions of $8,512,542.
- 2011 actuals (MIFRS) were $5,629,314, net of capital contributions of $4,165,260. The decrease from 2010 of $7,928,889 was due to the expensing of overhead costs previously capitalized under CGAAP, and a decrease in system access projects. The change to the capitalization of overhead costs as a result of the transition to IFRS is discussed in further detail in Tab 6, Schedule 5 of Exhibit 2.
- 2012 actuals, excluding the smart meter implementation, were $6,602,316, net of capital contributions of $9,810,885. The increase of $973,003 from 2011 was due to an

increase in road relocation projects. 2012 expenditures also include the addition of $23,277,588 related to the Smart Meter Implementation. Horizon Utilities substantially completed its mass deployment of Smart Meters in 2009 and, as at the end of 2011, had installed Smart Meters for 229,322 customers or 98.0% of all metering points.

- 2013 actuals were $6,369,274, net of capital contributions of $6,605,934. The decrease of $233,043 from 2012 was due to a reduction in road relocation projects partly offset by an increase in the number of customer connections projects.

The level of system access expenditures from the 2014 Bridge Year to the 2019 Test Year is as follows:

- The forecast for the 2014 Bridge Year is $7,539,601, net of capital contributions of $4,472,300. The increase from 2013 is $1,170,327, primarily due to an increase in meters of $840,104, an increase in road relocation projects and customer connections.
- The forecast for the 2015 Test Year is $8,242,598, net of capital contributions of $4,633,000. The increase from 2014 is $702,997 is primarily due to an increase in road relocations, partly offset by a decrease in customer connections.
- The forecast for the 2016 Test Year is $8,471,952, net of capital contributions of $4,654,000. The increase from 2015, is $229,354, is primarily due to an increase in road relocation projects and customer connections.
- The forecast for the 2017 Test Year is $7,896,202, net of capital contributions of $4,677,000. The decrease from 2016 of $575,750 is due to a decrease in road relocation projects.
- The forecast for the 2018 Test Year is $8,091,602, net of capital contributions of $4,700,000. The increase compared to 2017 of $195,400 is primarily due road relocations expenditures.
- The forecast for the 2019 Test Year is $8,273,338, net of capital contributions of $4,730,000. The increase compared to 2018 of $181,736, is due to road relocations expenditures.

System Renewal

System renewal investments comprise the replacement of aging equipment and/or refurbishment of distribution assets.

The level of system renewal expenditures in each of the 2010 to 2013 historical years was as follows:

- 2010 actuals (CGAAP) were $14,082,166;

- 2011 actuals (MIFRS) were $17,170,921. The increase from 2010 of $3,088,755 was due to a higher level of investment in in the 4kV and 8kV Renewal Program, partly offset by a decrease in the level of capitalized overhead costs due to the transition to IFRS. Further discussion of overhead costs and the impact of the transition to IFRS has been provided in Exhibit 2, Tab 6, Schedule 5 and Exhibit 6, Tab 2, Schedule 1. The 4kV and 8kV Renewal Program is discussed in further detail Section 3.1.3 and Section 3.5.3.

- 2012 actuals were $14,090,964. The decrease from 2011 of $3,079,957 was due to a decline in reactive renewal and the 4kV and 8kV Renewal Program required to offset increased expenditures system access projects.

- 2013 actuals were $18,424,977. The increase from 2012 of $4,334,013 was due to the start of the underground XLPE Cable Renewal Program, and an increase in substation breaker and relay renewal and reactive renewal, partly offset by the completion of the downtown network renewal for St. Catharines.

The level of system renewal expenditure from the 2014 Bridge Year to the 2019 Test Year is as follows:

- The forecast for the 2014 Bridge Year is $15,372,195. The decrease from 2013 of $3,052,782 is driven by the completion of the substation and relay renewal program in 2013.

- The forecast for the 2015 Test Year is $18,070,415. The increase from the 2014 Bridge Year of $2,698,220 is due to increased investment in the 4kV and 8kV Renewal and underground XLPE Cable Renewal Programs.

- The forecast for the 2016 Test Year is $28,293,649. The significant increase from the 2015 Test Year of $10,223,234 is due to the Gage TS rebuild of $4,793,000, and an increase in the 4kV and 8kV Renewal and underground XLPE Cable Renewal Programs. Horizon Utilities has provided further elaboration and justification for the Gage TS rebuild in Appendix A.

- The forecast for the 2017 Test Year is $33,167,877. The increase from the 2016 Test Year of $4,874,227 is primarily due to increased investment in the 4kV and 8kV Renewal and underground XLPE Cable Renewal Programs.

- The forecast for the 2018 Test Year is $33,208,155. The main drivers of the investment are the continuation of the 4kV and 8kV Renewal and underground XLPE Cable Renewal Programs, which are forecast to be at the same level as the 2017 Test Year.

- The forecast for the 2019 Test Year is $34,706,031. The increase from the 2018 Test Year of $1,497,876 is driven by further investment in the 4kV and 8kV Renewal and underground XLPE Cable Renewal Programs.

The significant increase in system renewal expenditure over the 2015 to 2019 Test Years is a result of the necessary investment in the 4kV and 8kV Renewal and the underground XLPE Cable Renewal Programs.

Expenditures for the 4kV and 8kV Renewal Program are forecast to increase from $8,160,000 in 2015 to $16,846,000 in 2019 as identified in Table 41 below.

4kV and 8kV Renewal Program	2015 Test Year	2016 Test Year	2017 Test Year	2018 Test Year	2019 Test Year
Total	$ 8,160,000	$ 10,160,000	$ 15,764,000	$ 15,684,000	$ 16,846,000

Table 41 - 4kV and 8kV Renewal Program 2015 - 2019

Horizon Utilities' 4kV and 8kV distribution system services approximately 75,000 customers, representing 31% of its customer base. The 4kV and 8kV distribution system was largely constructed in the 1950s and is at or nearing end-of-life thus exposing customers to a higher risk of equipment failure and outages. The 2015-2019 Test Year investments in the 4kV and 8kV Renewal Program are necessary to address this risk. Without these investments, these customers will be subject to higher rates of service interruptions, with outage durations potentially lasting for several hours, days or months depending on the nature of the failed asset.

Expenditures for the underground XLPE Cable Renewal Program are forecast to increase from $2,567,000 in 2015 to $10,271,000 in 2019 as identified in Table 42 below.

XLPE Cable Renewal Program	2015 Test Year	2016 Test Year	2017 Test Year	2018 Test Year	2019 Test Year
Total	$ 2,567,000	$ 4,926,000	$ 8,866,000	$ 9,384,000	$ 10,271,000

Table 42 - XLPE Renewal Program 2015 - 2019

Historically, cable renewal has primarily been performed reactively. Horizon Utilities must initiate proactive replacement of its underground cable to address increasing risk resulting from the declining health of the extensive underground system. The XLPE Cable Renewal Program is the primary plan to address the renewal of underground assets. Failure to invest in XLPE cable renewal at Horizon Utilities' proposed investment of $36,014,000 over the 2015 to 2019 Test Years will result in increased frequency and duration of service interruptions to large numbers of customers.

<u>System Service</u>

Projects in this category are driven by Horizon Utilities' expectations that the evolving use of the system may create system capacity constraints or may adversely impact system reliability.

These investments are required to support the expansion, operation and reliability of the distribution system. Horizon Utilities further classifies these investments in sub-categories of capacity, reliability, and security.

The level of system service expenditure in each of the 2010 to 2013 historical years is as follows:

- 2010 actuals (CGAAP) were $3,582,988, which includes a Hydro One contribution to increase capacity at the Vansickle TS;

- 2011 actuals (MIFRS) were $2,373,505. The decrease from 2011 of $1,209,483 is due to the expensing of certain costs previously eligible for capitalization under CGAAP, and a decrease in investments to address system capacity. Further discussion of the impact of the transition to IFRS on capitalization policy has been provided in Exhibit 2, Tab 6, Schedule 5 and Exhibit 6, Tab 2, Schedule 1.

- 2012 actuals were $2,885,476. The increase from 2011 of $511,971 was due to the construction of an additional feeder from the Vansickle Transformer Station to address system capacity and a Hydro One contribution to upgrade the capacity at the Nebo TS.

- 2013 actuals were $2,151,349, including an additional Hydro One contribution to increase capacity at the Nebo TS. The decrease from 2012 of $734,127 was due to a lower level of system capacity investments. The completion of the additional feeder from the Vansickle TS was offset by the final Hydro One contribution to upgrade the capacity at the Nebo TS.

The level of system service expenditure from the 2014 Bridge Year to the 2019 Test Year is as follows:

- The forecast expenditure for the 2014 Bridge Year is $4,101,053. The increase from 2013 of $1,979,704 is a result of a Green Energy Act ("GEA") feeder automation project and the completion of a new feeder at the Nebo TS.

- The forecast expenditure for the 2015 Test Year is $4,139,747. The increase from 2014 is $38,694. The completion of the additional feeder from the Nebo TS in 2014 is offset by the construction of a third feeder in the Waterdown area, and the establishment of increased capacity and back up supply to the redeveloped Caroline and George Street area of downtown Hamilton. Justification for these projects is provided in Appendix A and Appendix G of the DSP. Horizon Utilities' Basic Green Energy Act ("GEA") Plan-related feeder automation project is expected to be completed in 2015.

- The forecast expenditure for the 2016 Test Year is $294,732. The decrease from 2015 of $3,845,015 is due to the completion of capacity projects in 2015. Investment levels are expected to decline as a result of a higher prioritization of system renewal projects in this year, as identified above.

- The forecast expenditure for the 2017 Test Year is $535,135. The increase from the 2016 Test Year of $240,403 is to accommodate security/redundancy projects. More details on these projects, which are forecast to continue into 2018, are provided in Appendix A.

- The forecast for the 2018 Test Year is $2,031,847. The increase from the 2017 Test Year of $1,496,712 is primarily due to projects required to address security/redundancy. The main driver is a conductor upgrade at St. Paul Street in St. Catharines. This project is discussed in further detail in Appendix A.

- The forecast for the 2019 Test Year is $2,057,209, driven by projects to address security/redundancy. Horizon Utilities also anticipates a payment to Hydro One to increase the capacity at the Mohawk or Nebo TSs. These projects are discussed in further detail in Appendix A.

<u>General Plant</u>

General Plant projects include investments in tools, vehicles, building and information systems technology ("IST") equipment that are required to support the operation and maintenance of the distribution system.

The level of general plant expenditure in each of the 2010 to 2013 historical years was as follows:

- 2010 actuals (CGAAP) was $6,208,326;

- 2011 actuals (MIFRS) was $4,584,443. The decrease of $1,623,883 versus 2010 actuals was driven by the replacement of vehicles and a project to replace Horizon Utilities' existing two analog radio systems with a single digital system.

- 2012 actuals were $8,747,623. The increase from 2011 of $4,163,180 was driven by the start of a multi-year initiative (2012 – 2019) to renew and upgrade Horizon Utilities' buildings and information systems. Horizon Utilities' building renewal projects are provided in further detail in Tab 6, Schedule 2, page 8 of Exhibit 2 and in Appendix A and Appendix G of the DSP. Horizon Utilities also commenced a multi-year project (2012- 2015) to replace its end-of-life GIS.

- 2013 actuals were $12,559,044, an increase of $3,811,421 from 2012. The multi-year initiatives to renew and refurbish Horizon Utilities' buildings and to replace the GIS system continued into 2013. Horizon Utilities commenced a multi-year initiative in 2013 to upgrade its IFS ERP.

The level of general plant expenditure from the 2014 Bridge Year to the 2019 Test Year is provided below. Table 43 identifies the general plant expenditures for the 2015 to 2019 Test Years.

Fleet	$785,000	$778,000	$780,000	$775,000	$785,000	$785,000
Building and Facilities [1]	$4,250,000	$4,000,000	$2,195,000	$2,495,000	$1,595,000	$1,595,000
Computer Hardware & Software	$4,435,965	$3,707,347	$2,181,000	$1,886,700	$2,532,700	$3,107,700
Communication Equipment	$6,200	$245,000	$5,000	$5,000	$5,000	$5,000
Tools, Shop, Garage and Measurement Equipment	$665,300	$687,860	$657,200	$596,200	$620,200	$670,200
Other	$1,018,000	$369,000	$269,000	$69,000	$73,000	$73,000
Total General Plant	**$11,160,465**	**$9,787,208**	**$6,087,200**	**$5,826,900**	**$5,610,900**	**$6,235,900**

1 Buildings and Facilities includes building security

Table 43 - General Plan Investments 2015 - 2019

- The forecast for the 2014 Bridge Year is $10,760,465. The decrease from 2013 of $1,798,579 is primarily due to a decrease in expenditures for the building renewal, partly offset by an increase in expenditures for the GIS project and an increase in vehicle replacement costs. No vehicles were replaced in 2013 in order to redeploy investment capital into necessary building refurbishments. The project to upgrade the IFS ERP system is expected to continue into 2014.

- The forecast for the 2015 Test Year is $9,487,208. The decrease from the 2014 Bridge Year of $1,273,257 is primarily due to a reduction in expenditures for the GIS project, which is expected to be completed in 2015, and a reduction in building expenditures. This decrease is partly offset by an increase in expenditures for the ERP upgrade and a phone system upgrade.

- The forecast for the 2016 Test Year is $5,887,200. The decrease from the 2015 Test Year of $3,600,008 is driven by lower IST expenditures and facilities compared to 2015. 2015 IST expenditures include the completion of the GIS project and ERP upgrade ,. 2015 Facilitates expenditures include: the completion of the John Street and Hughson Street roof replacements; the Nebo Rd emergency back-up generator; investment required for the John Street and Hughson Street building renovations; and the completion of the communications system upgrades.

- The forecast for the 2017 Test Year is $5,826,900, primarily due to the building renewal and refurbishment initiative. Justification and project details by year for this multi-year initiative are provided Section 3.5.3 and Appendix A.

- The forecast for the 2018 Test Year is $5,610,900. The decrease from the 2017 Test Year of $216,000 is due to a decrease in expenditures for building renewal and refurbishment, partly offset by a lifecycle upgrade of the IFS ERP system. This project is discussed in further detail in Appendix A.

- The forecast for the 2019 Test Year is $6,235,900, primarily due to the building renewal and refurbishment at the Stoney Creek Service Centre and IST expenditures. Justification and project details by year for this multi-year initiative are provided Section 3.5.3 and Appendix A.

3.5. Justification of Capital Expenditures (5.4.5)

The following section supports the value of investments that have been included in the Horizon Utilities DSP. The data, information and analysis that are necessary to support the capital costs within the rate proposal are presented summarily with reference to previous detailed sections as applicable. As previously identified in Section 1 and 2, the capital expenditures required in this DSP will ultimately deliver value to customers through applicable methodologies, measures, and planning schemes. This will be evidenced below.

3.5.1. Comparative Expenditures by Category

Comparative expenditures by category over the historical period were provided in Section 3.4.1.

3.5.2. Forecast Impact on System Operating & Maintenance Costs

Horizon Utilities expects the increasing capital investment in the renewal of aging infrastructure is estimated to exert downward pressure on system operating and maintenance costs over the longer term. System operating and maintenance costs are increasing due to a number of factors associated with a relatively old infrastructure. The investments proposed in the 2015 through 2019 Test Years will have the following impacts on operating and maintenance costs through in the following areas:

- Horizon Utilities anticipates that without the increased capital expenditures, system operating and maintenance will increase at a faster rate than currently forecast .

- The 4kV and 8kV Renewal Program will result in the decommissioning of nine of Horizon Utilities' municipal substations in the 2015 to 2019 Test Years. The decommissioning of the nine substations will provide a reduction in operating costs however, as identified in Section 1.1.2, these reductions are forecast to be realized after the 2019 Test Year.

- Labour expenditures required to address service interruptions are forecast to be lower than otherwise incurred. The number and impact of material and equipment failures has increased in recent years, as illustrated in Section 2.2.3. Horizon Utilities has proposed a graduated series of investments to attain the level of investment recommended by Kinectrics' ACA. The overall health of the distribution system will continue to decrease while Horizon Utilities increases investment to the recommended levels. Improving the health, and subsequently reducing the volume of failures requires a sustained long-term investment at the recommended levels. It will take multiple years before reductions in reactive expenditures, required to address service interruptions, are realized.

- The renewal of underground assets to current construction and equipment standards will ultimately result in a reduction of labour costs to operate and maintain the underground distribution system. For example: the replacement of submersible transformers with pad mounted transformers decreases the time required to locate and access the transformers and eliminates the need to work in confined spaces; and direct buried cable extends outage durations and increases trouble shooting expenditures required to identify and repair failed sections of cable. It will take multiple years before the volume of renewed assets will provides efficiencies in the operation of the underground distribution system.

3.5.3. Justification and Investment Drivers

Horizon Utilities' capital plan provides for managing investments in the distribution system over a twenty year period. This plan provides an increase in annual capital expenditure, particularly in the area of asset renewal. The increased investment is driven by the high volume of distribution assets with a Health Index of 'very poor' or 'poor' as identified in Kinectrics' ACA and confirmed by KPMG. Improving the Health Index cannot be accomplished in a single year. Improvement will only be possible through increased investment, sustained over several years. Failure to invest at the levels proposed in this DSP will result in increasing risk, which will escalate to a point beyond Horizon Utilities' ability to address within reasonable timeframes or at reasonable costs. Horizon Utilities submits that this graduated increase in investment represents a prudent investment profile and is both necessary and reasonable to manage customer costs at a graduated pace. The graduated increase mitigates the rate impact to customers in any one year relative to the Kinectrics recommendation and it represents the minimum investment possible to avoid degradation in the Health Index distribution for this asset group.

System Access

System Access investments are non-discretionary projects initiated by customers or 3rd parties. These projects include connecting new customers, building new subdivisions, and relocating system plant for roadway reconstruction work. Horizon Utilities uses the economic evaluation methodology prescribed by the DSC to determine the level, if any, of capital contributions for each project; with such levels incorporated into the annual capital budget. These investments cannot be deferred and must proceed as planned.

Customer Connections

This is an on-going program comprised of non-discretionary projects initiated by customers or developers, where investment is required to enable customers to connect to Horizon Utilities' distribution system. This program includes customer service orders, such as new and upgraded service connections for residential, commercial and industrial customers.

Horizon Utilities uses the economic evaluation methodology prescribed by the DSC to determine the amount, if any, of capital contributions for each project; with the net investment required incorporated into the annual capital budget. These investments cannot be deferred and must proceed as planned.

Expenditures related to customer connection project costs are forecasted based on a number of factors which include: historical levels of activity and investment; known projects; a review of economic factors; and, inflationary adjustments for labour and materials.

The known projects are typically larger services that Horizon Utilities is able to plan for over a longer period of time (more than one year). System access projects are non-discretionary and outside of Horizon Utilities' control. There is a potential for actual expenditures to vary significantly from financial plans and from year to year. Annual plans are tracked monthly and new forecasts are issued quarterly as new customer connection information becomes available.

Level of Investment

The 2015 to 2019 Test Year investment requirements, as provided in Table 44, are consistent with the increasing trend in the volume of customer connection projects. The volume of Horizon Utilities' customer connection projects from 2010 to 2013 is provided below in Table 45. The increase in connection work is aligned with Statistics Canada's expected population growth of 1.85% per year in Hamilton and 0.20% in St. Catharines for 2016 to 2021.

Customer Connections	2015 Test Year	2016 Test Year	2017 Test Year	2018 Test Year	2019 Test Year
Total	$ 3,686,273	$ 4,031,103	$ 4,139,076	$ 4,250,289	$ 4,364,837

Table 44 - Customer Connections Investment

	2010	2011	2012	2013
Services Residential	31	71	73	79
Services <=300kW - >50kW	81	83	83	66
Services over 300kW	36	26	36	57
Services <=50kW	43	39	57	51
Embedded Generation	0	0	0	20
Other Customer Requests	12	7	8	9
Services Customer Owned Sub-Station	6	2	9	5
Total	209	228	266	287

Table 45 - Historical Number of Customer Connections Projects

In addition to assessing the historical expenditures of past years, Horizon Utilities also performs assessments of the local economy, the current customer requests project schedule, and potential future projects based upon discussion with customers and developers in the determination of future investment to support customer connections.

Horizon Utilities takes all steps possible to coordinate with the City of Hamilton and the City of St. Catharines on planning for customer connections. Ultimately, system access projects are driven by decision points within the City of Hamilton and City of St. Catharines. There is a potential for actual expenditures to vary from financial plans from year to year.

<u>Road Relocations</u>

Projects in this category involved the relocation of Horizon Utilities' assets to support road relocation and road reconstruction projects at the request of the City of Hamilton, the City of St. Catharines, and the Region of Niagara. The initiation and timing of these projects is outside of

Horizon Utilities' control and therefore the timing and value of investment required by Horizon Utilities is subject to change.

Road relocation projects are customer initiated and Horizon Utilities is obligated under the DSC and its Conditions of Service to perform these projects and incur related expenditures. These investments cannot be deferred and must proceed as planned, in compliance with the DSC and the Horizon Utilities' Conditions of Service. Horizon Utilities follows the *Public Service Works on Highways Act*, 1990 and associated regulations governing the recovery of costs related to road reconstruction work by collecting contributed capital for 50% of the labour; labour saving devices, and equipment rentals. Capital contributions toward the cost of all customer demand projects are collected by Horizon Utilities in accordance with the DSC and the provisions of its Conditions of Service.

Level of Investment

The forecast investments for the 2015 to 2019 Test Year are provided below in Table 46.

Road Relocations	2015 Test Year	2016 Test Year	2017 Test Year	2018 Test Year	2019 Test Year
Total	$ 2,085,651	$ 2,339,675	$ 1,710,951	$ 1,778,139	$ 1,845,327

Table 46 - Road Relocation Investment

Timelines for the execution of these projects are dictated by the City of Hamilton or St. Catharines, the Ministry of Transportation or the Region of Niagara. Horizon Utilities coordinates work with these stakeholders, wherever possible, on the road relocations with planned distribution projects. Horizon Utilities actively communicates with the Cities of Hamilton and St. Catharines, Region of Niagara, and the Ministry of Transportation and actively participates in P.U.C.C. meetings to identify the volume of road projects forecast in future years. Lead times for notification of projects range from 6 to 24 months, depending on the scope of the project.

Horizon Utilities' investment requirements for the 2015 Test Year is based upon the volume and scope of known road relocation projects. The 2016 to 2019 Test Year investment requirement is based on a forecast of 25 projects annually; the average annual number of road relocation projects based on 2011 to 2013 actuals and 2013 to 2015 forecasts. The average annual project cost used to determine the 2016 to 2019 Test Year investment requirements, relative to the maximum and minimum average annual project costs, is illustrated in Figure 78 below.

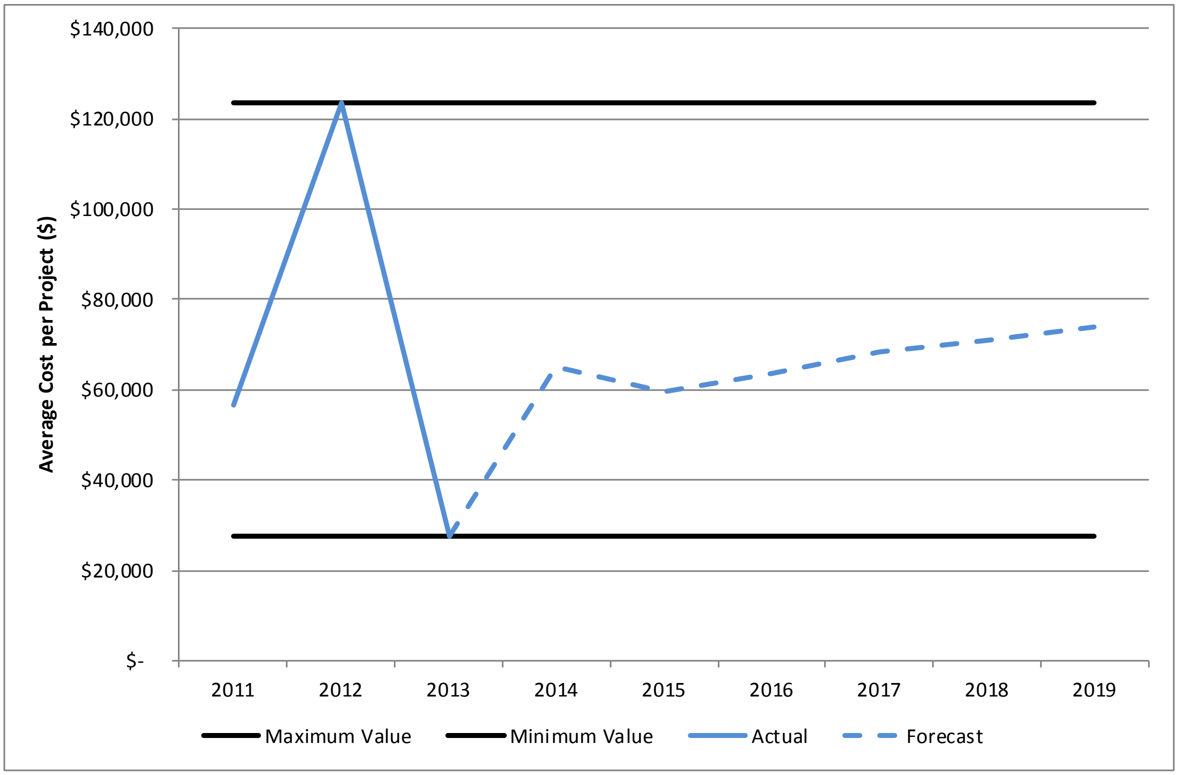

Figure 78 - Average Annual Road Relocation Project Cost

Meters

Meter investments includes the installation of Horizon Utilities' metering assets, in compliance with Measurement Canada standards. The work includes:

- installation of complex and commercial meters at new service locations;
- upgrade of metering installations for expanded service requirements;
- inspection and replacement of defective meters;
- installation of new and replacement metering for residential and multi-residential metered customers; and
- Smart Meter gatekeepers for replacement and growth.

Level of Investment

The forecast investments for the 2015 to 2019 Test Years are provided below in Table 47.

Meters	2015 Test Year	2016 Test Year	2017 Test Year	2018 Test Year	2019 Test Year
Total	$ 2,470,674	$ 2,101,174	$ 2,046,174	$ 2,063,174	$ 2,063,174

Table 47 - Meter Investment

Meter replacements are completed to address meter failures and to maintain metering assets in compliance with Measurement Canada regulations. Measurement Canada requires re-verification of meters upon seal expiry either through compliance sampling or full re-verification programs.

These investments cannot be deferred and must proceed as planned to meet customer requirements and maintain regulatory compliance.

Investments in meters are forecasted primarily through the review of required compliance sampling to comply with Measurement Canada regulations, metering requirements to support new connections and conversion of multi-residential buildings, metering installation requirements to support the Smart Metering Implementation Plan, and forecasted incremental growth.

System Renewal

System renewal investments are focused on replacing aging equipment and / or refurbishment of distribution assets. System renewal projects were planned, on a MIFRS basis, in the range of $15.1MM to $18.1MM over 2011 to 2015. The 2016 forecast of $28.3MM, an increase of $10.5MM over 2015, begins to address the declining health of the distribution system, in particular the underground 13.8kV and overhead 4kV and 8kV systems.

4kV and 8kV Renewal Program

The development of the 4kV and 8kV Renewal Program, filed as Appendix F of this DSP, involved a system-wide study of the 4kV and 8KV distribution systems and substation assets to prioritize capital investment requirements for the renewal of these systems. The resulting 40-year plan addresses the renewal of most of Horizon Utilities oldest overhead distribution assets that are nearing or past end-of-life and allows the decommissioning of Horizon Utilities substation assets over the life of the plan.

Horizon Utilities currently serves 75,000 customers with its 4kV and 8kV distribution systems. Horizon Utilities has 28 municipal substations which convert the electricity from the Hydro One supplied voltage of 13.8kV or 27.6kV to the distribution voltage of 4kV or 8kV, in order to serve these customers. The 4kV and 8kV distribution system and the associated substation assets are among the oldest of Horizon Utilities' assets.

It is necessary to renew both the distribution assets and the substation assets, due to the condition and age of the assets as described in the Kinectrics ACA provided in Appendix B. Horizon Utilities had two options to renew these assets:

i. Convert the 4kV and 8kV distribution system to a higher voltage by:

   a. Converting the distribution system to 13.8kV or 27.6kV while renewing the distribution assets. Customers could be serviced directly from 13.8kV or 27.6kV distribution assets and there is no incremental cost to renew at the higher voltage level;

   b. Investing in a limited number of substation assets to support the 4kV and 8kV system while the long-term 4kV and 8kV Renewal Program is being implemented; and

   c. Decommissioning the substation assets when the voltage conversions are completed. Utilize distribution pole top transformers instead of the substation transformers. Avoid capital investment to renew substations.

ii. Maintain the 4kV and 8kV distribution systems which requires:

   a. The renewal of all substation assets at the current voltage; and

   b. The renewal of the distribution assets at the current voltage

Horizon Utilities chose to convert the 4kV and 8kV distribution system to a higher voltage to avoid the cost of the investment in the renewal of the substations. The proposed investments in the 4kV and 8kV Renewal Program will allow nine substations to be decommissioned between 2015 and 2019. The decommissioning of these nine substations will result in the avoided capital substation renewal investment of $22,500,000. Regardless if the area is converted from 4kV or 8 kV to a higher voltage, the fundamental fact is that the distribution assets (the poles and wires) need to be replaced because they have reached their end of life.

The assets at end of life can be illustrated through two key measurements: the volume of conductor having a Health Index of “very poor” or “poor”; and the rate of service interruptions experienced by customers served by the 4kV distribution system. The 4kV distribution system contains over 200km of overhead conductor, 82% of the distribution system total, having a health index of ‘very poor’ or ‘poor’. Customers serviced by 4kV distribution system experience a disproportionally high outage rate when compared to the other distribution voltages. As illustrated in Figure 79 below, the 4kV distribution system experienced 225% and 254% more outages per circuit km than the 13.8kV and 27.6kV distribution systems respectively for outages caused by all cause codes over the four year period from 2010 to 2013. When considering only outages caused by equipment failures over this same period, the 4kV distribution system experienced 240% and 256% more outages per circuit km than the 13.8kV and 27.6kV distribution systems respectively.

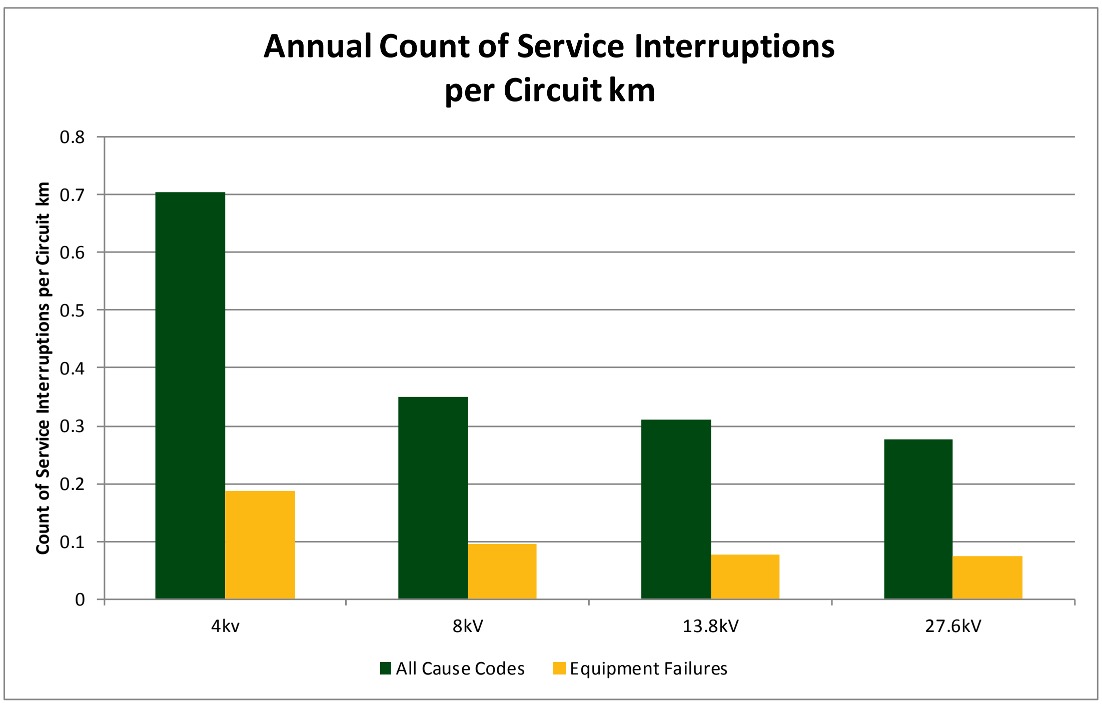

Figure 79 - Service Interruptions per Circuit km

By converting the distribution assets to a higher voltage (from 4 kV or 8 kV to 13.8 kV or 27.6kV respectively) the substation asset (i.e. transformer, switchgear, breakers, relays, and building enclosure) does not need to be renewed and as stated earlier this results in a more streamlined distribution system with a net economic benefit of $22,500,000, the value of the substation assets for the 9 locations.

The total avoided substation renewal investment over the remaining 35 years of the plan is $70,000,000 for all 28 substations. The consequence of not executing the conversions within the 40 year timeframe is that substation assets reaching end-of-life prior to being decommissioned will require unavoidable renewal investment to maintain service to those customers who are still served by the lower voltage system. The timing of the conversion of assets to the higher voltage in the 4kV and 8kV Renewal Program is such that the conversion is completed prior to the substation assets reaching end-of-life and otherwise requiring investment. Once the distribution assets are renewed, the substation assets are decommissioned.

Scope

The 4kV and 8kV Renewal Program is the primary vehicle to address the renewal of the distribution assets and the substation assets. Kinectrics' ACA provided the Health Index for 22 asset groups. Fifteen of these asset groups have an unacceptable Health Index distribution. An unacceptable Health Index distribution occurs when:

- at least 20% of the assets within the group have a Health Index of either “very poor” or “poor”; or
- the assets within the group, which have a “very poor” or “poor” health index, require a significant five year investment (greater than $5,000,000).

Horizon Utilities' 4kV and 8kV Renewal Program addresses the renewal of assets in seven of the fifteen asset groups. The seven asset groups are:

- Wood poles;
- Overhead conductors (primary);
- Overhead conductors (secondary);
- Overhead conductors (service);
- Pole mounted transformers;
- Substation switchgear; and

- Substation circuit breakers.

Horizon Utilities' service area originates from the amalgamation of six different cities through mergers and amalgamations. The 4kV and 8kV Renewal Program utilizes an area-wide approach centred on the substation and the surrounding area it serves. Generally a substation is normally backed up by one or more other substations in the area. This provides security and network resiliency for contingency purposes. In fact at the next level down from the substation the feeders themselves also are backed up by other feeders in the surrounding area. The prudent execution of the renewal program for these assets must consider converting adjoining feeders that back each other up and ultimately the substation to substation impact as the substation is converted over time to maintain backup and operational contingency for the area. To do otherwise would result in exposing customers to possibly lengthy outages and would require repairs to be fully completed prior to allowing customers to be restored. Depending on the nature of the repairs required it would not be unusual for it to take over 24 hours to complete. The ability to utilize a back up feeder or substation alleviates this concern by switching power flows around so as to restore customers back to service in minutes/hours.

Once the distribution assets are converted to the higher voltage, the substation assets will be decommissioned. Failure to renew the entire area would:

- Leave a large number of customers stranded in the event of a service interruption, due to lack of interconnection with an adjacent substation; and

- Require old substation assets to remain in service with high and increasing risk of critical failure.

The failure of these substation assets would result in a large number of customers being without service for an extended period of time; potentially greater than 24 hours. The schedule for the 4kV and 8kV projects in the 2015 to 2019 Test Years is provided in Table 48 below.

4kV and 8kV Renewal Program	2015 Test Year	2016 Test Year	2017 Test Year	2018 Test Year	2019 Test Year
Aberdeen S/S	$0	$0	$2,418,000	$2,643,000	$2,900,000
Baldwin S/S	$0	$0	$0	$1,788,000	$4,403,000
Central S/S	$0	$1,556,000	$1,876,000	$1,652,000	$648,000
Grantham S/S	$650,000	$2,633,000	$1,871,000	$13,000	$159,000
Highland S/S	$1,128,000	$0	$658,000	$0	$0
John S/S	$0	$0	$0	$2,516,000	$8,259,000
Strouds S/S	$1,020,000	$1,533,000	$1,787,000	$3,831,000	$0
Taylor S/S	$0	$0	$0	$26,000	$159,000
Vine S/S	$978,000	$2,472,000	$5,645,000	$13,000	$159,000
Welland S/S	$0	$0	$0	$13,000	$159,000
Whitney S/S	$4,384,000	$1,966,000	$1,509,000	$2,115,000	$0
York S/S	$0	$0	$0	$1,074,000	$0
4kV & 8kV Renewal Total	**$8,160,000**	**$10,160,000**	**$15,764,000**	**$15,684,000**	**$16,846,000**

Table 48 - 4kV and 8kV Renewal Program Investment

The operating areas serviced by the substations identified in Table 48 above are:

- St. Catharines – Grantham, Taylor, Vine, and Welland substations;
- Dundas – Baldwin, Highland, John, and York substations;
- Hamilton West – Strouds and Whitney substations;
- Hamilton Downtown – Aberdeen and Central substations

The selection and prioritization of these areas for renewal is either driven by substation asset health (St. Catharines, Hamilton West, and Hamilton Downtown operating areas) or by the health of the distribution system and operational constraints (Dundas operating area). The York substation distribution assets, located in the Dundas operating area, do not interconnect with any other assets and therefore have no back-up.

Horizon Utilities is proposing to increase investment in the 4kV and 8kV Renewal Program from an annual investment in the 2015 Test Year of $8,160,000 to an annual investment in the 2019 Test Year of $16,846,000. The justification for this investment is identified below by area.

St. Catharines Operating Area

The three substations (Vine, Welland, and Grantham) within the St. Catharines operating area service a total of 4,000 customers and were constructed between 1959 and 1965. These substations are in poor health and require renewal. The overall substation Health Index for Vine, Welland and Grantham substations is 57%, 59%, 58%, respectively, as identified in the 4kV and 8kV Renewal Program included in Appendix F. There is limited back-up between these substations. The loss of the Grantham or Vine substations would result in 900 and 1,100 customers respectively being without service for several days, at a minimum. Restoration of power to these customers would require the costly and unplanned emergency construction of new distribution assets all the while customers are without service. This situation is untenable and must be rectified as soon as possible.

The 4kV distribution assets in St. Catharines are underperforming, subjecting customers served by this system to a higher level of service interruptions than the remaining customers in St. Catharines. The SAIDI for these customers is 28% higher than for the customers served by the 13.8kV system in St. Catharines and 100% higher than Horizon Utilities' corporate target. Please reference Section 2.2.1 of the DSP for additional information

Dundas Operating Area

The four substations (Highland, Baldwin, John, and York) within the Dundas operating area service 3,000 customers. These substations are all single substations (i.e., they each have one power transformer and switchgear) with no allowance for a contingency event. Any transformer or switchgear failure would lead to the compete loss of the substation and would necessitate the transfer of load to neighbouring stations.

The switchgear at the Highland substation is 44 years old, with an effective age of 58 years old as determined by Kinectrics. The "effective age" is different from the chronological age in that it is based on the asset's condition and the stresses that have been applied to it over the life of the asset. Kinectrics' evaluation found that these switchgear had a high probability of failure within one to three years. Switchgear failure will result in the complete loss of the substation. Failure of the Highland substation will necessitate the transfer of load to the John substation. This will result in John substation operating in excess of feeder capacity. Furthermore, system operating analysis indicates that, due to the loading conditions, many customers will experience an under-voltage condition, referred to as “brownout”, that if sustained will damage customer-owned equipment, as well as cause outages.

The failure of any of the Highland, Baldwin and John substations will result in a load transfer to, and overload of, a neighbouring back-up station; thereby increasing the risk of failure of the back-up station. This cascading effect is highly likely and could lead to multiple failure points, causing over 1,000 customers to be without service for lengthy periods. The scenario below outlines a realistic chain of events that highlights the importance of commencing with the conversion of 4kV assets in the Dundas Area.

Scenario: Highland Substation (“Highland”) experiences a transformer or switchgear failure. 748 customers are without power. The following steps are required to transfer load and restore power.

Step 1: Transfer Highland Feeder 1 (“F1”) and F3 to Highland F2 – power is still out

Step 2: Off load John F1 to Baldwin F1 – power is still out

- The John F1 is the only back up for the Highland feeders. The capacity of the John F1 feeder cannot carry this entire load (600 amps of total load on a feeder limit of 530 amps), The overload on the John F1 feeder increases the risk of subsequent failures of feeder conductors and equipment at John Substation.

Step 3: Transfer Highland F2 to John F1 – All customers back on.

- Customers have been off for approximately 4 hours
- Low voltage will be experienced by approximately 187 customers, which could result in further outages and claims for damaged customer equipment
- At this point John F1 is carrying 3 times the normal load and Baldwin F1 is carrying double normal load. Risk of failure of equipment at John or Baldwin is now increased due to increased loading of station and distribution equipment.

Step 4: Remedy the equipment failure at Highland:

- For a switchgear failure: There is no spare equipment to remedy this situation and a new solution would have to be engineered. This could take many weeks to many months to perform permanent repairs.

- For a transformer failure: The only spare power transformer for all 4 stations in Dundas is located at York Substation. In order to remove this spare transformer, York needs to be taken offline which would result in 400 customers out for 12 hours while this work is completed. It will be an additional 24 hours to remove the old transformer and re-install the spare from York at Highland .

This scenario exhausts all contingencies available, and a failure of any equipment at John or Baldwin will result in large scale power outages until equipment can be repaired or replaced.

York substation does not have connections to the Highland, Baldwin and John substations and therefore the load cannot be transferred in the event of a failure. Loss of this substation will leave the 400 customers served by this substation stranded without power for an extended period.

The distribution assets in the Dundas operating area are in poor health and have significant operating constraints. This area has numerous radial feeds without backup. The Dundas operating area also contains 25% of the 4kV XLPE cable. The 4kV XLPE cable is in poor health with 38% of the assets having a Health Index of either ‘very poor’ or ‘poor’. The renewal of the assets in this area has the additional benefits of renewing the underground XLPE cable and allowing for the replacement of the radial feeders with a loop-fed system. A loop-fed system has two sources of supply which provides switching options to restore power more quickly. The underground XLPE Renewal Program is discussed in further detail in this Section.

The substations in the Dundas operating area are all single stations which require the transfer of the total substation load in the event of failure. This attribute, combined with the operational constraints and lack of backup at the distribution level, result in a high risk of sustained outages (greater than 4 hours) to a large number of customers.

Hamilton West Operating Area

The two substations within this operating area service a total of 5,400 customers and provide backup for each other. The switchgear at these stations have a Health Index of ‘very poor’ as identified in the Substation Asset Condition Assessment (“SACA”) and confirmed by the Kinectrics’ ACA. The switch gear at the Strouds and Whitney substations are 44 and 46 years old, with an effective age, as determined by Kinectrics, of 57 and 56 years old, respectively. Kinectrics identified that both substations’ switchgear had a high probability of failure within one to three years. Switchgear failure will result in the complete loss of the substation. A loss of both substations would result in an outage that would affect all 5,400 customers. These customers would be without power until the substation assets were repaired. Horizon Utilities does not maintain spare parts for all substation assets. The time required to procure replacement parts, if not obsolete and still available, would be several months.

Hamilton Downtown Operating Area

The two substations within this operating area are Aberdeen and Central. These substations service a total of 7,400 customers. The overall Station Health Index for Aberdeen and Central substations is 53% and 56% respectively, as identified in the 4kV and 8kV Renewal Program filed as Appendix F. The switchgear at the Aberdeen substation is 40 years old; Kinectrics determined its effective age is 54 years old. Kinectrics analysis determined that this switchgear has a high risk of failure within five years. Aberdeen substation, which services 2,600 customers, has inadequate backup for all feeders. The failure of the switchgear at this substation will leave customers without power or subject them to rotating blackouts.

The Central substation has ten feeders; six of which are obsolete, oil-filled breakers are at end-of-life. The Health Index for these breakers is “very poor” and Kinectrics forecasted that these circuit breakers have[p a high risk of failure within three years. Two of the six feeders are radial feeders with no backup. Failure of the breakers for these feeders would result in the loss of service for over 50 commercial customers in downtown Hamilton for a minimum of several hours to several days. Central substation has limited interconnection with other substations. The loss of the entire substation would affect all 3,100 customers who would be out of power until the substation assets were repaired. Repair and restoration of a failed substation can take months. Horizon Utilities does not maintain spare parts for all substation assets. The time required to procure replacement parts, if not obsolete and still available, for permanent repairs would be months.

The investment in the 4kV and 8kV Renewal Program is necessary to address the risk of imminent asset failures and prolonged customer outages.

XLPE Renewal Program

The XLPE Cable Renewal Program is the primary vehicle to renew Horizon Utilities' underground distribution assets. Horizon Utilities' XLPE Renewal Program addresses the renewal of assets in six of the fifteen asset groups having an unacceptable health index. These six asset groups are:

- XLPE Cables (Primary)
- Underground Cables (Secondary Direct Buried)
- Underground Cables (Secondary In Duct)
- Underground Cables (Service Direct Buried)
- Underground Cables (Service In Duct)
- Vault Transformers

Horizon Utilities' XLPE Renewal Program investment is provided in Table 49 below.

U/G (XLPE) Renewal	2015 Test Year	2016 Test Year	2017 Test Year	2018 Test Year	2019 Test Year
Ancaster/Flamborough/Dundas	$2,257,000	$1,269,000	$0	$0	$2,702,000
Hamilton Mountain	$0	$1,996,000	$6,607,000	$4,641,000	$3,473,000
St. Catharines	$310,000	$1,661,000	$1,759,000	$2,835,000	$4,096,000
Stoney Creek	$0	$0	$500,000	$1,908,000	$0
U/G (XLPE) Renewal	**$2,567,000**	**$4,926,000**	**$8,866,000**	**$9,384,000**	**$10,271,000**

Table 49 - XLPE Renewal Program Investment

The total length of XLPE primary cable, which has an unacceptable Health Index is 597km or 29% of Horizon Utilities' total installed XLPE cable asset base. XLPE cable has the highest investment requirement of the 22 asset groups, due to the high percentage of cable with a Health Index of "very poor" or "poor" and the high volume of installed cable. Total investments of $172,742,000 over twenty years and $54,684,00 over the next five years are required to renewal the XLPE primary cable identified by the Kinectrics ACA as flagged-for-action which have a high probability of failure.

An analysis of all service interruptions, caused by material or equipment failure from 2010 to 2013, revealed that 50% of service interruptions, measured by customer minutes of outage, were due to failures of underground cable and equipment. Over 30% of these outages exceeded four hours in duration, while 5% of these outages exceeded twelve hours in duration.

These durations far exceed Horizon Utilities' corporate target of one hour and nine minutes of outage on average per customer.

Maintaining the XLPE cable renewal investment at 2013 levels would result in a continual decrease in the Health Index distribution and further increase the frequency and duration of service interruption to customers.

The forecast of the future Health Index of this asset group at 2013 investment levels is illustrated in Figure 80 below. The percentage of XLPE primary cable having a Health Index of either "poor" or "very poor" would increase from the current value of 30% to 70% or 1,400km by 2034, if investment is held at the current 2013 level.

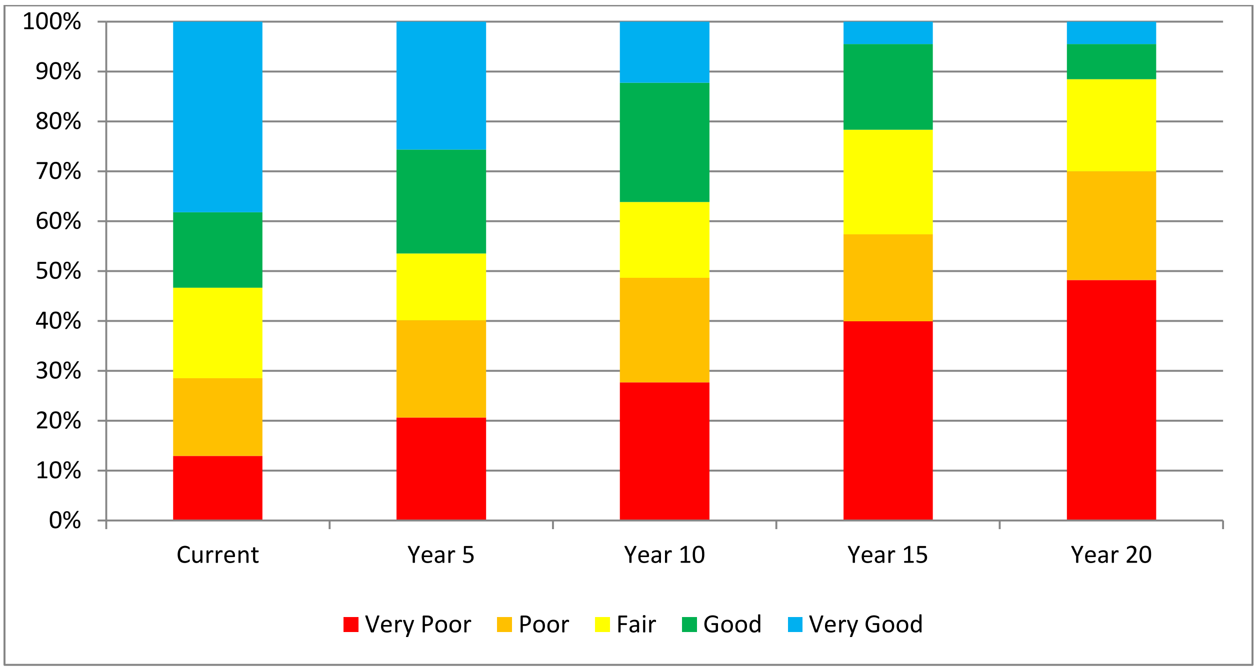

Figure 80 - Forecasted XLPE Health Index at Current Investment Levels

The failure rates associated with this level of risk will result in a significant increase in the number of outages experienced by customers compared to current levels and increased operational and maintenance costs associated with the location of faults, restoration and repair. Without proactive replacements, as assets continue to age and degrade, the cable will fail at an exponential rate and, in the worst case scenario, overrunning Horizon Utilities' ability to keep pace with repairs. Reliability will also deteriorate to unacceptable levels. Reactive replacements will be considerably more costly than the plan that has been submitted in this Application. Reactive renewal is estimated to be three times more costly than planned renewal.

The current backlog volume of XLPE primary cable requiring renewal cannot be addressed in a single year and requires a multiple year investment strategy. The optimal level of renewal for XLPE cable, based on a 40-year useful life replacement cycle, is 50km/year. Horizon Utilities' proposed investment for the 2015 to 2019 Test Years is $36,014,000, which provides for the replacement of 180km of cable over the 2015 to 2019 Test Years. This represents a managed, gradual increase in investment in order to balance rate payer concerns and practical operational limitations. This proposed investment is below the minimum investment required to maintain the current Health Index in 2015 to 2019, as identified in Figure 81 below. The backlog of XLPE cable with a "very poor" or "poor" Health Index continues to grow until 2019. It will take Horizon Utilities until 2017 to reach the optimal level of renewal, due to long lead times required to address planning and municipal consent processes and customer stakeholdering.

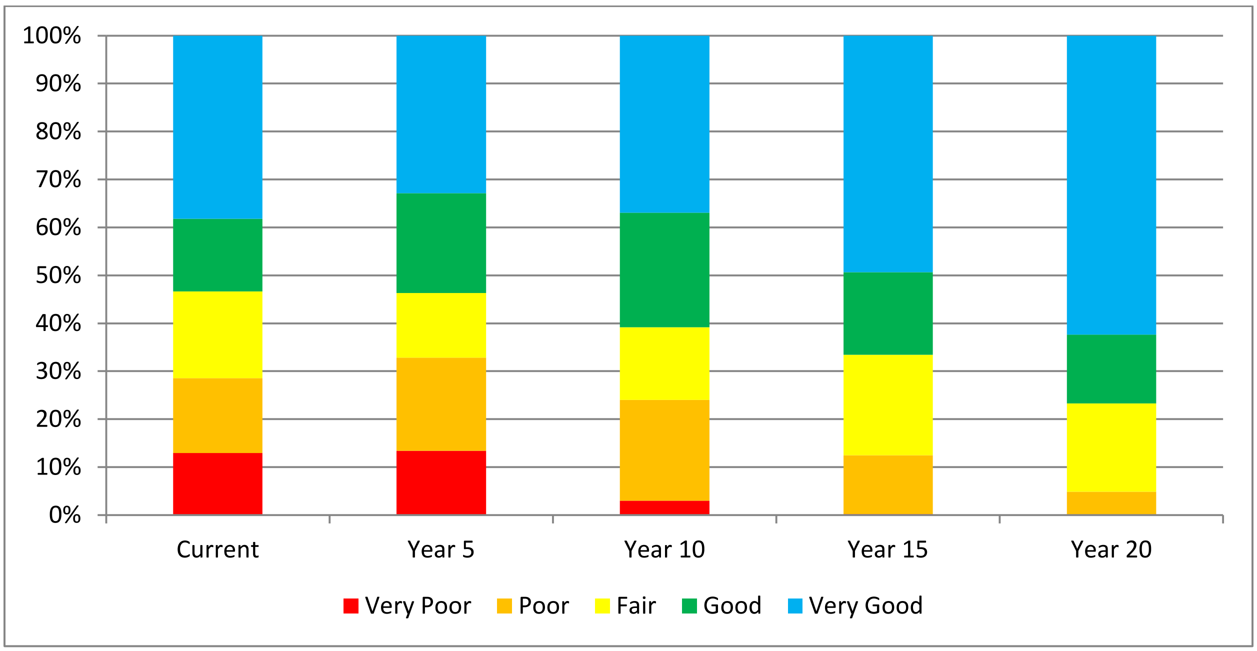

Figure 81 - Forecasted XLPE Health Index at Proposed Investment Levels

The Kinectrics ACA provided the guidance for determining the annual investment requirement. Horizon Utilities used operational performance analysis, including failure rates; location; and the identification of worst performing feeders to prioritize XLPE cable renewal projects.

The Hamilton Mountain, Stoney Creek, and St. Catharines operating areas are the focus areas for the proactive replacement of XLPE primary cable. These areas contain 66% of the total XLPE cable in Horizon Utilities' distribution system. Failed cable will be replaced reactively in the remaining areas, as the reliability and equipment failure statistics for these areas do not warrant a more proactive approach at this time. These areas will be candidates for renewal projects beyond the 2019 Test Year.

Failure to invest in XLPE cable renewal at Horizon Utilities' proposed level of $36,014,000 over 2015 to 2019 will result in increased and continued service interruptions to large volumes of customers, with outages lasting several hours. The underground XLPE cable Renewal and the 4kV and 8kV Renewal Programs address twelve of the fifteen asset groups which were identified as having an unacceptable Health Index.

Replacement Philosophy:

Horizon Utilities considered the four replacement philosophies for addressing risk inherent in the XLPE asset group: Area; Reactive; Selected; and Refurbishment.

Area Replacement

This approach involves the replacement of all XLPE primary cable within a selected area. This strategy minimizes the service interruptions to customers as it replaces the cable prior to failure. This also provides the opportunity to upgrade to current equipment standards, and to improve system protection and operating characteristics. Additionally, the deployment of Smart Grid technology is more cost effective than when retrofitted onto an existing system. This strategy has the lowest total life cycle cost.

Reactive Replacement

Reactive replacement results in extracting the maximum life from each cable segment as no cable is replaced prior to failure. However, this philosophy is entirely impractical due to the following:

- It exposes customer to a higher frequency and duration of service interruptions. The resulting fault locating and repair efforts will result in multiple excavations within an area causing significant disruption to customers;
- It results in a loss of economy of scale as the cables for an area are replaced individually at different times;
- The sheer length of cable in km, the nature of the work (i.e. significant set up time associated with underground excavation), purchasing lead time on cables, and the well

know and documented exponential rate of failures associated with material breakdown will result in the scenario where the failure rate will increase to a point that may affect Horizon Utilities' ability to repair and replace the failed assets in a reasonable time frame as expected by customers;

- Reactive replacement involves a higher cost than planned, proactive replacement;
- There are increased operating costs associated with fault finding and service restoration upon failure of the cable;
- Repetitive faults within an area places undue stress on the remaining sections and can lead to a reduction in the life of neighboring assets; and
- Multiple and continuous disruption to customers from excavation, directional boring, and replacement of cable.

Selected Replacement

Selective replacement involves the targeted replacement of some cables within an area. Section and prioritization is based upon testing and analysis of the cable condition. This option does not initially require the replacement of all assets but, due to the factors identified below, results in a higher overall total lifecycle costs.

- Prediction based upon testing and analysis is not exact and customers are still exposed to service interruptions from cable failures;
- Results in a loss of economy of scale as the cables for an area are replaced individually at different times;
- This philosophy dictates a like-for-like replacement strategy and improvement to system design standards, system protection, system operating characteristics, deployment of smart grid technology are difficult or impractical to implement; and
- Multiple and continuous disruption to customers from excavation, directional boring, and replacement of cable.

- Not practical, feasible from a customer engagement, customer service perspective. Makes living in a community very difficult if every other week or month construction pops up here and there.

Refurbishment

Refurbishment of aged XLPE cable by cable injection has been used in a number of countries including the USA and several European countries but has not been widely used by Ontario LDCs. This strategy has the following drawbacks:

- The presence of cable accessories (splices and terminations) that block the flow of injection fluids significantly reduces its application and effectiveness;
- Operational impacts from interruptions and work protection have been barriers to effective refurbishment of XLPE cable in distribution systems; and
- Relative cost benefit for cable injection has not yet been definitively proven.

XPLE Decisions

Horizon Utilities prefers the Area Replacement philosophy for selected areas of the service territory where the asset health analysis and the failure history indicates a substantial risk of continued failures. A reactive replacement philosophy will continued to be used for the remaining areas of the service territory.

The Selected Replacement philosophy was rejected because approximately 66% of the investment is directed at the Hamilton mountain area and in this area:

- The design is obsolete with radial feeds and inadequate or no ability to provide backup;
- There is inadequate protection on the feeders. Any small disruption or equipment failure often results in a prolonged outage to all customers on the feeder;
- The cable has the same demographics, operating characteristics and installation techniques. Identifying the selected segments of cable to replace with a high level of accuracy would be costly; and
- Area replacement is the lowest cost option on a lifecycle basis.

Cable refurbishment has been reviewed by Horizon Utilities and rejected as the characteristics of its system generally make it less cost effective than cable replacement. In order to make refurbishment cost effective, long cable runs with minimal splices are required. Horizon Utilities' system generally does not meet these criteria.

Level of Investment

A forecast of the future Health Index distribution of XLPE Primary cable was performed at the current renewal investment level. The forecast shows a substantial degradation of asset Health for this class going forward from the current and already unacceptable levels. Failure to invest in the renewal of these assets at the proposed rates will result in continued degradation of distribution assets and decreased service levels to Horizon Utilities' customers. Service interruptions could impact thousands of customers with prolonged outage durations lasting many days.

The investment in XLPE renewal projects increases from an annual value of $2.5MM in 2015 to $10.8MM in 2019. These investment values represent a substantial year over year increase, yet are lower than the optimal values recommended by Kinectrics in 2015 through 2019. The projected Health Index of this asset class at the current and forecast investment level is illustrated in Section 3.1 above. The planned forecast investment level stops the degradation but does not improve the Health Index distribution of this asset group.

Project Selection

Horizon Utilities currently has 2,060km of underground XLPE cable located in six operating areas. The Hamilton Mountain and St. Catharines operating areas, both areas where the underground distribution system is primary operating at 13.8kV, have the highest volume of XLPE primary cable. The Stoney Creek operating area has the highest volume of XLPE primary cable operating at 27.6kV. Investments in the Ancaster/Dundas/Flamborough Operating Area will address XLPE primary cable operating at 4.16kV. The breakdown by operating area of XLPE primary cable is illustrated below in Figure 82.

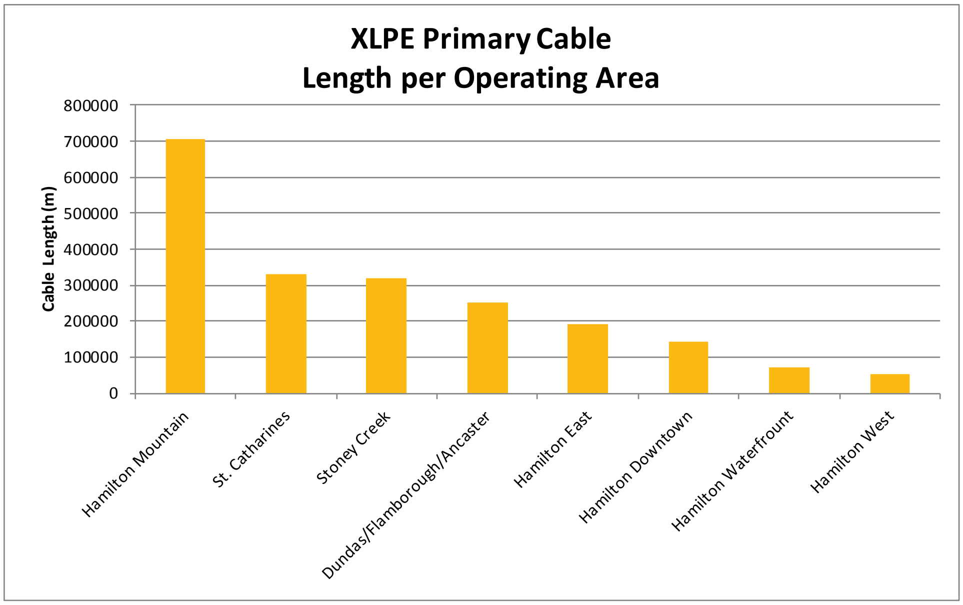

Figure 82 - XLPE Primary Cable per Operating Area

The Hamilton Mountain, Stoney Creek, St. Catharines, and Flamborough/Ancaster/Dundas/Lynden operating areas are the focus areas for the proactive replacement of XLPE primary cable. Reactive replacement of failed cable will be the primary methodology in the remaining areas as the reliability and equipment failure statistics for these areas do not warrant a more proactive approach at this time. These will be candidate areas for future projects beyond the 2019 Test Year.

Horizon Utilities' XLPE Renewal Program requires sustained investment over several years. This increased investment is required to prevent increased customer dissatisfaction through continued service interruption to customers and continued disruption to property through restoration and repair efforts. A significant volume of Horizon Utilities' XLPE assets are in poor health now and many more km of XLPE will degrade into poor health in the coming years. Failure to invest in the renewal of XLPE at the proposed level will result in the renewal needs in future years exceeding Horizon Utilities' capacity to execute.

System Service

Horizon Utilities' forecasted system service investment levels represent the lowest values possible in the 2015 to 2019 planning cycle.

System Service investments address reliability, security, capacity and safety issues.

Reliability Investments

Reliability investments in the 2015 to 2019 Test Years are focused on the deployment of distribution automation and are required to complete the investments identified in Horizon Utilities Basic GEA Plan filed in EB-2010-0301. Automation provides the ability to improve reliability through reduced fault identification and switching to isolate the faulted area and restore service to the unaffected areas. The deployment of automation is a key component of Horizon Utilities' reliability improvement efforts for the worst performing feeders and poor performing areas of the 13.8kV and 27.6kV distribution system.

Security Investments

Security investments are required to address projects identified through project prioritization as requiring investment to address lack redundancy and risk of failure without adequate contingency for backup. Justification on a project basis is included in the material project templates provided in Appendix G.

Capacity Investments

Capacity investments are limited in the 2015 to 2019 Test Years. Capacity drivers are a secondary driver on the Waterdown 3rd feeder project and for the Mohawk/Nebo TS investment. The Hamilton Mountain area is serviced by Mohawk and Nebo TS and as identified in Section 2.2.2, these stations have peak loading nearing their 10 day LTR.

Safety Investments

Safety Investments in the 2015 to 2019 Test Years are limited to investments in #6 Wire Replacement projects. These projects address the replacement of #6 primary wire where identified as a potential safety risk. Solid #6 conductors have a higher probability of failure which may result in a wire down incident. This small gauge solid conductor is not as durable as the current standard which provides for a multi-stranded conductor. Horizon Utilities has established a program to proactively replace #6 primary conductors to address the higher risk. This type of overhead conductor is also replaced when 4kV conversion projects are completed.

General Plant

The forecast investment in General Plant projects are focused on renewal of Horizon Utilities' buildings and the renewal of key IT systems.

Buildings Renewal

The majority of Horizon Utilities' buildings are largely unchanged from the time they were originally built and configured. Based on recent building condition and other assessments, it is apparent that these buildings require significant and urgent amounts of investment in refurbishment, reconfiguration, and supporting systems in order to: renew critical building, facilities, and supportive systems that are at or nearing end of life; address increasing risk of system failure; improve productivity within the work environment; accommodate growth in the workforce; and address identified health and safety risks.

Expenditures for the maintenance and operations of Horizon Utilities' buildings are increasing year over year, in part, due to required structural repairs, additional expenses to procure replacement parts for obsolete systems, and end-of-life systems.

Horizon Utilities identified that a long-term building asset renewal plan was necessary and commenced a series of studies in 2010 in order to:

- understand building and operational requirements;
- determine the level of required investment; and,
- prioritize and pace the prospective building renewal projects in order to balance related costs and customer rate implications against the risks and benefits of such projects.

The independent studies, previously identified in Section 2.1.2 above, were undertaken to aid in the development of Horizon Utilities' long-term building renewal strategy and to assess and evaluate the following:

- the health of building infrastructure systems including heating and air ventilation conditions, and their risk of failure;

- office space environmental conditions;
- health and safety concerns related to poor air quality, and unsecured access points;
- continued compliance with the Ontario Building Code ("OBC") and Fire Codes;
- the structural integrity of the buildings;
- office space availability to support current and future workforce and equipment; and
- options to renovate the five existing buildings as compared to building a new centralized Horizon Utilities' office.

Several issues and gaps were identified in the studies with respect to the condition of buildings, facilities, and supporting systems. The specific reports, observations, and recommendations are elaborated below.

<u>Space Study</u>

Horizon Utilities engaged PRISM Partners Inc., a leading project management and consulting firm to conduct its Space Study in 2010. PRISM has extensive experience in the healthcare, research, academic, municipal and private sectors. The Space Study is provided in Appendix L.

The Space Study evaluated all five of Horizon Utilities' buildings. It determined that the office work environment was congested and certain business units were divided between different locations resulting in operational inefficiencies and unproductive, overcrowded work environments. The Space Study determined that the present condition and configuration of existing office space cannot support the requirements of the current work force.

The Space Study also identified health and safety concerns, including:

- air quality resulting from vehicle emissions at the lowest end of the acceptable threshold range.
- certain electrical and fire and life support systems that were not compliant with the current OBC. Any systems installed prior to the current OBC are grandfathered and may remain in operation with proper maintenance and regular inspections. However, these systems had reached end-of-life and were at risk of not functioning effectively; and

- pedestrian work flows and vehicle traffic operating in common work areas, which result in dangerous environments for employees and customers.

The Space Study identified opportunities to reclaim under-utilized space and restructure existing space to resolve congested work areas, address health and safety risks, improve productivity, and support the requirements of the current and future workforce.

The significant observations and recommendations within the Space Study are as follows.

55 John Street and Hughson Street buildings

- The Customer Connections office staff and the Metering Testing Lab shared a common space, creating potential safety risks resulting from live electrical testing within an open environment in close proximity to office staff;

- Customer Connections office staff were working within a "warehouse" environment with insufficient lighting for an office. The staff did not have access to local washroom facilities, which is not compliant with the current OBC, and the under-sized Heating Ventilation and Air Conditioning ("HVAC") systems exposed staff to health and safety risks related to poor air quality;

- Employees within the same departments such as Procurement, Customer Service, Conservation and Demand Management, Customer Connections, and Information System Technology were located either in different buildings or on different floors resulting in communication, alignment and operational inefficiencies;

- Customer Service staff have a congested work space, which necessitates some staff to be located on the main floor adjacent to the customer lobby. This poses potential security concerns and provides a noisy and unproductive work environment due to the volume of employee and customer traffic. Other deficiencies include poor lighting, air quality concerns and non-ergonomic office furniture that does not comply with current ergonomic best practices;

- The size of the Computer Training room cannot accommodate the number of computers required for training sessions, and is equipped with temporary electrical outlets and extensions which create fire and tripping hazards; and

- Washroom facilities were non-existent or were in need of renovation to support current employee occupancy as per the current OBC and compliance with *Accessibility for Ontarians with Disabilities Act ("AODA")*.

<u>Nebo Road, Vansickle Road, and Hwy # 8 Service Centres</u>

- Entrances used by employees and customers were not adequately secured from unauthorized access;
- The ventilation systems were inadequate, resulting in air quality tests at Vansickle Road and Nebo Road Service Centres that were at the low end of the acceptable threshold range for office spaces, primarily as a result of vehicle emissions from nearby parking garages.
- The present building configurations did not support the safe and effective management of the flow of people, vehicles, equipment, and stock within the Service Centres;
- There was a need for additional office space and meeting and training rooms to support the current and future workforce at these locations   The lack of training and meeting space necessitated travel time to other locations and reduced productive time;
- Garages at the service centres located in Hamilton, Stoney Creek and St. Catharines, built between 1970 and 1980, were not designed or built to physically accommodate the current number and size of vehicles and equipment utilized by Horizon Utilities' staff. Some of the vehicles required to support Horizon Utilities' current distribution system are by design, larger; such as the 68 foot double bucket trucks required to reach longer pole lengths. Vehicles have been consolidated into the existing service centres as a result of amalgamations and mergers; creating traffic congestion, and an environment which is unsafe for employees and can cause damage to vehicles and equipment;
- Locker, washroom and shower space for field staff was congested, requiring additional lockers to be located in hallways and nearby rooms. Plumbing fixtures and air systems required ongoing repairs and replacement as they had reached the end of their useful life;

- An elevator was required at the Vansickle Service Centre to conform to current OBC and AODA regulation; and
- The staircase at the Nebo Road Service Centre needed to be rebuilt to improve the safety of employees due to lack of fire exits.

Despite some identified structural deficiencies and end-of-life equipment and systems, in general, the buildings were assessed to be structurally sound.

Based upon the observations and recommendations of the Space Study, Horizon Utilities commenced renovations of the Head Office and Service Centre buildings to: begin the necessary refurbishment and upgrades of the building assets; address safety related deficiencies; achieve compliance with current building codes; rationalize workspace to improve productivity and employee engagement; and accommodate the needs of a growing workforce.

In order to validate the decision to undertake renewal and refurbishment investments in the existing buildings, Horizon Utilities considered the conceptual alternatives of: i) procuring a modern facility to replace the Head Office, Nebo Road and Stoney Creek Service Centres; or ii) building a new Head Office and Service Centre at a location appropriate to support our customers and employees.

It was determined that it would be difficult to procure an existing building which would be appropriate to fully provide for combined Head Office and Service Centre operations. Such centralized facilities would need to meet: i) the operational needs of the 363 employees collectively residing within and operating from Head Office and the Nebo Road and Stoney Creek Service Centres; and ii) the corresponding requirements for office space, fleet parking, warehouse space suitable for large items such as transformers and poles, and garages for fleet maintenance.

As part of the evaluation of a new centralized facility, consideration was also given to: the estimated expenditures related to the renovation of a newly procured facility; and the logistical challenges and business impacts inherent in a move to a new facility.

Horizon Utilities also reviewed the experience of Enersource Corporation, which procured and renovated a new Head Office building for a projected 189 employees in 2011. The Enersource

2012 Cost of Service application (EB-2012-0033) provides details of capital costs related to the procurement and renovation of the building, which aggregated approximately $20,000,000.

Horizon Utilities reviewed the experience of Powerstream Inc. as detailed in its 2008 Cost of Service application (EB-2008-0244). Powerstream Inc. constructed a modern Head Office for a subset of its office staff at a reported capital cost of $27,700,000, inclusive of property procurement expenditures.

Horizon Utilities' asset renewal strategy for the renovation and refurbishment of its head office and service centres (five buildings in total) and related systems is expected to aggregate $19,157,000 over eight years at an average cost of $158 per square foot, based on 121,305 total square feet. This option is prudent as compared to procurement and construction alternatives and allows Horizon Utilities to implement a paced plan of refurbishment and addition to rate base in order to balance rate payer and utility affordability.

Horizon Utilities current Head Office and operational requirements for building space include 261,860 square feet of: office space; common areas; warehousing; fleet parking; and garage areas.

Horizon Utilities' building renewal strategy includes the reclamation of 40,295 square feet of under-utilized areas, reconfiguration, and standardization of office sizes in order to rationalize and provide for more productive work space.

The Space Study provided Horizon Utilities with an initial 5-year project plan; prioritized according to highest risk and greatest need. Work commenced in 2012 with: the renovations of the Customer Connections work space at Head Office; the provision of an elevator at the Vansickle Road Service Centre; and the reclamation of the third floor of the Hughson Street building to convert warehouse and storage space to usable office space.

Horizon Utilities undertook a series of specific studies to assess the health and condition of the buildings and related systems and security, as part of its continuous improvement efforts and to ensure that investments were prudent and prioritized.

BCA

A BCA for each of the main Horizon Utilities buildings and 23 substation buildings was conducted in 2013 by Evans Consulting Services, a leading firm in building assessments to identify known structural and systems deficiencies and forecast required expenditures to assist with the development of a long term building asset strategy.

The BCA included: the identification of each building's physical conditions; its systems and equipment conditions; and recommendations to address deficiencies. The assessment also included a forecast of replacement costs for major building and system components based on the predicted life of an asset. The building components that were assessed included the structural interior and exterior elements, and electrical, fire and life safety, and HVAC systems.

The information collected during the BCA process provided Horizon Utilities with enhanced asset condition data and a refreshed view of corresponding long-term capital expenditure requirements. This further informs the buildings planning process undertaken by Horizon Utilities in the pursuit of efficient and prudent building asset management.

The BCA findings included:

- HVAC, fire and life safety, and lighting systems had reached end-of-life at all of the buildings, and were not designed to support the current number of employees or current technologies. On-going repairs, which increased system downtime, were becoming too costly to maintain corresponding systems and it was difficult to source replacement components. Over the period of 2012 and 2013, Facilities had responded to 1,719 calls related to heating and cooling system issues. Facilities staff assess each call and contract out the required repair work. The number of calls regarding heating and cooling issues will decrease, along with the third party costs required for repair, as the HVAC, fire and life safety, and lighting systems are replaced.

- Vehicle and equipment emissions were present in the air within some of the office environments such as at the John Street building lobby, the Vansickle Road Service Centre's second floor, and the Nebo Road Service Centre's mezzanine offices, which posed potential health concerns for employees;

- Hazardous materials, such as asbestos and mold, were present within some of the office environments;

- The building fire annunciator devices were at end-of-life, and additional units were required to achieve the audibility requirements as per the current OBC;

- Entrances at the Nebo Road and Vansickle Road buildings used by employees and customers were not secure, which results in the potential for unauthorised access to the buildings and corresponding safety and security concerns for employees and assets;

- Renovation to building entrances and stairwells are necessary in order to meet current OBC requirements for all buildings;

- Building construction deficiencies, such as unsealed windows and uninsulated walls, were contributing to energy inefficiencies;

- The main vehicle exhaust systems at the fleet garages at the Vansickle and Nebo Road Service Centres were insufficient to remove vehicle exhaust from the work area;

- A number of fire and life safety-related deficiencies were identified including the need for fire dampers, fire rated walls to prevent fire from spreading, and the replacement of the existing fire rated doors and frames to comply with the OBC;

- Many components within electrical equipment and systems had deteriorated, were damaged, or were at end-of-life including receptacles, switches, light fixtures, conduit, wiring, panels and disconnects; and,

- The Service Centres' interior and exterior overhead doors: had reached end of life; maintenance and repairs had increased; and parts were becoming difficult to procure. These conditions increased downtime and created potential safety risks to employees if an unsecured door were to fall.

The recommended total capital expenditure investments in the BCA were $12,768,330 over 20 years to address the restoration of end-of-life assets. This report recommends the total capital expenditure over 2014-2019 period of $ 5,473,880. The Space Study recommends a total capital expenditure over a five year period of $10,382,000. The total recommended investment over five years of $15,855,880 is necessary to address operational deficiencies, building accessibility, the removal of hazardous materials, security, and air quality; and to replace assets which have reached end-of-life and ensure compliance with fire and OBC.

Security Study

The Security Study was undertaken in 2013 by CAPSYS Integrated Technology Consultants. [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

Roof Assessment

In 2013, a rooftop assessment was conducted by Garland Canada Inc. with respect to the rooftops at each of the John Street building, Hughson Street building, Hughson Substation building, and parking garage. The consultant concluded that these rooftops had reached end-of-life and were in poor condition. These rooftops were originally installed in 1999.

There were visible signs of deterioration. The rooftop membranes were starting to de-granulate, reducing the strength and UV resistance of the rooftop. Some adjacent exterior walls were in very poor condition and required new cladding, stucco, or coating. There were some blisters on the rooftops, which are caused when air and/or air vapour is trapped. Previous repairs to the rooftop have degraded and water leaks have damaged the windows and floor walls below.

Window Assessment

The condition of the windows at the 55 John Street building was evaluated in a 2013 energy efficiency gap assessment conducted by independent consultant MMM Group Limited. MMM Group Limited and its subsidiaries/affiliates comprise a global firm with more than 50 offices in Canada and around the world. MMM Group is a partner of choice for major design-build and P3 transportation and building projects in Canada, the U.S. (through Lochner MMM Group), and around the world.

The assessment was conducted using visual inspections, air leakage testing, and building energy simulations. The testing concluded that the condition of the operable windows at the John Street location is poor. The windows are no longer weather resistant or energy efficient and allow cold drafts to enter the building in the winter, and heat convection during summer months which leads to air conditioning inefficiency and additional stress on the HVAC systems. The windows collect frost on the inside in the winter which melts and damages interior walls and carpeting. The windows, installed in 1994, have reached end-of-life and require replacement in order to reduce energy costs and to maintain the comfort of the employees from a climate and noise perspective. Weather stripping was determined to be insufficient as identified through air leakage tests.[14]

A building renovation schedule was created to detail and prioritize the renovations that were required to renew critical building systems, ensure the health and safety of employees, and meet the capacity requirements of the current work force.

[14] Air leakage sampling testing conducted by Intertexk were in accordance with the test methods outlined in ASTM E783-02 (Reapproved 2010), "*Standard Test Method for Field Measurement of Air Leakage Through Installed Exterior Windows and Doors*" at a pressure differential of 75 Pa.

Horizon Utilities' original renovation plan was for five years, commencing in 2012, based on the results of the Space Study. The plan was expanded, based on the additional assessments completed in 2013, to ensure that all end-of-life systems were addressed as renovations were planned.

The building renovation plans were subsequently refined and aligned to long-term operational requirements as supported by the recommendations from the Space Study, the BCAs, the security reviews, and window and rooftop assessments.

The planning activities of the building renovation include the following major considerations:

- Building system demand;
- Building occupancy demand;
- Forecasted changes in employee headcount and office equipment requirements;
- Building equipment and systems failure reporting; and,
- Operational performance planning.

The planned renovation projects will be reviewed annually and, as necessary, modified to incorporate any changes arising from new business requirements, asset and systems conditions, or regulations.

<u>IST</u>

The capital investment strategy for IST and enterprise class systems is focused on the delivery and maintenance of technologies and systems that underpin the organization and provide necessary tools and services to support our business, customers and employees. Investments in the 2015 to 2019 Test Years are required to sustain the operation of Horizon Utilities corporate IT infrastructure.

A major upgrade to the Horizon Utilities ERP system installed in 2007-2008 is required in the 2015 to 2019 Test Years. This project was required to eliminate operational risks dependent on software, database and operating systems that will not be supported by respective vendors beyond 2014. In addition, the upgrade is required to provide an updated application for the implementation of redesigned, optimized and/or new business processes that will allow Horizon Utilities' to deliver planned productivity improvements.

The remainder of IT investments are sustainability based to address the replacement of corporate computers, expansion of the Storage Area Network to accommodate the increasing data storage volumes, and an upgrade to the phone system. All of these investments required to support and sustain daily operations. The justification for these projects is provided in Appendix A.

ERP Upgrade Justification

<u>Phase 1- Upgrade from IFS version 7.3 to IFS version 8.1 (completed in 2013)</u>

This phase was operationalized in September 2013 at a capital cost of $1,224,564. This phase was required to eliminate operational risks related to software, database and operating systems that will not be supported by the respective vendors beyond 2014.

Other benefits realized during this phase were:

- A reduced capital expenditure of approximately $450,000 by migrating the ERP environment to a cloud-based managed service from IFS thereby eliminating the need to purchase and implement new in-house servers;

- A reduction in annual operating expenditure requirements of approximately $172,000 per year achieved primarily through the elimination of one technical support FTE position as IFS provides these services as part of the managed services;

<u>Phase 2 – Removal of Custom Modifications (planned for 2014)</u>

This phase is focused on the removal of custom modifications from the Horizon Utilities' IFS implementation. The budget for this phase of the project is $980,260.

The justification for this phase is:

- A reduction in ongoing annual software maintenance related to custom modifications of approximately $50,000 per year;

- Annual future cost avoidance of approximately $40,000 related to current modifications for which IFS has not yet started billing Horizon Utilities;

- A reduction in future upgrade costs by not having to migrate custom modifications to new versions. IFS, the software development company, has stated that the next major upgrade of the application will require the rewrite custom modifications as the customization platform will change. The cost of rewriting Horizon Utilities' custom modifications during the next upgrade is estimated at $658,000, if custom modifications are not otherwise removed – this represents a recurring opportunity for savings at each following major upgrade. The next major upgrade is planned for 2018;

- Removal of the IFS custom modifications to establish an IFS ERP system foundation upon which to cost-effectively redesign and optimize business processes using core functionality in the application.

<u>Phase 3 – Business Process Redesign and Optimization (planned for 2015)</u>

This 2015 initiative is the third and final phase of an enterprise-wide project that commenced in 2013 to upgrade Horizon Utilities' ERP system from IFS version 7.3 to version 8.1 and to enhance the ERP system.

This objective for this phase is the redesign, optimization and implementation of new business processes using features and functions available in the IFS version 8.1 to deliver annual operational efficiencies and staff productivity improvements of approximately $703,000 as outlined in the Exhibit 4, Tab 3, Schedule 4.

Horizon Utilities has included further details regarding this initiative in Appendix A.

Horizon Utilities is planning a subsequent ERP upgrade in 2018 as identified below.

<u>2018 IFS ERP Upgrade</u>

This is an enterprise-wide project in 2018 for the lifecycle upgrade of Horizon Utilities' ERP system from IFS version 8.1 to the then current vendor supported version. This is a major upgrade to the IFS ERP system upgraded in 2013. This project is required to mitigate operational risks dependent on software not supported by the vendor. This project will be a straight migration of functionality to the new version.

The estimated capital expenditure for this project in 2018 is $1,225,000 with a target implementation date of September 2018.

Horizon Utilities has provided the justification for this project in Appendix A.

3.5.4. Material Investments (5.4.5.2)

Horizons Utilities has provided all of its material investment templates, which have been designed to address Section 5.4.5.2 of the Filing Requirements; attached to this DSP as Appendix G. Furthermore, requisite capital expenditures and justification for specific projects has been delineated throughout Appendix A.