APPENDIX 2-4: HORIZON UTILITIES' DISTRIBUTION SYSTEM PLAN

Horizon Utilities Corporation

Distribution System Plan

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Table of Contents

List of Figures

List of Tables

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'.

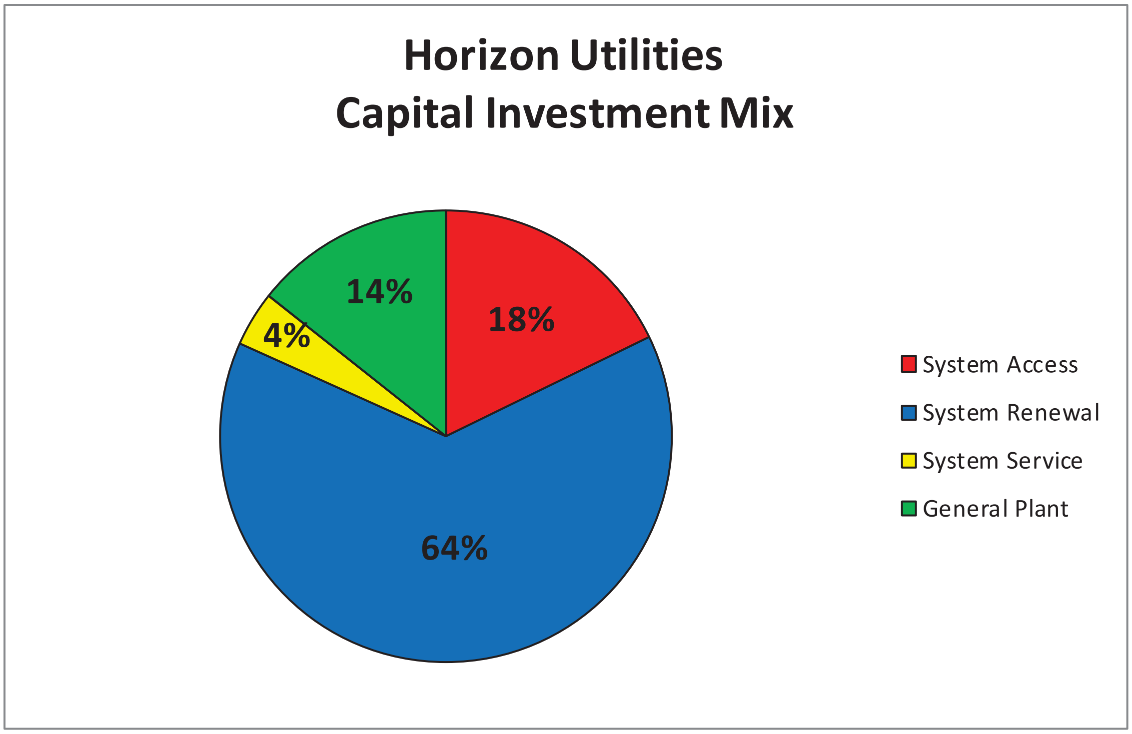

Figure 1 – Forecast Capital Investment Mix (as a percentage of total investment over 2015-2019)

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.

Customer Oriented Performance

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 50th and 75th 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)

Health Index Forecast

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.

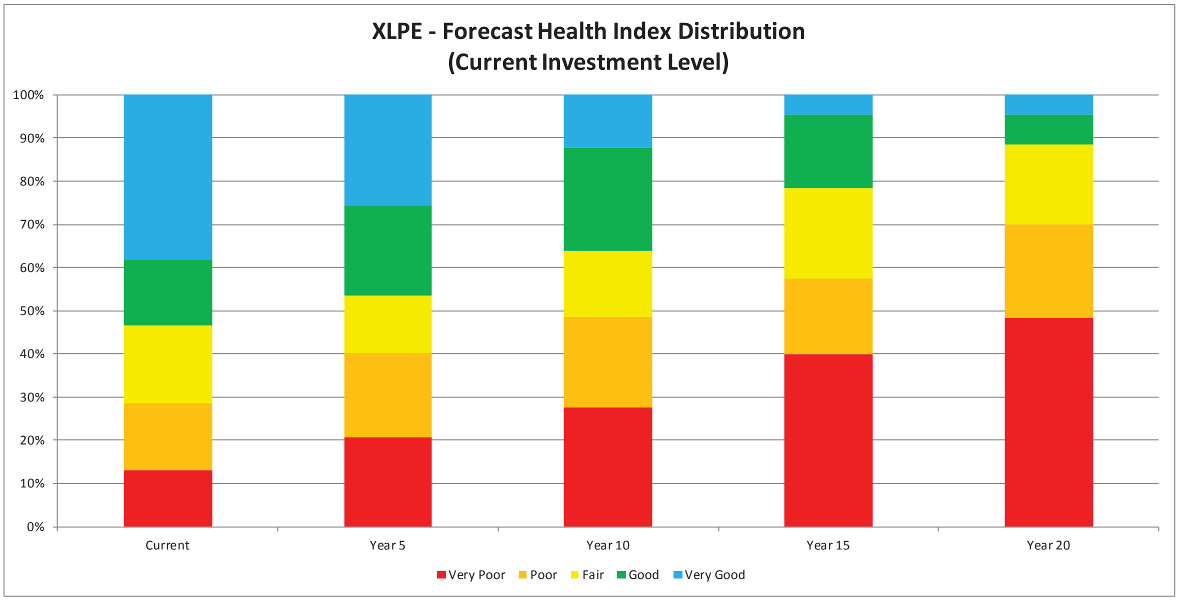

Figure 3 - XLPE Health Index Distribution Forecast at the Current Investment Level

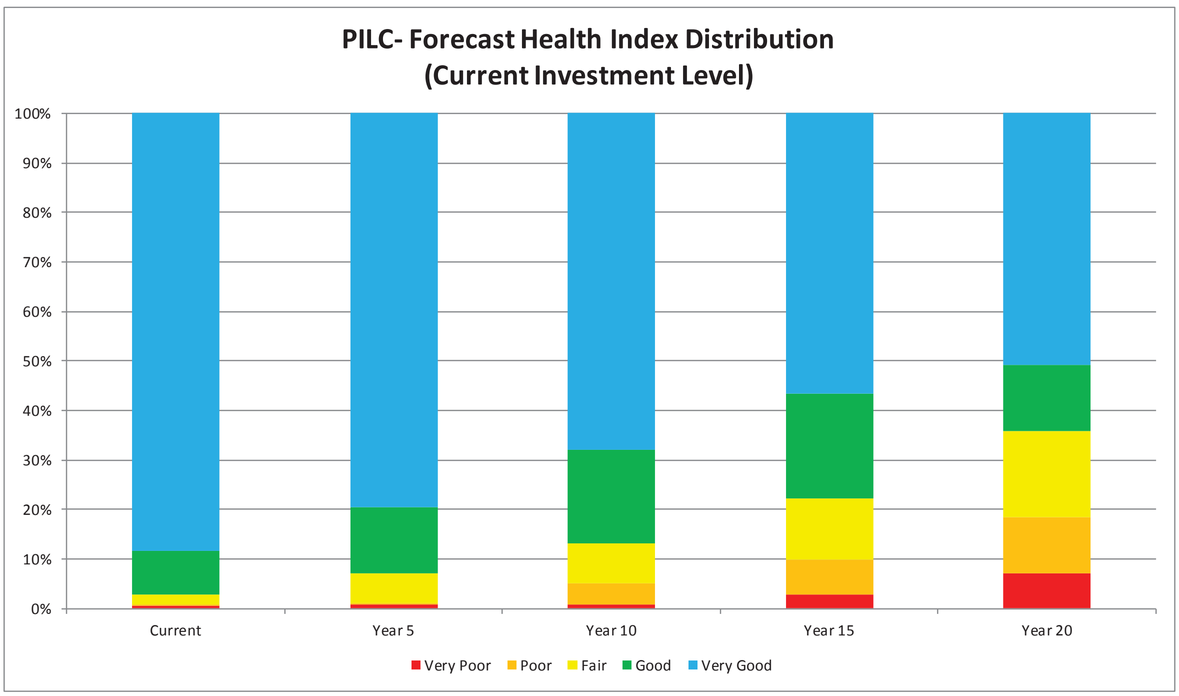

Figure 4 - Paper insulated lead covered ("PILC") Health Index Distribution at the Current Investment Level

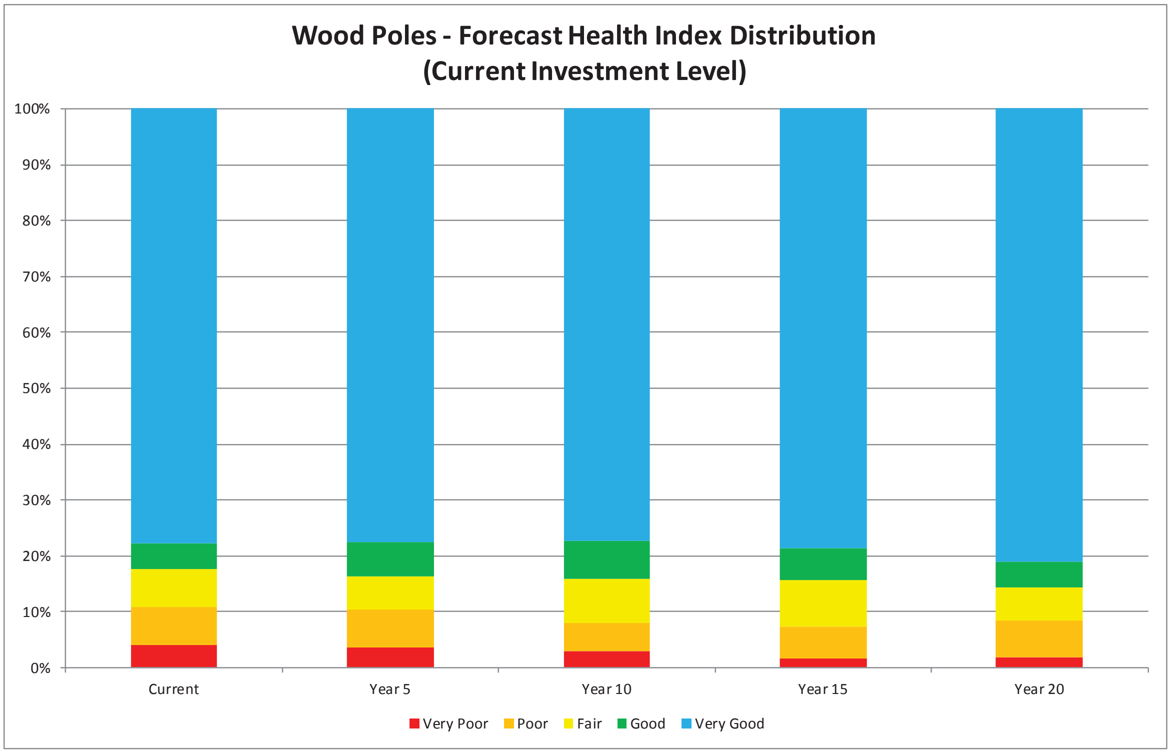

Figure 5 - Wood Pole Health Index Distribution at the Current Investment Level

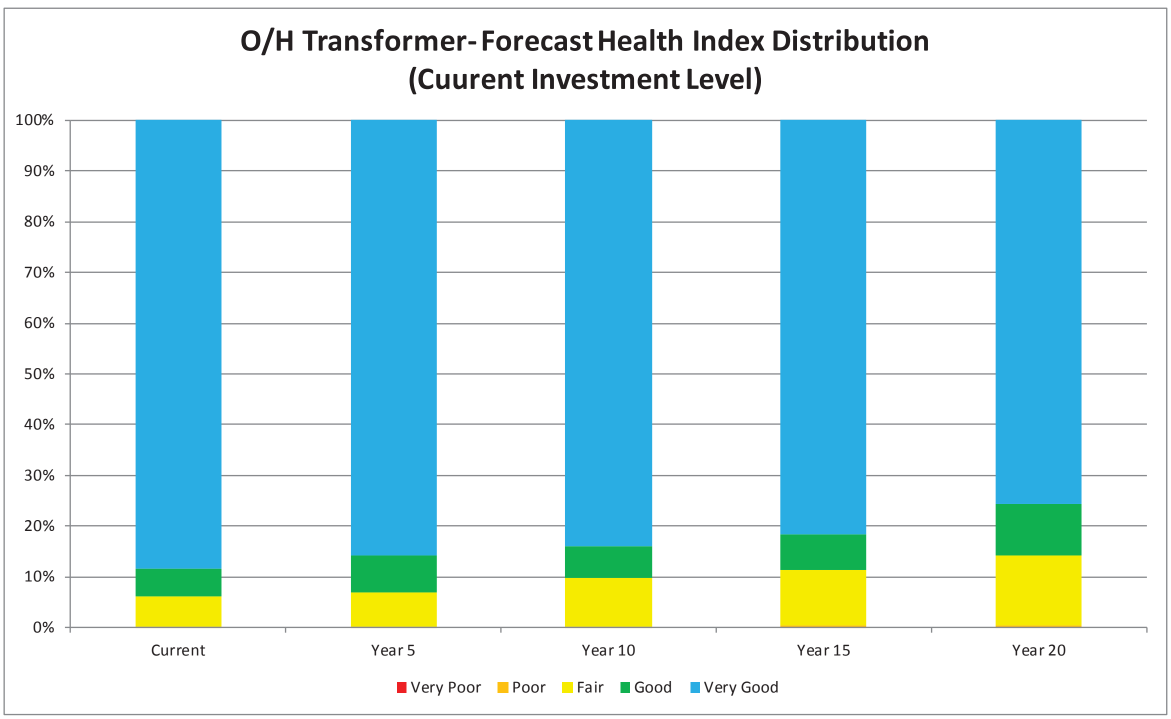

Figure 6 - O/H Transformer Health Index Distribution at the Current Investment Level

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.

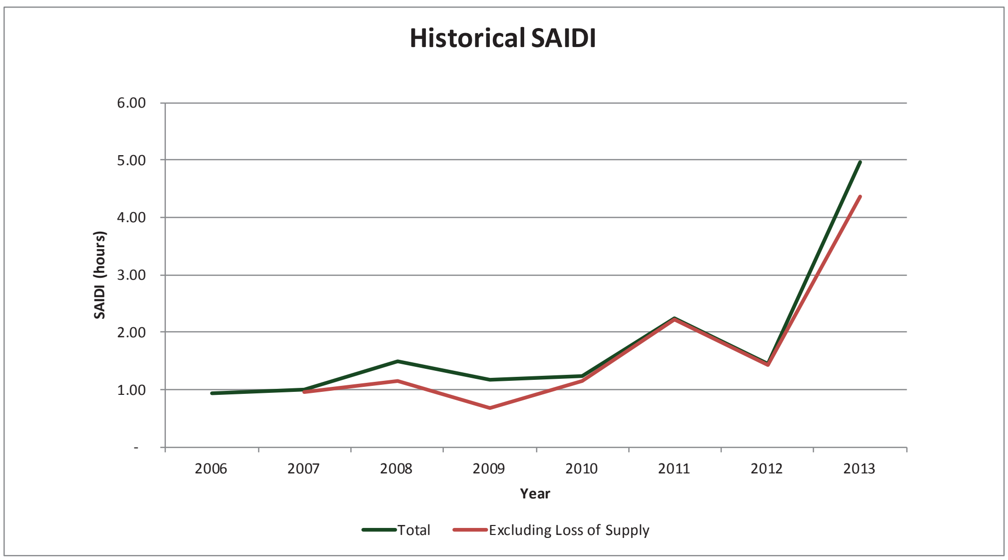

Figure 7 - Historical SAIDI

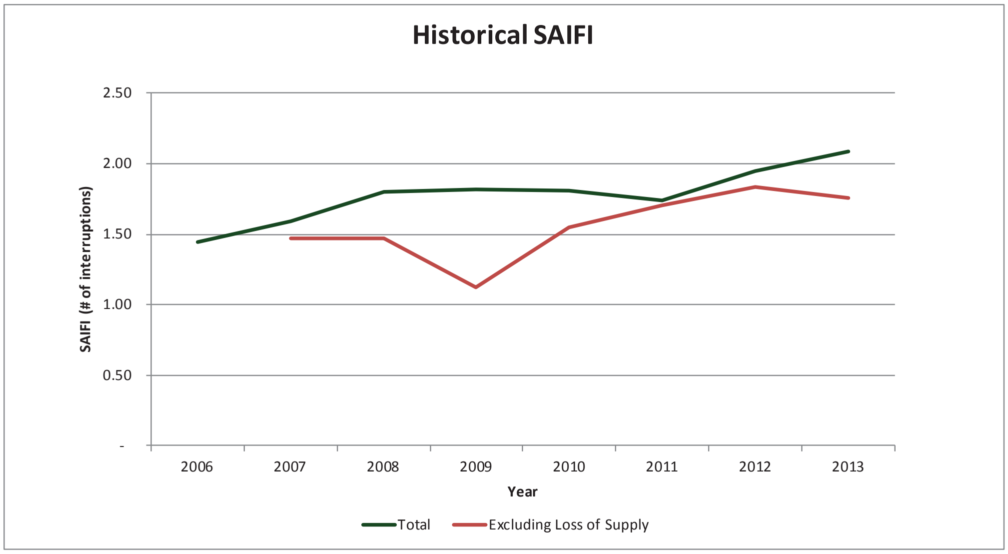

Figure 8 - Historical SAIFI

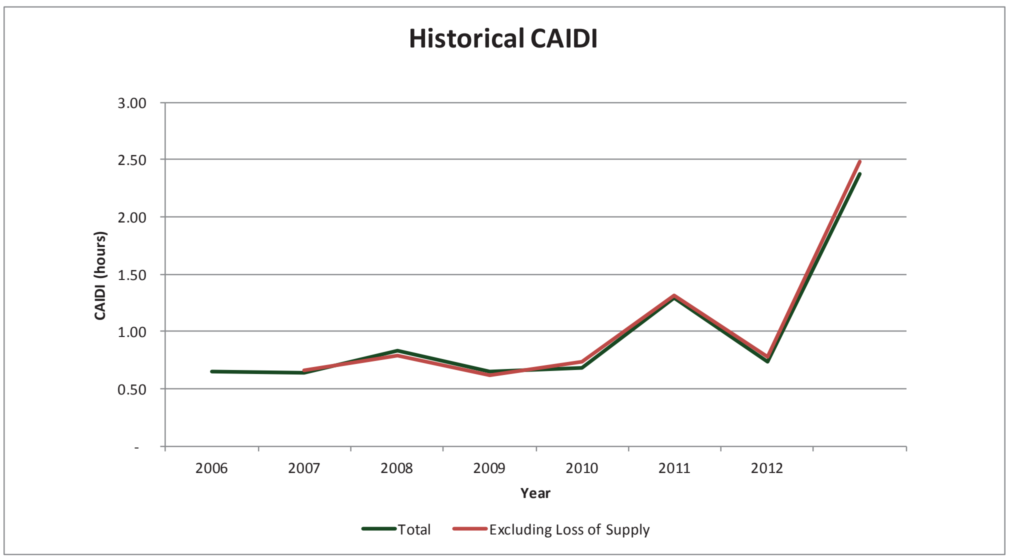

Figure 9 - Historical CAIDI

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.

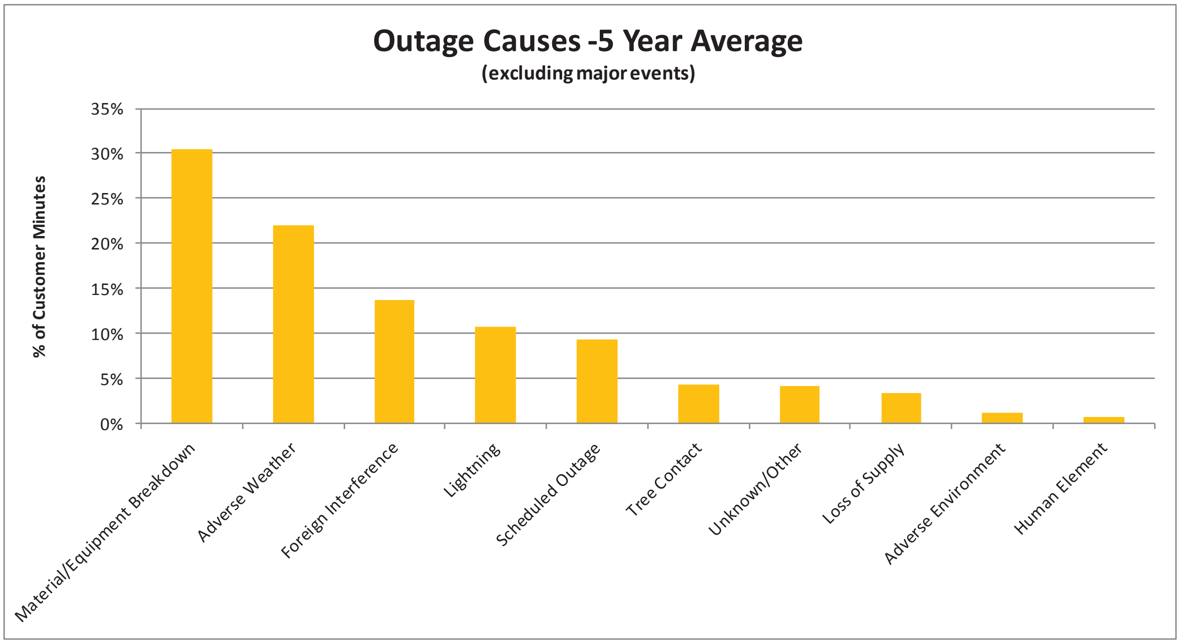

Figure 10 - Outage Cause Contributions for the years 2010 - 2013

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

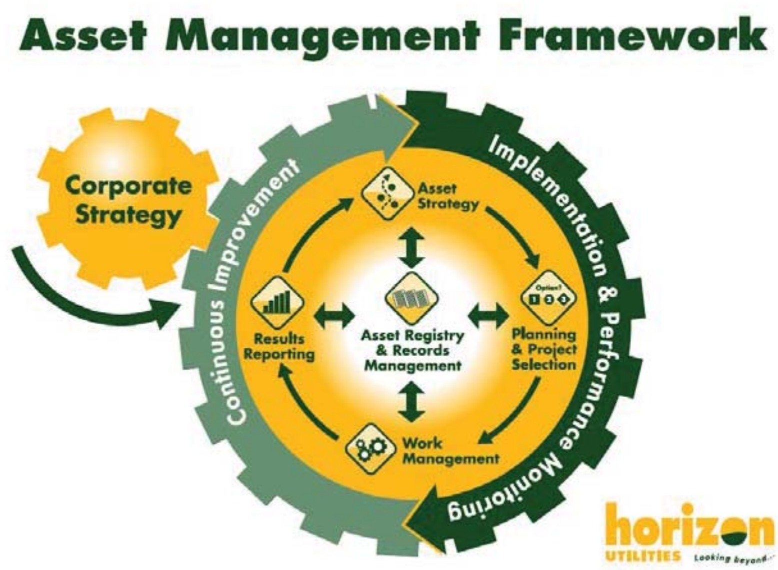

Figure 12 - Asset Management Framework

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.

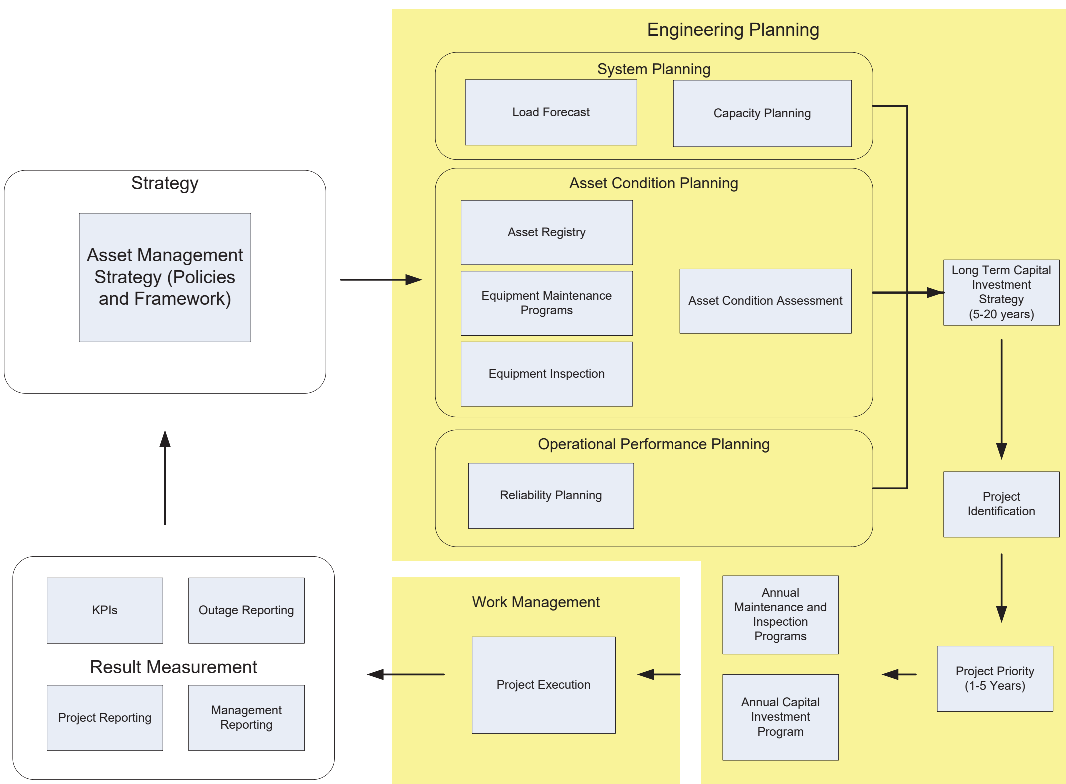

Figure 13 - Asset Management Model

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.

System Planning

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.

Operational Performance Planning

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.

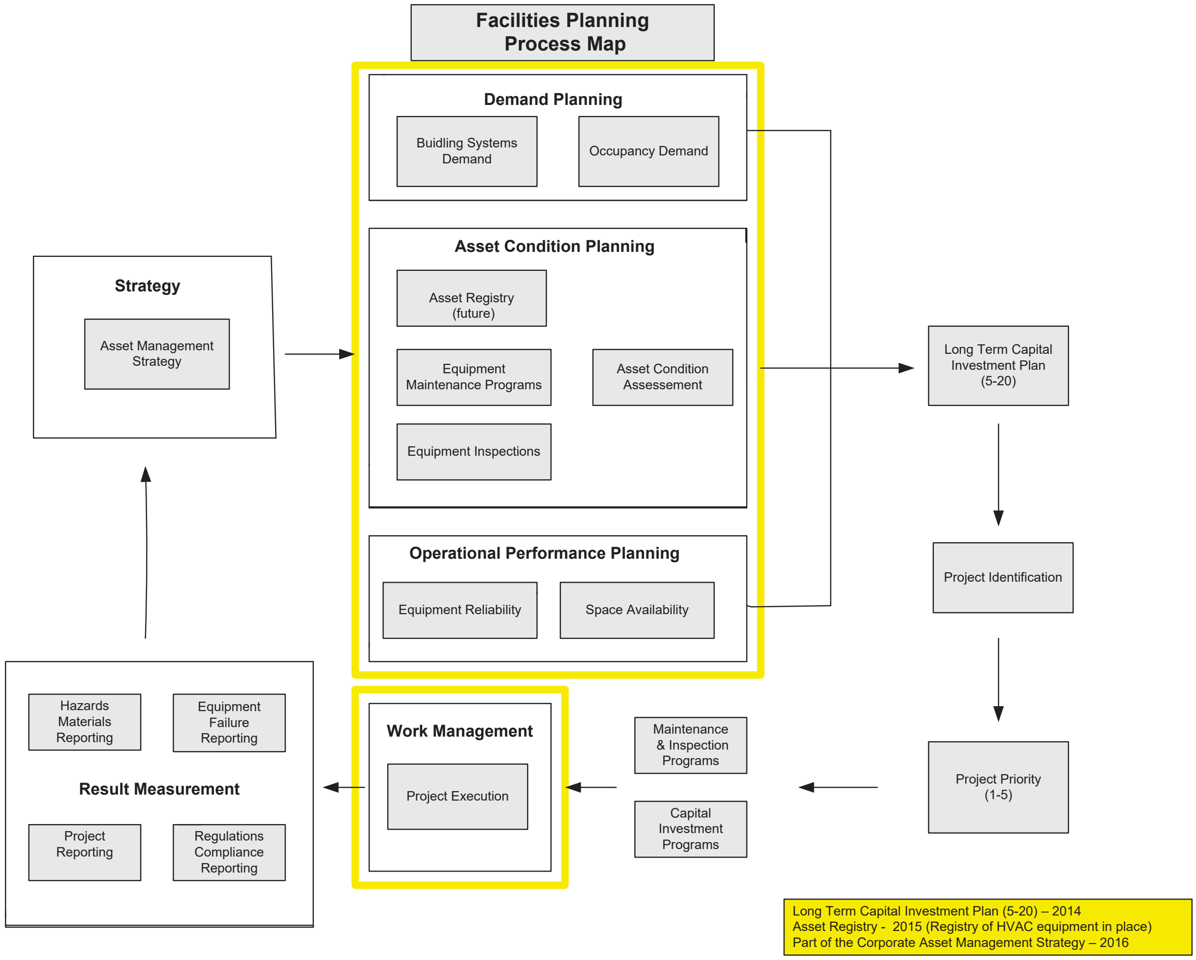

Figure 14 – Facility Planning Process Map

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").

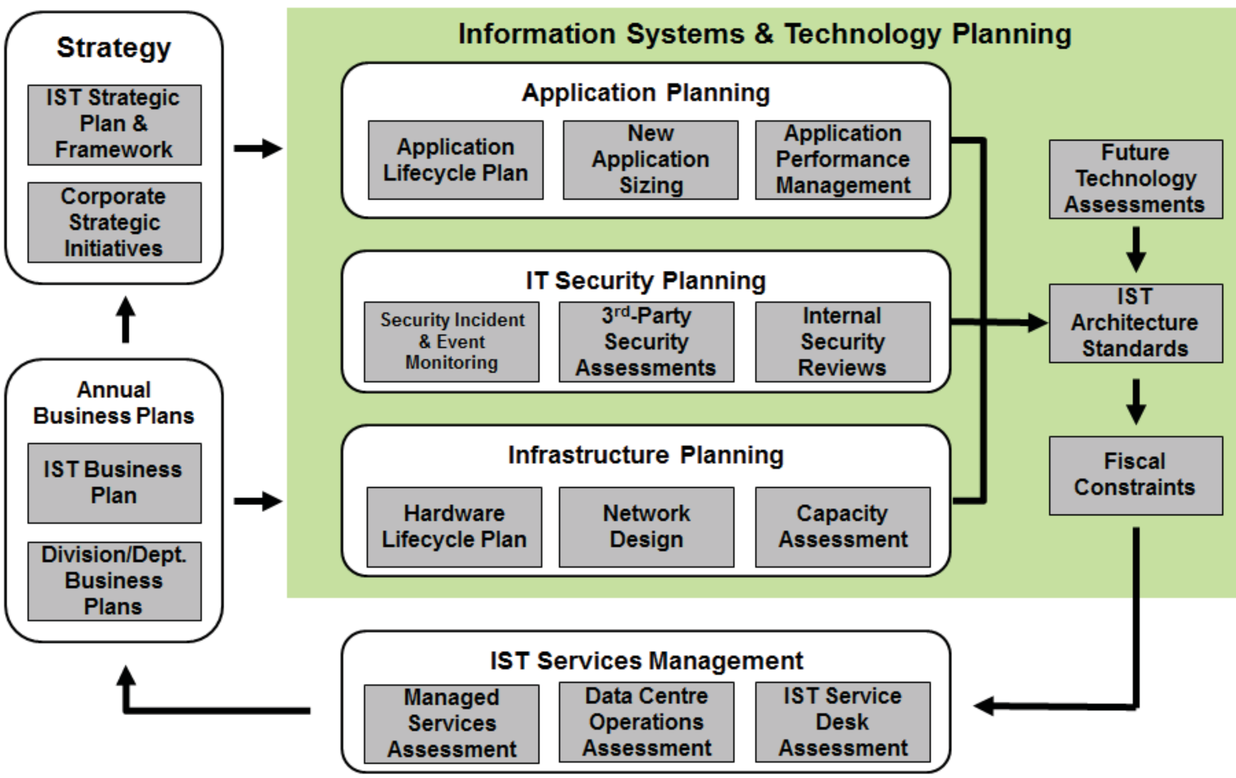

Figure 15 - IST Planning Process

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.

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[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.

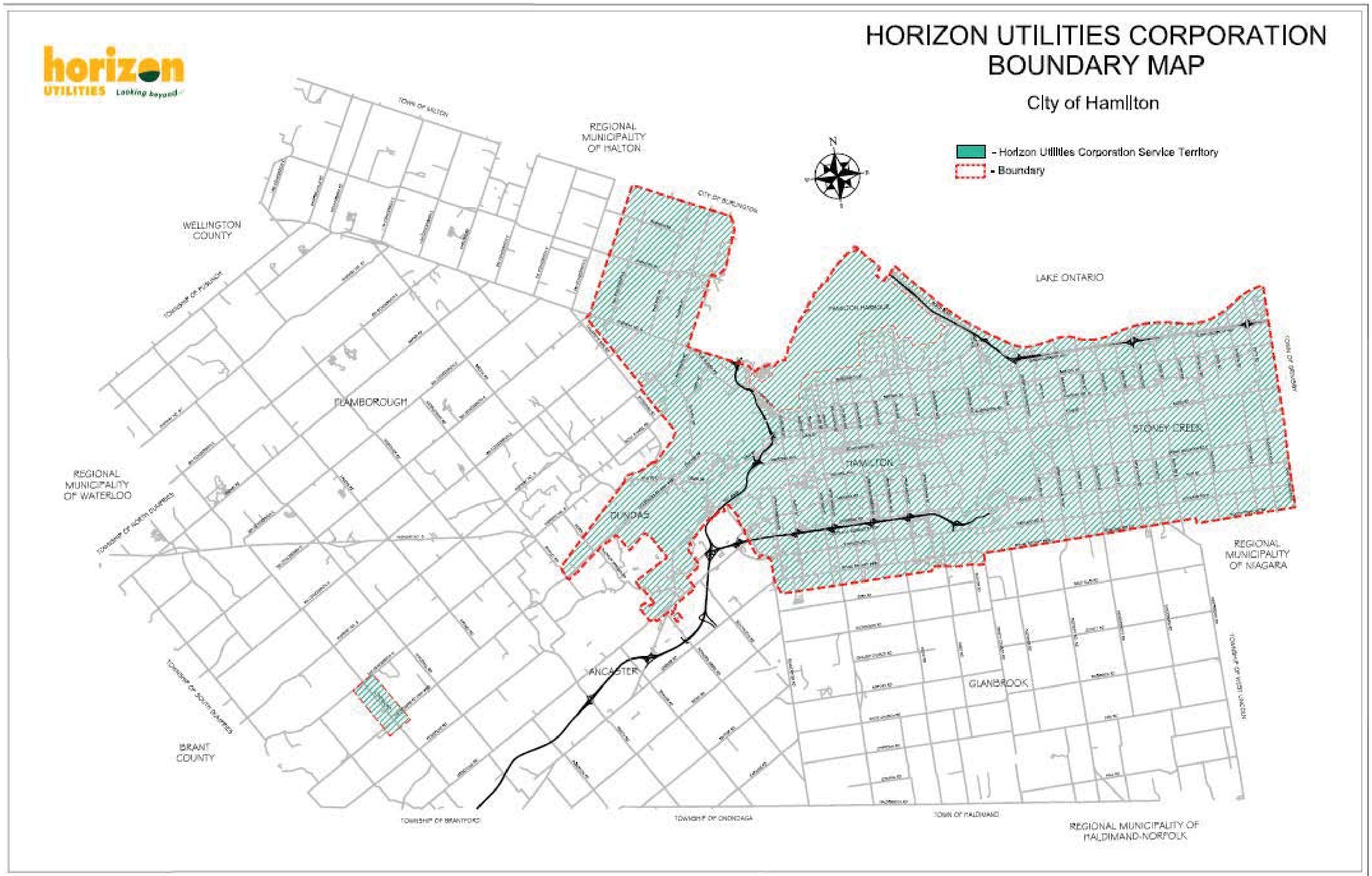

Figure 17 - Map of Horizon Utilities Boundary - Hamilton Service Territory

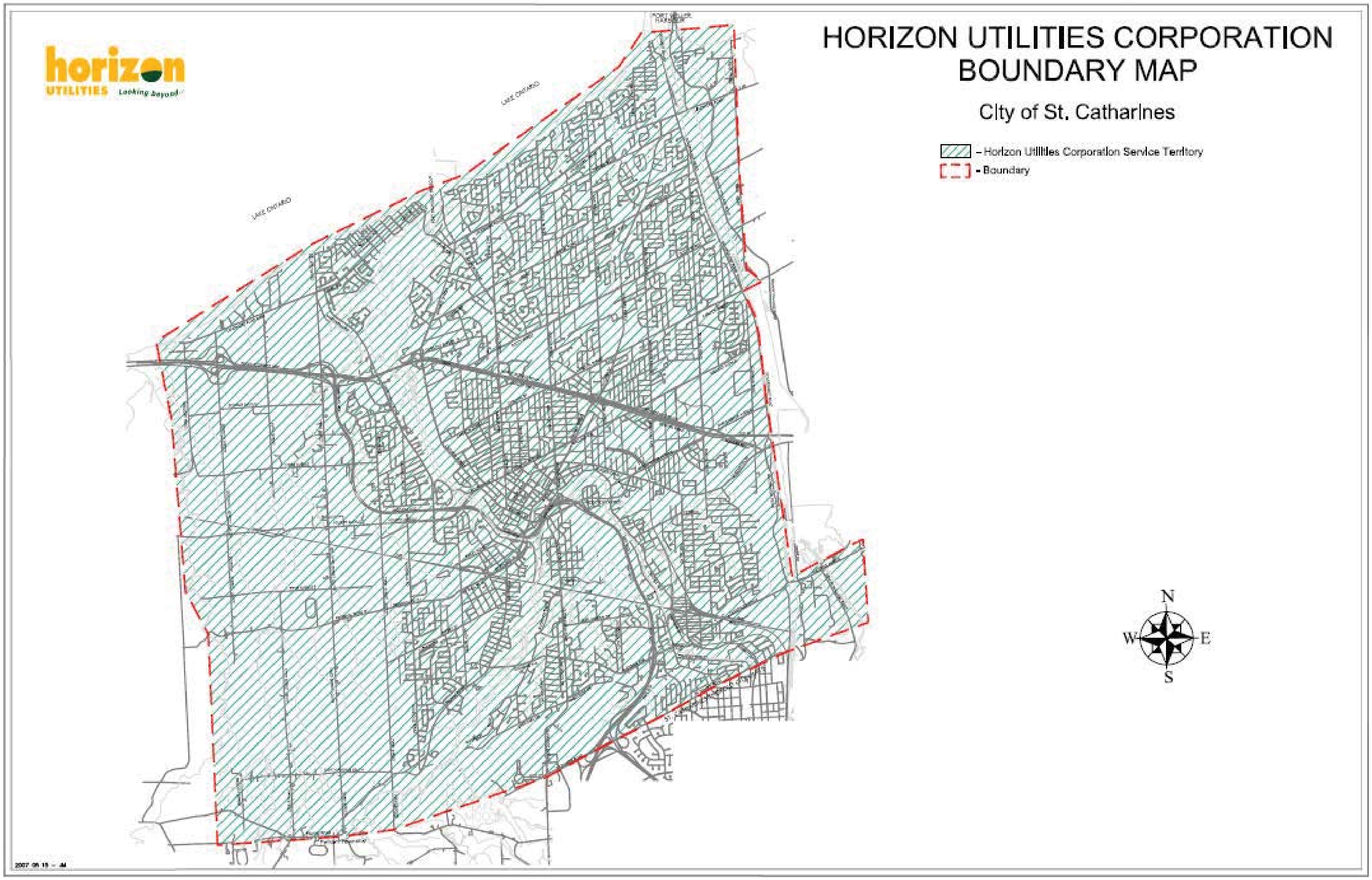

Figure 18 - Map of Horizon Utilities Boundary – St. Catharines Service Territory

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.

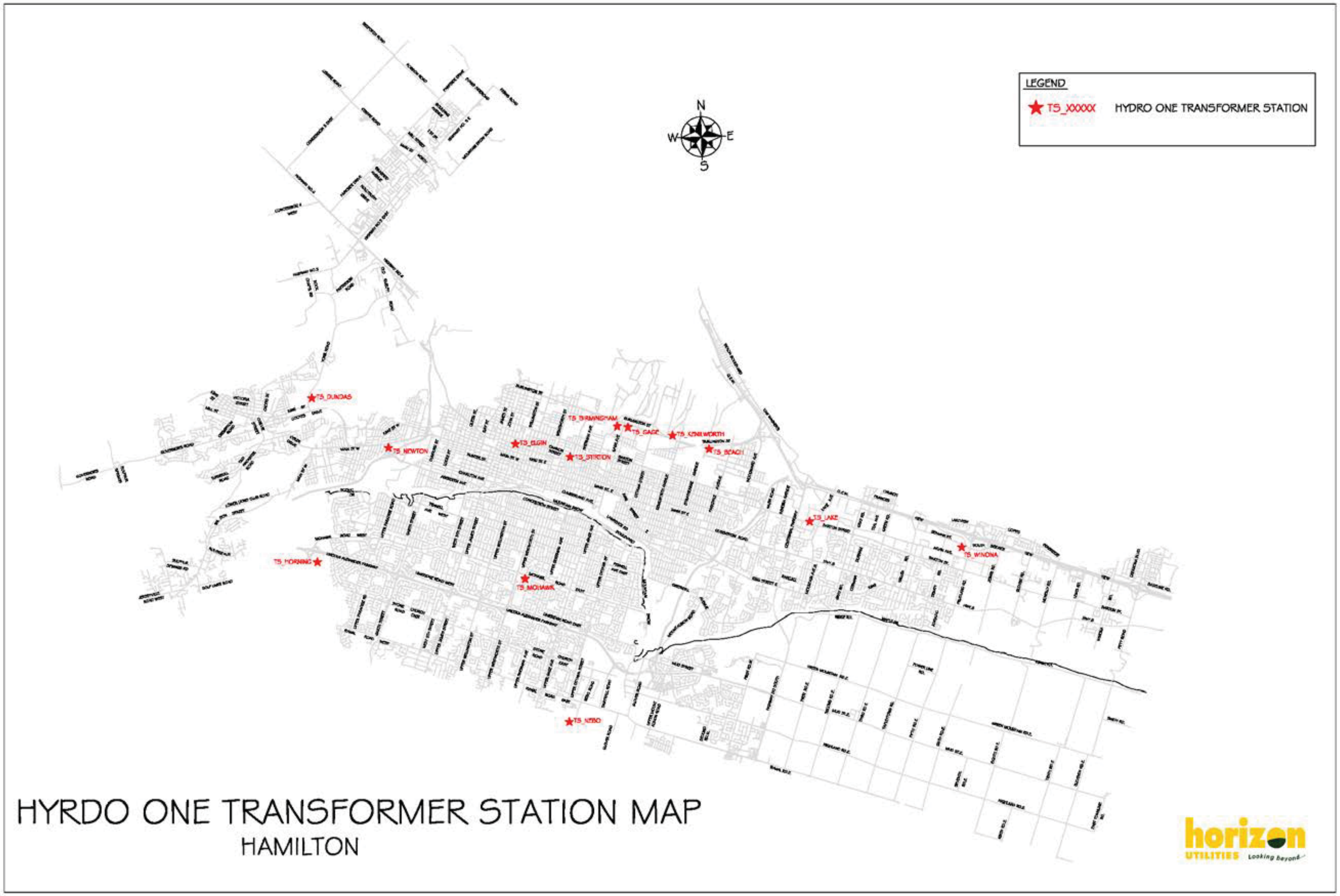

Figure 19 - Map of Transformer Stations Servicing the Hamilton Service Territory

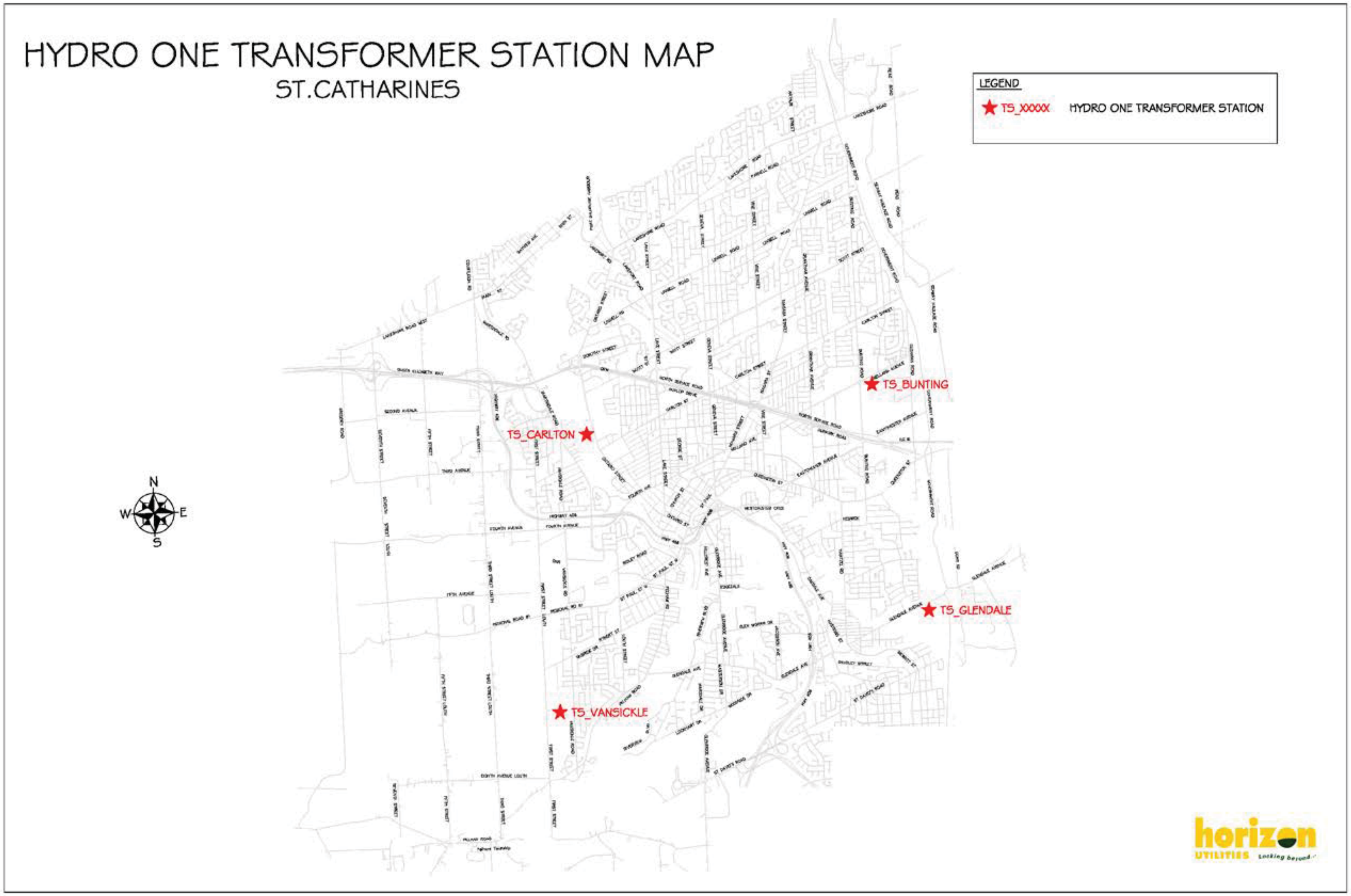

Figure 20 - Map of Transformer Stations Servicing the St. Catharines Service Territory

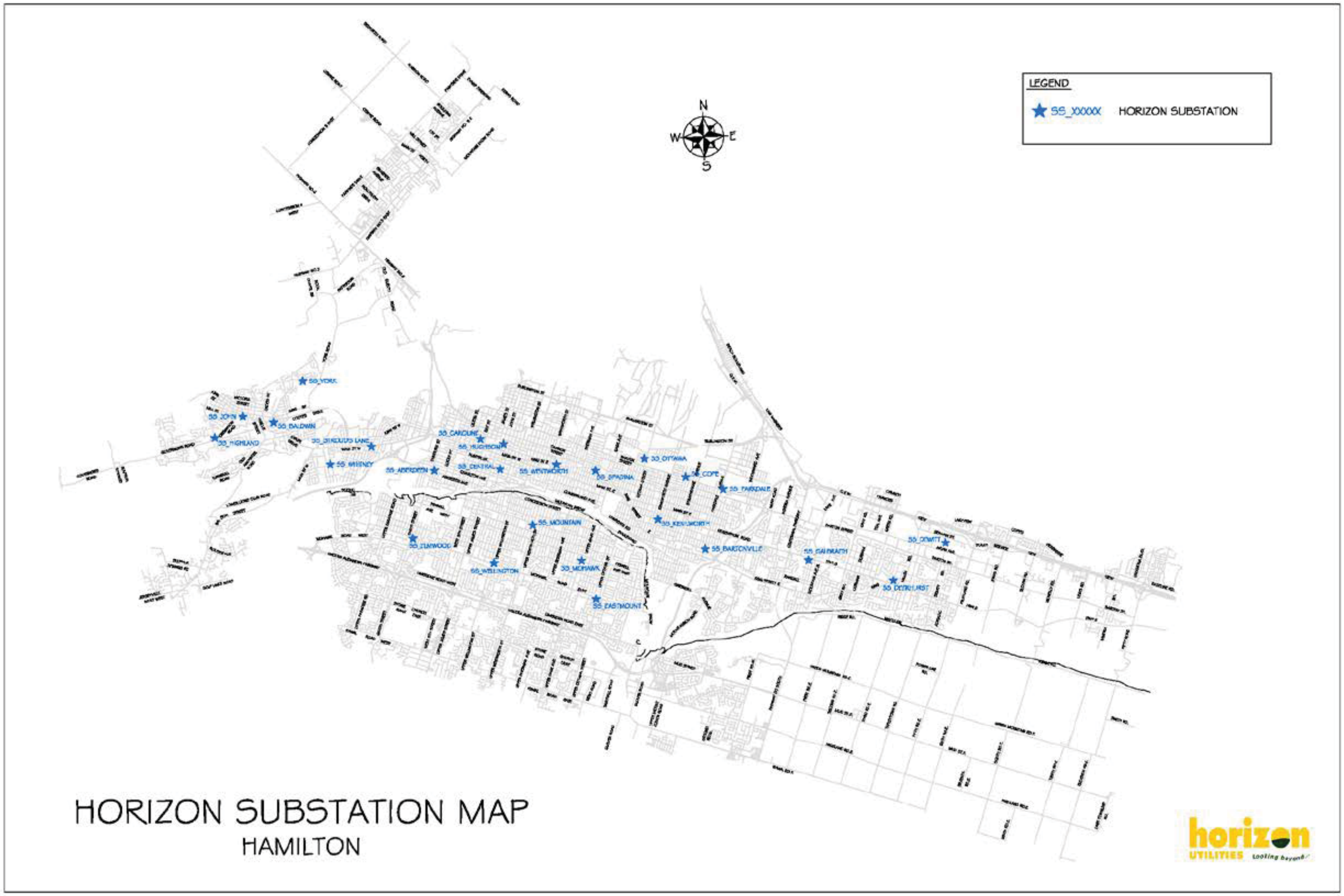

Figure 21 - Map of Municipal Substations Servicing the Hamilton Service Territory

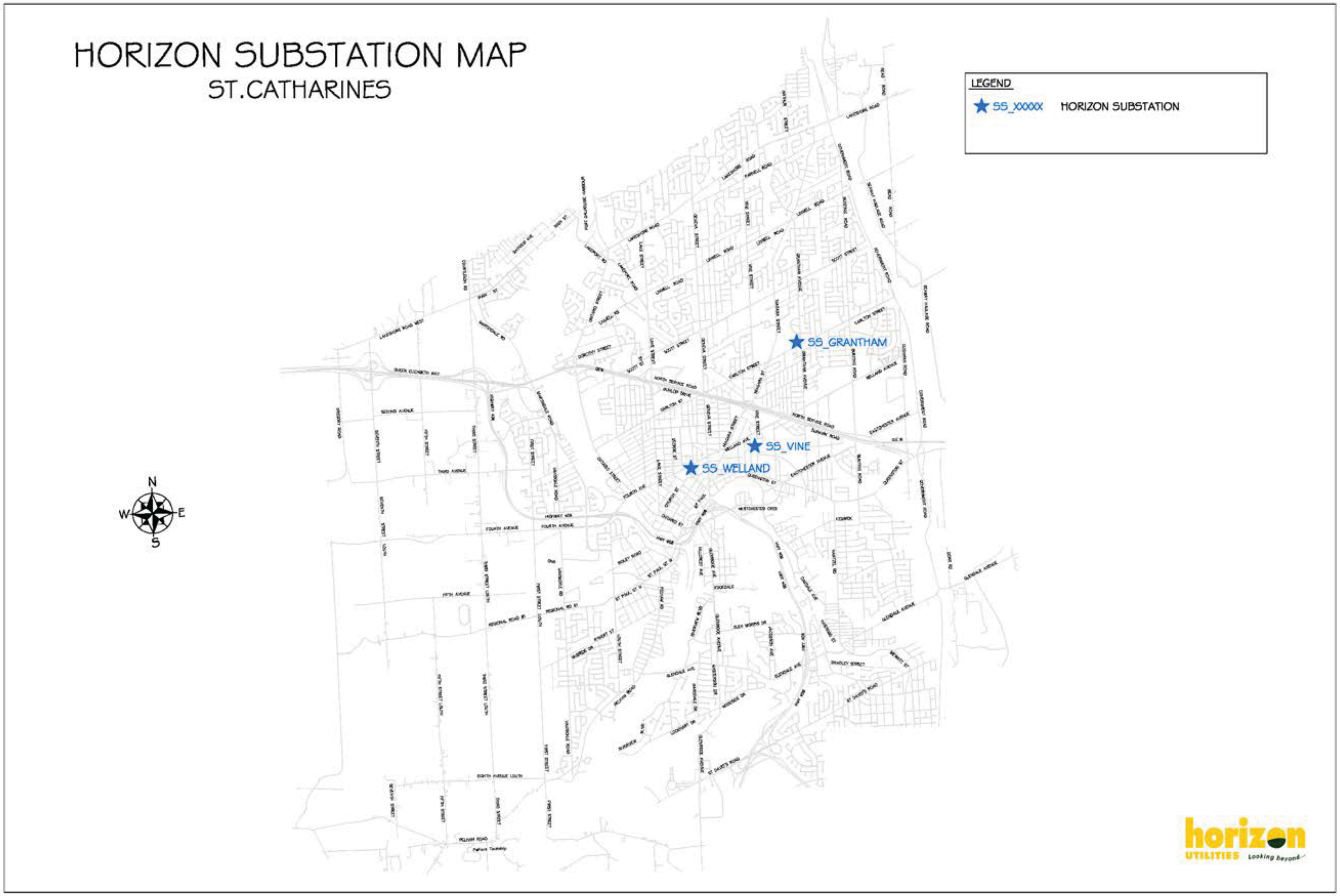

Figure 22 - Map of Municipal Substations Servicing the St. Catharines Service Territory

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.

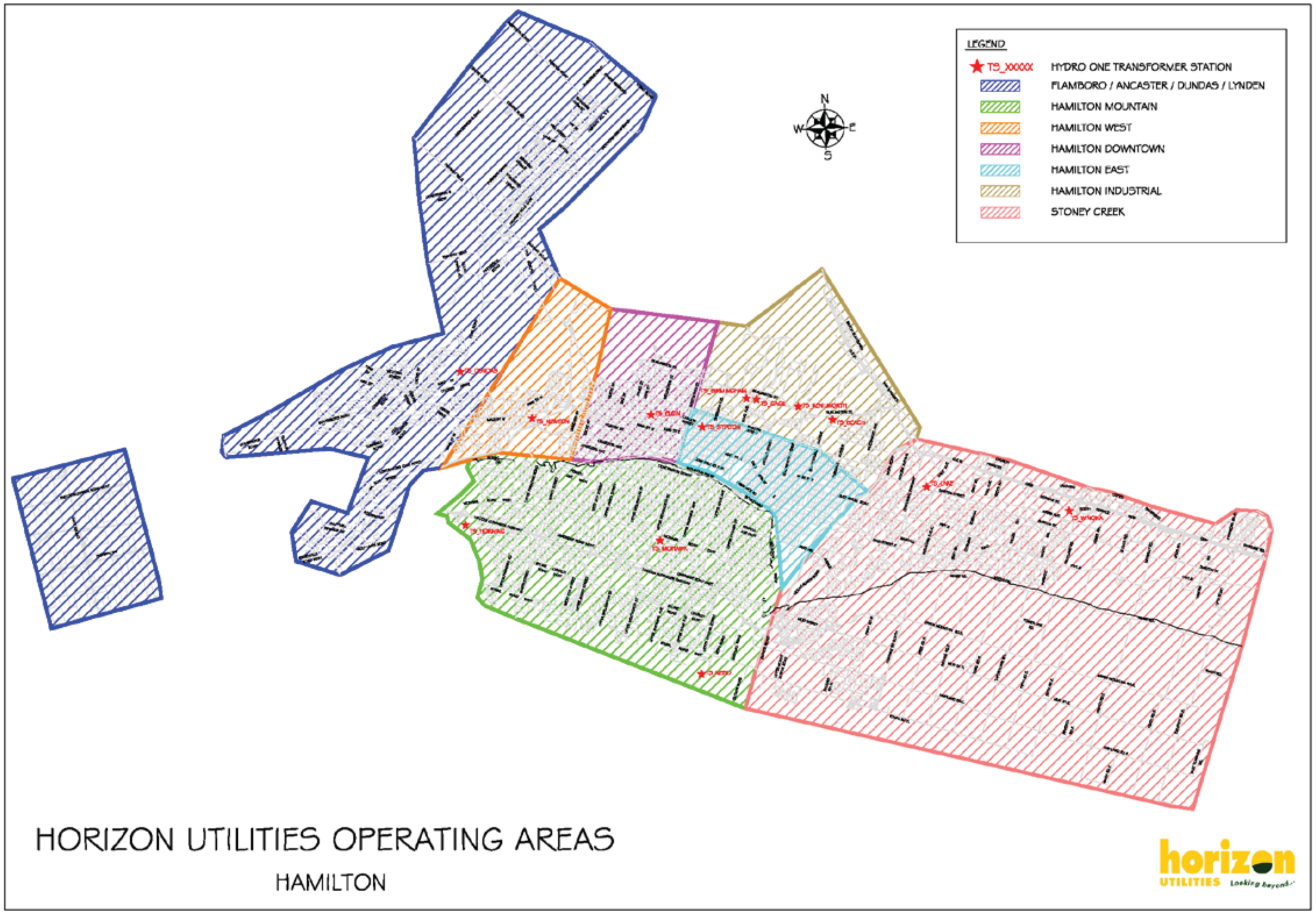

Figure 23 - Horizon Utilities Operating Areas in the Hamilton Service Territory

<u>Flamborough/Ancaster/Dundas/Lynden</u>

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.

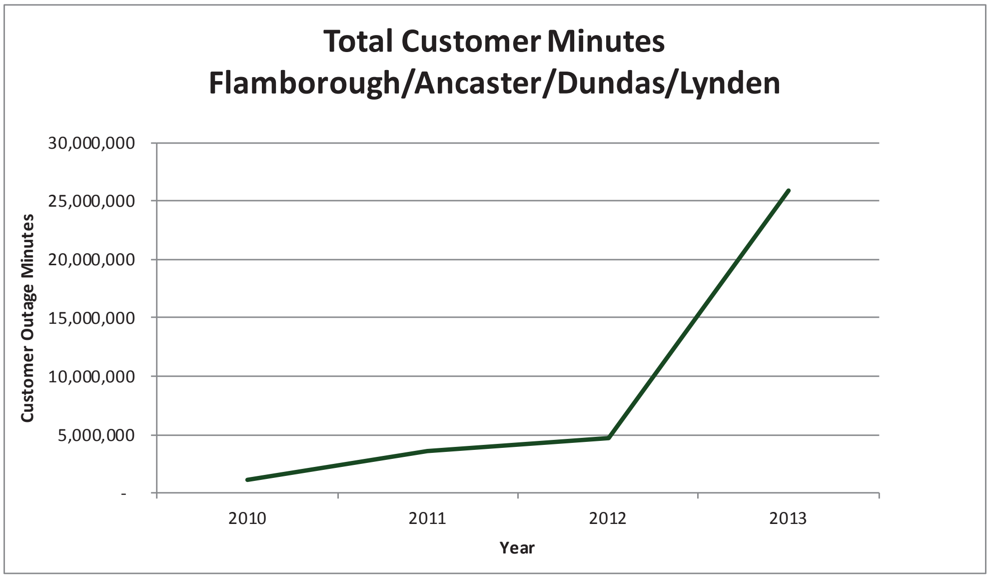

Figure 24 - Flamborough/Ancaster/Dundas/Lynden Operating Area - Historical Reliability

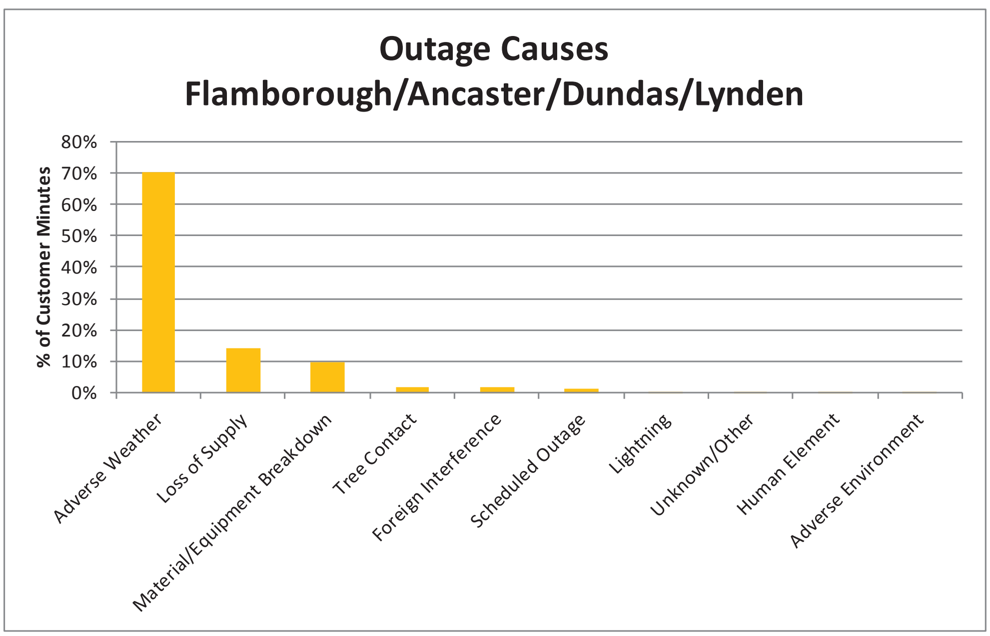

Figure 25 - Flamborough/Ancaster/Dundas/Lynden Operating Area - Cause of Outages

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.

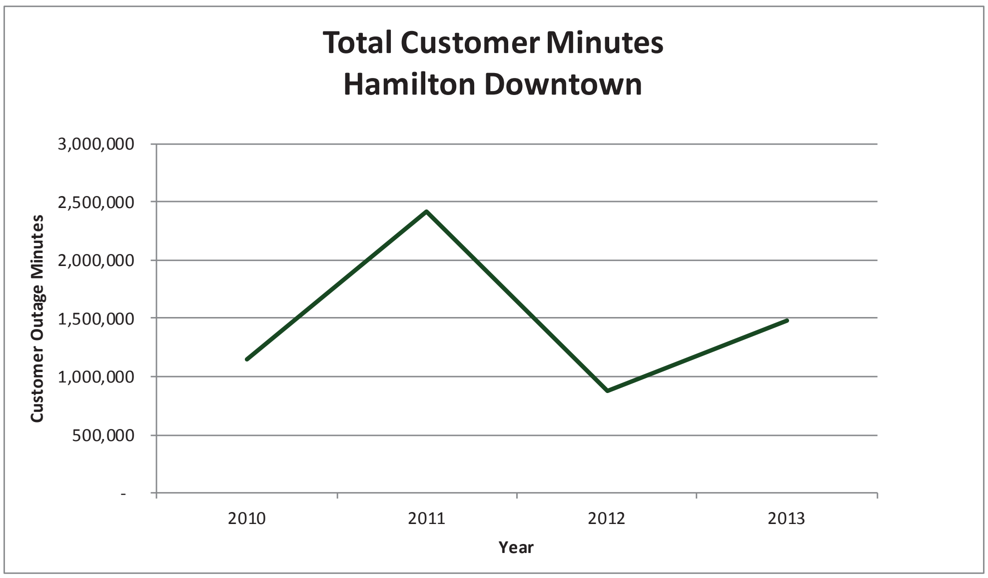

Figure 26 - Hamilton Downtown Operating Area - Historical Reliability

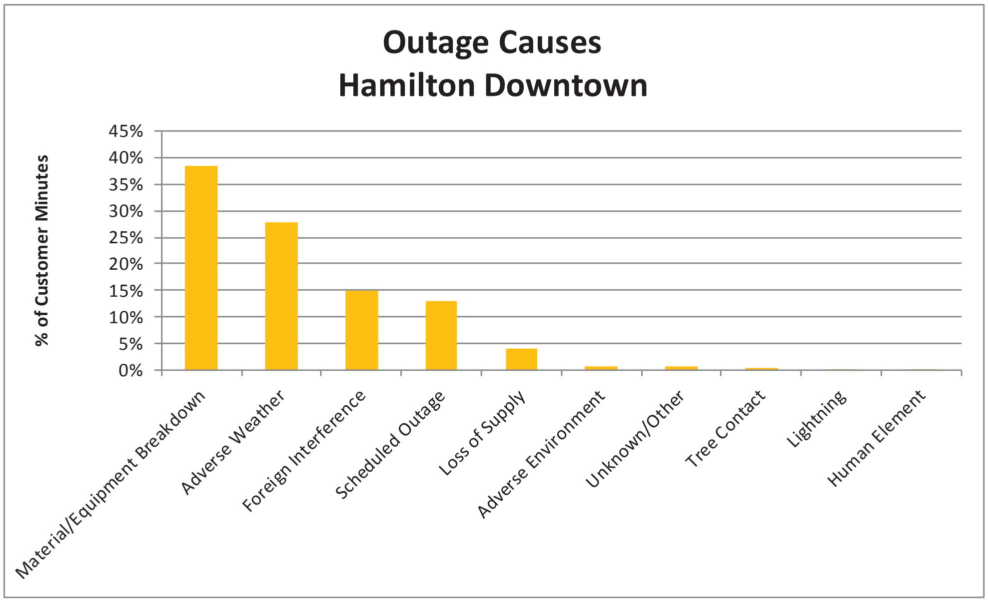

Figure 27 - Hamilton Downtown Operating Area - Cause of Outages

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.

<u>Hamilton East</u>

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.

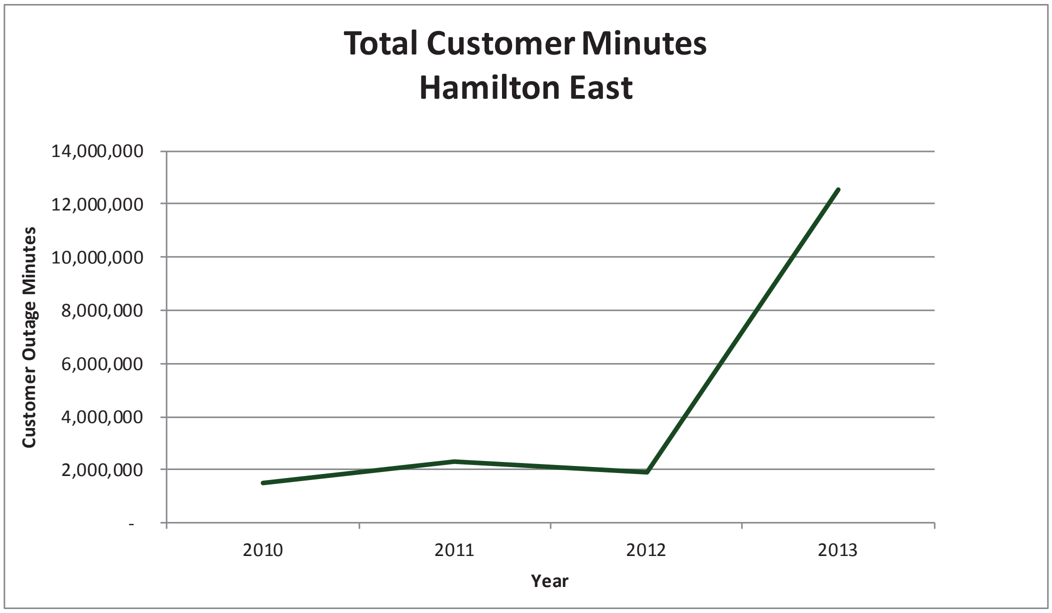

Figure 28 - Hamilton East Operating Area - Historical Reliability

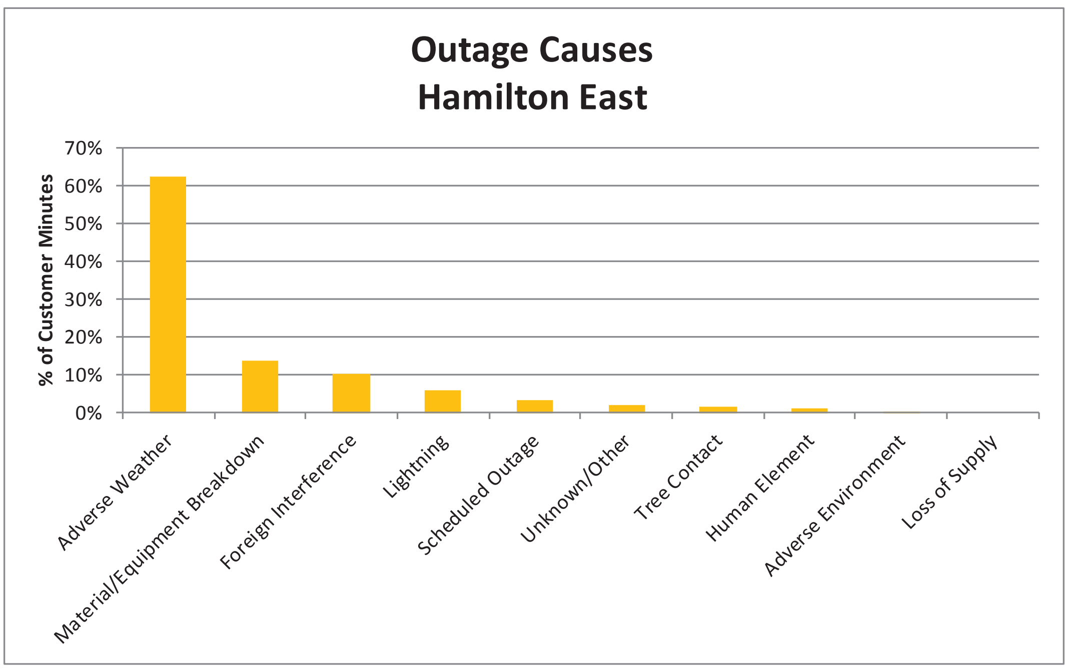

Figure 29 - Hamilton East Operating Area – Cause of Outages

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.

Hamilton Waterfront Industrial

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.

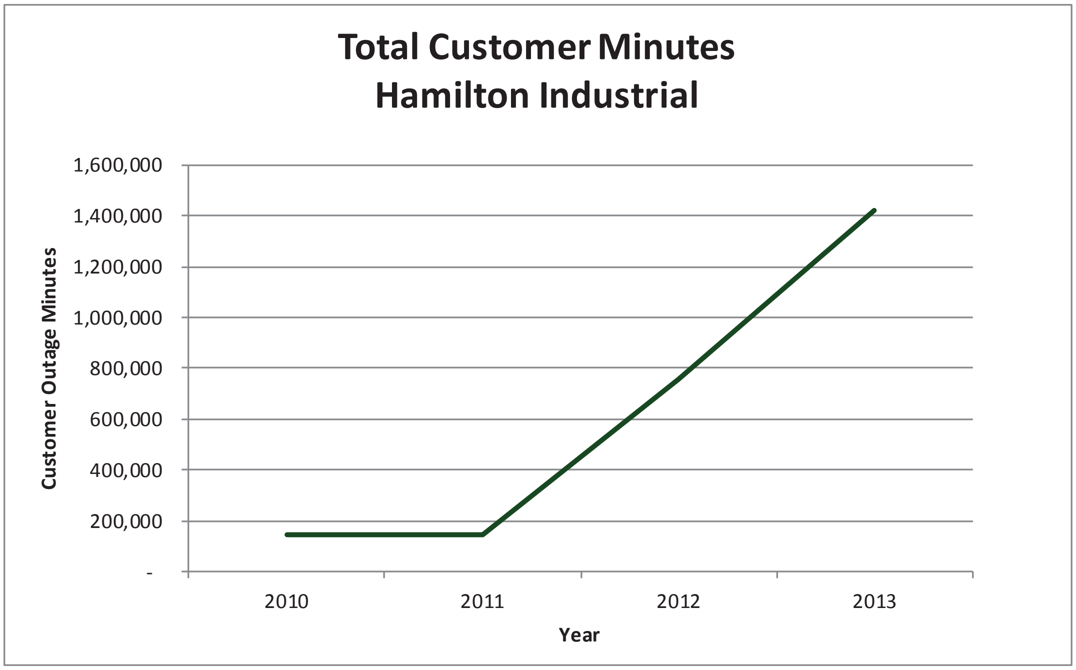

Figure 30 - Hamilton Waterfront Industrial Operating Area - Historical Reliability

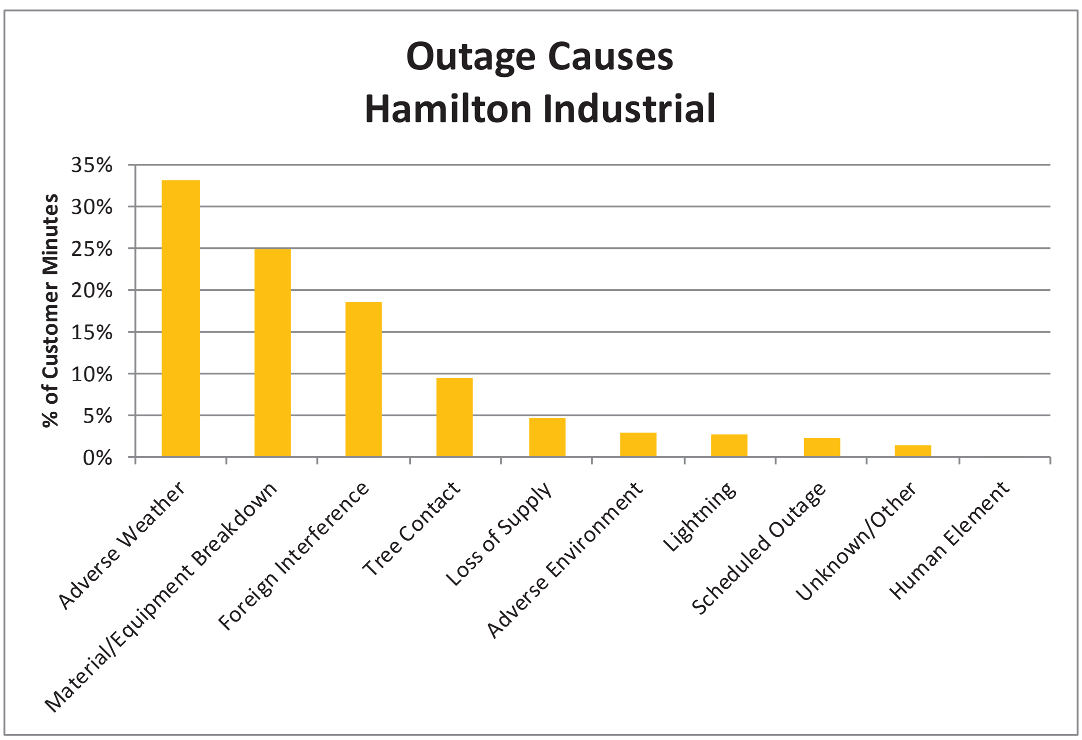

Figure 31 - Hamilton Waterfront Industrial Operating Area - Cause of Outages

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.

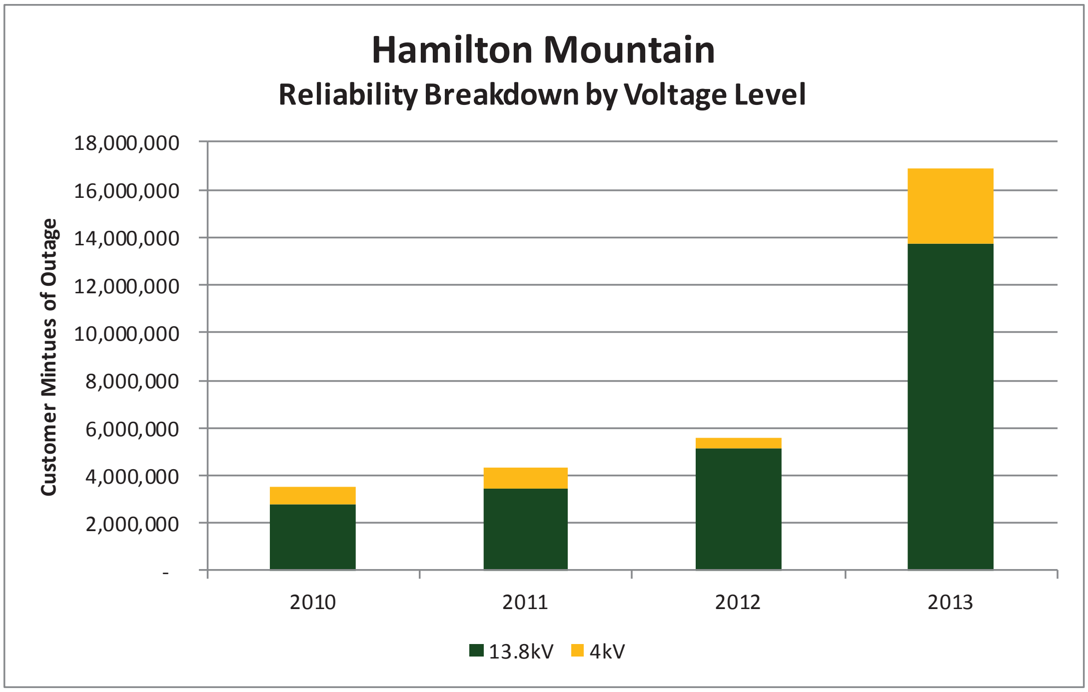

Figure 32 - Hamilton Mountain - Reliability Breakdown by Voltage Level

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.

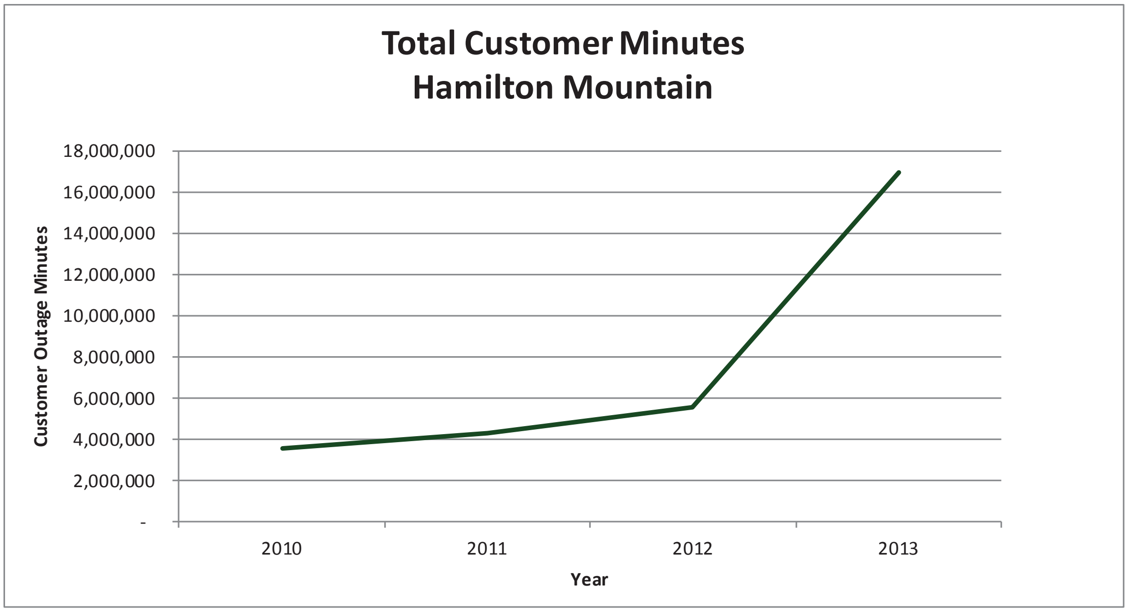

Figure 33 - Hamilton Mountain Operating Area - Historical Reliability

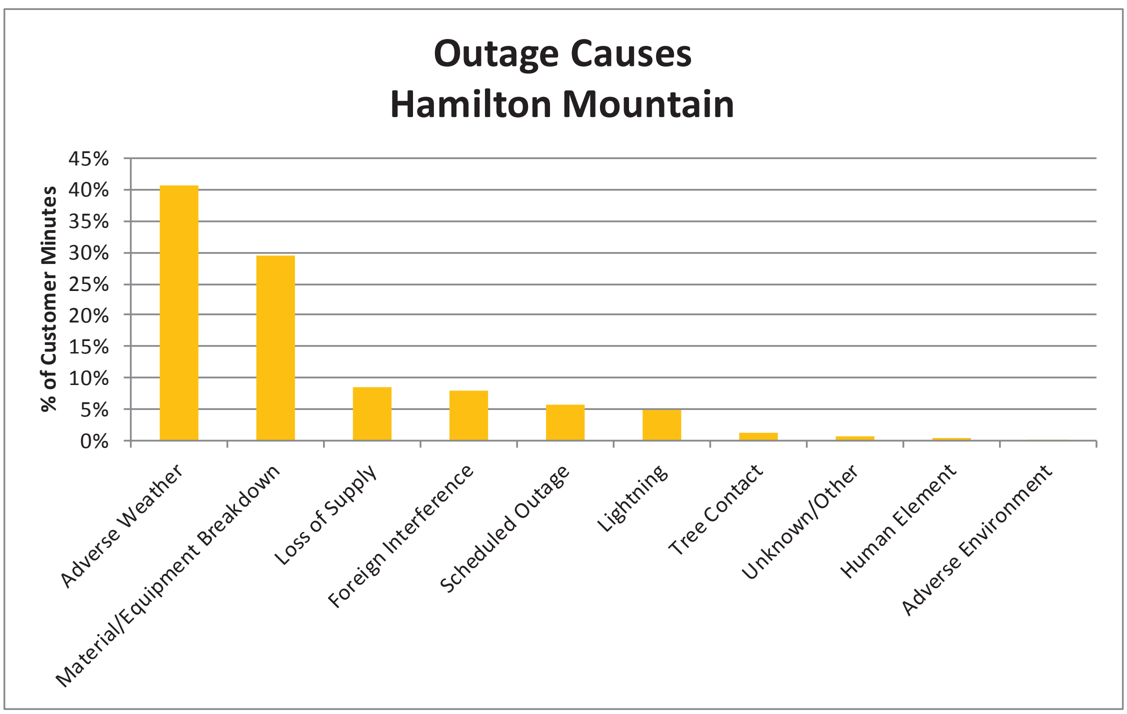

Figure 34 - Hamilton Mountain Operating Area – Cause of Outages

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.

Hamilton West

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.

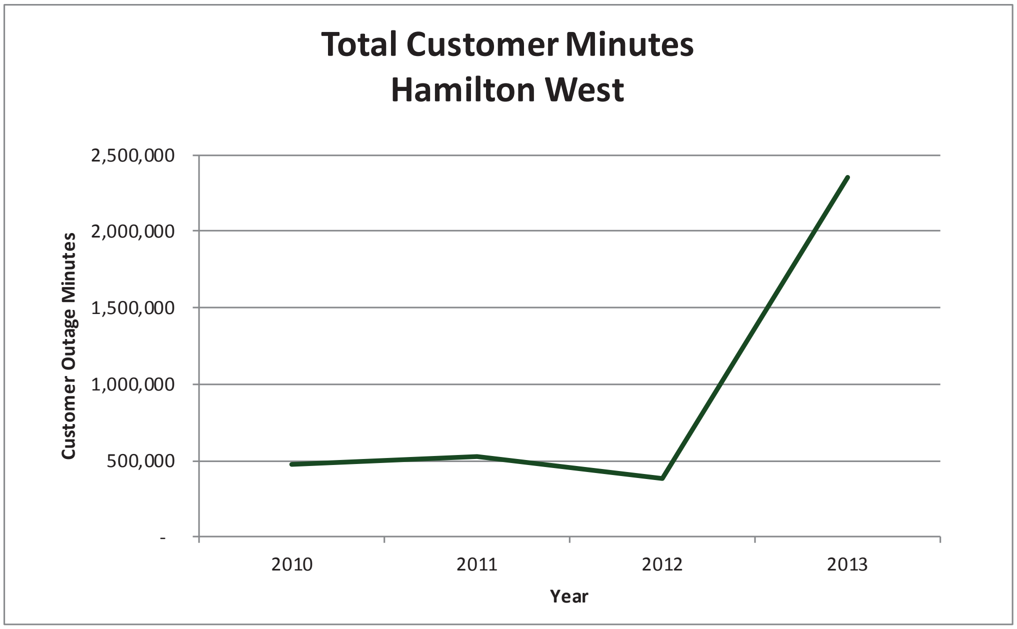

Figure 35 - Hamilton West Operating Area - Historical Reliability

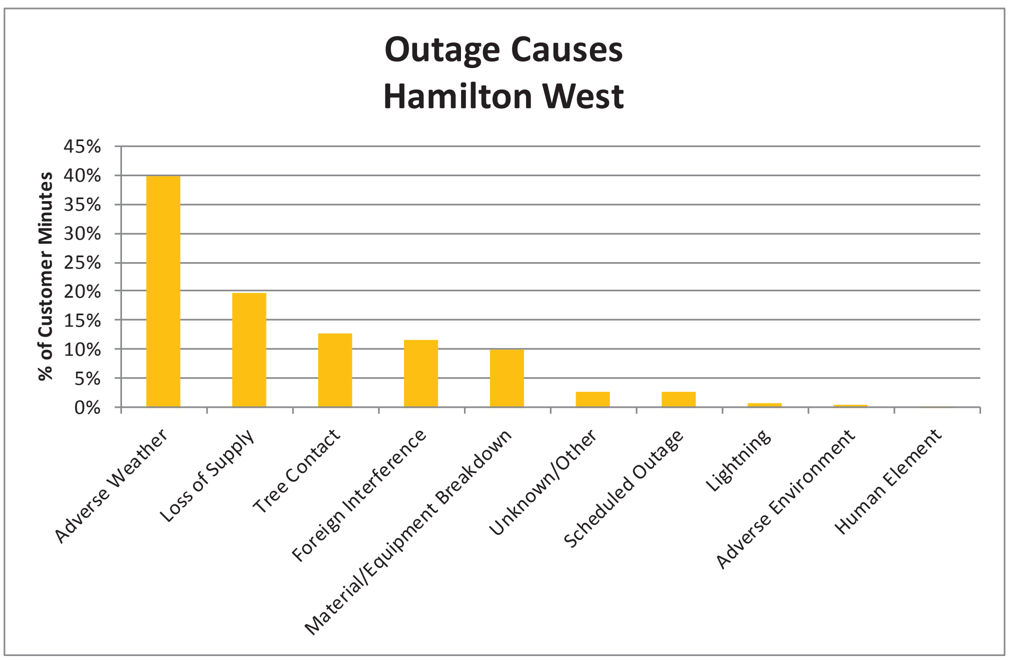

Figure 36 - Hamilton West Operating Area – Cause of Outages

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.

Stoney Creek

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.

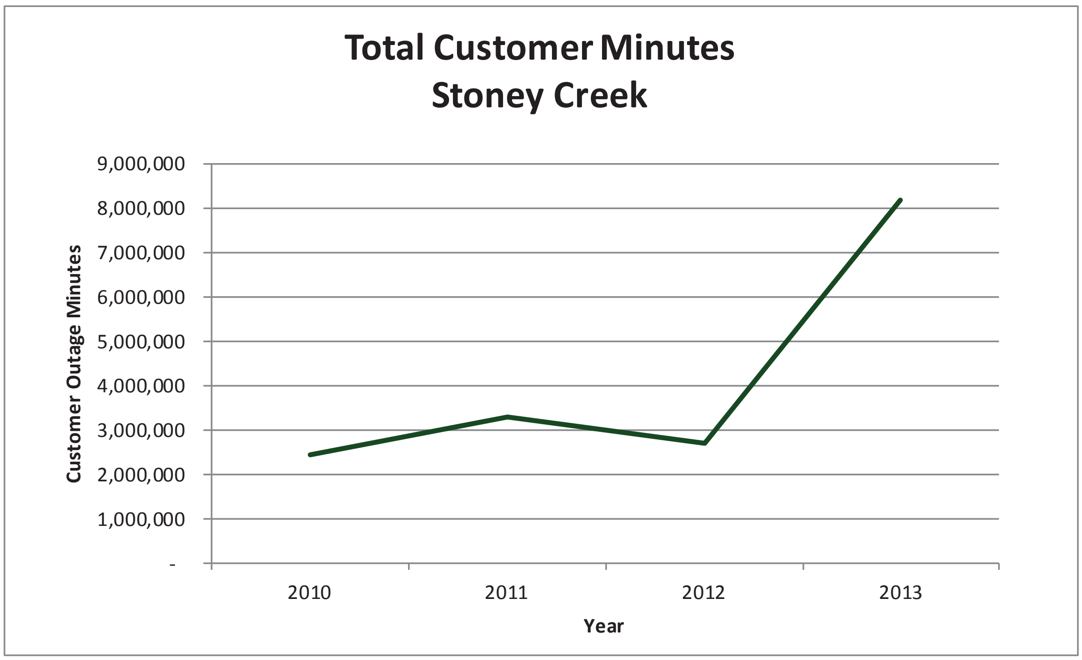

Figure 37 - Stoney Creek Operating Area - Historical Reliability

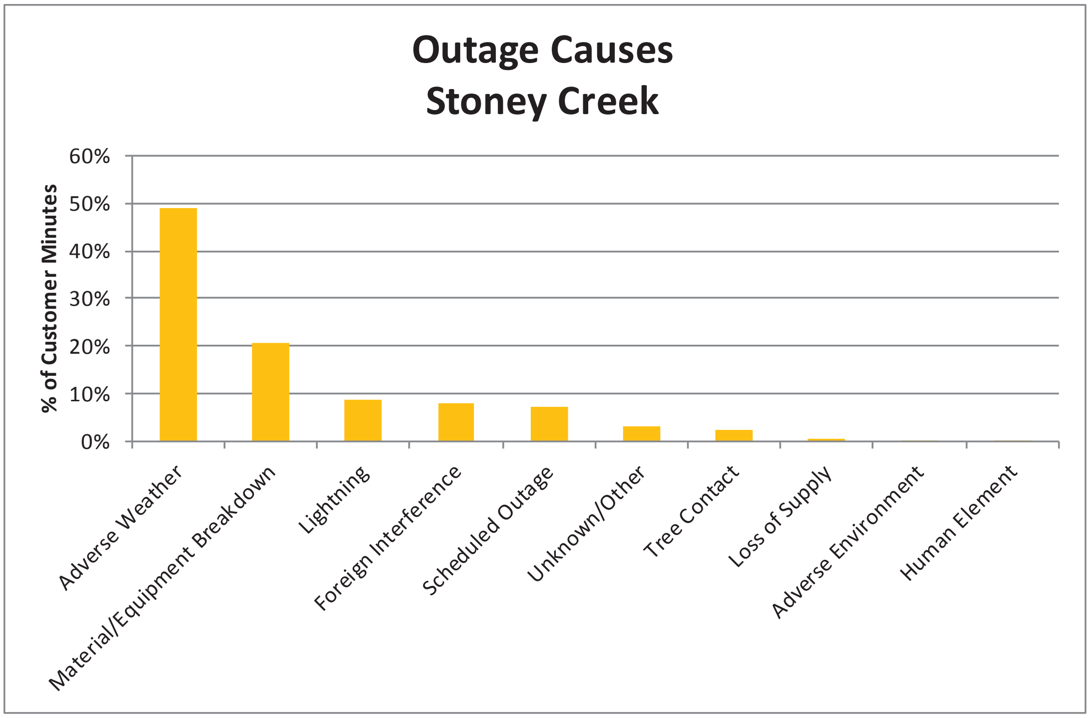

Figure 38 - Stoney Creek Operating Area – Cause of Outages

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.

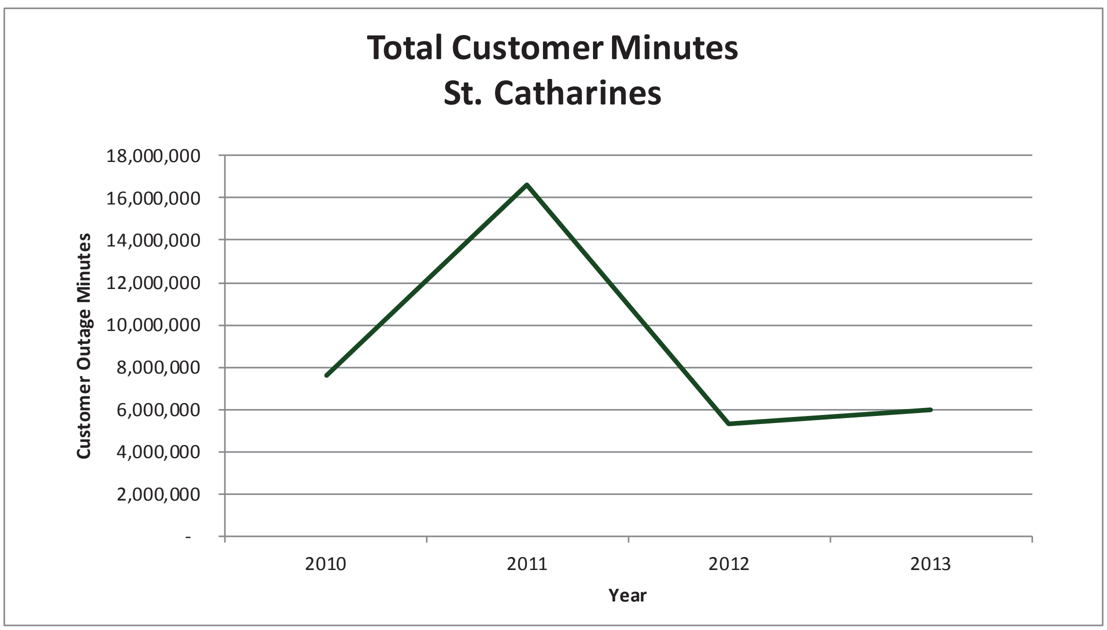

Figure 39 - St. Catharines Operating Area - Historical Reliability

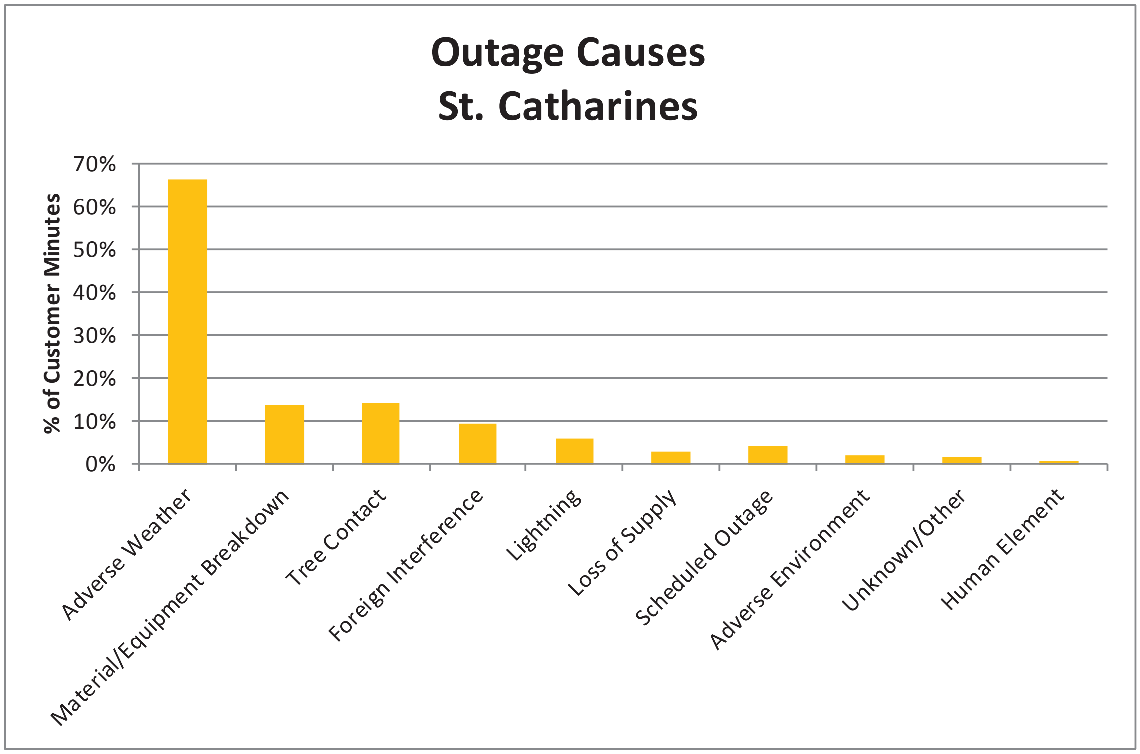

Figure 40 - St. Catharines Operating Area – Cause of Outages

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.

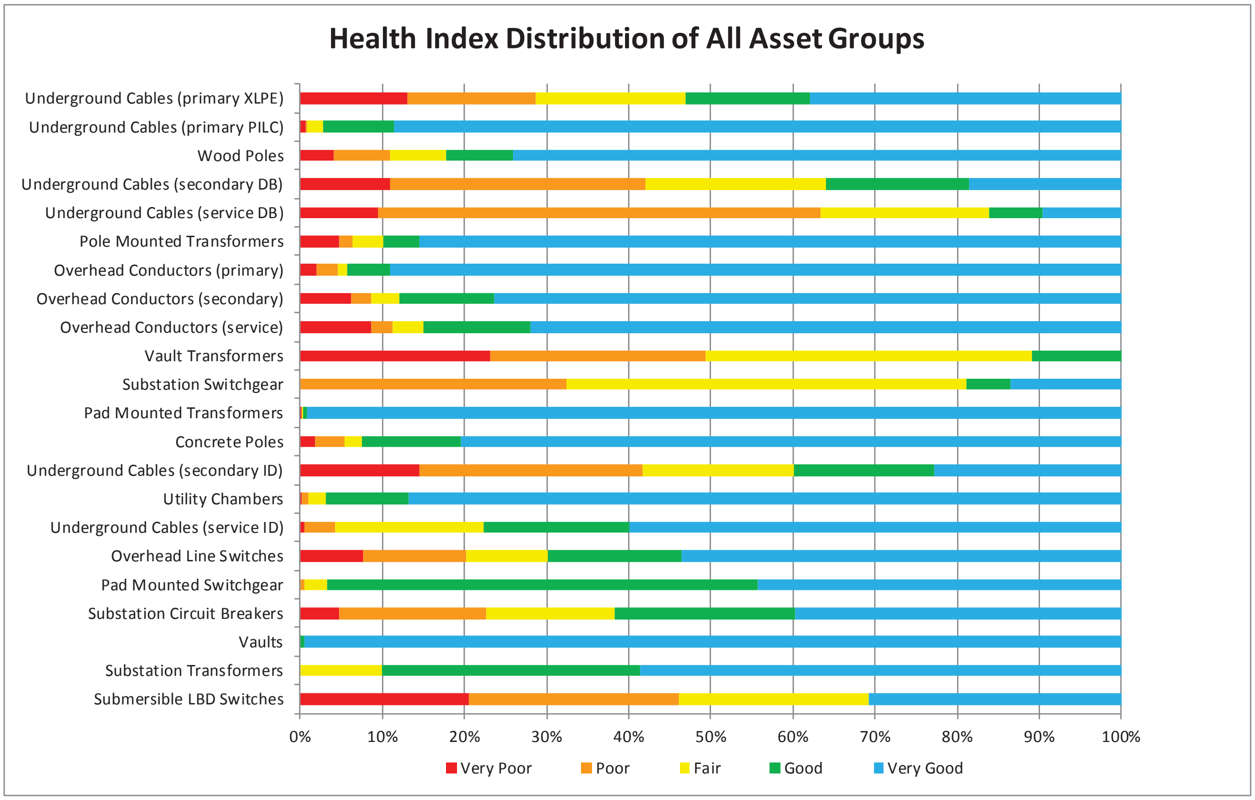

Figure 41 – Pictorial Summary of Health Index Results

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.*

   Horizon Utilities' Response: 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.*

   Horizon Utilities' Response: 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.

Substation Transformers

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.

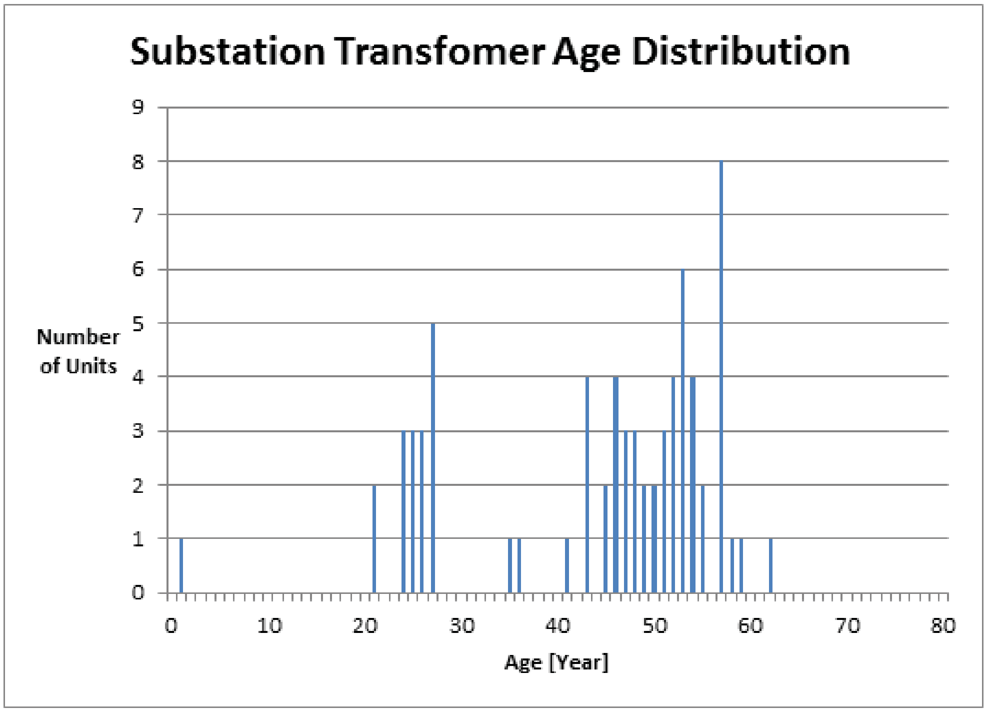

Figure 42 - Substation Transformers - Age Distribution

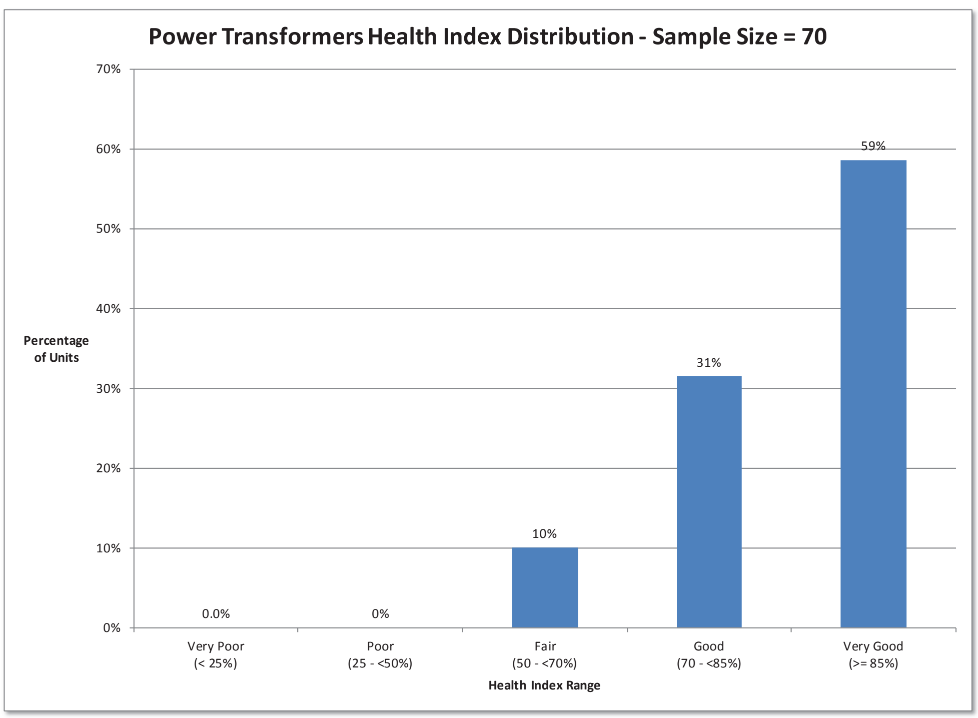

Figure 43 - Substation Transformer Health Index Distribution

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.

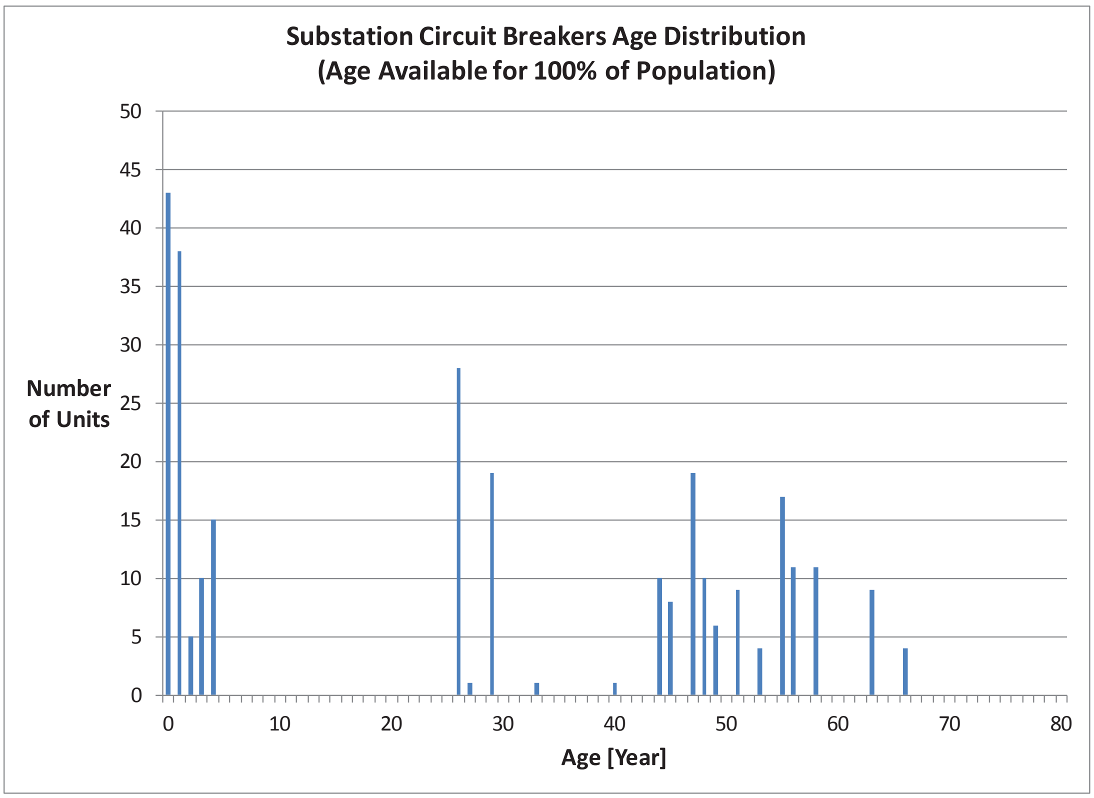

Figure 44 - Substation Circuit Breakers - Age Distribution

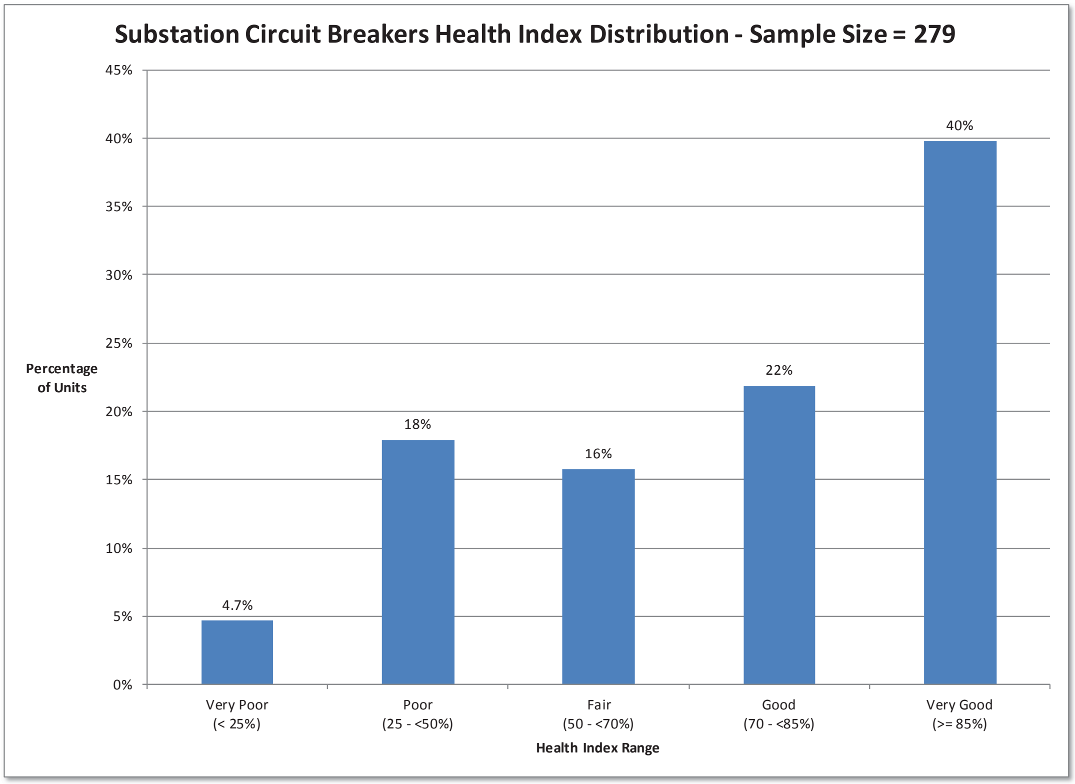

Figure 45 - Substation Circuit Breaker Health Index Distribution

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.

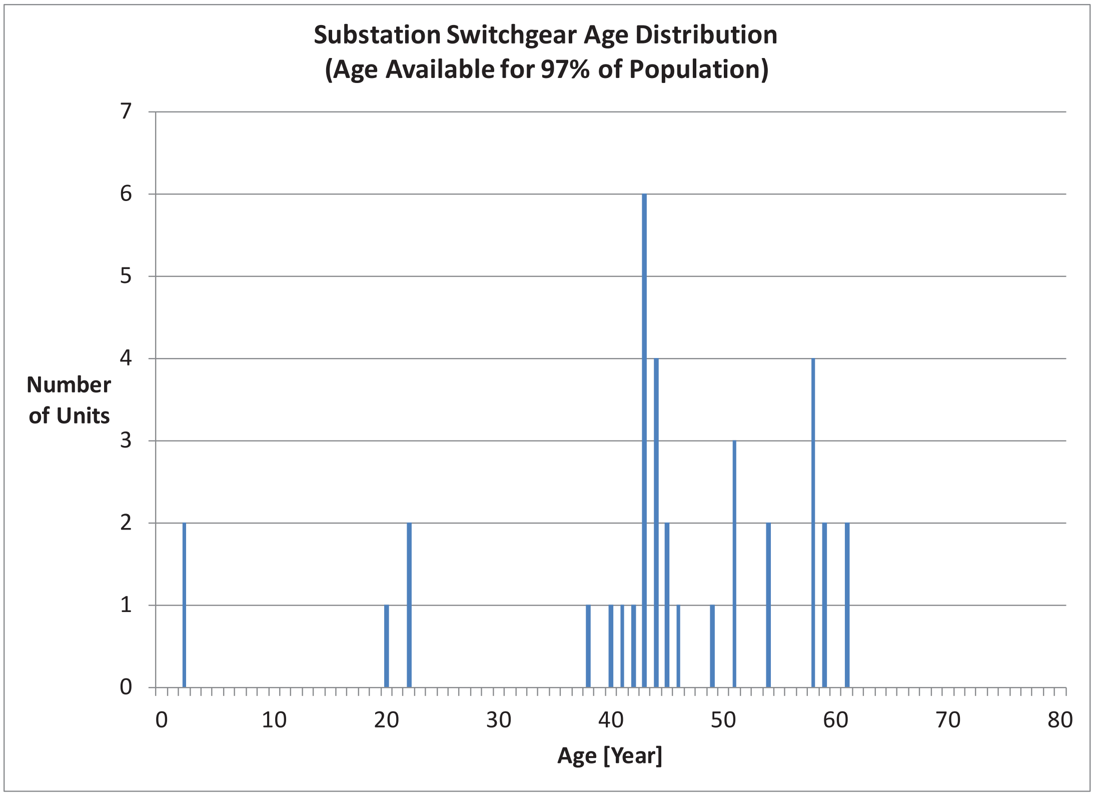

Figure 46 – Substation Switchgear – Age Distribution

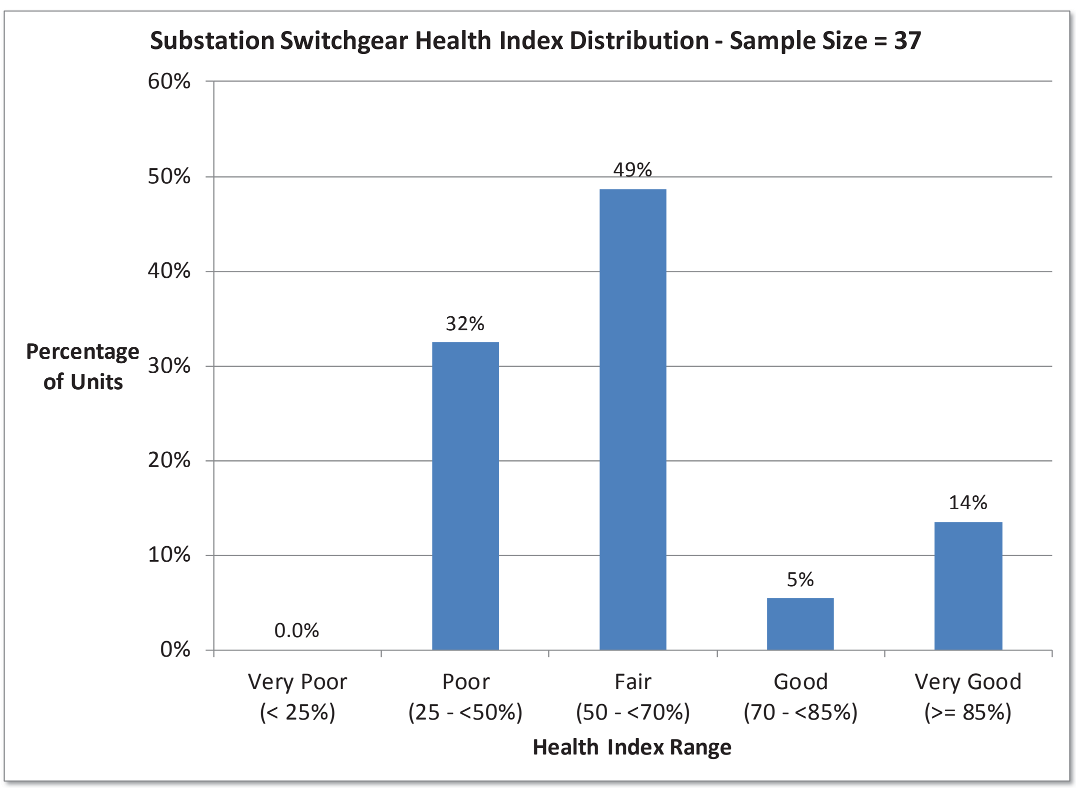

Figure 47 - Sub Station Switchgear Health Index Distribution

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.

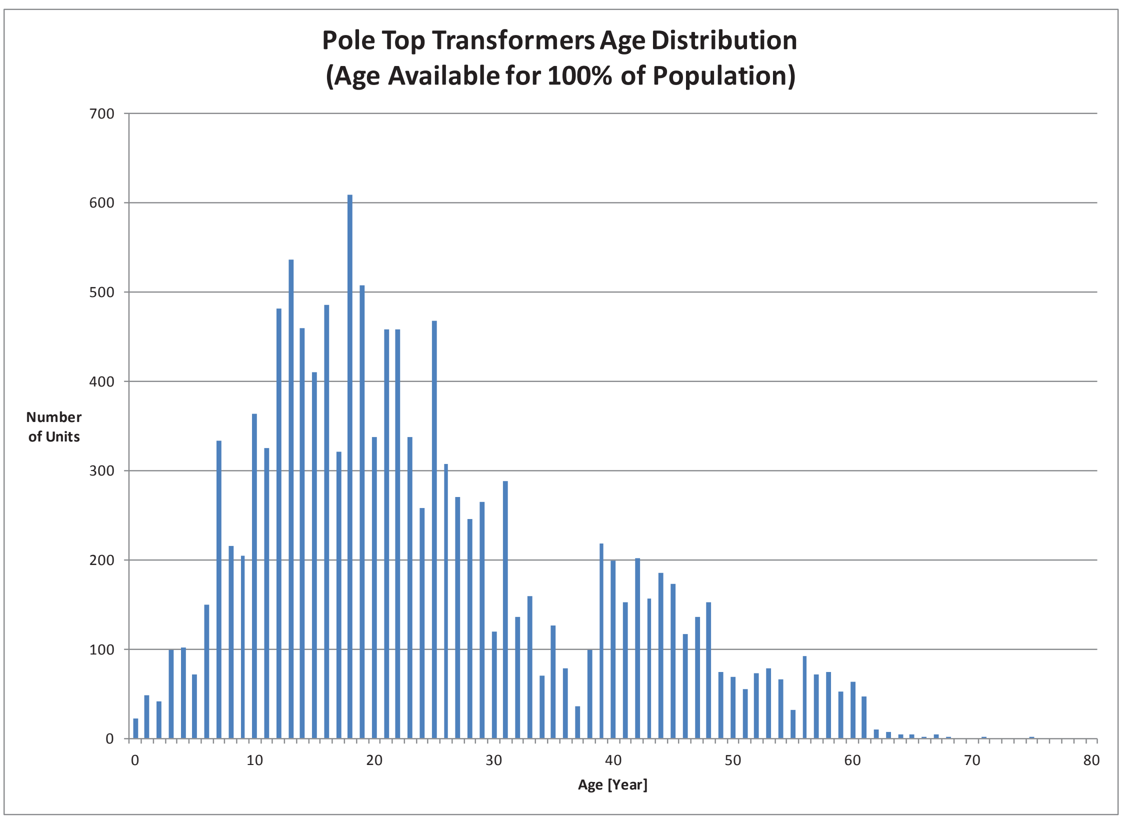

Figure 48 - Overhead Transformer - Age Distribution

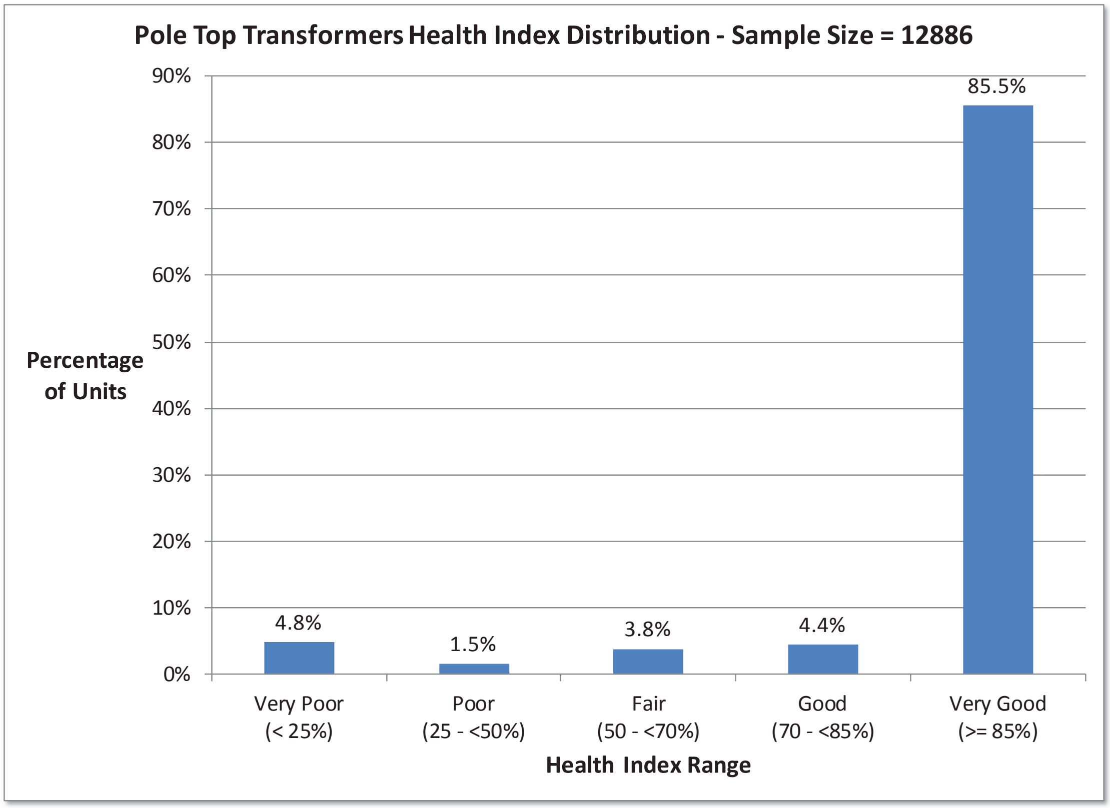

Figure 49 - Overhead Transformer Health Index Distribution

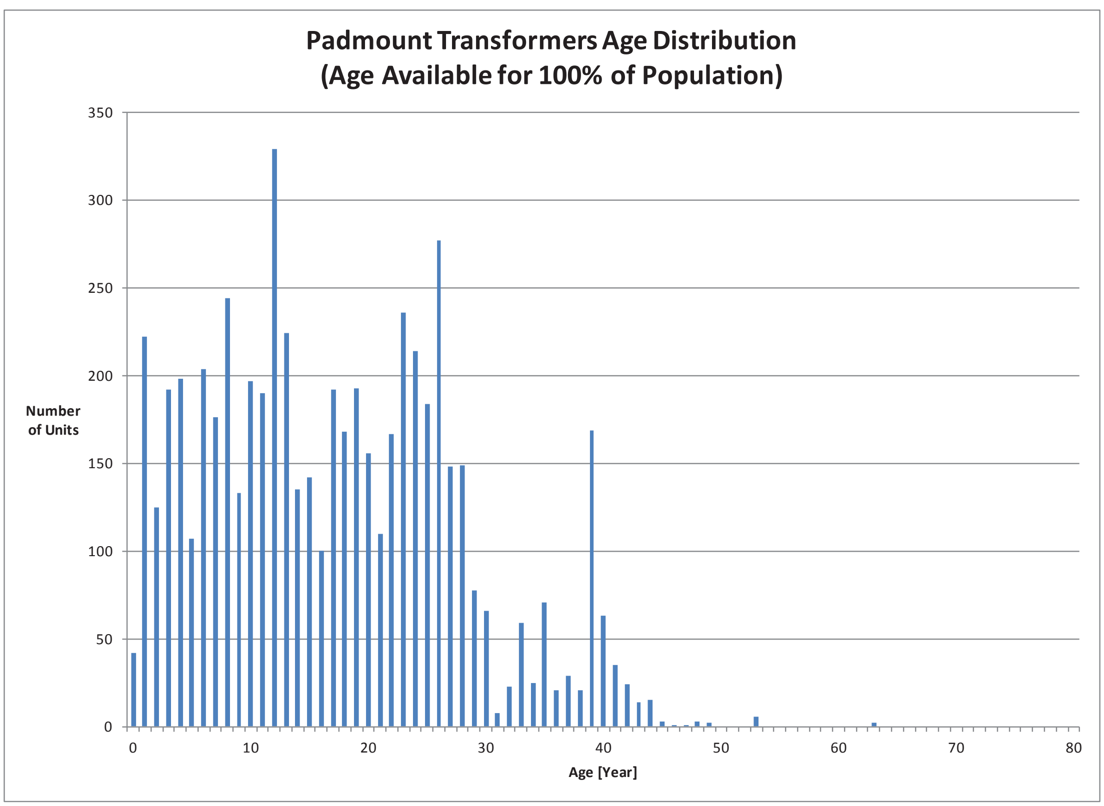

Figure 50 - Padmount Transformer - Age Distribution

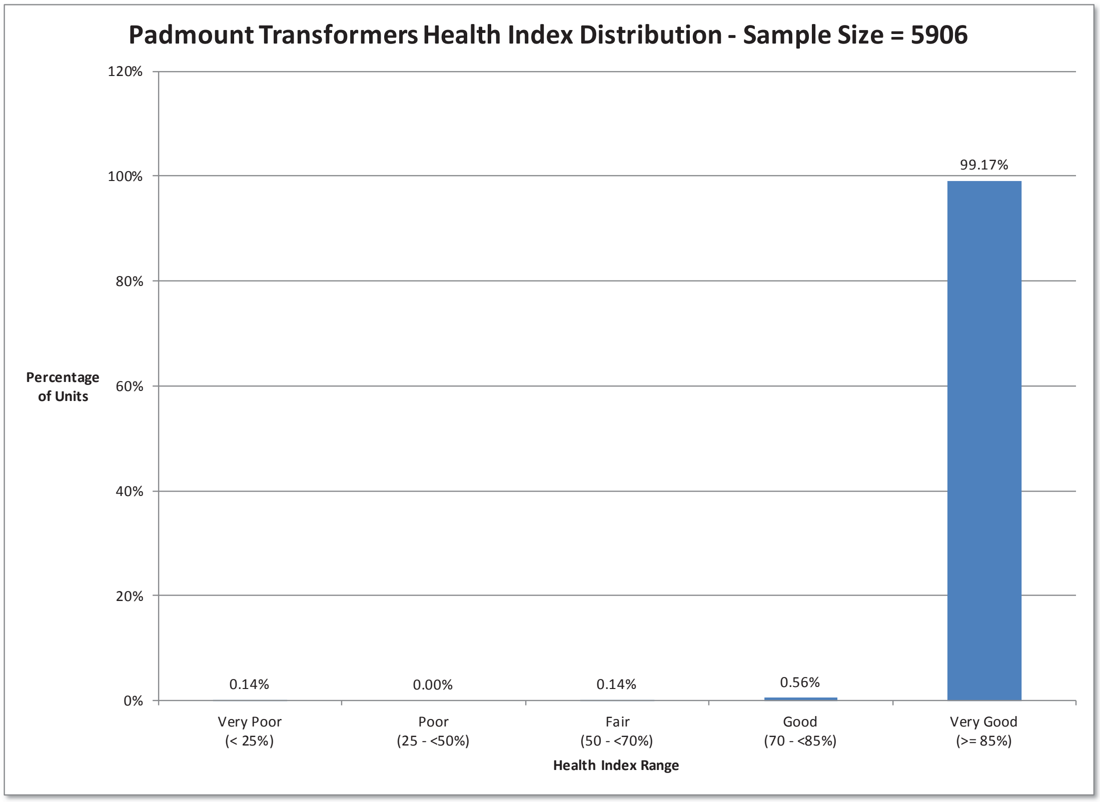

Figure 51 - Padmount Transformer Health Index Distribution

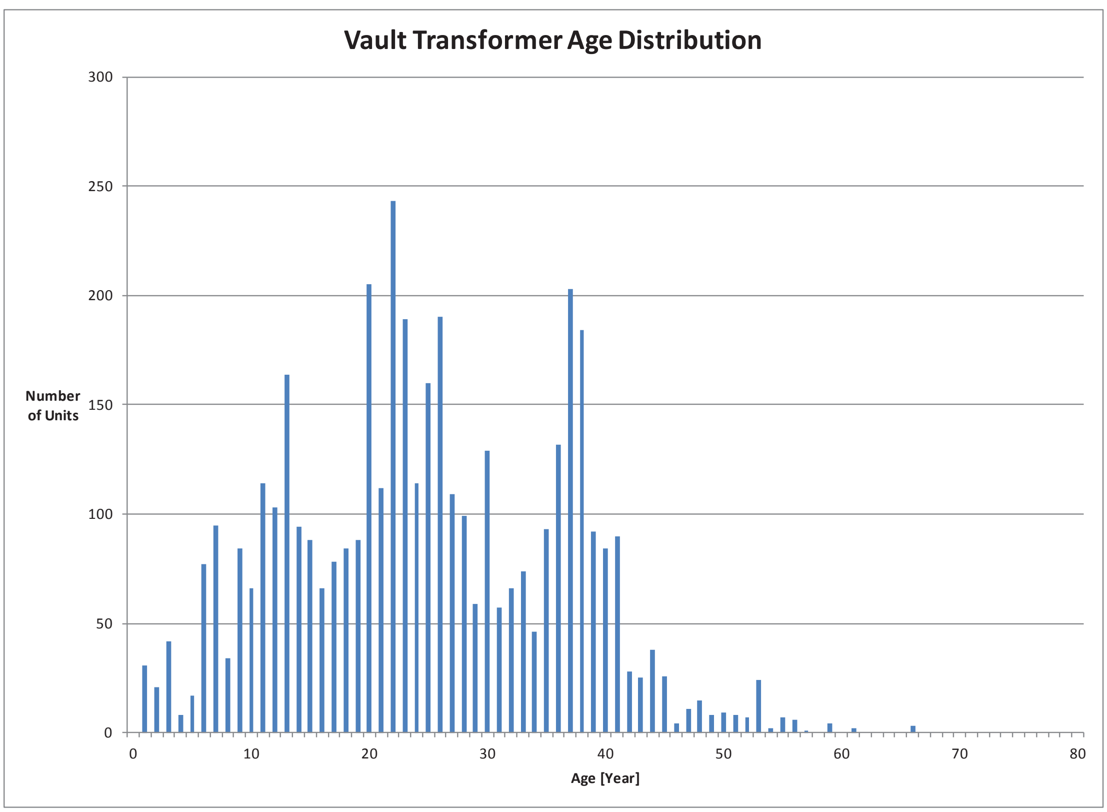

Figure 52 - Vault Transformer - Age Distribution

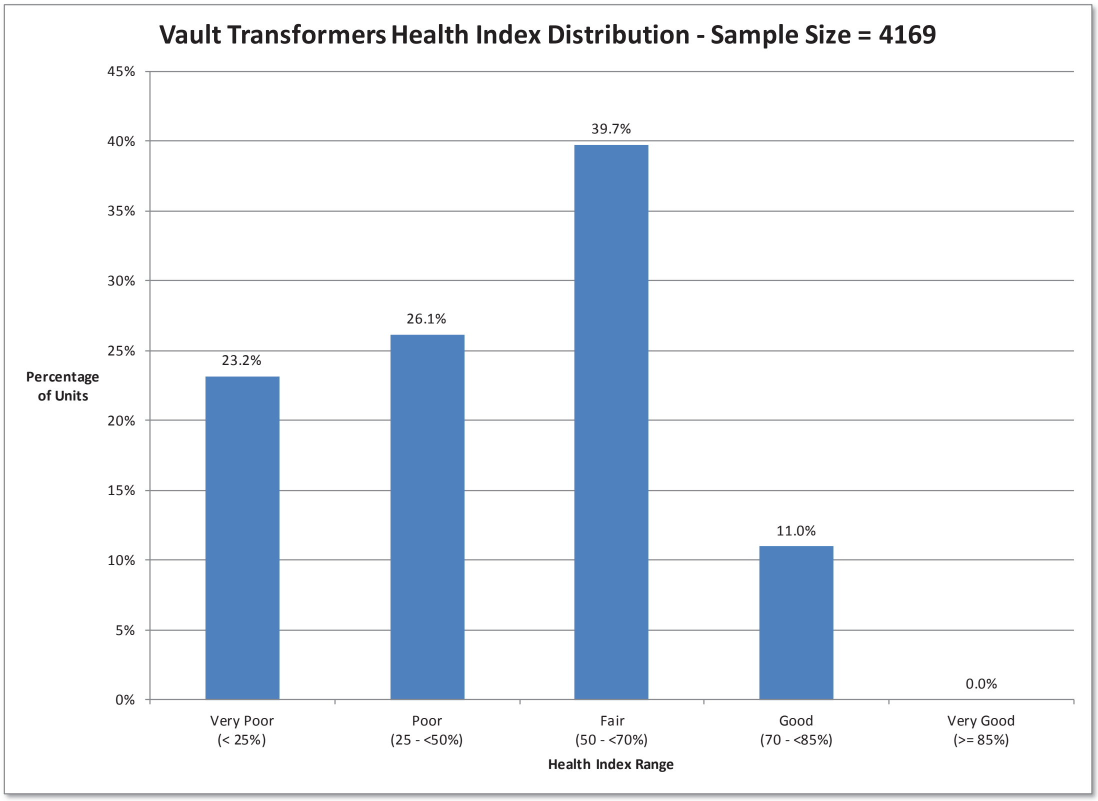

Figure 53 - Vault Transformer Health Index Distribution

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.

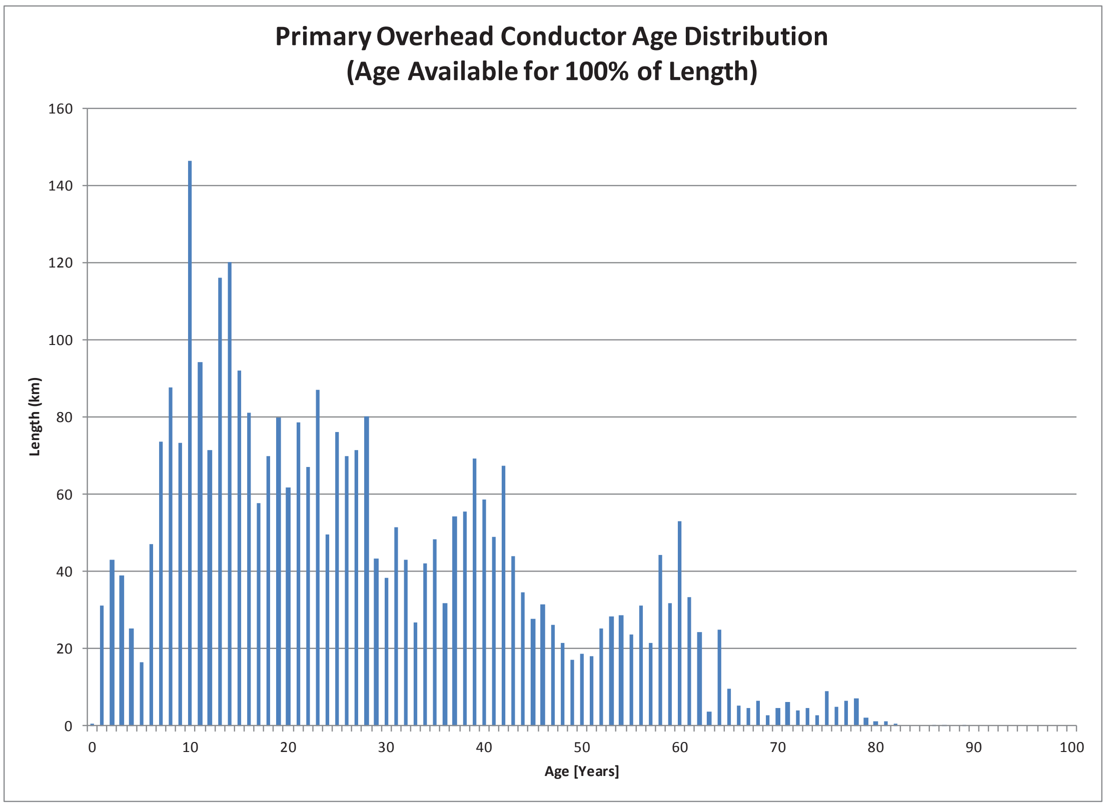

Figure 54 - Overhead Primary Conductor - Age Distribution

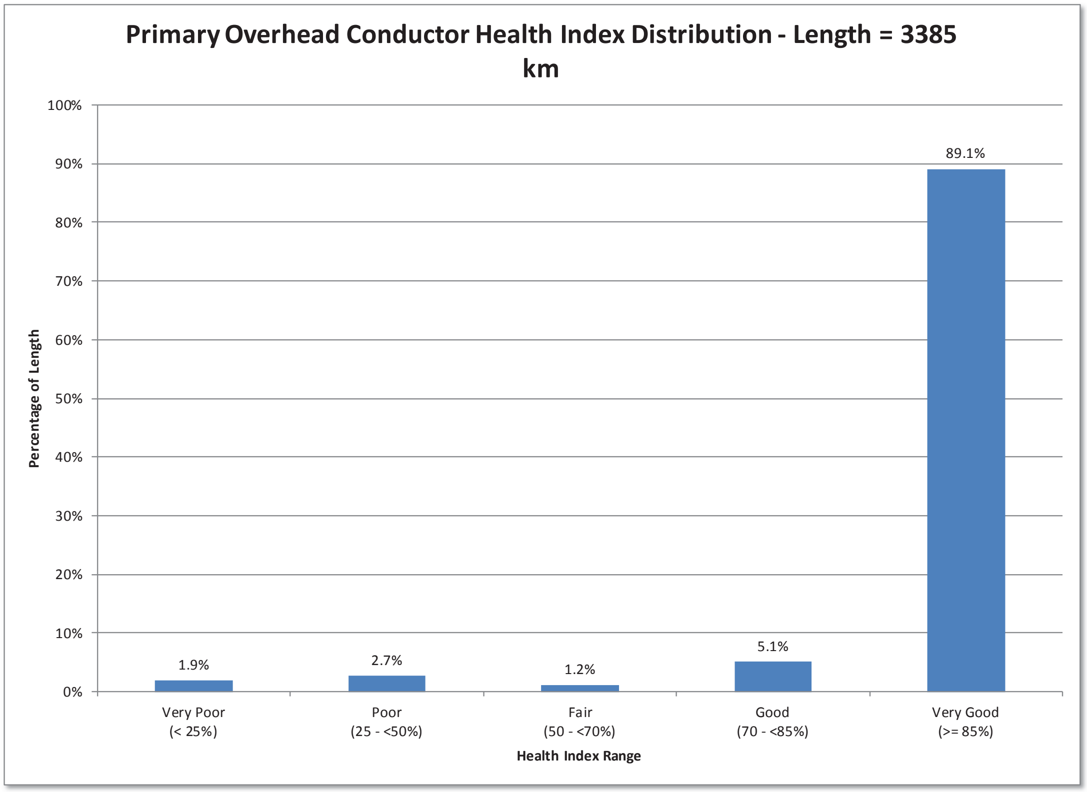

Figure 55 - Overhead Primary Conductor Health Index Distribution

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.

Overhead Line Switches

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.

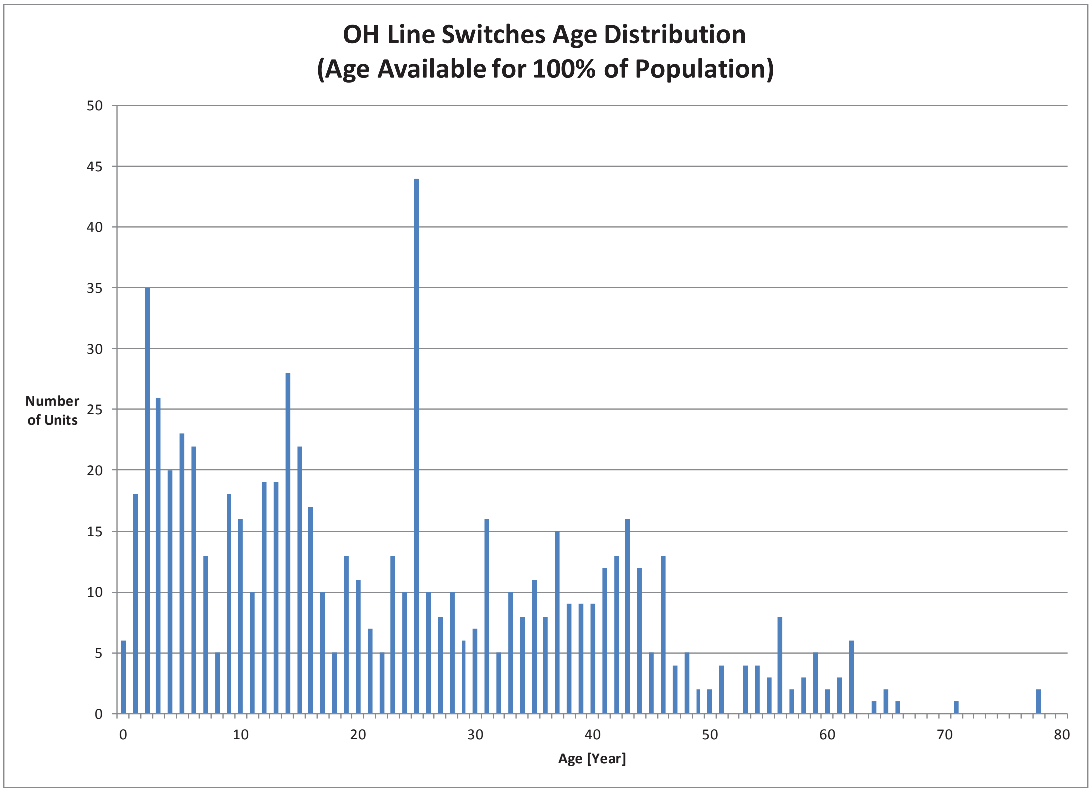

Figure 56 – Overhead Line Switch Age Distribution

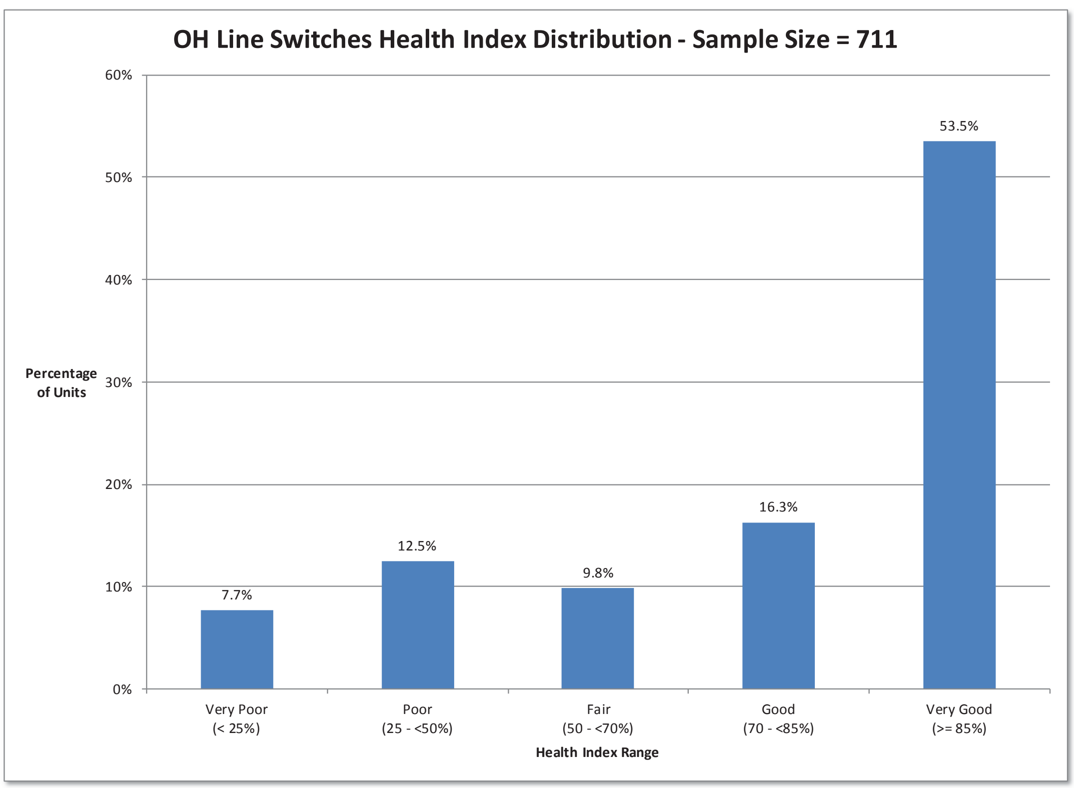

Figure 57 - Overhead Line Switch Health Index Distribution

Wood Poles

The age and Health Index distribution for wood poles is provided below in Figure 58 and Figure 59.

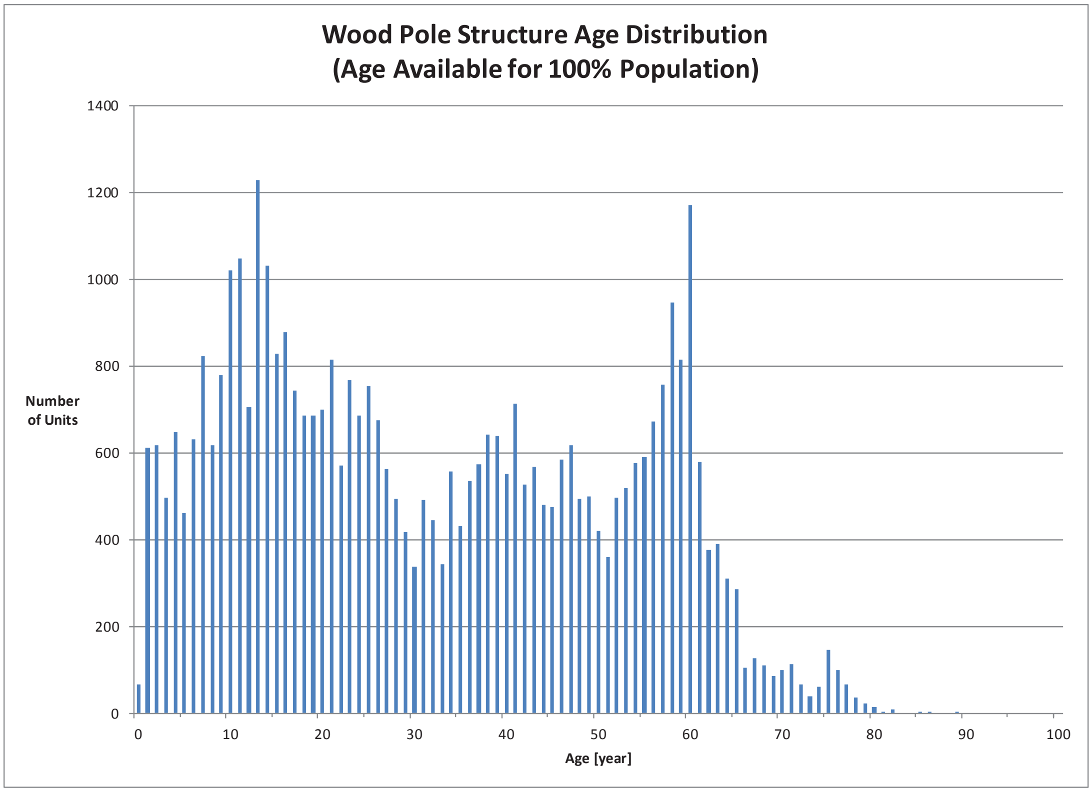

Figure 58 - Wood Pole - Age Distribution

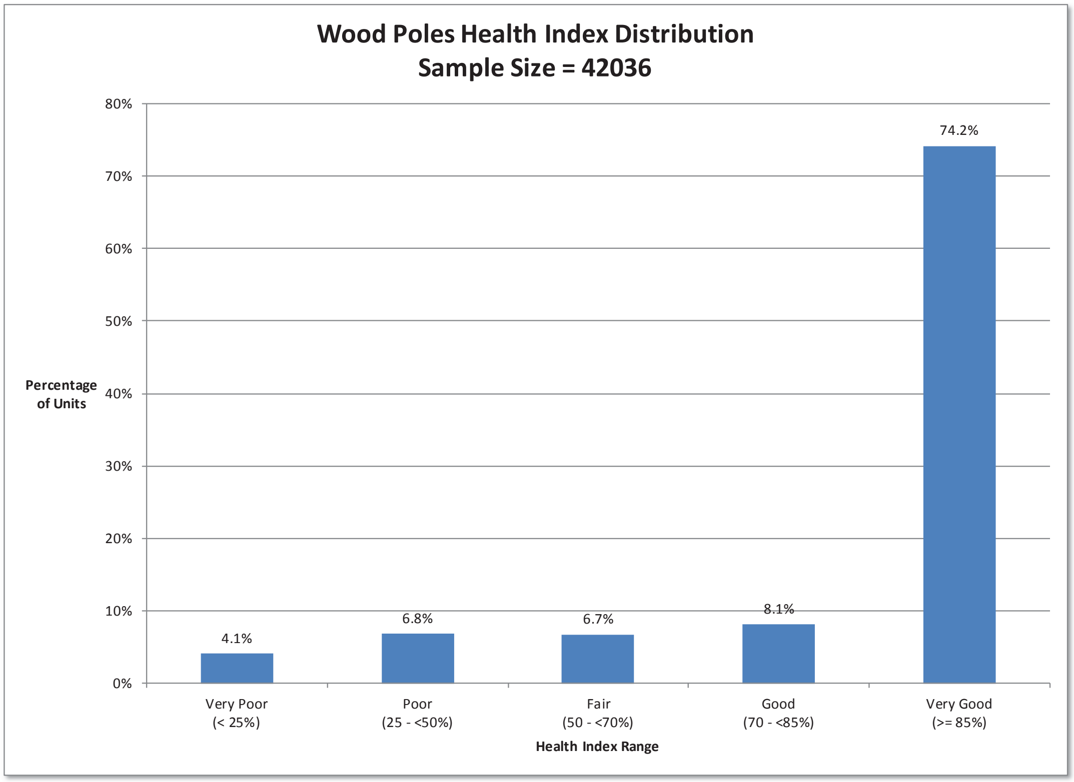

Figure 59 - Wood Pole Health Index Distribution

<u>Concrete Poles</u>

The age and Health Index distribution of concrete poles is provided below in Figure 61.

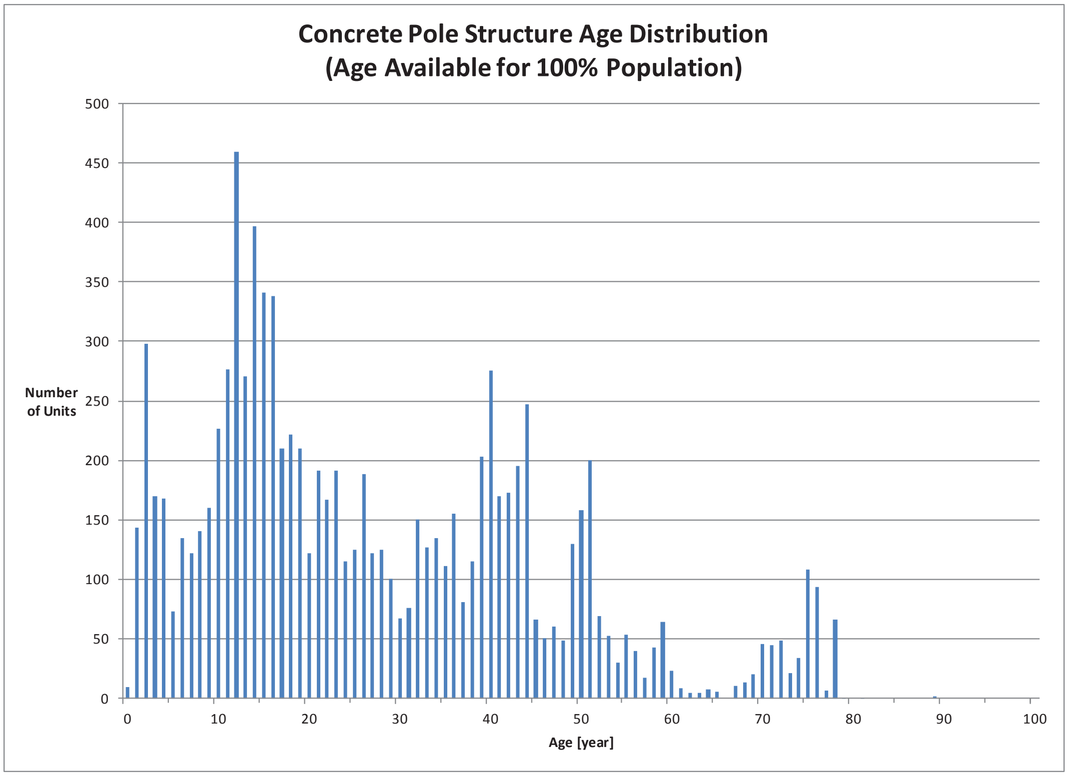

Figure 60 - Concrete Pole - Age Distribution

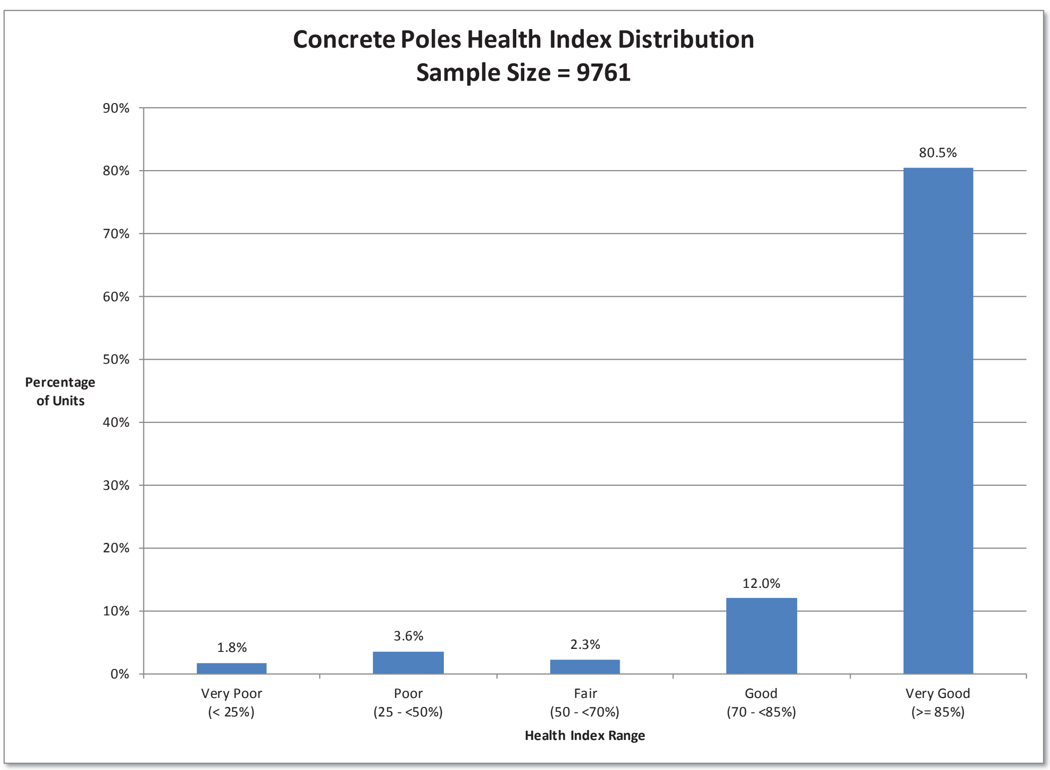

Figure 61 - Concrete Pole Health Index Distribution

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.

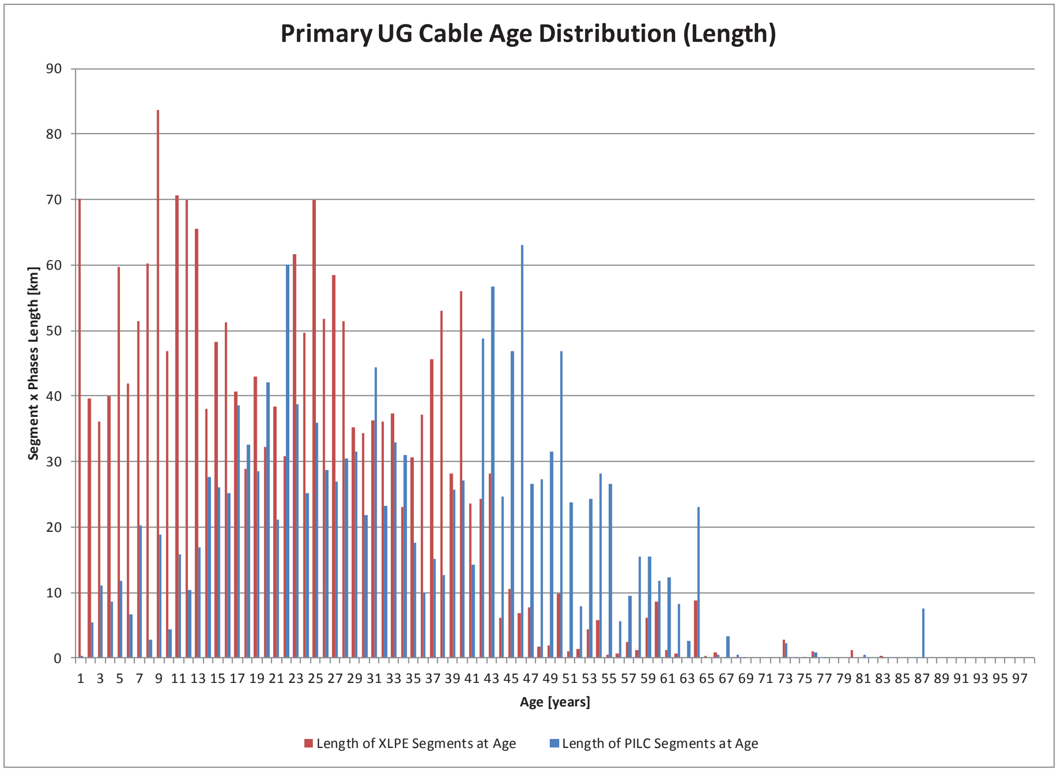

Figure 62 – Underground Primary Cable – Age Distribution

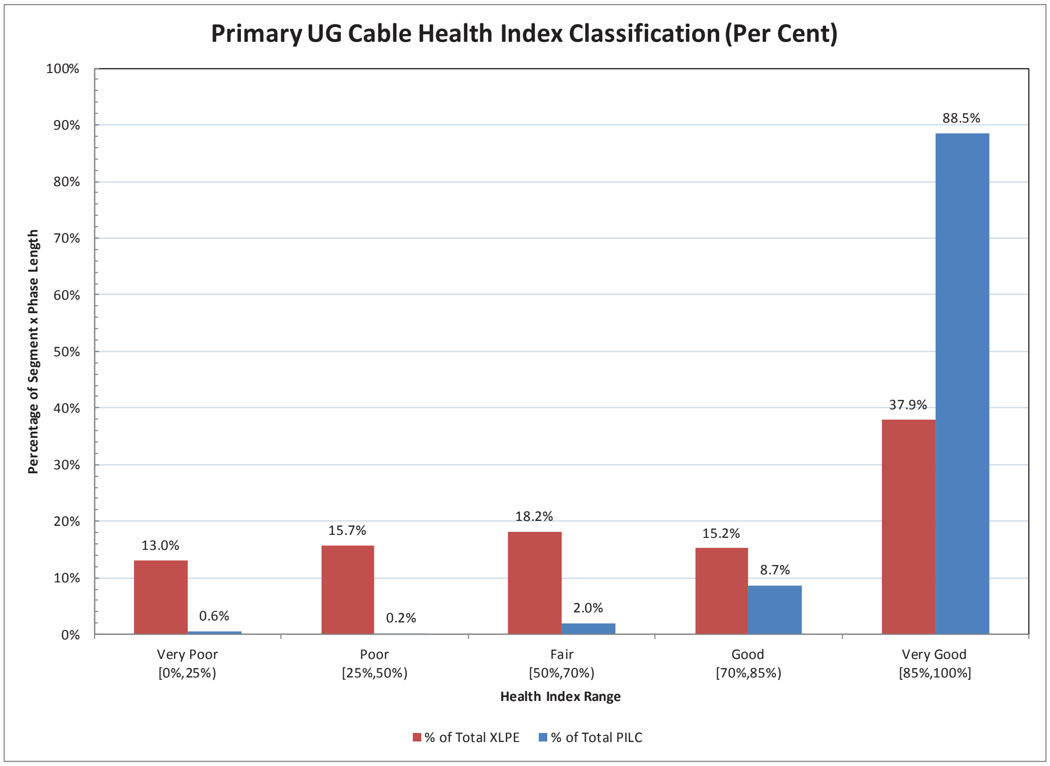

Figure 63 - Underground Primary Cable Health Index Distribution

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.

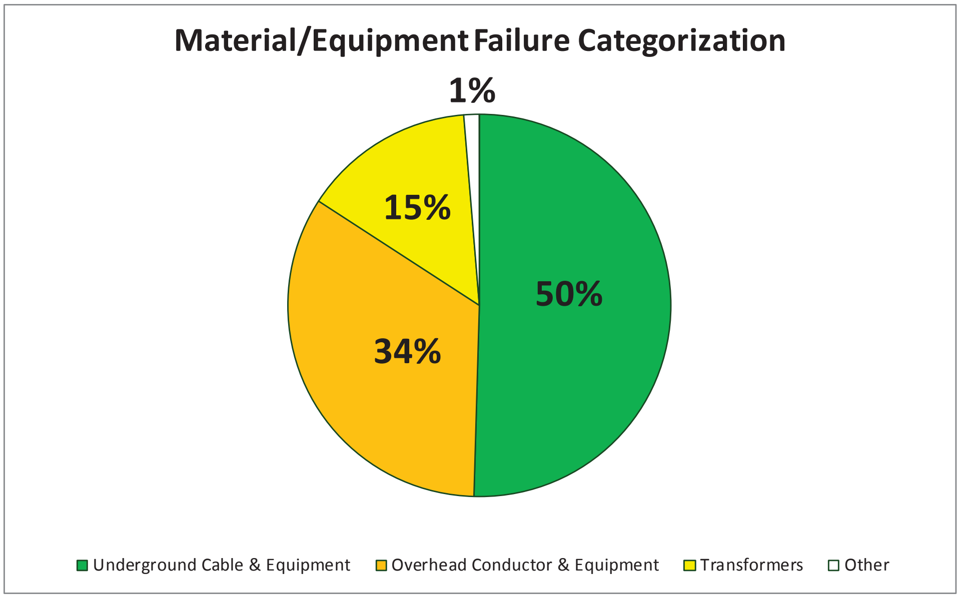

Figure 64 - Categorization of Equipment Failure Service Interruptions

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.

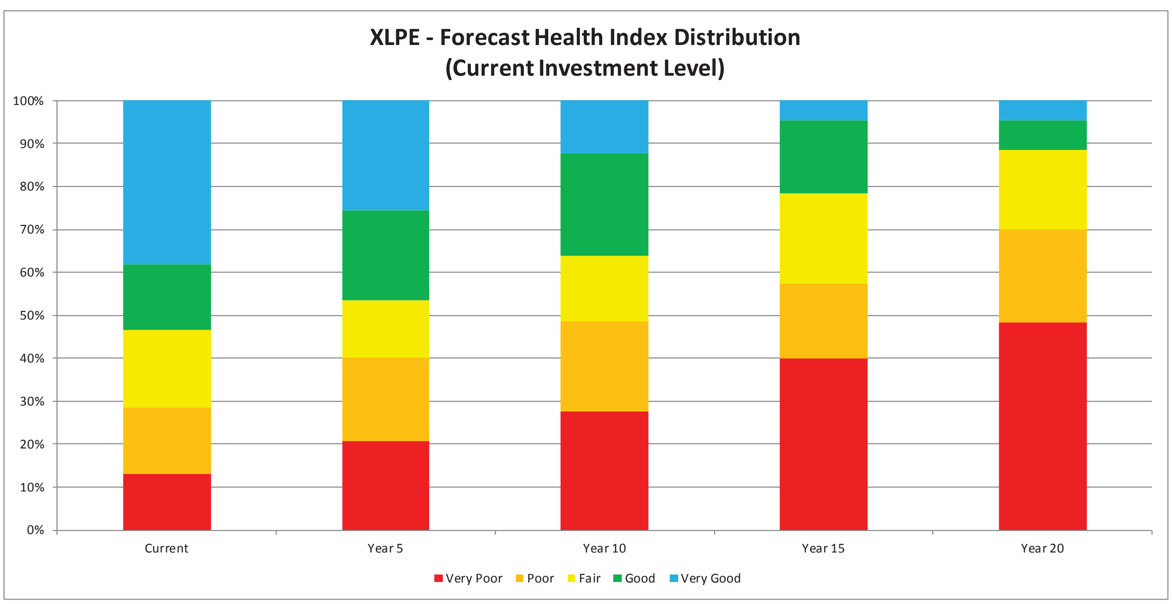

Figure 65 - XLPE Health Index Distribution Forecast at Current Investment Levels

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.

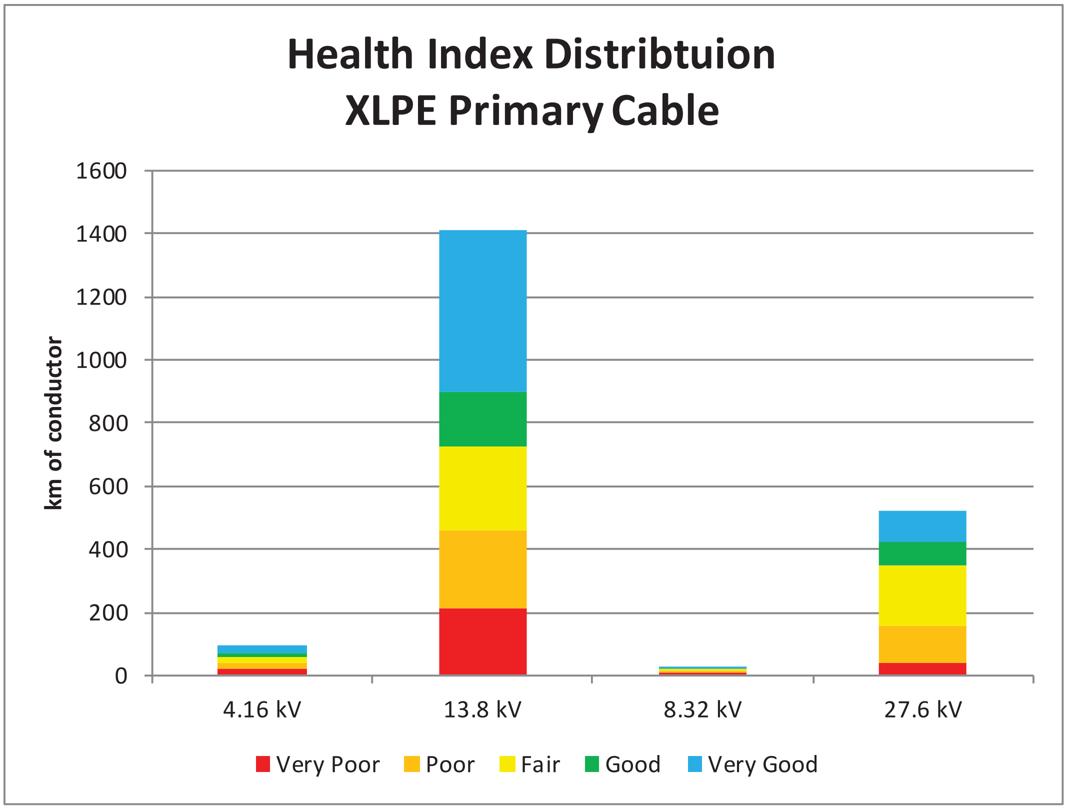

Figure 66 - XLPE Health Index Distribution by Voltage

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.

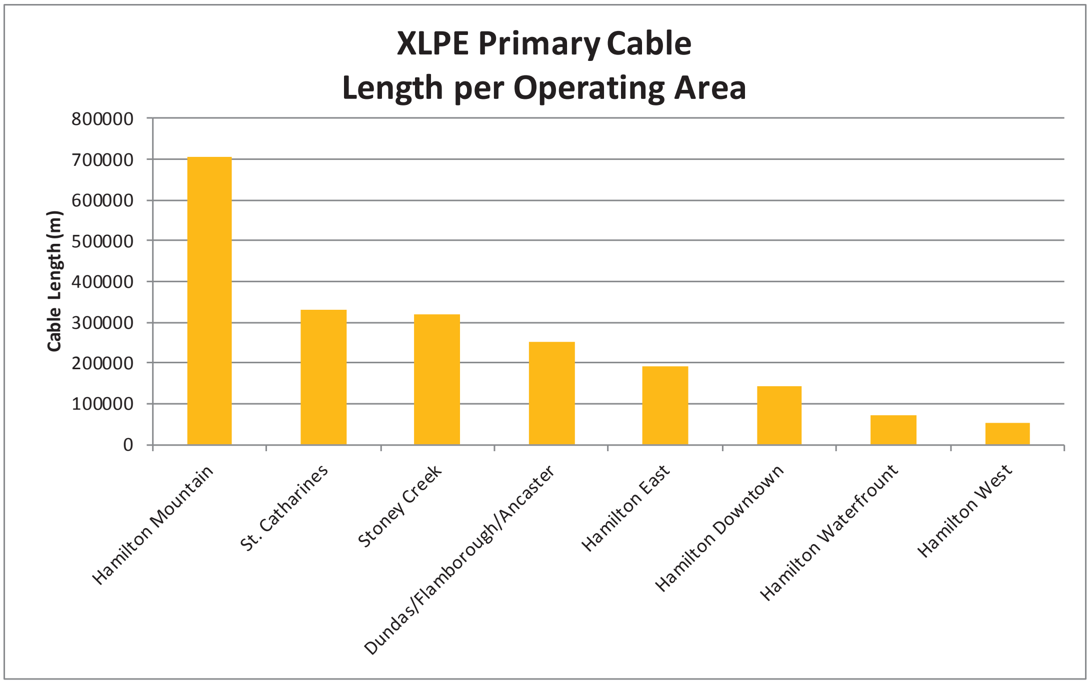

Figure 67 - XLPE Primary Cable per Operating Area

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.

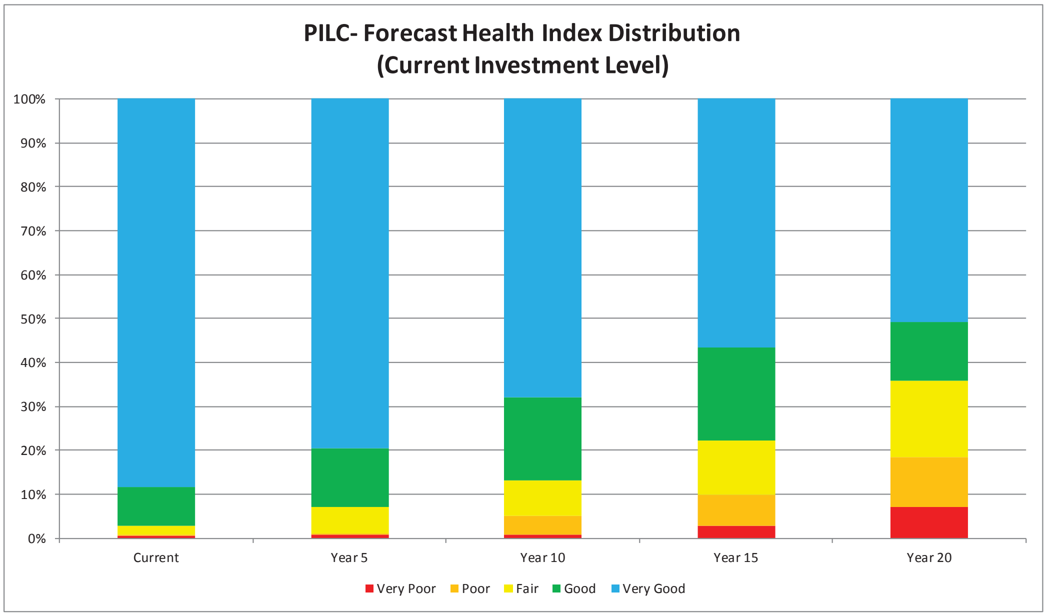

Figure 68 - PILC Forecasted Health Index Distribution at Current Investment Levels

<u>Pad Mounted Switchgear</u>

The age and Health Index distribution of pad mounted switchgear is provided below in Figure 69 and Figure 70.

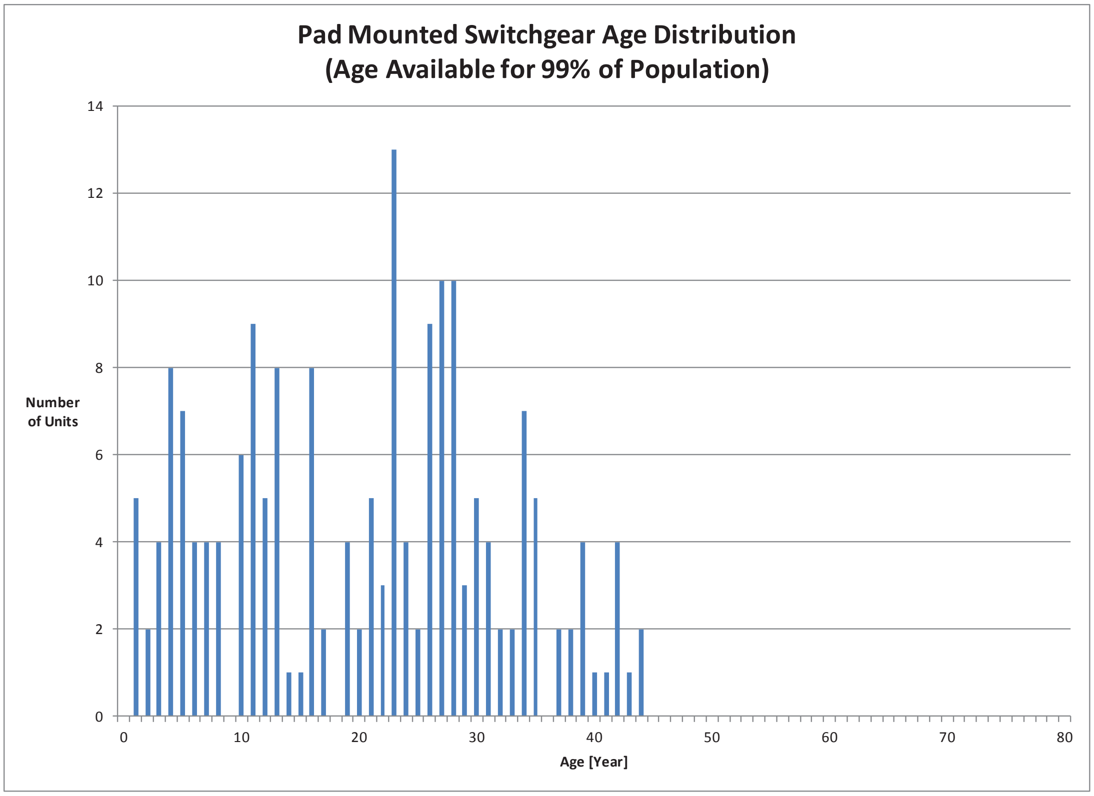

Figure 69 – Pad Mount Switchgear – Age Distribution

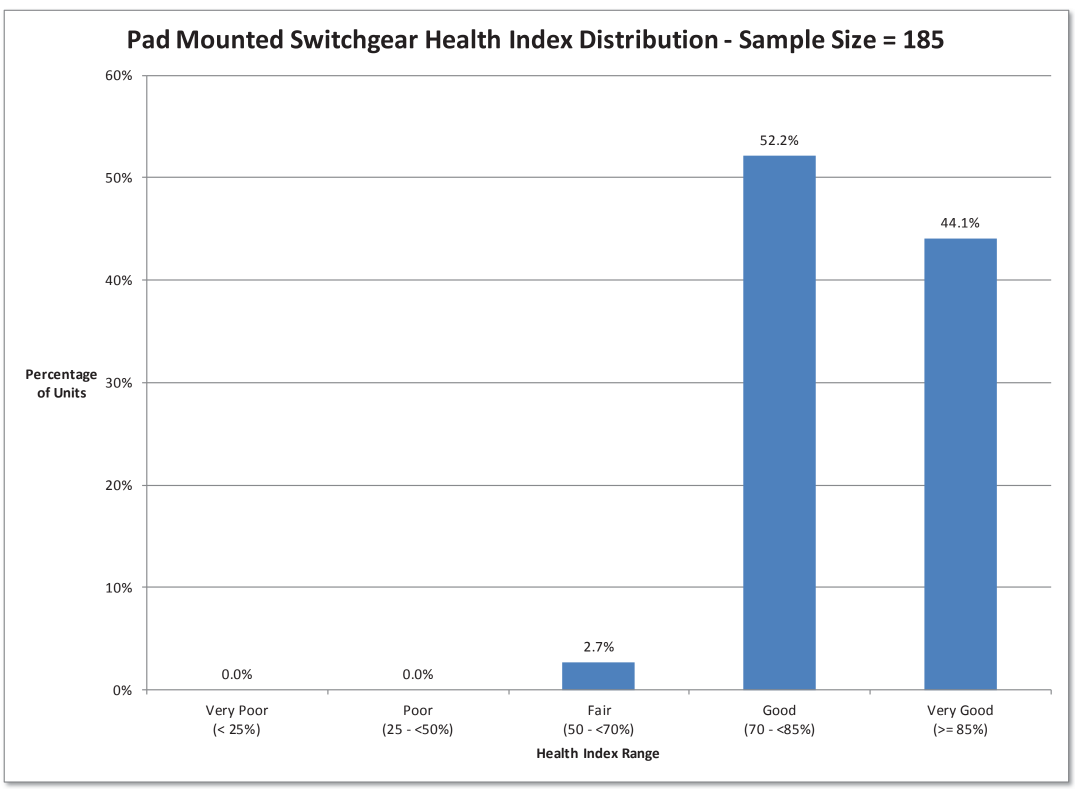

Figure 70 - Pad Mount Switchgear Health Index Distribution

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.

Vaults and Utility Chambers

The age and Health Index distribution for vaults and utility chambers are provided below in Figure 71 to Figure 74.

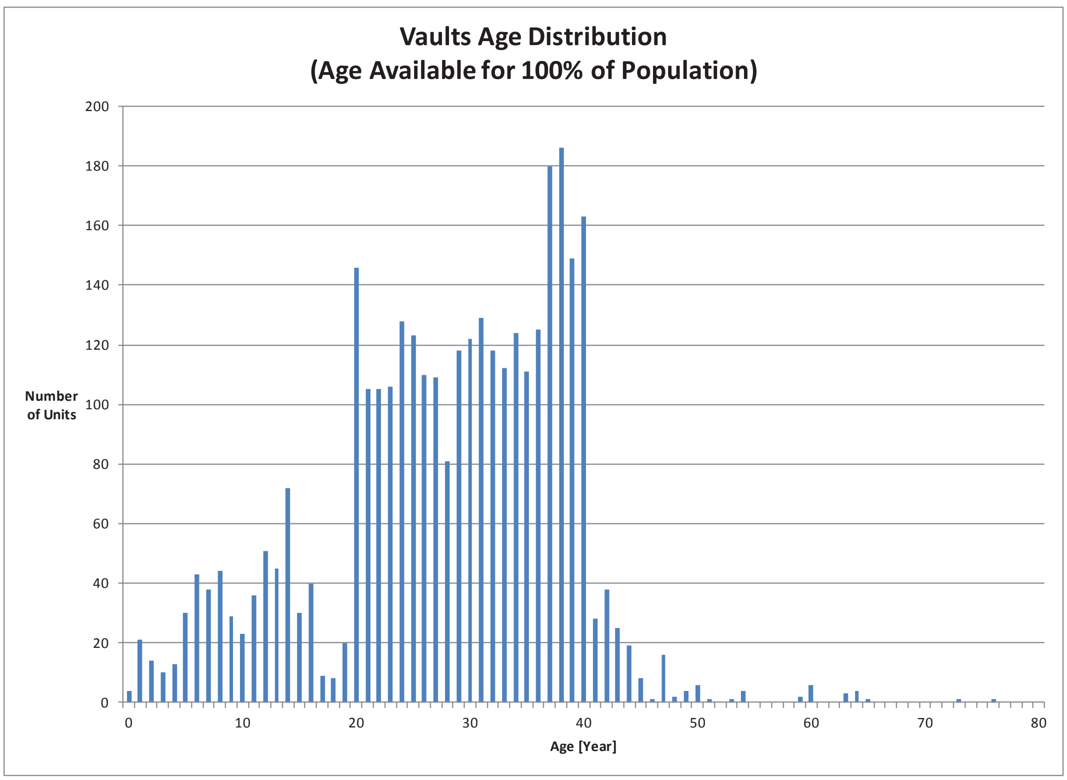

Figure 71 - Vault - Age Distribution

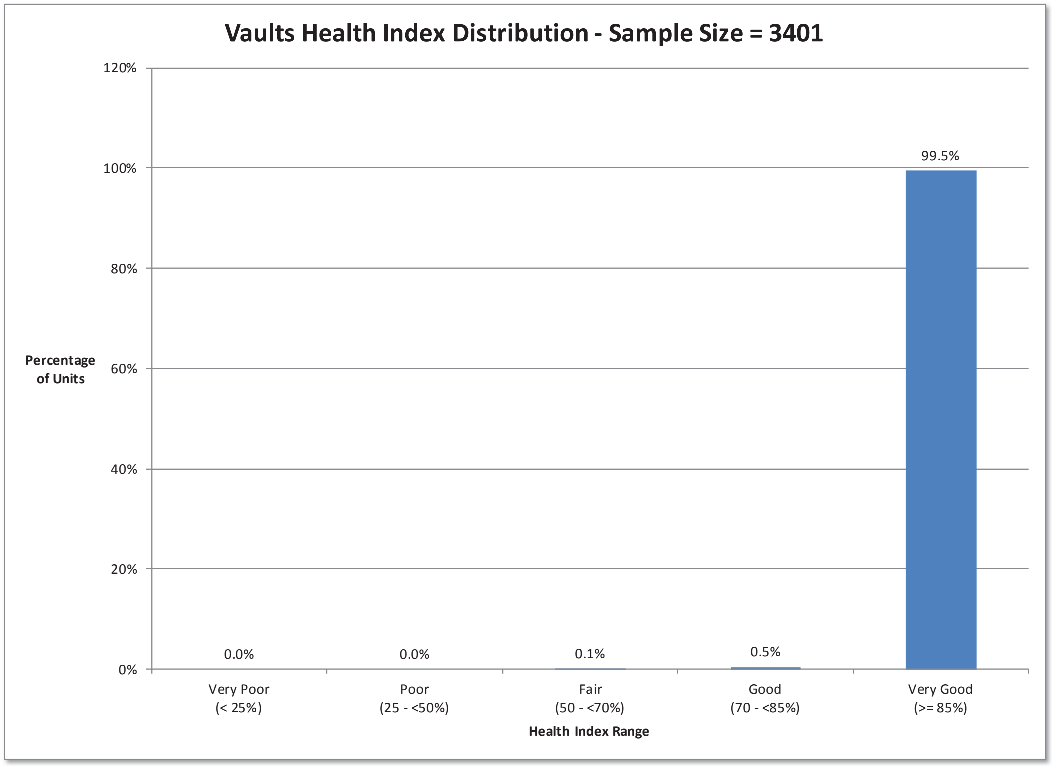

Figure 72 - Vault Health Index Distribution

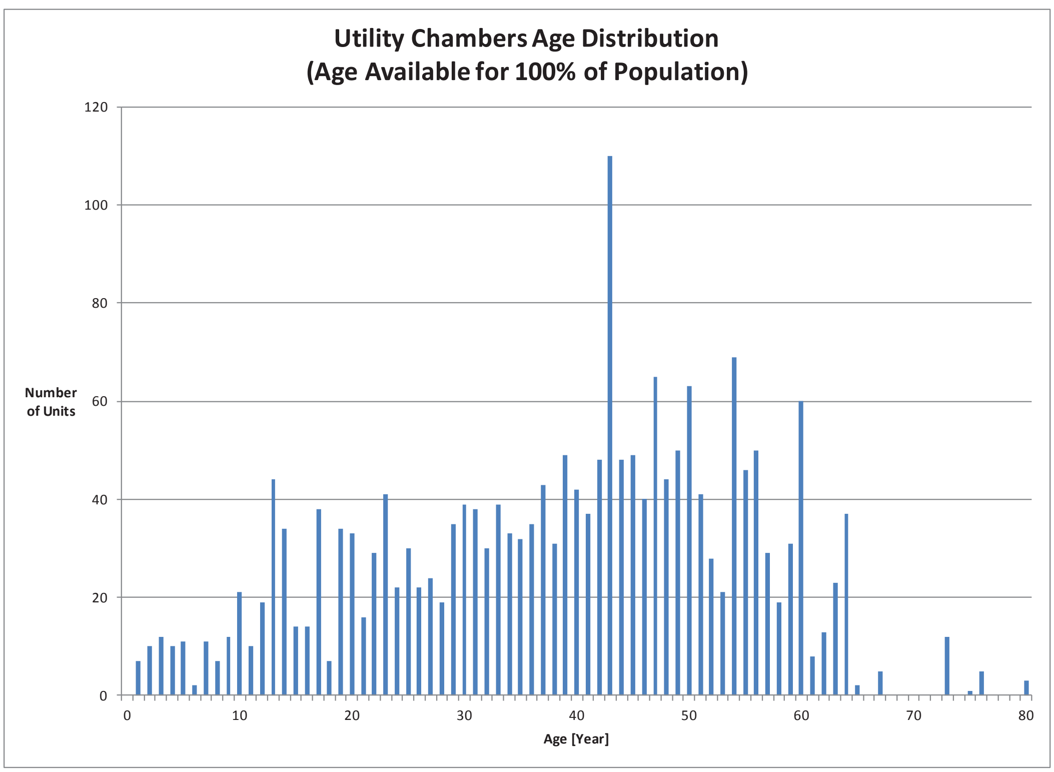

Figure 73 - Utility Chamber - Age Distribution

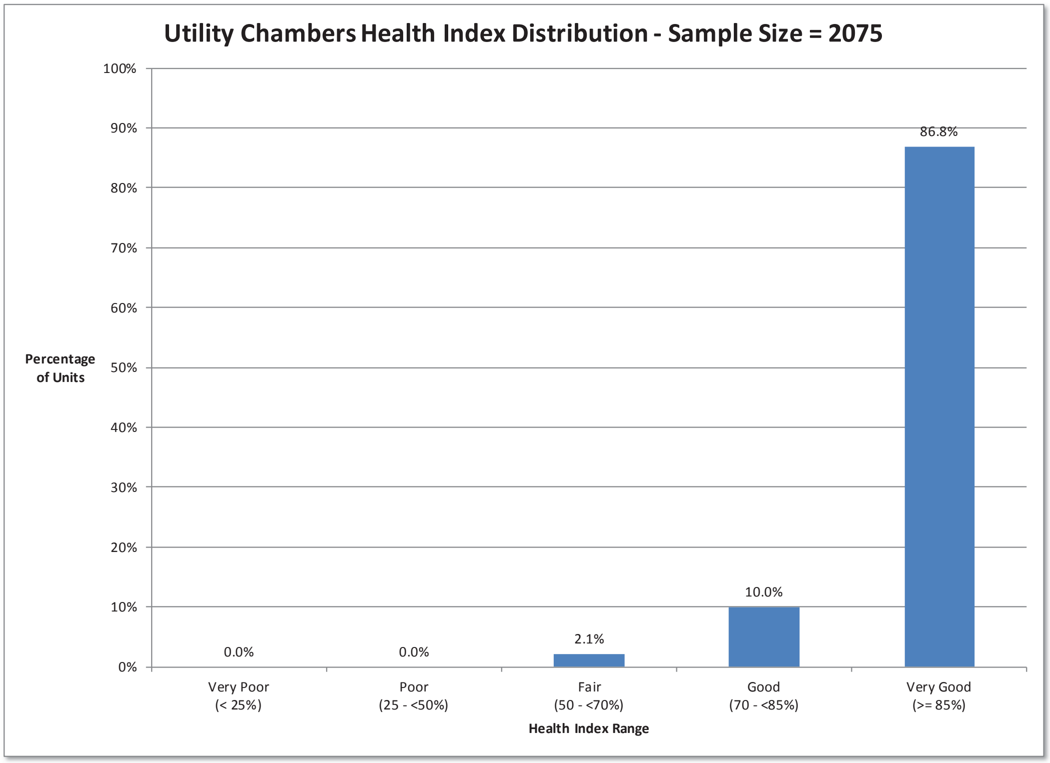

Figure 74 - Utility Chamber Health Index Distribution

<u>Submersible Load Break Switches</u>

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.

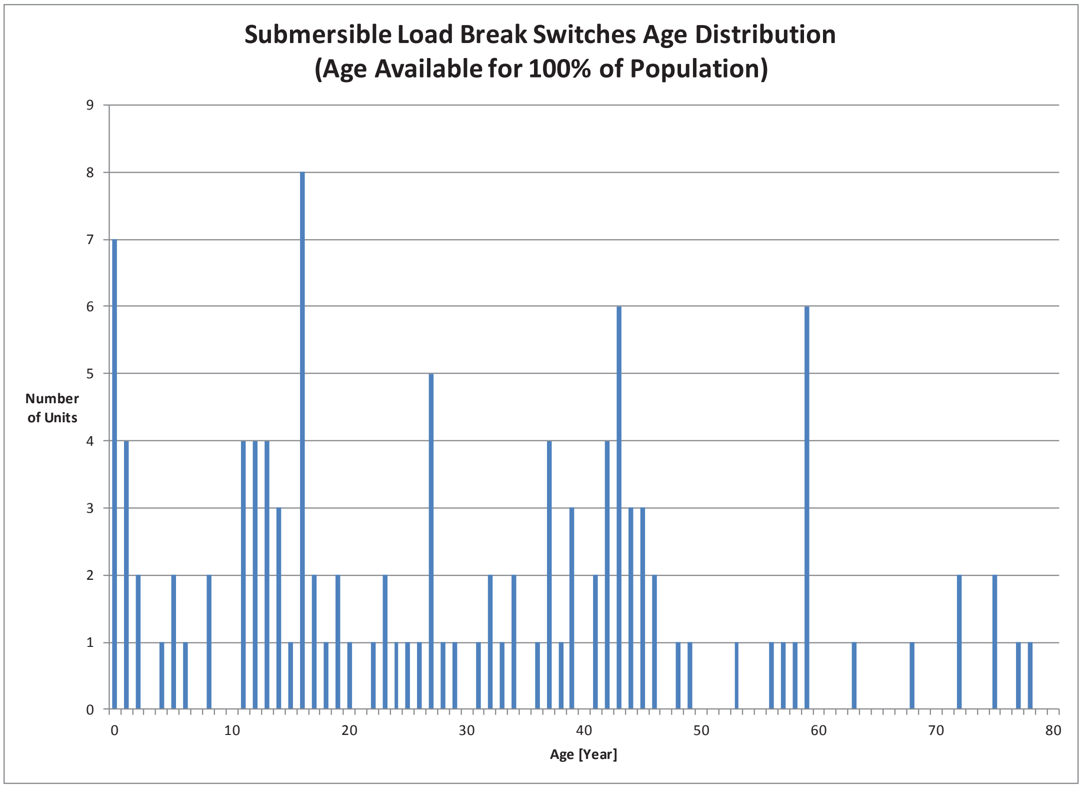

Figure 75 – Submersible Load Break – Age Distribution

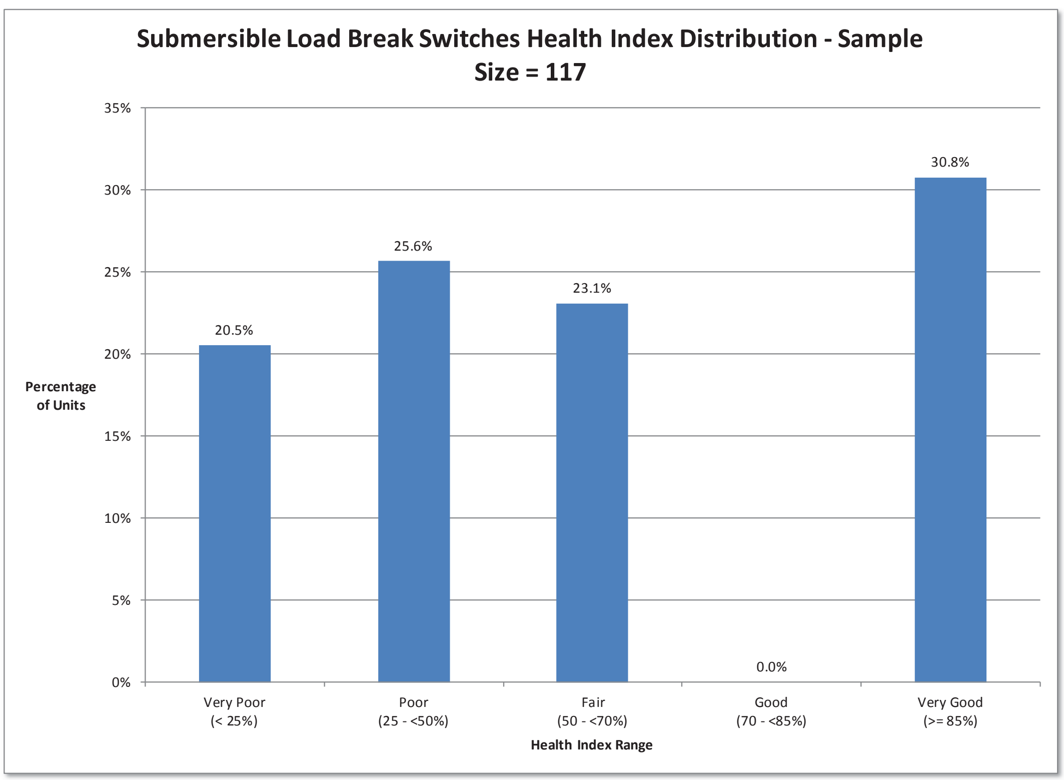

Figure 76 - Submersible Load Break Health Index Distribution

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.

<u>Investment Strategy</u>

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,

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[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.

Load Break Switch Maintenance

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. <u>Capital Expenditure Plan (5.4)</u>

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.

<u>Flamborough/Ancaster/Dundas</u>

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.

<u>Hamilton Downtown</u>

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.

System Access

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
		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
		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
		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.

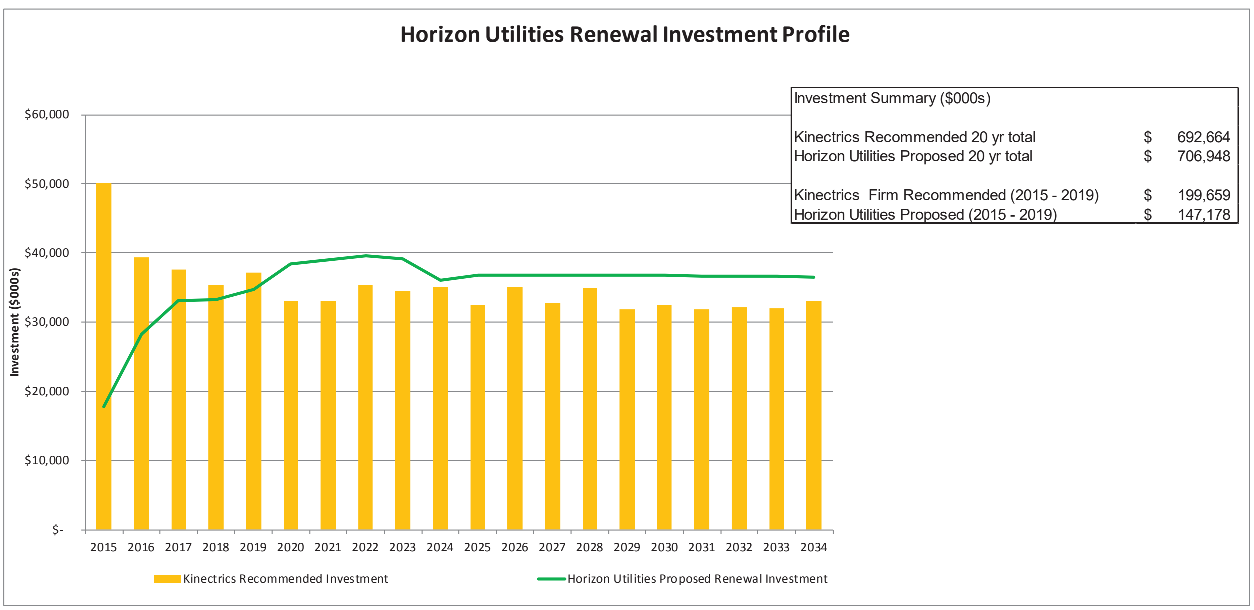

Figure 77 - Horizon Utilities Renewal Investment Profile

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 6th 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.

<u>Tools, Shop and Garage Equipment</u>

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

<u>General Plant Capital</u>

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.

System Access

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.

General Plant

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.

Road Relocations

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.

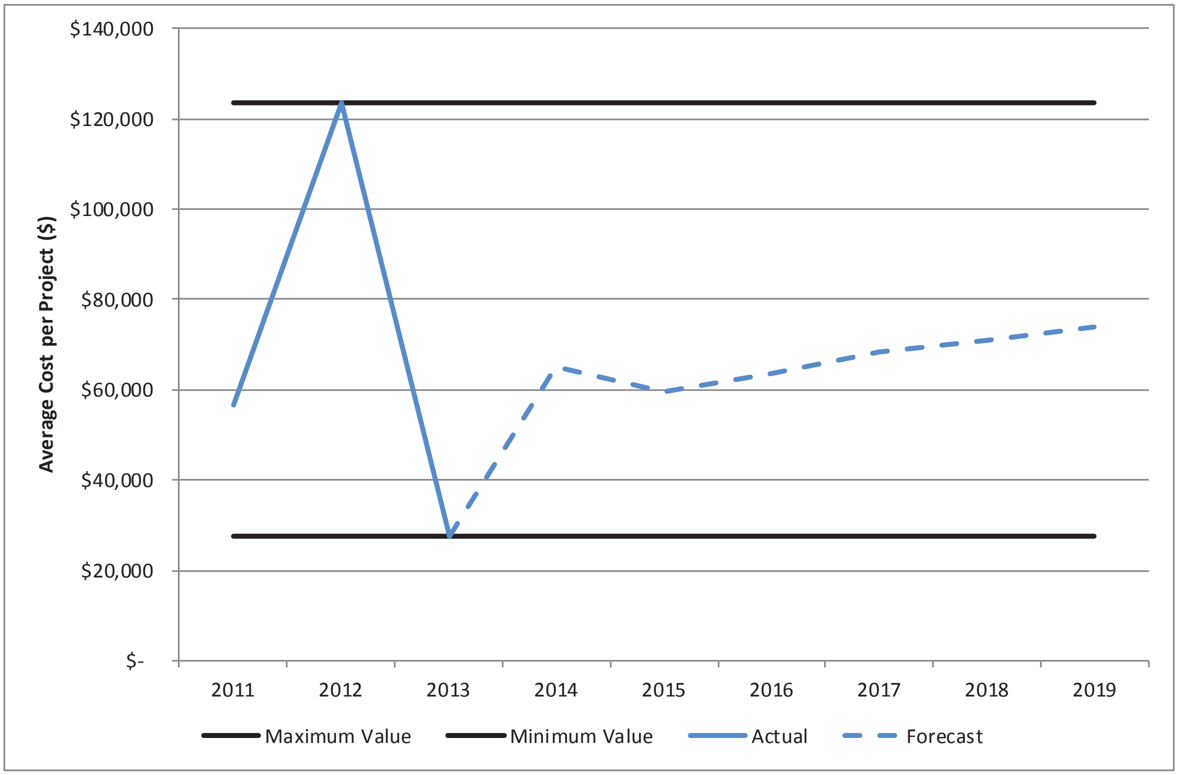

Figure 78 - Average Annual Road Relocation Project Cost

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.

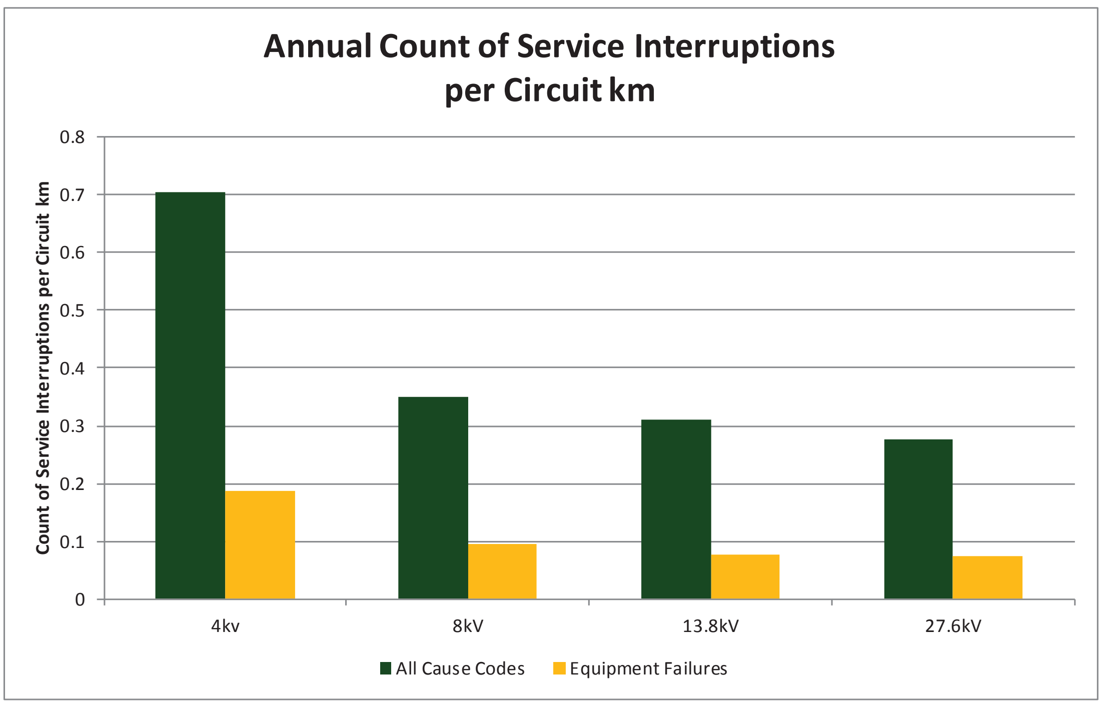

Figure 79 - Service Interruptions per Circuit km

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.

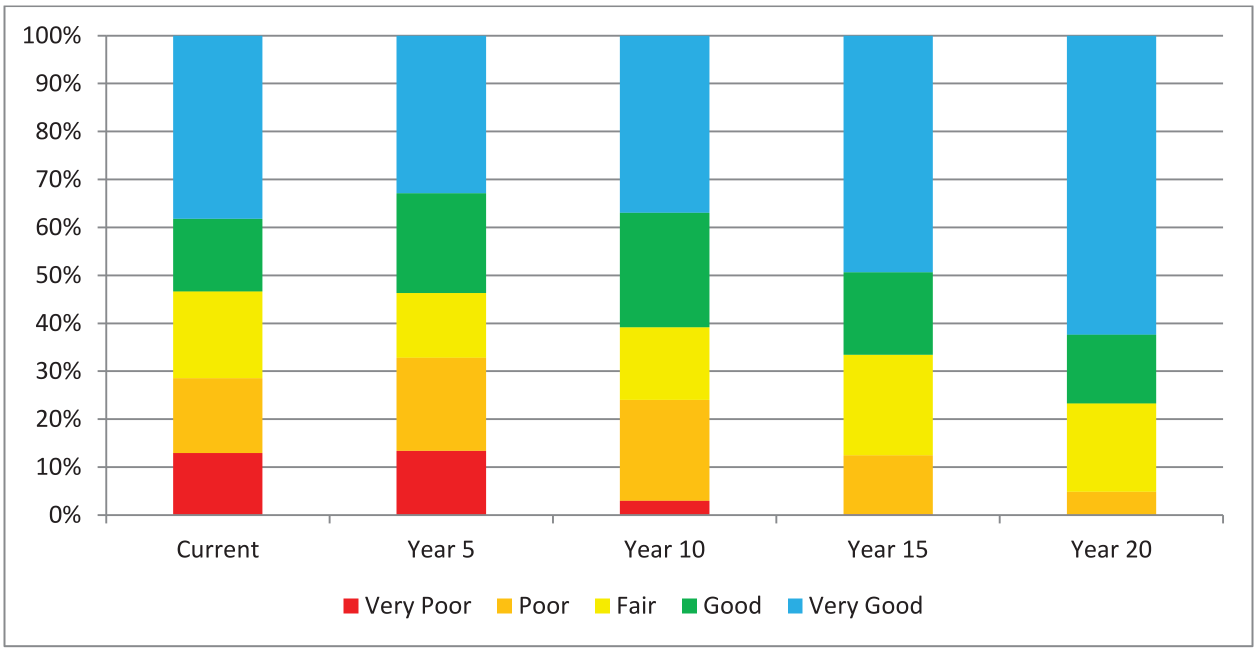

Figure 81 - Forecasted XLPE Health Index at Proposed Investment Levels

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.

<u>Area Replacement</u>

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.

<u>Reactive Replacement</u>

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.

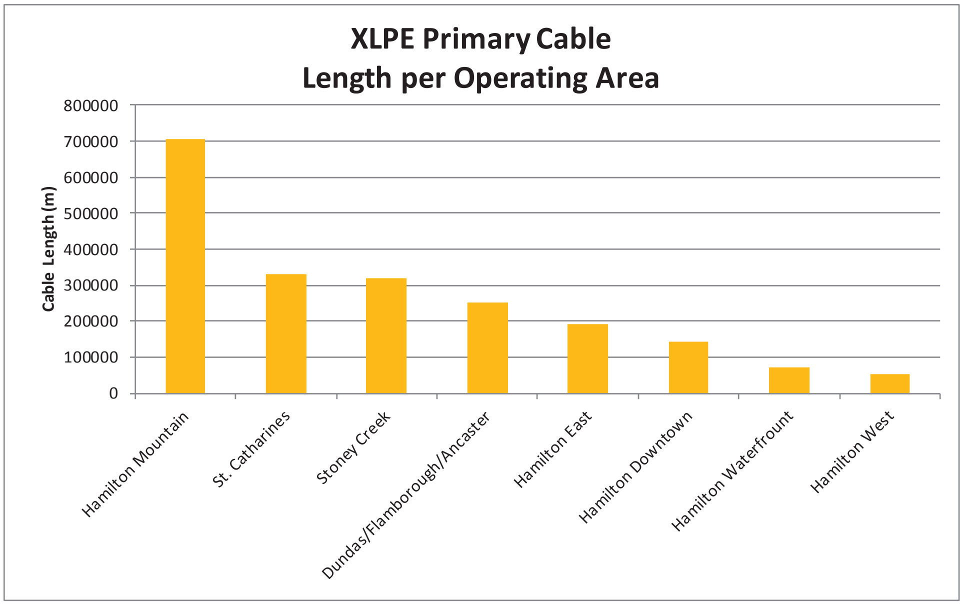

Figure 82 - XLPE Primary Cable per Operating Area

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.

<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 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”)*.

Nebo Road, Vansickle Road, and Hwy # 8 Service Centres

- 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.

<u>BCA</u>

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.

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[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

Phase 1- Upgrade from IFS version 7.3 to IFS version 8.1 (completed in 2013)

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;

Phase 2 – Removal of Custom Modifications (planned for 2014)

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.

Appendix A – Material Capital Projects

Appendix A – Material Capital Expenditure Projects

Chapter 2 of the Board's *Filing Requirements for Transmission and Distribution Applications updated July 17, 2013* (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 to be 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 $564,780 (0.5% of Horizon Utilities' distribution revenue of $112,956,026). The Materiality Threshold that Horizon Utilities will be using for the purpose of this section of the DSP is $300,000.

Tables 1 and Table 2 provide a summary of the Material Capital Expenditure projects for the 2015 – 2019 Test Years sorted by investment category, in accordance with Section 5.4.1(d) of the Chapter 5 Filing Requirements for Transmission and Distribution Applications - *Consolidated Distribution System Plan Filing Requirements* (the "Chapter 5 Filing Requirements")

The remainder of this appendix provides a description of these significant projects and activities to be undertaken and their respective key drivers; the relationship between investments and Horizon Utilities' objectives and targets; and the primary factors affecting the timing of material projects within each category.

Horizon Utilities has provided detailed Material Investment Templates in Appendix G of the DSP. These templates address Section 5.4.5.2 of the Chapter 5 Filing Requirements for each project. Appendix A includes detailed cross-references to Appendix G throughout.

Table 1: Material Capital Expenditures: System Access and System Renewal

Project ID	Project Name	2015 Test Year	2016 Test Year	2017 Test Year	2018 Test Year	2019 Test Year
Reporting Basis		**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**
System Access						
SA-1	Customer Connections	$ 3,686,273	$ 4,031,103	$ 4,139,076	$ 4,250,289	$ 4,364,837
SA-2	Road Relocations	$ 2,085,651	$ 2,339,675	$ 1,710,951	$ 1,778,139	$ 1,845,327
SA-3	Meters	$ 2,470,674	$ 2,101,174	$ 2,046,174	$ 2,063,174	$ 2,063,174
System Access Total		**$ 8,242,598**	**$ 8,471,952**	**$ 7,896,201**	**$ 8,091,602**	**$ 8,273,338**
System Renewal						
4kV & 8kV Renewal						
	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	$ -	$ -
SR-1	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**
U/G (XLPE) Renewal						
	Ancaster/Flamborough/Dundas	$ 2,257,000	$ 1,269,000	$ -	$ -	$ 2,702,000
SR-2	Hamilton Mountain	$ -	$ 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	$ -	$ -	$ 500,000	$ 1,908,000	$ -
	U/G (XLPE) Renewal Subtotal	**$ 2,567,000**	**$ 4,926,000**	**$ 8,866,000**	**$ 9,384,000**	**$ 10,271,000**
SR-3	**Reactive Renewal**	**$ 4,780,000**	**$ 4,339,000**	**$ 4,457,000**	**$ 4,536,000**	**$ 4,608,000**
SR-4	**Substation Infrastructure Renewal**	**$ 464,000**	**$ 473,000**	**$ 482,000**	**$ 491,000**	**$ 500,000**
Other Renewal						
SR-5	Pole Residual Replacements	$ 1,226,000	$ 1,262,000	$ 1,297,000	$ 1,333,000	$ 1,369,000
SR-6	LDBS Renewal	$ 323,000	$ 334,000	$ 345,000	$ 357,000	$ 368,000
SR-7	Proactive TX Replacements	$ 350,000	$ 361,000	$ 373,000	$ 384,000	$ 395,000
SR-8	Gage TS Egress Feeder Renewal	$ -	$ 4,793,000	$ -	$ -	$ -
SR-9	Rear Lot Conversion	$ -	$ 1,342,000	$ 1,382,000	$ 696,000	$ -
	Other Renewal Subtotal	**$ 1,899,000**	**$ 8,092,000**	**$ 3,397,000**	**$ 2,770,000**	**$ 2,132,000**
System Renewal Total		**$ 17,870,000**	**$ 27,990,000**	**$ 32,966,000**	**$ 32,865,000**	**$ 34,357,000**

Table 2: Material Capital Expenditures: System Service and General Plant

Project ID	Project Name	2015 Test Year	2016 Test Year	2017 Test Year	2018 Test Year	2019 Test Year
Reporting Basis		**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**
System Service						
SS-1	# 6 Wire Replacement	$ 570,000	$ -	$ -	$ -	$ -
SS-2	Distribution Automation	$ 1,250,000	$ -	$ -	$ -	$ -
SS-3	Waterdown 3rd Feeder	$ 984,000	$ -	$ -	$ -	$ -
SS-4	Caroline/George Redundancy	$ 952,000	$ -	$ -	$ -	$ -
SS-5	Duct Structure - Elgin TS to King St.	$ -	$ -	$ 535,000	$ -	$ -
SS-6	East 16th and Mohawk Security Project	$ -	$ -	$ -	$ 324,000	$ -
SS-7	St. Paul Street Conductor Upgrade	$ -	$ -	$ -	$ 1,362,000	$ -
SS-8	Grays Road	$ -	$ -	$ -	$ -	$ 413,000
SS-9	Mohawk/Nebo T/S Upgrade	$ -	$ -	$ -	$ -	$ 1,000,000
System Service Total		**$ 3,756,000**	**$ -**	**$ 535,000**	**$ 1,686,000**	**$ 1,413,000**
General Plant						
Information Systems Technology ("IST")						
GP-1	Annual Corporate Computer Replacement	$ 319,000	$ 324,000	$ 353,000	$ 361,200	$ 361,200
GP-2	IFS ERP Upgrade	$ 1,382,600	$ -	$ -	$ 1,225,000	$ -
GP-3	SAN Expansion	$ 200,000	$ -	$ 200,000	$ -	$ 300,000
GP-4	Enterprise Phone System Upgrade	$ 400,000	$ -	$ -	$ -	$ -
GP-5	Capital Lease - IBM	$ -	$ 900,000	$ -	$ -	$ 900,000
	IST Sub-Total	**$ 2,301,600**	**$ 1,224,000**	**$ 553,000**	**$ 1,586,200**	**$ 1,561,200**
Buildings						
GP-6	Building Renovations - John and Hughson Street	$ 2,000,000	$ 1,600,000	$ 2,200,000	$ 1,200,000	$ -
GP-7	Building Renovations - Stoney Creek	$ -	$ -	$ -	$ -	$ 1,200,000
GP-8	Building Security Replacement	$ 300,000	$ 200,000	$ -	$ -	$ -
GP-9	John Street Roof Replacement	$ 900,000	$ -	$ -	$ -	$ -
GP-10	Nebo Road Emergency Backup Generator	$ 300,000	$ -	$ -	$ -	$ -
GP-11	John Street Window Replacement	$ 300,000	$ 300,000	$ 200,000	$ -	$ -
	Buildings Sub-Total	**$ 3,800,000**	**$ 2,100,000**	**$ 2,400,000**	**$ 1,200,000**	**$ 1,200,000**
GP-12	**Vehicle Replacement**	**$ 778,000**	**$ 780,000**	**$ 775,000**	**$ 785,000**	**$ 785,000**
GP-13	**Tools, Shop and Garage Equipment**	**$ 555,560**	**$ 567,600**	**$ 508,600**	**$ 530,600**	**$ 580,600**
General Plant Total		**$ 7,435,160**	**$ 4,671,600**	**$ 4,236,600**	**$ 4,101,800**	**$ 4,126,800**
Total		**$ 37,303,758**	**$ 41,133,552**	**$ 45,633,801**	**$ 46,744,402**	**$ 48,170,138**

Multiple Year System Access Projects

<u>Project ID: SA-1</u>

Project Name: Customer Connections

Driver: System Access

Scope: This on-going multi-year program involves a number of projects where investment is required to enable customers to connect to Horizon Utilities' distribution system (excluding customers' contributed capital payments). Projects in this category include: installations of service wires and transformers to connect new customers; and upgraded services to the electrical distribution system. The amount of annual investment for this program is identified in Table 3 below:

Table 3: Customer Connections Projects

Project Name	2015 Test Year	2016 Test Year	2017 Test Year	2018 Test Year	2019 Test Year
Customer Connections	$ 3,686,273	$ 4,031,103	$ 4,139,076	$ 4,250,289	$ 4,364,837

System access projects are entirely customer driven and arise as a result of customer requests to connect to Horizon Utilities' distribution system. The 2015-2019 Test Year total expenditures are therefore derived from historical levels of expenditures. The historical expenditures represent actual total annual expenditures to connect residential and small commercial customers and as such these costs are the best available predictor of future expenditures. The 2015 to 2019 Test Year investment requirements, as provided in Table 3 above, are consistent with the increasing trend in the volume of customer connection projects experienced. Over the period of 2010-2013, Horizon Utilities has experienced a 37% increase in the number of customer connection projects. Please refer to Section 3.5.3, Table 45 of the DSP for additional information.

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.

Justification of Project: System Access projects are investments required to meet customer service obligations in accordance with the Distribution System Code ("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 required for each project; with such levels incorporated into the annual capital budget. In order to meet the requirements of the DSC and the Horizon Utilities' Conditions of Service, these investments cannot be deferred and must proceed as planned.

Additional Information: The following projects fall under Customer Connections as defined above and exceed Horizon Utilities' materiality threshold. They are individually identified and justified in the Material Project Templates in Appendix G.

- 2015 Customer Connections
- 2016 Customer Connections
- 2017 Customer Connections
- 2018 Customer Connections
- 2019 Customer Connections

<u>Project ID: SA-2</u>

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 at the request of the City of Hamilton, the City of St. Catharines, the Ministry of Transportation, and the Region of Niagara. The initiation and timing of these projects are dictated by the City of Hamilton, City of St. Catharines, the Ministry of Transportation, or the Region of Niagara. Consequently, the timing and value of investment required by Horizon Utilities is subject to change.

The amount of annual investment required for Road Relocation projects is identified in Table 4 below:

Table 4: Road Relocations Projects

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

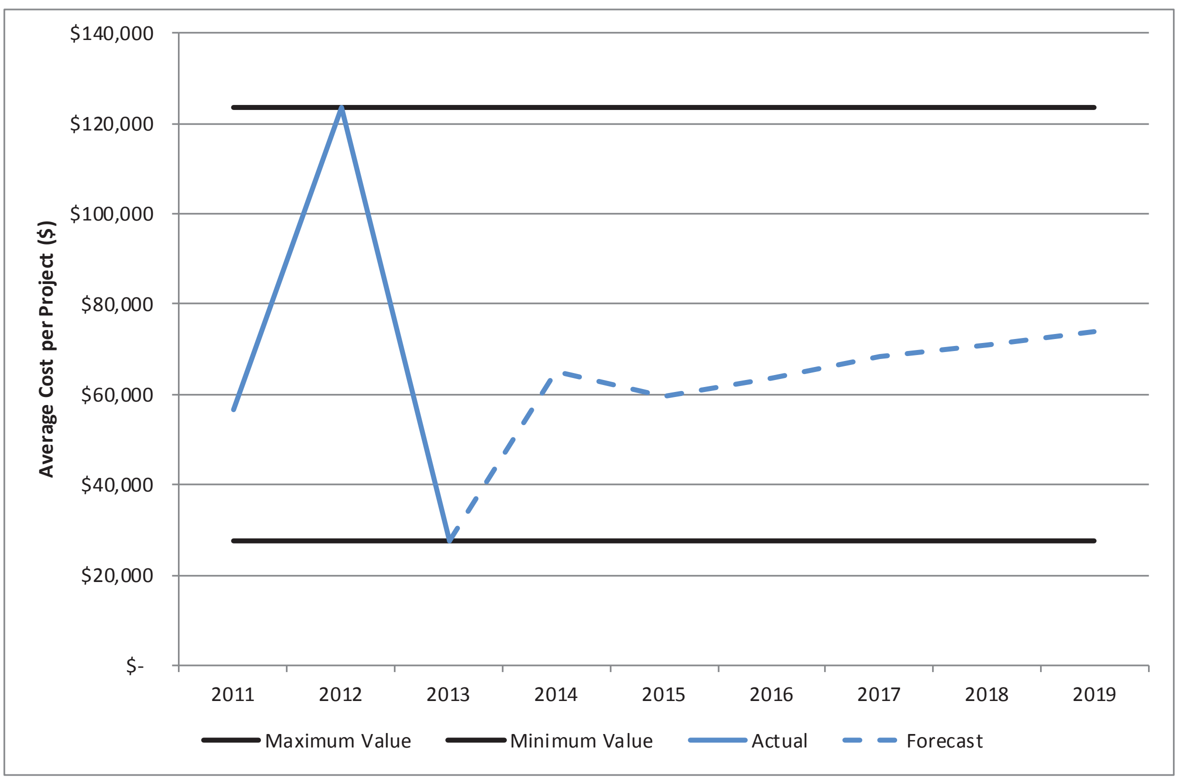
The Road Relocation expenditure amounts identified in Table 4 represent the total investment required for each of the Test Years. Investment levels in 2015 and 2016 are higher than the 2017 – 2019 Test Years in order to accommodate the Highway 5 and Highway 6 grade separation in Waterdown.

The Cities of Hamilton and St. Catharines, the Ministry of Transportation and Region of Niagara provide project lead times that range from six to 24 months, depending on the scope of the project.

Justification of Project: 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. Timelines for the execution of these projects are dictated by the City of Hamilton, the City of 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 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.

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. 25 projects is the average annual number of road relocation projects based on the 2011 to 2013 actuals and the 2014 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 1 below.

Figure 1 - Average Annual Road Relocation Project Cost



Additional Information: The following projects are categorized as Road Relocations as defined above and, exceed Horizon Utilities' materiality threshold. These are individually identified and justified in Appendix G.

- 2015 Road Relocations
- 2016 Road Relocations
- 2017 Road Relocations
- 2018 Road Relocations
- 2019 Road Relocations

Project ID: SA-3

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:

- the installation of complex and commercial meters at new service locations;
- the upgrade of metering installations for expanded service requirements;
- the inspection and replacement of defective meters;
- the 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 for meters is provided in Table 5 below:

Table 5: Meters

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

Meter expenditure amounts identified in Table 5 represent the total investment required for each of the Test Years 2015 - 2019.

Meter investments for 2015 – 2019 Test Years are relatively stable for each of the years based on a forecast of new and replacement meter installations. Horizon Utilities is forecasting 3,400 installations for residential, small commercial and multi-residential locations for growth and replacement metering at a cost of $1,326,000, which includes labour and materials. The forecast also includes costs for 385 installations for the growth and replacement of complex and commercial meters and for the replacement and growth of gatekeepers (collectors) at a cost of $775,000, which includes labour and materials. Horizon Utilities is forecasting a slight decrease in investment requirements in 2017 onwards due to the reduction in meter components, such as adapters, which will no longer be required for new meter installations.

Justification: The installation of meters is driven by customer initiated projects.

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 meter 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.

Additional Information: The following projects are categorized as Meters as defined above and exceed Horizon Utilities' materiality threshold. They are individually identified and justified in Appendix G.

- 2015 Meters
- 2016 Meters
- 2017 Meters
- 2018 Meters
- 2019 Meters

Multiple Year System Renewal Projects

<u>Project ID: SR-1</u>

Project Name: 4kV and 8kV Renewal Program

Driver: System Renewal

Scope: The 4kV and 8kV Renewal Program is the primary program to renew Horizon Utilities' oldest distribution assets. Projects generated as part of this program involve the conversion of all existing 4kV and 8kV distribution assets to either 13.8kV or 27.6kV. Conversion to either 13.8kV or 27.6kV is based on the corresponding distribution voltage from transmission connected supply points depending on the operating area. The prioritization of areas is fully described in the 4kV and 8kV Plan provided in Appendix F of the DSP. The 4kV and 8kV Renewal Program is performed in areas defined by the municipal substation serving the area. Projects with durations of several years are required to renew these assets within the operating area served by each municipal substation. The corresponding substation asset will be decommissioned once the distribution assets are converted to the higher voltage. The schedule for the 4kV and 8kV projects in the 2015 to 2019 Test Years is provided in Table 6 below.

Table 6: 4kV and 8kV Renewal Plan

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**

The operating areas serviced by the substations identified in Table 6 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.

Justification of Project:

Project Identification

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 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' Asset Condition Assessment ("ACA") provided in Appendix B of 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:

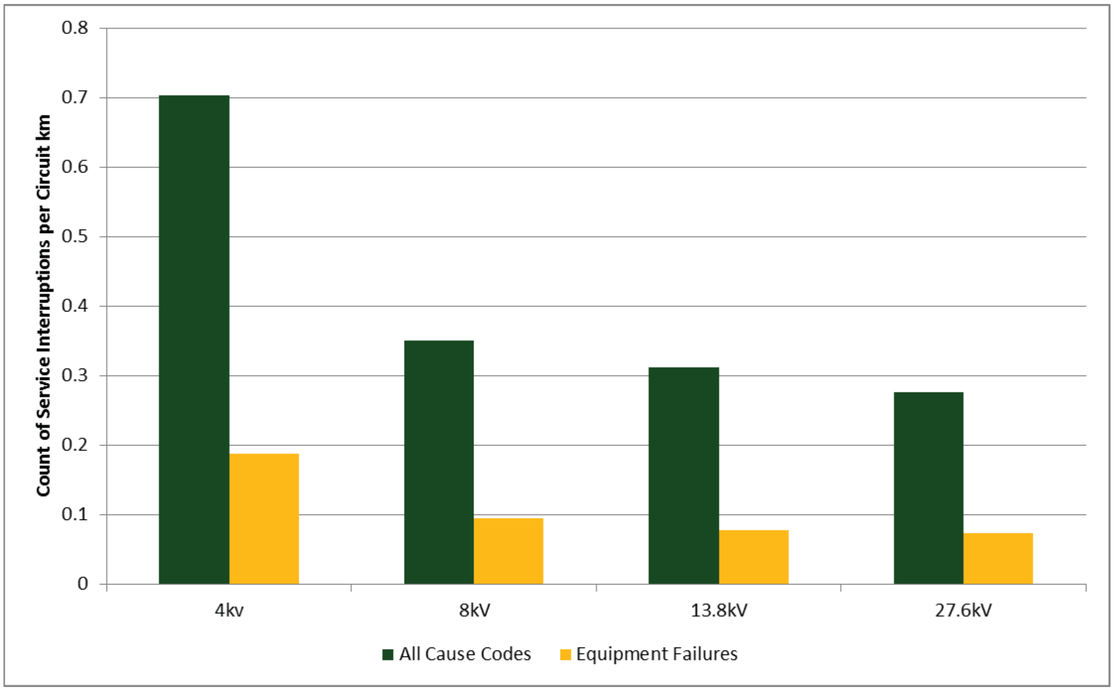
a. The renewal of all substation assets at the current voltage; and

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 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 82% (over 200km) of the total overhead conductor in Horizon Utilities’ distribution system with a health index of poor or very poor. Customers serviced by 4kV distribution system experience a disproportionally high outage rate when compared to the other distribution systems. As illustrated in Figure 2 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 2 – Service Interruptions per Circuit km



By converting the distribution assets to a higher voltage (from 4kV or 8kV to 13.8kV 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.

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.

The 4kV and 8kV Renewal Program is the primary vehicle to address the renewal of the oldest distribution assets in Horizon Utilities' service territory. The Kinectrics ACA provided the Health Index for 22 asset groups. For further details on the Kinectrics ACA, please refer to Appendix B of the DSP. Fifteen of these asset groups have an unacceptable Health Index distribution. Horizon Utilities defines an unacceptable Health Index distribution as:

- 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 these 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.

Impact of Failures

St. Catharines Operating Area

The three substations (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 Appendix F of the DSP. 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% worse than for the customers served by the 13.8kV system in St. Catharines and 100% worse than Horizon Utilities' corporate target. Please reference Section 2.2.2 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 switchgears 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 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 will cause 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 three times the normal load and Baldwin F1 is carrying double the 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.
- For a transformer failure: The only spare power transformer for all four substations 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 twelve hours while this work is completed. It would take 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 Cross-linked Polyethylene ("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 Section 3.5.3 of the DSP.

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 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 of 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 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 at end-of-life. The Health Index for these breakers is “very poor” and Kinectrics that this switchgear has 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, 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.

Additional Information: The following projects within the 4kV and 8kV Renewal Program exceed Horizon Utilities’ materiality threshold and are individually identified and further justified in Appendix G:

- HI-F3 Renewal – Governor’s Road West of Pirie Drive;
- ST-F7 Renewal – Part 1;
- WH-F3 Renewal;
- WH-F3 Rear Lot;
- GR-F4 Renewal;
- VE-F5 Renewal;
- CE-F4 Renewal - Hunter Street/Stinson St;
- ST-F7 Renewal – Part 2
- WH-F5 Renewal – Main St. W;
- GR-F1 – Renewal – South of Facer St
- GR-F2 – West of Vine Av
- VE-F1 Renewal - Queenston St;
- VE-F5 - West of Haynes Ave;
- AB-F5 Renewal Dundurn St;
- CE-F5 Renewal - Forest Ave.;
- HI-F2 Renewal – conversion to 2D7X;
- ST-F2 & ST-F6 Renewal;

- WH-F6 – Ewen St;
- VE-F1 Renewal – North of Queenston St;
- VE-F3 Renewal
- VE-F4 Renewal – Welland Ave and North St;
- GR-F2 – East of Vine Ave;
- AB-F2 & AB-F4 Renewal - Aberdeen East;
- BD-F1 Renewal – Cross St;
- CE-F10 Renewal – John St. S;
- JN-F1 Renewal;
- ST-F3 & ST-F4 Renewal;
- WH-F6 Renewal – Whitney Ave;
- YK-F1 York Rd Renewal;
- AB-F2 Renewal – Bold St;
- BD-F1 Renewal Alma St.;
- BD-F2 Renewal;
- CE-F4 Renewal – Freeman Pl;
- JN-F1 Renewal;
- JN-F2 Renewal;

<u>Project ID: SR-2</u>

Project: Underground XLPE Cable Renewal Program

Driver: System Renewal

Scope: This multi-year program involves the necessary renewal of Underground ("U/G") XLPE primary cable. Annual projects are determined using the combined analysis of XLPE cable asset condition assessment studies with XLPE cable failure data and the resulting service interruptions to customers.

This is a multi-year program with several projects forecast for each year. The amount of annual investment is provided in Table 7 below:

Table 7: XLPE Cable Renewal Program Investment

Project Name	2015 Test Year	2016 Test Year	2017 Test Year	2018 Test Year	2019 Test Year
Ancaster/Flamborough/Dundas	$ 2,257,000	$ 1,269,000	$ -	$ -	$ 2,702,000
Hamilton Mountain	$ -	$ 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	$ -	$ -	$ 500,000	$ 1,908,000	$ -
U/G (XLPE) Renewal Subtotal	**$ 2,567,000**	**$ 4,926,000**	**$ 8,866,000**	**$ 9,384,000**	**$ 10,271,000**

Justification of Project:

Justification for the increase in XLPE cable renewal expenditures in the 2015 to 2019 Test Years stems from the following factors:

- The current volume of assets with a Heath Index of either 'poor' or 'very poor';
- The forecasted Health Index distribution at 2013 investment levels will result in unacceptable levels of further deterioration of the health of this category; and
- Impact of underground cable failures on customers.

Current Health Index

As depicted in Section 2.2.3, Figure 63 of the DSP, 29% of the total length of XLPE primary cable has a Health Index of either 'poor' or 'very poor'. The percentage of cable in poor health, combined with the high volume of installed cable, results in XLPE primary cable having the highest investment requirements. Total investments of $172,742,000 over twenty years and $54,684,000 over the next five years are required to renew the XLPE primary cable identified by the Kinectrics ACA as flagged-for-action (i.e. having a high probability of failure).

Forecasted Health Index

Maintaining the XLPE cable renewal investment at 2013 levels would result in further unacceptable degradation in the Health Index distribution of this asset group as illustrated above in Figure 65 in Section 2.2.3 of the DSP. At 2013 levels of investment, the percentage of XLPE primary cable having a Health Index of either 'poor' or 'very poor' would increase from the current value of 29% to 70% or 1,400 km by 2034. 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. Ultimately, in the absence of proactive renewal as provided in this application, customers would experience unacceptable levels of system failures and outages beyond the ability of Horizon Utilities to resolve within a reasonable timeframe as these assets continue to age and degrade. Reactive replacements will also be considerably more costly than the forecast expenditure that has been submitted in this Application.

Impact of Underground Cable Failures

An analysis of all service interruptions caused by material or equipment failure reveals that 50% of such are due to failures of underground cable and equipment. Of the service interruptions caused by underground cable and equipment, 88% are caused by XLPE cable and associated equipment, with the remaining 12% attributable to paper insulated lead covered ("PILC") cable and equipment. Failures of underground distribution assets have represented approximately 16% of the total customer minutes in the 2010 to 2013 time period when major events are excluded[1]. It is reasonable to expect that the negative impact on customers will increase, as the Health Index of this asset group declines.

[1] April 2011 windstorm, July 2013 windstorm and December 2013 ice storm

Project Identification

While the Kinectrics ACA informed the annual investment requirements in this Application, operational performance analysis (failure rates, location, and identification of worst performing feeders) are the primary drivers in the project selection process.

The Ancaster/Dundas/Flamborough investments address end-of-life 4kV XLPE primary cable. XLPE renewal projects provide renewal of end-of-life XLPE primary cable but also support the 4kV and 8kV Renewal Program. This renewal will involve the conversion of the Ancaster/Dundas/Flamborough operating area to the 27.6kV distribution system because that is the Hydro One distribution supply voltage in this operating area.

Expenditures in the Hamilton Mountain, St. Catharines, and Stoney Creek areas are driven by poor reliability and the impact of underground distribution system failures in each area. Approximately 50% of the total XLPE renewal investment will be for the Hamilton Mountain area as the 13.8kV distribution system in this area contains 33% of the total XLPE cable in Horizon Utilities' distribution system and receives over 50% of the customer outage minutes due to equipment failures. Projects within each area are identified and selected through equipment failure analysis and the resulting impact upon customers from the failure of underground distribution assets.

Additional Information: The following projects within the XLPE Renewal Program exceed Horizon Utilities' materiality threshold and are individually identified and justified in the following Material Project Templates in Appendix G.

- HI-F3 Renewal – U/G Bridlewood subdivision;
- GR-F4 Renewal Charleen Circle U/G;
- 2015 St. Catharines XLPE Renewal;
- 2016 Hamilton Mountain XLPE Renewal;
- HI-F1 Renewal – U/G Conversion to 2D14X
- GR-F2 - Roehampton URD;
- 2016 St. Catharines XLPE Renewal;
- 2017 Hamilton Mountain XLPE Renewal;
- 2017 Stoney Creek XLPE Renewal;
- 2017 St. Catharines XLPE Renewal;
- 2018 Hamilton Mountain XLPE Renewal;
- 2018 Stoney Creek XLPE Renewal;
- 2018 St. Catharines XLPE Renewal;
- 2019 Hamilton Mountain XLPE Renewal;

- 2019 Stoney Creek XLPE Renewal;
- 2019 St. Catharines XLPE Renewal;
- YK-F2 Watson's Lane XLPE Renewal.

<u>Project ID: SR-3</u>

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 as a result of the following:

- 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 inspections;
- Urgent and necessary replacement of assets identified through Horizon Utilities' inspection and maintenance programs; and
- Projects required to address customer power quality issues.

Reactive renewal expenditure is required to support the restoration of service to the customer. The 2015-2019 forecast values are based on a three year rolling average, and would equate to, on average, the replacement of 234 poles and 112 transformers and the associated conductors and hardware each year.

Table 8: Reactive Renewal

Project Name	2015 Test Year	2016 Test Year	2017 Test Year	2018 Test Year	2019 Test Year
Reactive Renewal	$ 4,780,000	$ 4,339,000	$ 4,457,000	$ 4,536,000	$ 4,608,000

Justification of Projects:

Horizon Utilities experiences a large volume of equipment failures annually resulting in service interruption to customers. Capital investment is required to repair the distribution system and restore service to customers where equipment has failed. These expenditures are reactive in nature originating from over 3,500 customer outage calls/year on average into Horizon Utilities'

System Control Centre. In addition, Horizon Utilities completes 140 projects on average each year to address safety and power quality concerns.

Investment is required annually to restore service to affected customers; address power quality; and to address other urgent issues identified through Horizon Utilities' inspection programs or reported by external organizations (e.g. ESA). Failure to perform these investments will result in the inability to address:

- safety concerns identified by ESA and Horizon Utilities inspection programs; and
- power quality concerns identified by Horizon Utilities' customers.

Additional Information: The following projects within the Reactive Renewal Plan exceed Horizon Utilities' materiality threshold and are individually identified and justified in the following Material Project Templates in Appendix G.

- 2015 Enhancements
- 2015 OH/UG Reactive Renewal
- 2016 Enhancements
- 2016 OH/UG Reactive Renewal
- 2017 Enhancements
- 2017 OH/UG Reactive Renewal (Hamilton)
- 2018 Enhancements
- 2018 OH/UG Reactive Renewal
- 2019 Enhancements
- 2019 OH/UG Reactive Renewal

Project ID: SR-4

Project Name: Substation Infrastructure Renewal

Driver: System Renewal

Scope: This program involves the ongoing renewal of substation infrastructure throughout Horizon Utilities' service territory. Horizon Utilities performs annual substation maintenance and inspection programs. Through these inspections, Horizon Utilities identifies a number of required investments for the continued safe and reliable operation of Horizon Utilities' substations. Investments within this program include battery replacements, Supervisory Control and Data Acquisition ("SCADA") and communication upgrades, and grounding improvements.

This is a multi-year project with the following annual investment requirements:

Table 9: Substation Infrastructure Renewal

Project Name	2015 Test Year	2016 Test Year	2017 Test Year	2018 Test Year	2019 Test Year
Substation Infrastructure Renewal	$ 464,000	$ 473,000	$ 482,000	$ 491,000	$ 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. The 4kV and 8kV Renewal Program is structured to decommission Horizon Utilities' 28 substations over the next 34 years. There is no investment in the renewal of the major electrical assets (power transformers, switchgear and breakers) forecasted for the 2015 to 2019 Test Years. The investments provided above are required to maintain the ancillary substation assets in safe working order. Substation investment requirements are identified though preventative maintenance programs performed on both routine maintenance cycles and monthly inspections. 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. Investments are required to address both electrical assets within the substation (e.g. replacement of switchgear components and instrument transformers), and ancillary equipment (e.g. SCADA, communication equipment, or backup batteries). These are critical to the continued 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 ID: SR-5

Project Name: **Pole Residual Replacements**

Driver: System Renewal

Scope: This project involves the replacement of wood poles that are determined to have a high probability of imminent failure through Horizon Utilities' maintenance and inspection programs.

This is a multi-year project with the following annual investment requirements:

Table 10: Pole Residual Replacement

Project Name	2015 Test Year	2016 Test Year	2017 Test Year	2018 Test Year	2019 Test Year
Pole Residual Replacements	$ 1,226,000	$ 1,262,000	$ 1,297,000	$ 1,333,000	$ 1,369,000

Justification of Project: Wood pole replacement requirements are primarily identified through the following programs representing best utility practice:

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 cycle. Failed poles as identified through visual, sound and resistograph testing are scheduled for replacement. Further details for this program can be found in Section 3.1.3 of the DSP.

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, as 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, as such, it is prudent to replace poles based on proactive testing rather than on failure-based replacement approaches.

Additional Information: The following projects fall under Pole Residual Replacement as defined above and exceed Horizon Utilities' materiality threshold and are individually identified and justified in the Material Project Templates in Appendix G.

- 2015 Pole Residual Replacements
- 2016 Pole Residual Replacements
- 2017 Pole Residual Replacements
- 2018 Pole Residual Replacements
- 2019 Pole Residual Replacements

Project ID: SR-6

Project Name: **Load Break Disconnect Switches (“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 found through Horizon Utilities’ maintenance and inspection programs. Such switches will be replaced with automated switches for this program. This is a multi-year program based on sixteen replacements per year. The annual investment requirements are as follows:

Table 11: LBDS Renewal

Project Name	2015 Test Year	2016 Test Year	2017 Test Year	2018 Test Year	2019 Test Year
LDBS Renewal	$ 323,000	$ 334,000	$ 345,000	$ 357,000	$ 368,000

Justification of Project: During routine inspection and maintenance of LBDS, a small percentage of switches are found to be inoperable or require extensive maintenance that would exceed the cost of simply replacing the unit. LBDS are critical devices for the operation of the distribution system and are installed at key operating points (e.g. feeder tie points, feeder sectionalizing). Unplanned failures of these devices would 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%).

Additional Information: The following projects within the LBDS Program exceed Horizon Utilities’ materiality threshold and are individually identified and justified in the Material Project Templates in Appendix G.

- 2015 LBDS Replacement
- 2016 LBDS Replacement
- 2017 LBDS Replacement
- 2018 LBDS Replacement
- 2019 LBDS Replacement

<u>Project ID: SR-7</u>

Project Name: **Proactive Transformer Replacement**

Driver: System Renewal

Scope: This project was established to proactively replace distribution transformers as 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. This is a multi-year project, based on 25 replacements per year. The investment requirements are as follows:

Table 12: Proactive Transformer Replacement

Project Name	2015 Test Year	2016 Test Year	2017 Test Year	2018 Test Year	2019 Test Year
Proactive TX Replacements	$ 350,000	$ 361,000	$ 373,000	$ 384,000	$ 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, in a reactive replacement scenario, the customer(s) may be subject to extended outage duration.
- Transformers that have visible oil leaks, and
- Transformers that have been identified through testing as containing PCBs.

These criteria were selected due to the level of associated risk. Transformers with visible oil leaks or containing PCBs represent a significant environmental risk. All oil spills must be tracked, reported, and the oil reclaimed where possible. Obsolete transformers, where a replacement is not available in inventory, represent a risk of prolonged service interruption upon failure and are replaced to reduce the risk of outage to the customer. Details regarding the Proactive Transformer Replacement Program are found in Section 3.1.3 of the DSP.

Additional Information: The following projects within the Proactive Transformer Replacement Program exceed Horizon Utilities' materiality threshold and are individually identified and justified in the Material Project Templates in Appendix G.

- 2015 Proactive Transformer Replacement
- 2016 Proactive Transformer Replacement
- 2017 Proactive Transformer Replacement
- 2018 Proactive Transformer Replacement
- 2019 Proactive Transformer Replacement

<u>Project ID: SR-9</u>

Project Name: **Rear Lot Conversion**

Driver: System Renewal

Scope: This project involves the replacement of rear lot overhead distribution assets. Replacement options include relocating primary only, or relocating all assets to either overhead or underground in the front lot. Options are dependent on many factors (e.g. presence of trees and availability of room in the road allowance) and are assessed on a case by case basis.

This project will involve the renewal of end-of-life rear lot overhead distribution assets serviced at 13.8kV and therefore are not included in the 4kV and 8kV renewal programs. This is a multi-year project with the following investment requirements:

Table 13: Rear Lot Conversion

Project Name	2015 Test Year	2016 Test Year	2017 Test Year	2018 Test Year	2019 Test Year
Rear Lot Conversion	$ -	$ 1,342,000	$ 1,382,000	$ 696,000	$ -

Justification of Project:

Horizon Utilities has identified several residential areas serviced by a rear lot overhead distribution system. Horizon Utilities has experienced a dramatic increase in reliability issues surrounding rear lot distribution systems due to falling customer-owned trees and lack of access for utility crews to repair or replace equipment. The poles are a mix of wood and concrete that, by design, are unsafe to scale to repair; and replacement of poles and equipment is labour intensive and requires specialized equipment to access rear yards. Access is restrictive and as such restoration time is significantly extended in the event of a failure. These identified assets are nearing or beyond end-of-life and should be replaced. In the past several years, storm related failures in these areas have increased, with corresponding long outage durations (in excess of 24 hours). These outages have precipitated the need to create a multi-year program to address the residential areas serviced by a rear lot distribution system.

Additional Information: The following projects within the Rear Lot Conversion Program exceed Horizon Utilities' materiality threshold and are further detailed in Appendix G.

- 2016 Rear Lot Conversion
- 2017 Rear Lot Conversion
- 2018 Rear Lot Conversion

Multiple Year General Plant Projects

<u>Project ID: GP-1</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. 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 are replaced annually (~150 PCs/year).

This is a multi-year project with the following annual investment requirements:

Table 14: Annual Corporate Computer Replacement

Project Name	2015 Test Year	2016 Test Year	2017 Test Year	2018 Test Year	2019 Test Year
Annual Corporate Computer Replacement	$ 319,000	$ 324,000	$ 353,000	$ 361,200	$ 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 Information Technology ("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, Geospatial Information Systems ("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 be able to respond quickly to electrical system issues; response time and customer safety could be compromised if computer hardware is not functioning properly.

In recent years Horizon Utilities' has invested heavily in new systems such as GIS, Outage Management System ("OMS"), and Budgeting and Forecasting. These systems are data and processing intensive, requiring increased computational power.

Additional Information: The following projects within the Annual Corporate Computer Replacement exceed Horizon Utilities' materiality threshold and are individually identified and justified in the Material Project Templates in Appendix G.

- 2015 Annual Corporate Computer Replacement
- 2016 Annual Corporate Computer Replacement
- 2017 Annual Corporate Computer Replacement
- 2018 Annual Corporate Computer Replacement
- 2019 Annual Corporate Computer Replacement

<u>Project ID: GP-2</u>

Project Name: Industrial and Financial Systems ("IFS") Enterprise Resource Planning ("ERP") Upgrade

Driver: General Plant

Scope: 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. Details related to Phase 1 and 2 are provided in Exhibit 2, Tab 6, Schedule 1.

This phase involves the redesign and optimization of existing business processes using new features and functions available in IFS version 8.1, which are expected to deliver operational efficiencies and staff productivity improvements. Processes being optimized or implemented include:

- Optimization of Accounts Payable processing to: automate invoice 3-way matching to reduce manual effort and processing time;;
- Implementation and optimization of purchase order processes to: improve purchase authorization process; automate supplier contract document routing process; optimize server-based document storage; and, streamline project inventory process to improve purchase order process;
- Implement IFS mobile work order functionality to automate processing and eliminate duplicate data entry;
- Simplification of standardized labour rates and Activity Based Costing ("ABC") reporting;
- Implementation to the IFS Eco-Footprint Module to reduce manual effort and cost of Global Reporting Initiative ("GRI") and Sustainment auditing and reporting;
- Implementation of IFS mobile applications to improve authorization processes for purchase requisitions, purchase orders, travel expenses, and time entry;
- Implementation of IFS dashboards and analysis to reduce the manual effort required to extract and compile data outside of IFS; and
- Streamline processes for OEB reporting and reduce manual effort.

The 2015 investment of this multi-year initiative is $1,382,600 consisting of $750,000 of capitalized internal labour and $632,600 in software add-ons and third-party consulting support.

Justification of Project: The estimated annual benefit for this phase is approximately $703,500 and is detailed in Exhibit 4, Tab 3, Schedule 4. These benefits will be realized in the following areas:

- Staff productivity improvements – This phase of the project is estimated to deliver approximately 6,965 hours of annual staff productivity improvements with an estimated value of $603,500. These improvements will be realized through reductions in transaction processing times and automation of manual tasks.

- Cost Reductions and Cost Avoidance - For some processes it is estimated that process changes will deliver reduction in costs related to transaction completion and elimination of fees currently being incurred. Removal of these modifications will contribute to operational effectiveness by: reducing the costs of annual software maintenance fees by $50,000 related to the modifications; avoiding future cost for annual software maintenance on modifications for which IFS will start billing if the modifications are not removed; and reduce costs related to future upgrades by eliminating the requirement to transition modifications to future software versions.

  The automation of some processes will allow existing staff to process more transactions, avoiding future cost increases related to incremental headcount to support transaction volumes. The estimated annual total of these cost reductions and cost avoidance improvements is $100,000.

These productivity gains are part of the productivity achievements discussed in Exhibit 4, Tab 3, Schedule 4.

Additional Information: The following project within the IFS ERP upgrade exceeds Horizon Utilities' materiality threshold and is individually identified and justified in the Material Project Templates in Appendix G.

- 2015 IFS ERP Upgrade

Project Name: 2018 IFS ERP Upgrade

Scope: 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 most current version.

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

Justification of Project: Horizon Utilities uses IFS to manage business critical processes in Finance, Human Resources, Supply Chain Management, Asset Management, and Engineering Project Planning. This project is both a lifecycle upgrade and a risk mitigation project. IFS's software development plans are to release a new major version of the system every three years. IFS will only provide support for the two most recent versions. The application must be upgraded in order to maintain IFS support for this system.

Horizon Utilities has scheduled this project in 2018 to manage required IT investment and manage internal resource commitments to minimize impact on customers and business operations. Any delay of this project would also conflict with a required major upgrade of Horizon Utilities' CIS system, the development for which begins in 2019. Horizon Utilities would not be able to support both an IFS upgrade and CIS upgrade concurrently.

Additional Information: The following project within the IFS ERP upgrade exceeds Horizon Utilities' materiality threshold and is individually identified and justified in the Material Project Templates in Appendix G.

- 2018 IFS ERP Upgrade

Project ID: GP-3

Project Name: Storage Area Network ("SAN") Expansion

Driver: General Plant

Scope: This is a risk management and sustainment project scheduled every two years to ensure adequate data storage capacity for Horizon Utilities at the production data centre in Hamilton and the disaster recovery data centre in St. Catharines. The project involves the expansion of the existing SAN in both the production and disaster recovery data centres.

This is a multi-year project with the following annual investment requirements:

Table 15: SAN Expansion

Project Name	2015 Test Year	2016 Test Year	2017 Test Year	2018 Test Year	2019 Test Year
SAN Expansion	$ 200,000	$ -	$ 200,000	$ -	$ 300,000

Justification of Project: This project is required to support Horizon Utilities' annual data growth rate which, based on historical experience, exceeds 30% per annum. The data growth rate is expected to increase during the 2015-2019 Test Years as new applications such as GIS and OMS are implemented.

This investment in SAN expansion will eliminate risk related to insufficient storage capacity to support day-to-day business operations.

The risk of not proceeding with this project is that Horizon Utilities will not have enough disk storage capacity to sustain its systems environment to meet its business requirements.

Additional Information: The following project is identified and justified in the Material Project Templates in Appendix G:

- Storage Area Network ("SAN") Expansion

<u>Project ID: GP-5</u>

Project Name: Capital Lease – IBM (2016 and 2019)

Driver: General Plant

Scope: This project is the end of lease replacement of the IBM iSeries server hardware environment used to run the Daffron Customer Information System ("CIS") which supports Horizon Utilities' customer management and meter-to-cash processes. The hardware is a three-year lease with planned renewals in 2016 and 2019. The environment includes a production IBM iSeries server in Hamilton and an identical IBM iSeries server at the Disaster Recovery Data Centre in St. Catharines.

This project has the following annual investment requirements:

Table 16: Capital Lease – IBM

Project Name	2015 Test Year	2016 Test Year	2017 Test Year	2018 Test Year	2019 Test Year
Capital Lease - IBM	$ -	$ 900,000	$ -	$ -	$ 900,000

Justification of Project: The IBM iSeries hardware lease will expire December 31, 2015 and December 31, 2018. This environment is required to maintain the continued operation of Horizon Utilities' Daffron CIS system to ensure appropriate technology for the customer management and meter-to-cash processes. Replacement of the IBM iSeries hardware at end-of-life reduces the likelihood of hardware failures that could disrupt normal business operations, impacting Horizon Utilities' ability to: read smart meters; bill customers; apply customer payments; manage customer interactions; and manage customer work orders.

Additional Information: The following projects are identified and justified in the Material Project Templates in Appendix G:

- 2016 Capital Lease – IBM
- 2019 Capital Lease – IBM

<u>Project ID: GP-6</u>

Project Name: Building Renovations – John Street

Driver: General Plant

Scope:

This is a multi-year project with the following annual investment requirements:

Table 16: Building Renovations and Refurbishment

Project Name	2015 Test Year	2016 Test Year	2017 Test Year	2018 Test Year	2019 Test Year
Building Renovations & Refurbishment Projects	$ 2,000,000	$ 1,600,000	$ 2,200,000	$ 1,200,000	$ -

The 2015 scope of this multi-year project includes the renovation to a portion of the fifth floor in an effort to consolidate all IST employees into one workspace. Additional space will also be provided to accommodate current and future requirements for the Human Resources, Corporate Communications, and Health and Safety employees. Space that was formerly occupied by the Hughson substation building will be reclaimed and converted into the main corporate training room, currently located on the fifth floor. 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 2016 scope of this multi-year project involves the renovation of the second floor to: consolidate Customer Service and Conservation and Demand Management (“CDM”) employees to a single floor; improve employee security and safety; and address lighting and air quality deficiencies.

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 Resource and Office Space Utilization Study, included as

Appendix J of the DSP and 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.

The 2018 scope of this multi-year project includes the renovation to the John Street basement locker, washroom, and shower space which is largely original to the 1950s building. These end-of-life facilities, equipment and systems continue to fail and require constant repairs. The renovation will also accommodate the size and needs of the workforce, remediate hazardous materials, and replace end-of-life facilities. The project will also include renovations to the public and customer entrance to improve the utilization of space and to address employee and public security.

Justification of Project: Horizon Utilities has five main buildings on four properties, comprised of two adjacent head office buildings and three Service Centres. Horizon Utilities also has 28 substations; 23 of which are inside a building enclosure within the cities of Hamilton and St. Catharines. These building 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.

Building 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 original floor layouts, building systems and structures do not meet the needs of the current workforce.

In addition, operational expenditures for the maintenance and operations of the Horizon Utilities' buildings are increasing year-over-year 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 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 risk and benefits of such projects.

The independent studies included: a Resource and Office Space Utilization Study Report ("Space Study"), filed as Appendix J in the DSP 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.

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 identified 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.

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.

The BCA, [redacted] 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: [redacted] 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 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.

2015 Planned Building Renovations

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

Fifth Floor – Head Office

This project will: consolidate IST staff which currently reside in three different locations onto one floor; 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
- lighting.

The space will be converted into a large training room which will become the main corporate training room for Head Office. This will reduce travel time for Head Office employees who currently travel approximately 30 minutes or 20 km from 55 John St to the Stoney Creek Service Centre Training Room. Reclamation of the industrial space represents a capital expenditure of $1,500,000.

2016 Planned Building Renovations

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 – Head Office

The second floor of the Head Office 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 Customer Service cashiers 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 Ontario Building Code “OBC”. All Heating, Ventilation and Air Conditioning “HVAC” components will be replaced and redirected as required to ensure air quality meets appropriate standards.

2017 Planned Building Renovations

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 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 – Head Office

The renovation of the sixth floor, which houses 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 from other floors at Head Office;
- the installation of HVAC and fire and life safety systems that are at end-of-life;
- the disposal of hazardous materials including asbestos and anticipated mould resulting from an leaking roof; and
- the creation of necessary meeting room space.

2018 Planned Building Renovations

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

Basement / Lobby – Head Office

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].
- the necessary installation of fire stops devices in walls, doors and frames which require fire rating as per Ontario Building Code.

Additional Information: The following projects within the Building Renovations and Refurbishment – John Street exceed Horizon Utilities' materiality threshold and are individually identified and justified in the Material Project Templates in Appendix G.

- 2015 Building Renovations – John Street
- 2016 Building Renovations – John Street
- 2017 Building Renovations – John Street
- 2018 Building Renovations – John Street

<u>Project ID: GP-8</u>

Project Name: Building Security Replacement

Driver: General Plant

Scope: This multi-year initiative involves [redacted].

This is a multi-year project with the following annual investment requirements:

Table 17: Building Security Replacement

Project Name	2015 Test Year	2016 Test Year	2017 Test Year	2018 Test Year	2019 Test Year
Building Security Replacement	$ 300,000	$ 200,000	$ -	$ -	$ -

Justification of Project:

[redacted]

[redacted]

[redacted]

Additional Information: The following projects within the Building Security Replacement exceed Horizon Utilities' materiality threshold and are individually identified and justified in the Material Project Templates in Appendix G.

- 2015 Building Security Replacement
- 2016 Building Security Replacement

<u>Project ID: GP-11</u>

Project Name: John Street Window Replacement

Driver: General Plant

Scope:

This multi-year project involves replacement of the windows at the John Street location. 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.

This is a multi-year project with the following annual investment requirements:

Table 18: John Street Window Replacement

Project Name	2015 Test Year	2016 Test Year	2017 Test Year	2018 Test Year	2019 Test Year
John Street Window Replacement	$ 300,000	$ 300,000	$ 200,000	$ -	$ -

Justification:

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.

Additional Information: The following projects within the John Street Window Replacement exceed Horizon Utilities' materiality threshold and are individually identified and justified in the Material Project Templates in Appendix G.

- 2015 John Street Windows Replacement
- 2016 John Street Windows Replacement
- 2017 John Street Windows Replacement

Project ID: GP-12

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.

This is a multi-year project with the following annual investment requirements:

Table 19: Vehicle Replacement

Project Name	2015 Test Year	2016 Test Year	2017 Test Year	2018 Test Year	2019 Test Year
Vehicle Replacement	$ 778,000	$ 780,000	$ 775,000	$ 785,000	$ 785,000

The following vehicles are scheduled for replacement in the 2015 to 2019 Test Years.

Table 20: Vehicles Scheduled for Replacement

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

Justification of Project:

Horizon Utilities has a six year Fleet Replacement Plan which is updated annually. The 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 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. Using the fleet asset replacement criteria, Horizon Utilities has identified 24 light and heavy duty vehicles that require replacement between 2015 and 2019, as identified in Table 20. Horizon Utilities is not adding any new vehicles or replacing any trailers during these test years.

Table 21: Replacement Criteria

<table>
<tr><th>Fleet Class</th><th>Replacement Assessment Criteria</th></tr>
<tr><td rowspan="2">Light Duty Vehicles</td><td>Assessed at 6 years and every year after, and/or high mileage (excess of 150,000 km)</td></tr>
<tr><td>Typical replacement schedule: 6 to 8 years</td></tr>
<tr><td rowspan="3">Heavy Duty Vehicles</td><td>Assessed at 11 year service, and every year after, and/or high mileage (excess of 200,000 km)</td></tr>
<tr><td>High engine hours (excess of 15,000 engine hours)</td></tr>
<tr><td>Typical replacement schedule: 16 to 19 years</td></tr>
<tr><td rowspan="3">Trailers</td><td>Trailer replacement will follow the same core principles as the vehicle replacement criteria with the following differences:</td></tr>
<tr><td>i) When assessing trailer conditions, trailers will be refurbished rather than replaced</td></tr>
<tr><td>ii) When trailers cannot be refurbished due to application change or condition, trailers will be flagged for replacement</td></tr>
</table>

The replacement life for light duty and heavy duty vehicles as identified above is:

- six to eight years for light duty vehicles. Horizon Utilities has 93 light duty vehicles, of which 45 or 48% are currently eight years and older.
- sixteen to nineteen years for heavy duty vehicles. 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 replacement 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. All vehicles scheduled for replacement have surpassed the replacement criteria listed above.

Additional Information: The following projects within the Vehicle Replacement exceed Horizon Utilities' materiality threshold and are individually identified and justified in the Material Project Templates in Appendix G.

- 2015 Vehicle Replacement
- 2016 Vehicle Replacement
- 2017 Vehicle Replacement
- 2018 Vehicle Replacement
- 2019 Vehicle Replacement

Project ID: GP-13

Project Name: Tools, Shop and Garage Equipment

Driver: General Plant

Scope: This project includes expenditures pertaining to the purchase and replacement of tools and equipment, which are either: worn; beyond repair; or the continued use of such creates health and safety risk. This equipment is used by various trades/technical employees at Horizon Utilities including: Distribution System Line Trades (Line persons, 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:

Table 22: Tools Shop and Garage Equipment

Project Name	2015 Test Year	2016 Test Year	2017 Test Year	2018 Test Year	2019 Test Year
Tools, Shop and Garage Equipment	$ 555,560	$ 567,600	$ 508,600	$ 530,600	$ 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.

Additional Information: The following projects within the Tools and Equipment Program exceed Horizon Utilities materiality threshold and are individually identified and justified in the Material Project Templates in Appendix G.

- 2015 Tools, Shop and Garage Equipment;
- 2016 Tools, Shop and Garage Equipment
- 2017 Tools, Shop and Garage Equipment
- 2018 Tools, Shop and Garage Equipment
- 2019 Tools, Shop and Garage Equipment

2015 System Service Projects

Project ID: SS-1

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.

Justification of Project: Horizon Utilities will replace an aggregate of 3km of #6 wire at a cost of $570,000 in 2015. 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.

Additional Information: The following project #6 Wire Replacement exceeds Horizon Utilities' materiality threshold and are individually identified and justified in the Material Project Templates in Appendix G.

- # 6 Wire Removal - Eastmount

Project ID: SS-2

Project Name: Distribution Automation

Driver: System Service

Scope: This project involves the deployment of automated switches, reclosers and fault indicators through Horizon Utilities' service territory as identified in Horizon Utilities' Basic GEA Plan as submitted in Horizon Utilities 2011 Cost of Service Application (EB-2010-0131).

An investment of $1,250,000 is required for the deployment of distribution automation in 2015.

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 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). Horizon Utilities worst performing feeders with the largest number of customer minutes of outage are the highest priority for automation.

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.

Automation, once fully deployed throughout the distribution system, is expected to improve reliability by 10%. Horizon Utilities' reliability is driven by a small number of large outages (1% of outages constitute 40% of the total customer of minutes annually). Analysis of the 2013 largest impact outages (excluding the July 2013 windstorm and December 2013 ice storm) indicated that automation would have reduced the impact of these outages by 25%. These results, when extrapolated across all outages, would result in a reduction of 10% annually.

Additional Information: The following project, within the Distribution Automation Program, exceeds Horizon Utilities' materiality threshold and is individually identified and justified in the Material Project Templates in Appendix G.

- 2015 GEA Feeder Automation

<u>Project ID: SS-3</u>

Project Name: Waterdown Third Feeder

Driver: System Service

Scope: This project involves the construction of an alternate, third feeder to improve the security for the Waterdown express feeders 2D12X and 2D13X.

An investment of $984,000 in 2015 is required to complete this project.

Justification of Project: The Dundas 2D12X and 2D13X feeders service the Waterdown area and provide back-up to one another. The construction of a third feeder will address both capacity and security issues in the Waterdown area. The two existing feeders (2D12X and 2D13X) share a common pole line from Dundas TS to the intersection of Highway 5 and Highway 6. The section along Valley Road from York Rd to Rock Chapel Road is especially susceptible to outages as this section ascends the Niagara Escarpment through heavy vegetation. This poses a risk to security as pole failure or falling trees that damage the conductors will affect both feeders and leave the 7,000 customers in Waterdown without service until repairs are complete. This project will construct a third feeder along an alternate route to improve the security of the feeders servicing Waterdown. This investment must be made in 2015 as the Ministry of Transportation is redeveloping the Highway 5 and Highway 6 interchange in 2015/2016, which will require the removal of both of the existing feeders, leaving Waterdown without service.

This project will address security issues in the Waterdown area, as well as provide capacity for the projected load growth in Waterdown.

Additional Information: The following project within the Watertown Third Feeder Program exceeds Horizon Utilities' materiality threshold and is individually identified and justified in the Material Project Templates in Appendix G.

- Waterdown 3rd Feeder - Upgrade York Road

<u>Project ID: SS-4</u>

Project Name: Caroline/George Redundancy

Driver: System Service

Scope: This project will create an alternative backup supply to the redeveloped Hamilton downtown in the Caroline and George St. area.

This project requires an investment of $952,000 in 2015.

Justification of Project: Existing assets are not able to provide full redundancy and therefore an additional circuit must be installed to provide proper backup to these customers. Other alternatives such as transfer of load to adjacent feeders have been reviewed but failed preliminary assessment. This project must be completed in 2015 as the forecasted load growth will exceed the existing backup supply in 2016. Customers in this newly redeveloped section of downtown Hamilton would not be adequately serviced should a failure to the primary service occur.

Additional Information: The following project within the Caroline/George Program exceeds Horizon Utilities materiality threshold and is individually identified and justified in the Material Project Templates in Appendix G.

- Caroline and George Backup

2015 General Plant Projects

<u>Project ID: GP-4</u>

Project Name: Enterprise Phone System Upgrade

Driver: General Plant

Scope: This 2015 project is a planned lifecycle upgrade of Horizon Utilities' Cisco phone system and call center management software installed in 2010. This project involves replacement of the phone system and call centre software in Hamilton and the redundant backup phone system in St. Catharines. The two phone systems are configured to provide automatic failover in the event of loss of service at either site.

An investment of $400,000 is required in 2015 to complete this project.

Justification of Project: This planned lifecycle replacement of the Horizon Utilities' phone system is required to ensure critical call centre software, and the associated supporting hardware, are at vendor supported versions. The Horizon Utilities' phone system is a critical infrastructure component that is the primary method of communication with customers and as such, needs to be at vendor supported levels to maintain optimum customer service levels. The vendor will cease to support the current phone hardware system in 2016.

Additional Information: The following project Enterprise Phone System Upgrade exceeds Horizon Utilities' materiality threshold and is individually identified and justified in the Material Project Templates in Appendix G.

- Enterprise Phone System Upgrade

<u>Project ID: GP-9</u>

Project Name: John and Hughson Street Roof Replacement

Driver: General Plant

Scope: The rooves at the John Street and Hughson Street buildings have surpassed end-of-life and as per a roof assessment conducted by Garland Canada Inc. ("Roof Inspection Review") filed as Appendix N in the DSP, 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.

Justification:

Garland Canada concluded that the rooftops at each of the John Street building, Hughson Street building, Hughson Substation building, and parking garage. had reached end-of-life and were in poor condition.

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.

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 an RFP to obtain competitive pricing in accordance with Horizon Utilities' procurement practices as defined within its Procurement Policy.

Additional Information: The following project John Street Roof Replacement exceeds Horizon Utilities' materiality threshold and is individually identified and justified in the Material Project Templates in Appendix G.

- 2015 John St Building Roof Replacement

Project ID: GP-10

Project Name: Nebo Road Business Continuity

Driver: General Plant

Scope: This project covers the installation of a 300kW permanent backup generator at Nebo Road service center to allow the facility to function and operate independent of the electrical distribution grid during power outages.

An investment of $300,000 is required in 2015 to complete this project.

Justification: Nebo Road, Horizon Utilities' largest Service Center, supports all customers in the 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, and the dispatching of emergency crews and contractors was hampered. 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, who concluded that in order to safely connect a generator to power the Service Centre in the event of a power failure, Horizon Utilities would need to modify the existing switchgear and install an automatic transfer switch for the 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 forecasted at $300,000 in 2015.

Additional Information: The following project Nebo Road Business Continuity exceeds Horizon Utilities' materiality threshold and is individually identified and justified in the Material Project Templates in Appendix G.

- 2015 Nebo Road Business Continuity

2016 System Renewal Projects

<u>Project ID: SR-8</u>

Project Name: **Gage TS Egress Feeder Renewal**

Driver: System Renewal

Scope: The scope of this project involves the replacement of the egress cables at Gage TS to facilitate Hydro One Networks' renewal of the station. This investment forecast has been developed based on the preliminary plans provided by Hydro One as of February 25, 2014.

An investment of $4,793,000 in 2016 is required to complete this project.

Justification of Project: Gage TS is one of the oldest transformer stations within Hydro One's inventory and the oldest station in Horizon Utilities' service territory. This station services Horizon Utilities' two largest industrial customers, and has experienced a number of major equipment failures that have affected these customers. Hydro One has scheduled the renewal of Gage TS starting in 2015. This is a multi-year project for Hydro One, but Horizon Utilities portion of work is scheduled for 2016. This project involves moving 56 cables from their existing position to the new Hydro One bus structure that is being built approximately 210m away. A total of 11.7km of cable will be replaced.

A staged migration of cables from the old equipment to new equipment must occur in order to minimize the downtime of sensitive industrial Horizon customers connected to Gage TS. Additional civil duct work will be required due to constraints with the existing duct structure.

Additional Information: The following project within the Gage TS Egress Feeder Renewal Program exceeds Horizon Utilities materiality threshold and is individually identified and justified in the Material Project Templates in Appendix G.

- Gage TS Egress Feeder Renewal

2017 System Service Projects

Project ID: SS-5

Project Name: **Duct Structure – Elgin TS to King St.**

Driver: System Service

Scope: This project involves the installation of additional civil capacity to support 4kV renewal and address general load growth in the downtown Hamilton operating area.

An investment of $535,000 in 2017 is required to complete this project.

Justification of Project: Horizon Utilities does not have adequate civil infrastructure to create the feeder interties required to support the 4kV conversion and general load growth in the Hamilton Downtown area. The installation of these ducts runs along the border of Elgin TS and Stirton TS. This civil infrastructure will support the interconnections required between these stations to provide backup and reduce the impact of a major outage at either station.

Additional Information: The following project within the Duct Structure Program exceeds Horizon Utilities' materiality threshold and is individually identified and justified in the Material Project Templates in Appendix G.

- Duct Structure – Elgin TS to King St

2018 System Service Projects

Project ID: SS-6

Project Name: **East 16th and Mohawk Security Project**

Driver: System Service

Scope: A school, Seniors Centre, and other commercial buildings are on a 13.8kV radial circuit with no backup and are susceptible to long duration outages for repair in the event of a failure. Additional underground civil structures and underground cable are required to complete a loop feed to correct this deficiency and provide greater security.

An investment of $324,000 is required in 2018 to complete this project.

Justification of Project: A variety of commercial customers are fed from a 13.8kV radial line with no adjacent ties. The line directly feeding the school experienced a cable fault in 2011 which caused the school to be closed for two days until repairs were made. This presents an unacceptable risk to these critical customers.

Additional Information: This project exceeds the materiality threshold and is individually identified and justified in the Material Project Templates in Appendix G.

- East 16th and Mohawk Security Project

<u>Project ID: SS-7</u>

Project Name: **St. Paul Street Conductor Upgrade**

Driver: System Service

Scope: This project will upgrade the feeder capacity along St. Paul Street in St. Catharines and builds on the Vansickle TS upgrade completed in 2009.

An investment of $1,362,000 is required in 2018 to complete this project.

Justification of Project: Horizon Utilities requested additional feeders and capacity from Hydro One for Carlton TS in 2007. Horizon Utilities and Hydro One agreed that, due to difficulty and cost, the alternative of providing these feeders and capacity at Vansickle TS was the better option. 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. Hydro One also requested that due to the overloading at Carlton TS that load be transferred from Carlton TS to Vansickle TS. The upgrade was completed in 2010. Since then, Horizon Utilities has been completing projects to take advantage of the capacity and security of the upgraded Vansickle TS.

This project is required to alleviate a capacity constraint on the Vansickle M53 feeder ("VSM53") along St. Paul street by upgrading the conductor to full capacity. The VSM53 cannot properly support a load transfer from Carlton TS, without this upgrade.

The higher ampacity gained from upgrading this section of conductor would allow the VSM53 to back up the adjacent feeder. This would also improve overall system security as the VSM53 would be able to handle more load in a back-up scenario.

Additional Information: The following project within the Paul Street Conductor Program exceeds Horizon Utilities' materiality threshold and is individually identified and justified in the Material Project Templates in Appendix G.

- St. Paul St Conductor Upgrade

2019 System Service Projects

<u>Project ID: SS-8</u>

Project Name: **Grays Road**

Driver: System Service

Scope: Building a loop supply to customers currently on a radial feeder; these customers are a mix of commercial and residential and are on Grays Road north of the QEW.

This project requires an investment of $413,000 in 2019.

Justification of Project: Past security reviews have flagged this radial section as high risk for prolonged outages. The solution to this problem involves installing an intertie to a neighbouring feeder to create a loop feed to provide customers with proper backup supply in the event of an equipment failure. In 2013, the radial cable supplying this area had a failure and customers were without power for over 24 hours until repairs were made. The project has not been previously completed as the project could not be included within the approved budget envelopes and was displaced by higher priority projects.

Additional Information: The following project within the Grays Road Program exceeds Horizon Utilities materiality threshold and is individually identified and justified in the Material Project Templates in Appendix G.

- Security – Lake 141X Grays Rd

Project ID: SS-9

Project Name: **Mohawk/Nebo TS Upgrade**

Driver: System Service

Scope: Capacity increases at Mohawk TS or Nebo TS (13.8kV) to support customer growth in the central mountain area of Hamilton. The first payment in 2019 is estimated at $1,000,000 based on other TS upgrade projects.

Justification of Project: Long term load forecasts have projected capacity issues on the 13.8kV system fed from Mohawk TS and Nebo TS (13.8kV). Even with projecting a modest growth percentage, the busses at these TSs are encroaching on the 10-day LTR[2] limit. Horizon Utilities has discussed this project on several occasions with Hydro One regarding the need for review and assessment. Mohawk TS has passed the 10-day LTR for three out of the last four years. A capacity increase at either station will be required to alleviate the loading at the bus level. This project will be financed similarly to historical TS capacity upgrade projects (Vansickle TS and Nebo TS) in that its payment will be spread over multiple years.

Additional Information: The following project Mohawk/Nebo T/S Upgrade Program exceeds Horizon Utilities materiality threshold and is individually identified and justified in the Material Project Templates in Appendix G.

- Mohawk/Nebo TS Upgrade

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[2] The capacity of a Hydro One transformer at 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.

2019 General Plant Projects

<u>Project ID: GP-7</u>

Project Name: Building Renovations – Stoney Creek

Driver: General Plant

Scope: 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. The Stoney Creek Service Centre is a centralized training location for Horizon Utilities and a satellite office for Utility Operations.

The project will include the renovation of the locker, washroom, and shower space, and replace end-of-life plumbing, lighting, HVAC, and fire and life support systems. 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.

This project requires an investment of $1,200,000 in 2019.

Justification of Project:

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 Head Office and resolve compliance issues with fire codes and building codes for the Head Office and the Stoney Creek locations.

Additional Information: The following project - Stoney Creek Service Centre Renovations - exceeds Horizon Utilities materiality threshold and is individually identified and justified in the Material Project Templates in Appendix G.

- 2019 Facility Renovations – Stoney Creek

Appendix B – Kinectrics' 2013 Asset Condition Assessment

HORIZON UTILITIES
2013 Asset Condition Assessment

November 27, 2013

Kinectrics Inc.
800 Kipling Avenue
Toronto, ON
M8Z 6C4 Canada
www.kinectrics.com

DISCLAIMER

HORIZON UTILITIES
2013 ASSET CONDITION ASSESSMENT

Kinectrics Report: K-418442-RA-0001-R03

November 27, 2013

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Dated: 2013-11-27

To: Horizon Utilities
55 John Street North
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EXECUTIVE SUMMARY

Horizon Utilities determined a need to perform a condition assessment of its key distribution assets. Such an undertaking would result in a quantifiable evaluation of asset condition, aid in prioritizing and allocating sustainment resources, as well as facilitate further development of their Asset Management Plan.

In 2013, Horizon Utilities selected and engaged Kinectrics Inc. (Kinectrics) to perform an Asset Condition Assessment (ACA) on Horizon Utilities key distribution assets.

The assets were divided into 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

For each asset category, the ACA included the following tasks:

- Gathering relevant condition data
- Developing a Health Index Formula
- Calculating the Health Index for each asset
- Determining the Health Index distribution
- Developing a 20-year condition-based Flagged-For-Action Plan
- Recommending condition data availability improvements

This Asset Condition Assessment Report summarizes the methodology and approaches used in this project, and present the resulting findings and recommendations.

Asset Condition Assessment Methodology

The Asset Condition Assessment Methodology involves the process of determining asset Health Index, as well as developing a Condition-Based Flagged-For-Action Plan for each asset category.

Health Index

Health Indexing quantifies equipment condition based on numerous condition 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 condition data used in this study were obtained from Horizon Utilities and included the following:

- Asset Properties (e.g. age, asset type, location information)
- Test Results (e.g. Oil Quality, DGA)
- Horizon Utilities database, e.g. GIS database
- Expert opinion of Horizon Utilities technical staff

A Health Index was calculated for each asset with sufficient condition data. As well, in order to provide an effective overview of the condition of each asset category, the Health Index Distribution for each asset category was determined.

Condition-Based Flagged-For-Action Plan

Once the Health Indices 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 or have action plan developed for addressing their deteriorating condition in the next 20 years. The numbers of units were estimated using either a *reactive* or *proactive* approach.

For assets with a relatively small consequence of failure, units are generally replaced *reactively* or following a failure. The Flagged-For-Action Plan for such an approach is based on the asset group's failure rate. This approach incorporates the possibility that assets may fail prematurely, prior to their expected typical end of lives, or, conversely, may last longer than the typical end of life.

In the *proactive* approach, units are assumed to be replaced or refurbished to extend their original end of life prior to failure. For asset groups that fall under this approach, a risk assessment was used to determine the units to be considered for replacement. This process first establishes a relationship between asset Health Index and the corresponding probability of failure. Also involved was the quantification of asset criticality through the assignment of weights and scores to factors that impact consequence of failure. The combination of criticality and probability of failure determines risk and Flagged–For-Action priority for that unit. It is worth noting that for proactively replaced units replacement is not the only option: the appropriate actions could include refurbishment, modifying spares strategy, e.g. keeping a spare units ready if failure were to occur, installing real time monitoring devices with alarms indicating an imminent failure based on specific real time measurements, or "doing nothing" in some cases with low criticality and/or where replacement with larger units due to the system growth is planned in the near future.

Health Index Results

Figure 1 shows a graphical summary of the Health Index evaluation results. It is seen from the summary that based on their derived condition the assets with at least 20% of the units in "very poor" or "poor" condition are:

- substation circuit breakers
- substation switchgear
- overhead line switches
- underground XLPE primary, secondary and direct buried service cables
- vault transformers
- submersible LBD switches

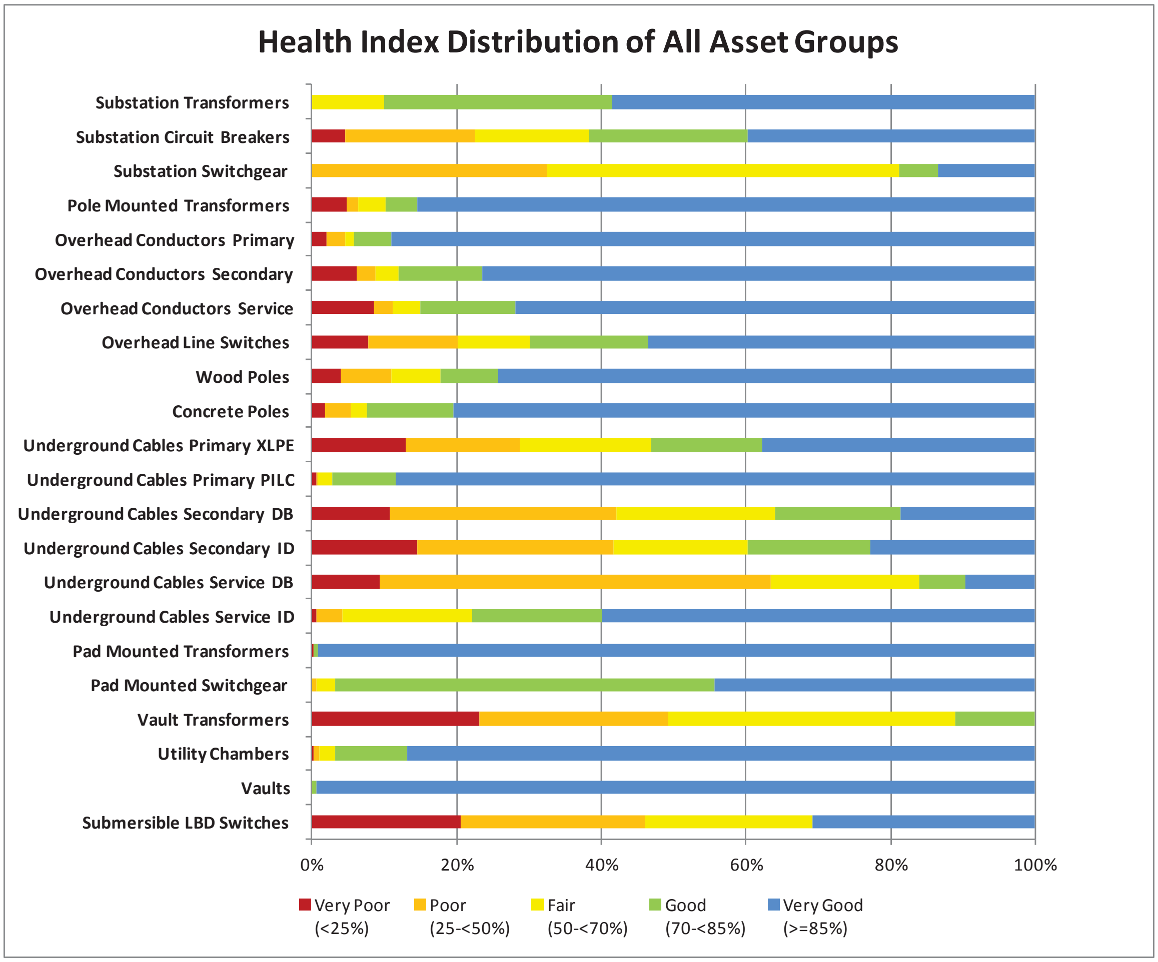

Figure 1 Visual Summary of Health Index Results

These assets represent a mix of proactively and reactively replaced assets and, therefore, the strategy of dealing with their overall condition degradation should be developed based on the most cost effective course of action for each asset category.

Condition Based Flagged-For-Action Plan

Table 1 shows the condition-based Flagged-For-Action Plan for the first year and the type of asset replacement strategy typically used for each asset group.

Horizon Utilities most significant replacements relative to the population size (5 % or more) in the year one are expected to be for substation circuit breakers, pole mounted transformers, overhead service conductors, primary underground XLPE cables, vault transformers, and submersible LBD switches.

Table 1 Year 1 Condition-Based Flagged-For-Action Plan

Asset	Sub-Category	Condition-Based Flagged-For-Action Plan for Year 1 [Number of Units]		Flagged-for-Action Percentage for Year 1	Primary Replacement Strategy
Substation Transformers	-	0		0%	proactive
Substation Circuit Breakers	-	16		6%	proactive
Substation Switchgear	-	1		3%	proactive
Pole Mounted Transformers	-	593		5%	reactive
Overhead Conductors	Primary	53 km		2%	reactive
	Secondary	86 km		4%	reactive
	Service	97 km		5%	reactive
Overhead Line Switches	-	31		4%	reactive
Wood Poles	-	1509		4%	reactive
Concrete Poles	-	97		1%	reactive
Underground Cables	Primary	XLPE	126 km	6%	reactive
		PILC	11 km	1%	reactive
	Secondary	DB	28 km	4%	reactive
		ID	21 km	4%	reactive
	Service	DB	20 km	4%	reactive
		ID	10 km	2%	reactive
Pad Mounted Transformers	-	17		0%	reactive
Pad Mounted Switchgear	-	3		2%	reactive
Vault Transformers	-	309		7%	reactive
Utility Chambers	-	12		1%	reactive
Vaults		6		0%	reactive
Submersible LBD Switches	-	14		12%	reactive

Data Assessment

In general, sufficient data and/or information were available for all the asset categories to develop a meaningful Health Index distribution.

Sufficient information and data were available for ACA study for all the three asset categories inside substations (namely substation transformers, substation circuit breakers and substation switchgear), as well as wood poles and pad mounted switchgear to develop a credible Health Index distribution.

Distribution transformers (pole mounted, pad mounted and vault transformers) in addition to their age had a count of occasions in 2011 and 2012 when their loading exceeded the nameplate rating: this information, which is rarely available in other utilities, was included in the calculation and resulted in identifying for replacement some specific units.

Wood pole testing data for 2011 and 2012 were incorporated in deriving their Health Index distribution.

For pad mounted switchgear and utility chambers age and available inspection records were used to determine Health Index distribution.

For the remaining asset categories age was the primary driver for determining Health Index distribution.

The main areas were efforts should be made to improve or maintain condition data availability is:

- Establish DGA trending by individual gases for substation transformers
- Start Partial Discharge (PD) testing for XLPE underground cable (scheduled to begin in 2014)

Conclusions and Recommendations

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.

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 existing data collection practices with some improvements as recommended in the Data Assessment section above.

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 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 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.

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.

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TABLE OF CONTENTS

TABLE OF TABLES

TABLE OF FIGURES

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I INTRODUCTION

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I Introduction

Horizon Utilities is a local distribution company that distributes electricity to over 240,000 customers in the City of Hamilton and St. Catharines.

Horizon Utilities is wholly-owned by Horizon Holdings Inc. ("HHI"). HHI is a holding company that is a subsidiary of Hamilton Utilities Corporation ("HUC"), which owns 78.9% of the common shares of HHI. HUC is wholly owned by the City of Hamilton. The remaining 21.1% of the common shares of HHI are owned by St. Catharines Hydro Inc. ("SCHI"). SCHI is wholly owned by the City of St. Catharines. Horizon Utilities activities, performance standards, and rates are regulated by the Ontario Energy Board.

Kinectrics Inc. (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.

In 2013, Horizon Utilities selected and engaged Kinectrics Inc. (Kinectrics) to perform an Asset Condition Assessment (ACA) on Horizon Utilities key distribution assets.

The Asset Condition Assessment Report summarizes the methodology, demonstrates specific approaches used in this project, and presents the resultant findings and recommendations.

I.1 Objective and Scope of Work

The assets in this study are categorized as follows:

- Substation Transformers
- Substation Circuit Breakers
- Substation Switchgear
- Pole Mounted Transformers
- Overhead Conductors
  - Primary
  - Secondary
  - Service
- Overhead Line Switches
- Wood Poles
- Concrete Poles
- Underground Primary Cables
  - Primary (XLPE, PILC)
  - Secondary (Direct Buried, In-Duct)
  - Service (Direct Buried, In-Duct)

- Pad Mounted Transformers
- Pad Mounted Switchgear
- Vault Transformers
- Utility Chambers
- Vaults
- Submersible LBD Switches

For each asset category, the ACA included the following tasks:

- Gathering relevant condition data
- Developing a Health Index Formula
- Calculating the Health Index for each asset
- Determining the Health Index distribution
- Developing a 20-year condition-based flagged-for-action plan
- Data assessment

I.2 **Deliverables**

The deliverables in this study include spread sheets containing all the calculations performed by Kinectrics and this Report that includes the following information:

- Description of methodology for condition assessment of Flagged-For-Action Plan (Section II)
- Data Assessment (Section III)
- Overall Results (Section IV)
- Conclusions and Recommendations (Section V)
- For each asset category the following are included (VI Appendix A: Results and Findings for Each Asset Category, sub-Sections 1-15):
    - Short description of the asset groups and a discussion of asset degradation and end-of-life issues
    - Age distribution
    - Health Index formulation
    - Health Index distribution
    - Condition-based Flagged-For-Action Plan
    - Data Assessment

II ASSET CONDITION ASSESSMENT METHODOLOGY

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II Asset Condition Assessment Methodology

The Asset Condition Assessment (ACA) Methodology involves the process of determining asset Health Index, as well as developing a Condition-Based Flagged-For-Action Plan for each asset group. The methods used are described in the subsequent sections.

II.1 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 an asset's end of life. The Health Index is an indicator of the asset's overall health and is typically given in terms of percentage, with 100% representing an asset in brand new condition. Health Indexing provides a measure of long-term degradation and thus differs from defect management, whose objective is finding defects and deficiencies that need correction or remediation in order to keep an asset operating prior to reaching its end of life.

Condition parameters are the asset characteristics or properties that are used to derive the Health Index. A condition parameter may be comprised of several sub-condition parameters. For example, a parameter called "Oil Quality" may be a composite of parameters such as "Moisture", "Acid", "Interfacial Tension", "Dielectric Strength" and "Colour".

In formulating a Health Index, condition parameters are ranked, through the assignment of *weights*, based on their contribution to asset degradation. The *condition parameter score* for a particular parameter is a numeric evaluation of an asset with respect to that parameter.

Health Index (HI), which is a function of scores and weightings, is therefore given by:

$$HI = \frac{\sum_{m=1}^{\forall m} \alpha_m (CPS_m \times WCP_m)}{\sum_{m=1}^{\forall m} \alpha_m (CPS_{m.\max} \times WCP_m)} \times DR \qquad \textbf{Equation 1}$$

where

$$CPS = \frac{\sum_{n=1}^{\forall n} \beta_n (CPF_n \times WCPF_n)}{\sum_{n=1}^{\forall n} \beta_n (WCPF_n)} \qquad \textbf{Equation 2}$$

CPS	Condition Parameter Score (0 to 4)
WCP	Weight of Condition Parameter
α_m, β_n	Data availability coefficient for condition parameter (=0 if data unavailable, =1 if data available)
CPF	Sub-Condition Parameter Score (0 to 4)
WCPF	Weight of Sub-Condition Parameter
DR	De-Rating Multiplier

The scale that is used to determine an asset's score for a particular parameter is called the *condition criteria*. For this project, a condition criteria scoring system of 0 through 4 is used. A score of 0 represents the worst score while 4 represents the best score. i.e. $CPS_{max} = 4$.

II.1.1 Health Index Example

Consider the asset class "Oil Circuit Breaker". The condition and sub-condition parameters, as well as their weights are shown on Table II-1.

Table II-1 Oil Circuit Breaker Condition and Sub-Condition Parameters

Health Index Formula for Oil Circuit Breakers			
Condition Parameters		**Sub-Condition Parameters**	
Name	**Weights (WCP)**	**Name**	**Weights (WCPF)**
Operating Mechanism	14	Lubrication	9
		Linkage	5
		Cabinet	2
Contact Performance	7	Closing Time	1
		Trip Time	3
		Contact Resistance	1
		Arcing Contact	1
Arc Extinction	9	Moisture	8
		Leakage	1
		Tank	2
		Oil Level	1
		Oil Quality	8
Insulation	2	Insulation	1
Service Record	5	Operating Counter	2
		Loading	2
		Age	1

Assume a parameter scoring system of 0 through 4, where 0 and 4 represent the "worst" and "best" scores respectively. The maximum score for any condition or sub-condition parameter (maximum CPS and CPF) is therefore "4".

Scores are determined using *condition criteria*. Each criterion defines the score of a particular parameter. Consider, for example, the age criteria given on Table II-2. An asset that is 35 years old will receive a score of "2" for "Age".

Table II-2 Age Criteria

Parameter Score	Condition Description
4	0-19
3	20-29
2	30-39
1	40-44
0	45+

Table II-3 shows a sample Health Index evaluation for a particular oil breaker. The sub-condition parameter scores (CPFs) shown are assumed values between 0 through 4.

The Condition Parameter Score (CPS) is evaluated as per Equation 2. The Health Index (HI) is calculated as per Equation 1. As no de-rating factors are defined, there is no multiplier for the final Health Index.

Table II-3 Sample Health Index Calculation

Condition Parameters	Operating Mechanism			Contact Performance			Arc Extinction			Insulation			Service Record		
Sub-Condition Parameters Scores (CPF) Weights (WCPF)	Sub-Condition Parameter	CPF	Weight (WCPF)	Sub-Condition Parameter	CPF	Weight (WCPF)	Sub-Condition Parameter	CPF	Weight (WCPF)	Sub-Condition Parameter	CPF	Weight (WCPF)	Sub-Condition Parameter	CPF	Weight (WCPF)
	Lubrication	4	9	Closing Time	2	1	Moisture	4	8	Insulation	4	1	Operating Counter	3	2
	Linkage	2	5	Trip Time	3	3	Leakage	3	1				Loading	4	2
	Cabinet	3	2	Contact Resistance	2	1	Tank	3	2				Age	3	1
				Arcing Contact	3	1	Oil Level	2	1						
							Oil Quality	3	8						
Condition Parameter Score (CPS)	Operating Mechanism CPS (4*9 + 2*5 + 3*2) / (9+5+2) = 3.25			Contact Performance CPS (2*1 + 3*3 + 2*1 + 3*1) / (1+3+1+1) = 2.67			Arc Extinction CPS (4*8 + 3*1 + 3*2 + 2*1 + 3*8) / (8+1+2+1+8) = 3.35			Insulation CPS (4*1) / (1) = 4			Service Record CPS (3*2 + 4*2 + 3*1) / (2+2+1) = 3.4		
Weights (WCP)	*Weight = 14*			*Weight = 7*			*Weight =9*			*Weight = 2*			*Weight = 5*		
Health Index (HI)	HI = (3.25*14 + 2.67*7 + 3.35*9 + 4*2 + 3.4*5) / ((14 + 7 + 9 + 2 + 5)*4) = **80.6%**														

II.1.2 Health Index Results

As stated previously, an asset's Health Index is given as a percentage, with 100% representing "as new" condition. The Health Index is calculated only if there is sufficient condition data. The subset of the population with sufficient data is called the *sample size*. Results are generally presented in terms of number of units and as a percentage of the sample size. If the sample size is sufficiently large and the units within the sample size are sufficiently random, the results may be extrapolated for the entire population.

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%

Note that for critical asset groups, such as Station Transformers, the Health Index of each individual unit is given.

II.2 **Condition-Based Replacement Methodology**

The Condition-Based Flagged-For-Action Plan outlines the number of units that are projected to be replaced in the next 20 years. The numbers of units are estimated using either a *proactive* or *reactive* approach. In the proactive approach, units are considered for replacement prior to failure, whereas the reactive approach is based on expected failures per year.

Both approaches consider asset failure rate and probability of failure. The failure rate is estimated using the method described in the subsequent section.

II.2.1 Failure Rate and Probability of Failure

Where failure rate data is not available, a frequency of failure that grows exponentially with age provides the best model. This is based on the Gompertz-Makeham law of mortality. The original form of the failure function is:

$$f = \gamma e^{\beta t}$$

Equation 3

f	= failure rate per unit time
t	= time
γ, β	= constant that control the shape of the curve

Depending on its application, there have been various forms derived from the original equation. Based on Kinectrics' expertise in failure rate study of multiple power system asset groups, the following variation of the failure rate formula is adopted:

$$f(t) = e^{\beta(t-\alpha)}$$

Equation 4

f	= failure rate of an asset (percent of failure per unit time)
t	= age (years)
α, β	= constant parameters that control the rise of the curve

The corresponding cumulative probability of failure function (thereafter referred to as probability of failure) is therefore:

$$P_f(t) = 1 - e^{-(f - e^{-\alpha\beta})/\beta}$$

Equation 5

P_f = probability of failure

Different asset groups experience different failure rates and therefore different probabilities of failure. As such, the shapes of the failure and probability curves are different. The parameters α and β are used to control the location and steepness of the exponential rise of these curves. For each asset group, the values of these constant parameters were selected to reflect typical useful lives for these assets.

Consider, for example, an asset class where at the ages of 25 and 65 the asset has probabilities of failure of 10% and 99% respectively. It follows that when using Equation 5, α and β are calculated as 74 and 0.093 respectively. As such, for this asset class the probability of failure equation is:

$$P_f(t) = 1 - e^{-(e^{\beta(t-\alpha)} - e^{\alpha\beta})/\beta} \; = \; 1 - e^{-(e^{0.093(t-74)} - e^{-6.882})/0.093}$$

The failure rate and probability of failure graphs are as shown:

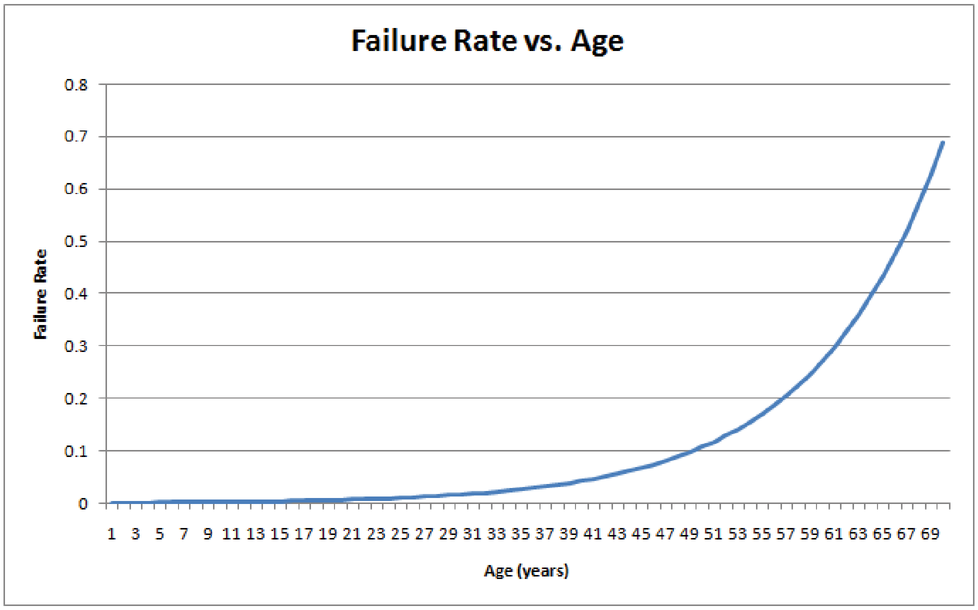

Figure II-1 Failure Rate vs. Age

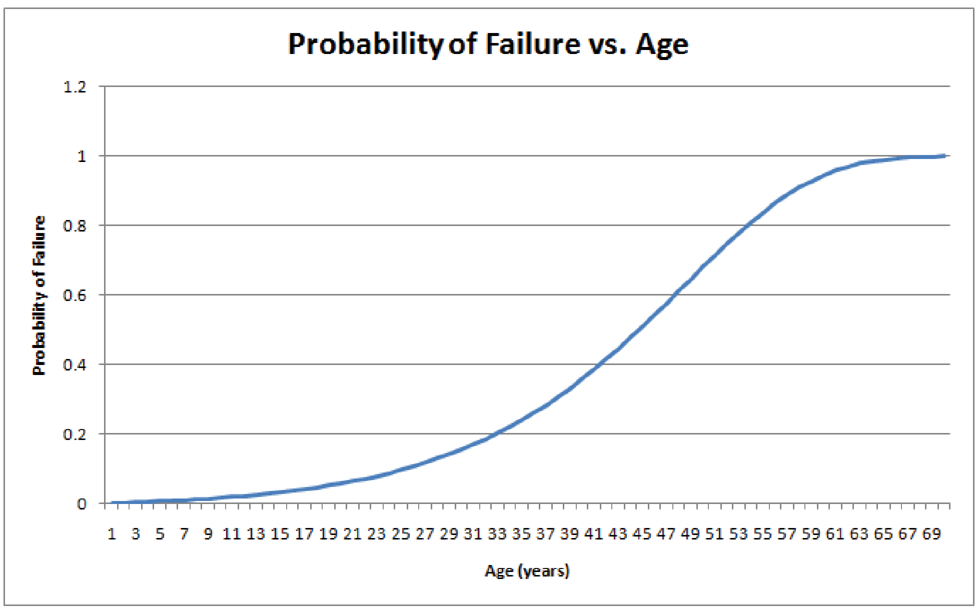

Figure II-2 Probability of Failure vs. Age

II.2.2 Projected Flagged-For-Action Plan Using a Reactive Approach

Because their consequences of failure are relatively small, many types of distribution assets are reactively replaced.

For such asset types, the number of units expected to be replaced in a given year are determined based on the asset's failure rates. The number of failures per year is given by Equation 4:

$$f(t) = e^{\beta(t-\alpha)}$$

with α and β determined from the probability of failure of each asset class.

An example of such a Flagged-For-Action Plan is as follows: Consider an asset distribution of 100 - 5 year old units, 20 – 10 year old units, and 50 - 20 year old units. Assume that the failure rates for 5, 10, and 20 year old units for this asset class are f_5 = 0.02, f_{10} = 0.05, f_{20} = 0.1 failures / year respectively. In the current year, the total number of replacements is 100(.02) + 20(0.05) + 50(0.1) = 2 + 1 + 5 = 8.

In the following year, the expected asset distribution is, as a result, as follows: 8 – 1 year old units, 98 – 6 year old units, 19 – 11 year old units, and 45 - 21 year old units. The number of replacements in year 2 is therefore 8(f_1) + 19(f_6) + 45(f_{11}) + 45(f_{21}).

Note that in this study the “age” used is in fact “effective age, or condition-based age where available, as opposed to the chronological age of the asset.

II.2.3 Projected Flagged-For-Action Plan Using a Proactive Approach

For certain asset classes, the consequence of asset failure is significant, and, as such, these assets are proactively replaced prior to failure. The proactive replacement methodology involves relating an asset's Health Index to its probability of failure by considering the stresses to which it is exposed.

Relating Health Index and Probability of Failure

Failure of an asset occurs when the stress to which an asset is exposed exceeds its strength. Assuming that stress is not constant, and that stress is normally distributed, the probability of stress exceeding asset strength leads to the probability of failure. This is illustrated in the figure below. A vertical line represents condition or strength (Health Index) and the area under the curve to the right of the Health Index line represents the probability of failure.

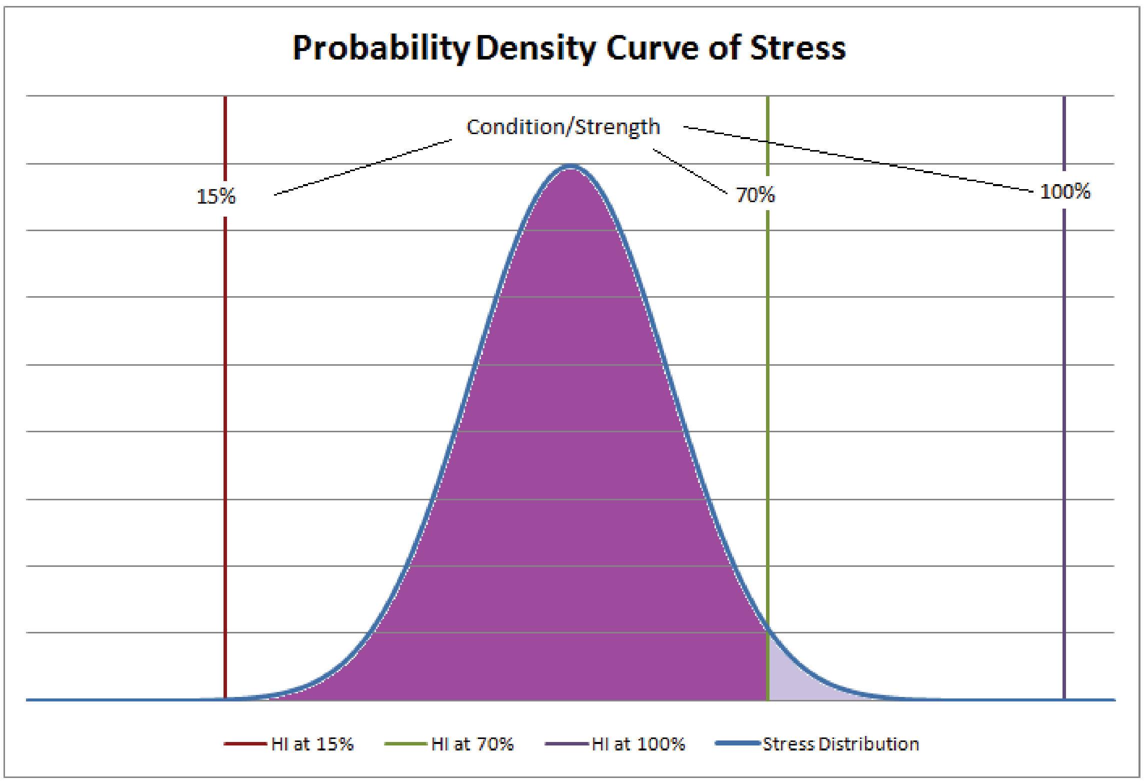

Figure II-3 Stress Curve

Two points of Health Index and probability of failure are needed to generate the probability of failure at other Health Index values. A Health Index of 100% represents an asset that is in brand new condition and a Health Index of 15% represents the asset's end of life. The 100% and 15% conditions are plotted on the stress curve by finding the points at which the areas under the stress curve are equal to $P_{f\ 100\%}$(age at 100% Health Index) and $P_{f\ 15\%}$ = P_f(age at 15% Health Index). By moving the vertical line left from 100% to 15%, the probabilities of failure for other Health Indices can be found.

The probability of failure at a particular Health Index is found from plotting the Health Index on the X-axis and the area under the probability density curve to the right of the Health Index line on the Y-axis as shown on the graph of the figure below.

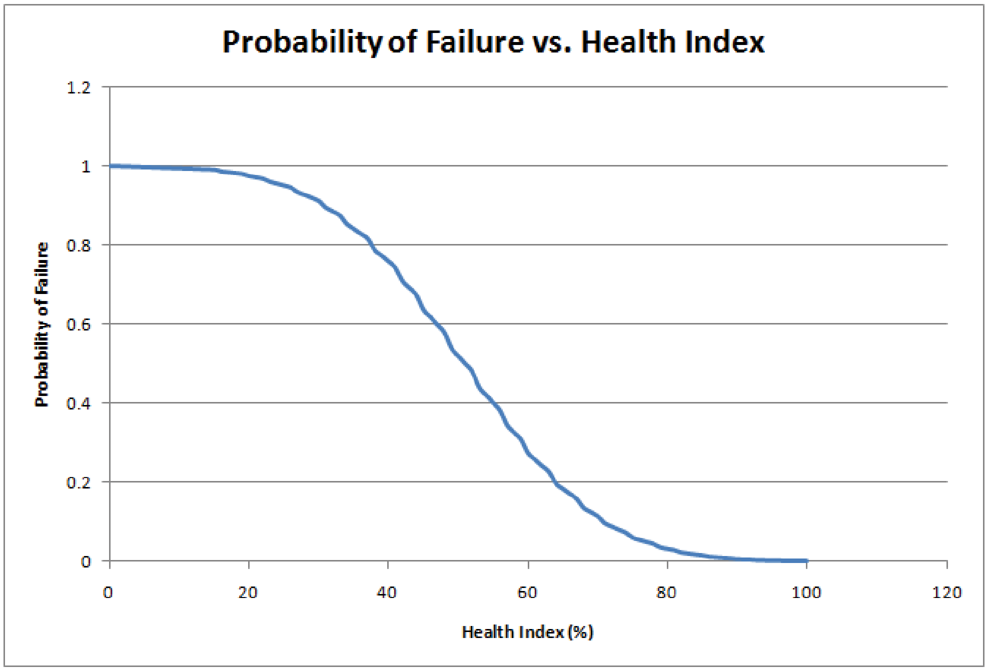

Figure II-4 Probability of Failure vs. Health Index

Relating Health Index to Effective Age

Once the relationship between probability of failure and Health Index has been found, the "effective age" of an asset can be determined. The "effective age" is different from chronological age in that it is based on the asset's condition and the stresses that are applied to the asset.

The probability of failure associated with a specific Health Index can be found using the Probability of Failure vs. Health Index (Figure II-4) and Probability of Failure vs. Age (Figure II-2). The probability of failure at a particular Health Index can be found from Figure II-4. The same probability of failure is located on Figure II-2, and the effective age is on the horizontal axis of Figure II-2. See example on the Figure II-5 below where a Health Index of 60% corresponds to an effective age of 35 years.

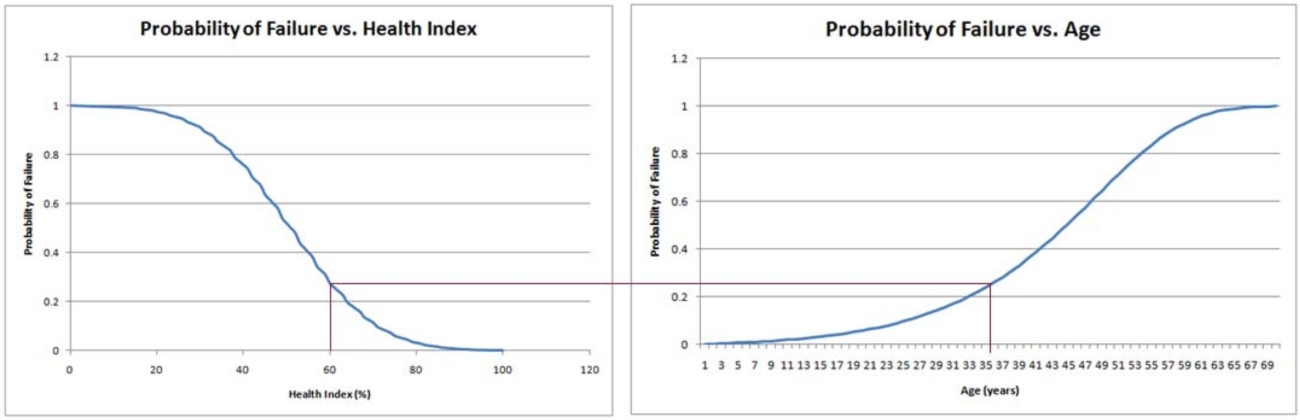

Figure II-5 Effective Age

<u>Condition-Based Flagged-For-Action Plan</u>

In order to develop a Flagged-For-Action Plan, the risk of failure of each unit must be quantified. Risk is the product of a unit's probability of failure and its consequence of failure.

The probability of failure is determined by an asset's Health Index. In this study, the metric used to measure consequence of failure is referred to as *criticality*.

Criticality may be determined in numerous ways, with monetary consequence or degree of risk to corporate business values being examples. For Substation Transformers, factors that impact criticality may include things like number of customers or location. The higher the criticality value assigned to a unit, the higher is it's consequence of failure.

It is assumed in this study that each asset group has a base criticality value, Criticality_{min}. The individual units in the asset group are assigned Criticalities that are multiples of Criticality_{min}. A unit becomes a candidate for replacement when its risk value, the product of its probability of failure and criticality, is greater than or equal to 1.

In the example shown below, Asset 1 and Asset 2 are candidates for replacement.

Table II-4 Sample Replacement Ranking

Asset Name	Age	Health Index (HI)	Consequence of Failure (Criticality)	Probability of Failure (POF) Corresponding to HI	Risk (POF*Criticality)	Replacement Ranking
Asset 1	41	30.00%	2	82.5%	1.630	1
Asset 2	29	30.00%	1.5	82.5%	1.237	2
Asset 3	37	30.00%	1	78.20%	0.782	3
Asset 4	42	50.00%	2	12.80%	0.256	4
Asset 5	18	50.00%	1.5	12.80%	0.192	5
Asset 6	20	50.00%	1	12.80%	0.128	6

II.3 Flagged-For-Action Plan

For *proactively* replaced assets, the Condition-Based Flagged-For-Action Plan considers assets for replacement once their probability of failure becomes equal to or exceeds 80%. Assets are then Flagged-For-Action in a year when their Risk Score which is calculated as a product of probability of failure times criticality exceeds 1.1875 (1.1875 value represents Risk Score for an asset with a $Criticality_{min}$ of 1.25 and probability of failure equal to 95% assumed to be the maximum acceptable probability of failure). Assets are automatically Flagged-For-Action when their probability of failure is equal to or exceeds 95%, regardless of their criticality.

For *reactively* replaced assets, the Condition-Based Flagged-For-Action Plan is determined by the probability of failure curves.

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III DATA ASSESSMENT

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III Data Assessment

The condition data used in this study were obtained from Horizon Utilities and included the following:

- Asset Properties (e.g. age, equipment ID, location information)
- Test Results (e.g. Oil Quality, DGA, wood pole testing)
- Distribution transformers overloading records
- Expert opinion of Horizon Utilities technical staff

For each asset category general description of what types of data/information were used is provided. When warranted, recommendation is also in included on what steps could be taken to improve ant existing data availability.

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IV RESULTS

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IV Results

This section summarizes the findings of this study.

Health Index Results

A summary of the Health Index evaluation results is shown in Table IV-1. The population and sample size, or number of assets with sufficient data for Health Indexing, are given (for underground cable asset categories population sizes for subsets of the population are shown in the "Sample Size" column, i.e. XLPE and PILC for primary cables, and direct buried and in-duct for secondary and service cables). For each asset category the Health Index Distribution, total number in "Poor" and "Very Poor" condition, and average age are shown.

It can be seen from the results that:

1. For substation asset groups, substation transformers are in good shape. Substation circuit breakers and switchgear are in adequate shape, except that a small portion of breakers need immediate action.

2. 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 estimated 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.

3. For asset groups associated with underground system, primary XLPE cables, underground secondary 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, pad mounted transformers and service in-duct cables is fairly good, a sustained investment over the next 20 years is required to maintain their overall condition at the existing level.

More specifically, the results show that based on their derived condition the assets with at least 20% of the units in "poor" or "very poor" condition are:

- substation switchgear
- overhead line switches
- underground XLPE primary, secondary and direct buried service cables
- vault transformers
- submersible LBD switches

Condition Based Flagged-For-Action Plan

Table IV-2 shows the 20 year Flagged-For-Action Plan.

Once the Health Indices 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 20 years. The numbers of units were estimated using either a *reactive* or *proactive* approach. Table IV-2 also shows average annual replacement cost for each of the asset categories.

For assets with a relatively small consequence of failure, units are generally replaced *reactively* or on failure. The Flagged-For-Action Plan for such an approach is based on the asset group's failure rate. This approach incorporates the possibility that assets may fail prematurely, prior to their expected typical end of lives, or, conversely, may last longer than the typical end of life.

In the *proactive* approach, units are assumed to be replaced or refurbished to extend their original end of life prior to failure. For asset groups that fall under this approach, a Risk Assessment study was conducted to determine the units to be considered for replacement. This process first establishes a relationship between asset Health Index and the corresponding probability of failure. Also involved was the quantification of asset criticality through the assignment of weights and scores to factors that impact consequence of failure. The combination of criticality and probability of failure determines risk and Flagged–For-Action priority for that unit. It is worth noting that for proactively replaced units replacement is not the only option: the appropriate actions could include refurbishment, modifying spares strategy, e.g. keeping a spare units ready if failure were to occur, installing real time monitoring devices with alarms indicating an imminent failure based on specific real time measurements, or "doing nothing" in some cases with low criticality and/or where replacement with larger units due to the system growth is planned in the near future.

It is important to note that the Flagged-For-Action Plan suggested in this study is based solely on asset condition. It uses a probabilistic, non-deterministic, approach and as such can only show expected failures or probable number of units for replacement. While the Condition-Based Flagged-For-Action Plan can be used as a guide or input to Horizon Utilities' Replacement Plan, it is not expected to be followed directly or being used as the final deciding factor in making decisions regarding sustainment capital expenditures. There are numerous other factors and considerations that will influence Horizon Utilities' asset management decisions, such as obsolescence, municipal initiatives, distribution system growth, etc.

Horizon Utilities most significant expected replacements relative to the population size (5% or more) in the year one are expected to be for substation circuit breakers, pole mounted transformers, overhead service conductors, primary underground XLPE cables, vault transformers and submersible LBD switches.

Table IV-1 Health Index Results Summary

Asset		Sub-Category	Population	Health Index Distribution (Units)					Total of Poor and Very Poor (Units)
				Very Poor (< 25%)	Poor (25 - <50%)	Fair (50 - <70%)	Good (70 - <85%)	Very Good (≥85%)	
Substation Transformers		-	70	0	0	7	22	41	0
Substation Circuit Breakers		-	279	13	50	44	61	111	63
Substation Switchgear		-	37	0	12	18	2	5	12
Pole Mounted Transformers		-	12886	616	198	489	571	11012	814
Overhead Conductors (in km)		Primary	3386	65	90	40	173	3016	156
		Secondary	2196	135	56	74	254	1677	191
		Service	1901	164	50	70	248	1365	214
Overhead Line Switches		-	712	55	89	70	116	381	144
Wood Poles		-	42036	1723	2876	2836	3424	31176	4599
Concrete Poles			9761	171	354	214	1167	7855	525
Underground Cables (in km)	XLPE	Primary	3593	269	323	375	313	780	592
	PILC			9	3	30	133	1356	13
	DB	Secondary	1290	82	236	166	132	140	318
	ID			77	145	98	91	121	223
	DB	Service	1035	42	241	92	29	43	283
	ID			3	22	106	105	353	25
Pad Mounted Transformers		-	5906	8	0	8	33	5857	8
Pad Mounted Switchgear		-	186	0	1	5	97	82	1
Vault Transformers		-	4169	966	1089	1657	457	0	2055
Utility Chambers		-	2075	4	18	44	207	1802	22
Vaults		-	3413	0	0	2	16	3383	0
Submersible LBD Switches		-	117	24	30	27	0	36	54

Table IV-2 Twenty Year Condition Based Flagged-For-Action Plan

Asset	Sub-Category		Total Population	Avg. Annual Replacement Cost ($000s)	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	$ 37.50	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	1	0	1	0	2
Substation Circuit Breakers	-		279	$ 200.25	16	0	10	0	11	0	9	0	17	0	7	0	0	0	0	9	1	0	0	9
Substation Switchgear	-		37	$ 975.00	1	0	1	1	4	0	0	4	2	4	0	4	1	4	0	0	0	0	0	0
Pole Mounted Transformers	-		12886	$ 1,939.21	593	277	232	218	215	217	220	223	226	228	229	229	230	230	231	234	238	244	252	262
Overhead Conductors	Primary		3386	$ 1,480.86	53	45	40	37	34	32	31	30	29	30	30	31	32	32	32	33	33	33	33	34
	Secondar		2196	$ 1,747.96	86	63	52	44	40	38	38	38	39	39	39	39	39	39	38	37	36	34	33	32
	Service		1897	$ 1,677.46	97	69	54	44	39	36	35	36	36	36	36	36	36	35	34	33	32	30	28	27
Overhead Line Switches	-		711	$ 262.31	31	26	23	22	20	20	19	18	19	18	18	18	17	17	17	17	16	17	17	17
Wood Poles	-		42037	$ 3,628.76	1509	1103	1011	967	935	905	876	845	814	782	752	724	699	678	662	648	637	627	619	611
Concrete Poles	-		9761	$ 550.25	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	$ 8,637.10	126	103	96	91	88	85	83	80	78	76	74	72	71	70	69	68	67	66	66	66
		PILC	1532	$ 4,190.48	11	11	12	12	12	13	14	14	15	16	17	18	19	20	20	21	22	23	24	25
	Sec.	DB	757	$ 3,240.93	28	28	28	27	27	27	27	27	26	26	26	26	25	25	25	25	24	24	24	24
		ID	533	$ 454.19	21	21	21	20	20	19	19	19	18	18	18	18	17	17	17	17	17	16	16	16
	Serv.	DB	446	$ 2,192.03	20	20	20	19	19	19	19	18	18	18	18	17	17	17	16	16	16	15	15	15
		ID	588	$ 319.59	10	11	11	11	11	12	12	12	13	13	13	13	14	14	14	14	14	15	15	15
Pad Mounted Transformers	-		5893	$ 937.53	17	17	20	23	27	31	36	41	47	53	59	65	70	75	79	83	87	92	98	105
Pad Mounted Switchgear	-		186	$ 192.50	3	3	3	3	3	3	3	3	3	3	3	4	4	4	4	4	4	4	4	5
Vault Transformers	-		4169	$ 1,448.22	309	294	282	270	260	250	240	230	221	212	203	194	186	178	170	162	156	150	144	139
Utility Chambers	-		2075	$ 389.60	12	13	13	14	15	15	16	17	17	18	19	20	20	21	22	23	23	24	25	26
Vaults	-		3413	$ 97.91	6	7	7	7	8	8	9	10	10	11	12	12	13	14	15	16	17	18	19	20
Submersible LBD Switches	-		117	$ 33.60	14	8	7	6	5	5	5	4	4	4	3	3	3	3	2	2	2	2	2	3

Data Assessment Results

In general, sufficient data and/or information were available for all the asset categories to develop a meaningful Health Index distribution, in fact for distribution transformers (pole mounted, pad mounted and vault) overloading information typically not available at other utilities was provided by Horizon Utilities.

Sufficient information and data were available for ACA study for all the three asset groups inside substations (namely substation transformers, substation circuit breakers and substation switchgear), as well as wood poles and pad mounted switchgear to develop a credible Health Index distribution.

Distribution transformers (pole mounted, pad mounted and vault transformers) in addition to their age had a count of occasions in 2011 and 2012 when their loading exceeded the nameplate rating. This information is used together with age as the condition parameters in health index calculation.

Wood pole testing data for 2011 and 2012 were incorporated in deriving their Health Index distribution.

For pad mounted switchgear and utility chambers, age and available inspection records were used to determine Health Index distribution.

For the remaining asset categories age was the primary driver for determining Health Index distribution.

The main areas were efforts should be made to improve or maintain condition data availability is:

- Establish DGA trending by individual gases for substation transformers
- Start Partial Discharge (PD) testing for XLPE underground cable (schedule to begin in 2014)
- Continue with tracking occasions when distribution transformers loading exceeds their nameplate rating

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V CONCLUSIONS AND RECOMMENDATIONS

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V Conclusions and Recommendations

1. 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.

2. 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 with the existing data collection practices with some improvements as recommended in the Data Assessment section above.

3. For substation asset groups, substation transformers are in good shape. Substation circuit breakers and switchgear are in adequate shape, except that a small portion of breakers need immediate action.

4. 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 their overall condition at the existing level.

5. 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, pad mounted transformers and service in-duct cables is fairly good, a sustained investment over the next 20 years is required to maintain their overall condition at the existing level.

6. There are a number of legacy units that need to be dealt with in order to at least sustain the existing level of reliability, particularly in the following asset categories:

   - distribution transformers, pole mounted and vault
   - primary, secondary and service overhead conductors
   - overhead line switches
   - wood poles
   - primary XLPE underground cables
   - vault transformers
   - submersible load break switches

7. It is recommended to put in place asset specific program to not only address improving the overall condition of these asset categories but also to maintain existing overall condition level for the remaining asset categories. Not doing so will results in deteriorating reliability performance, taking unnecessary risks associated with failures of assets with significant consequence off 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 and if a long-term investment strategy put in place at this time.

8. 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.

9. It is recommended that Horizon Utilities look into implementing an IT solution that will allow them to integrate data and information from different existing data sources, will improve field data collection and storage, will be fully integrated with the work execution process, and will enable automated periodic updating of the ACA results based on the new condition data and/or modified Health Index formulations.

VI APPENDIX A: RESULTS AND FINDINGS FOR EACH ASSET CATEGORY

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1 Substation Transformers

While substation power transformers can be employed in either step-up or step-down mode, a majority of the applications in distribution stations involve step down of the transmission or sub-transmission voltage to distribution voltage levels. Power transformers vary in capacity and ratings over a broad range. There are two general classifications of power transformers: transmission station transformers and distribution station transformers. For distribution stations, power transformer ratings typically range from 3 MVA to 30 MVA. The units included in this study range from 3 MVA to 10 MVA.

Power transformers employ many different design configurations, but they are typically made up of the following main components:

- Primary and secondary windings
- Laminated iron core
- Internal insulating mediums
- Main tank
- Bushings
- Cooling system, including radiators, fans and pumps (Optional)
- Off load tap changer (Optional)
- On load tap changer (Optional)
- Instrument transformers
- Control mechanism cabinets
- Instruments and gauges

The primary and secondary windings are installed on a laminated iron core and serve as the coils in which electromotive force is produced when alternating magnetic flux passing through the core links with the windings. The internal insulating mediums provide insulation for energized coils. Insulating oil serves as the insulating medium as well as serves as the coolant. Due to its low cost, high dielectric strength, excellent heat-transfer characteristics, and ability to recover after dielectric overstress, mineral oil is the most widely used transformer insulating material. The transformer coil insulation is reinforced with different forms of solid insulation that include wood-based paperboard (pressboard), wrapped paper and insulating tapes. Because the dielectric strength of oil is approximately half that of the pressboard, the dielectric stress in the oil ends up being higher than that in the pressboard, and the design structure is usually limited by the stress in the oil. The insulation on the conductors of the winding may be enamel or wrapped paper which is either wood or nylon based. The use of insulation directly on the conductor actually inhibits the formation of potentially harmful streamers in the oil, thereby increasing the strength of the structure. Heavy paper wrapping is also usually used on the leads coming from the windings.

The main tank holds the active components of the transformer in an oil volume and maintains a sealed environment through the normal variations of temperature and pressure. Typically, the main tank is designed to withstand a full vacuum for initial and subsequent oil fillings and is able to sustain a positive pressure. The main tank also supports the internal and external components of the transformers. Main tank designs can be classified into 2 types: those being conservator type or sealed type. Conservator types have an externally-mounted tank that usually holds 10% of the main tank's volume. As the transformer oil expands and contracts due to system loading and ambient changes, the corresponding oil volume change must be accommodated. This tank is used to provide a holding mechanism for the expansion and contraction of the main tank's oil over these temperature variations. The liquid seal also provides some protection against moisture ingress into the insulation systems. A sealed tank design incorporates a gas header on top of the oil volume using nitrogen or dry air. This gas header can be either in a positive pressure or vacuum mode depending on the system loading or ambient changes. The pressure and vacuum conditions of a sealed tank design are controlled by the use of a regulator that ensures the tank is within its design limits.

Bushings are used to facilitate the egress of conductors to connect ends of the coils to a power supply system in an insulated, sealed (oil-tight and weather-tight) manner. A bushing is typically composed of an outer porcelain body mounted on a metallic flange. The phase leads are either independent paper-insulated or are an integral part of the bushing. At higher voltage levels, additional insulation is incorporated in the form of mineral oil and/or wound paper leads installed within the porcelain column.

The purpose of a cooling system in a power transformer is to efficiently dissipate heat generated due to copper and iron losses and to help maintain the windings and insulation temperature within acceptable range. The utilization of a number of cooling stages allows for an increase in load carrying capability. Loss of any stage or cooling element may result in a forced de-rating of the transformer. Transformer cooling system ratings are typically expressed as:

- Self-cooled (radiators) with designation as ONAN (oil natural, air natural)
- Forced cooling first stage (fans) with designation as ONAF (oil natural, air forced)
- Forced cooling second stage (fans and pumps) with designation as OFAF (oil forced, air forced)

An off-load tap changer allows the transformer turns ratio to be altered over a small range to effect changes in output voltage as required. An off-load tap changer typically allows for an adjustment of 5% above nominal and 5% below nominal voltage in 2 ½ % steps. An off-load tap changer must only be operated with the transformer off potential. Under-load tap changers (ULTCs) allow for automatic voltage regulation in response to varying load conditions on the line. ULTCs consist of moving mechanical parts, a drive motor, linkages and voltage regulation sensing equipment. Instrument transformers include CT's and PTs for metering or control purposes. Power transformers are equipped with externally-mounted control cabinets for voltage and current control relay(s), secondary control circuits, and in some cases the tap changer motor and position indicators.

From the view of both financial and operational risk, power transformers are the most important asset deployed on the distribution and transmission systems. A significant proportion of power transformers employed by North American utilities were installed in the 1950s, 1960s or early 1970s. Despite the fact that the number of transformer failures arising due to End-of-Life (EOL) has to-date been relatively small, there is awareness that a majority of the transformer population will soon be reaching its end-of-life, which may significantly impact transformer failure rates.

1.1 Substation Transformers Degradation Mechanism

For a majority of transformers, EOL is expected to be spelled by the failure of insulation system and more specifically the failure of pressboard and paper insulation. While the insulating oil can be treated or changed, it is not practical to change the paper and pressboard insulation. The condition and degradation of the insulating oil, however, plays a significant role in aging and deterioration of transformer, as it directly influences the speed of degradation of the paper insulation. The degradation of oil and paper in service in transformers is essentially an oxidation process. The three important factors that impact the rate of oxidation of oil and paper insulation are presence of oxygen, high temperature and moisture.

Transformer oil is made up of complex hydrocarbon compounds, containing anti-oxidation compounds. Despite the presence of oxidation inhibitors, oxidation occurs slowly under normal operating conditions. The rate of oxidation is a function of internal operating temperature and age. The oxidation rate increases as the oil ages, reflecting both the depletion of the oxidation inhibitors and the catalytic effect of the oxidation products on the oxidation reactions. The products of oxidation of hydrocarbons are moisture, which causes further deterioration of the insulation system and organic acids, which result in formation of solids in the form of sludge. Increasing acidity and water levels result in the oil being more aggressive with regard to the paper and hence accelerate the ageing of the paper insulation. Formation of sludge adversely impacts the cooling capability of the transformer and adversely impacts its dielectric strength. An indication of the condition of insulating oil can be obtained through measurements of its acidity, moisture content and breakdown strength.

The paper insulation consists of long cellulose chains. As the paper ages through oxidization, these chains are broken. The tensile strength and ductility of insulting paper are determined by the average length of the cellulose chains; therefore, as the paper oxidizes the tensile strength and ductility are significantly reduced and insulating paper becomes brittle. The average length of the cellulose chains can be determined by measurement of the degree of polymerization (DP). However, this test can be performed only after de-tanking or the core and coil and therefore, is not a practical test. For a new transformer the DP value of the paper is normally greater than 1,000. As the paper ages this figure gradually decreases. When the DP value approaches below 250, the paper is in a very brittle and fragile condition. The lack of mechanical strength of paper insulation can result in failure if the transformer is subjected to mechanical shocks that may be experienced during normal operational situations.

In addition to the general oxidation of the paper, degradation and failure can also result from partial discharge (PD). PD can be initiated if the level of moisture is allowed to develop in the paper or if there are other minor defects within active areas of the transformer.
The relative levels of carbon dioxide and carbon monoxide dissolved in oil can provide an indication of paper degradation. Detection and measurement of Furans in the oil provides a more direct measure of the paper degradation. Furans are a group of chemicals that are created as a bi-product of the oxidation process of the cellulose chains. The occurrence of partial discharge and other electrical and thermal faults in the transformer can be detected and monitored by measurement of hydrocarbon gases in the oil through Dissolved Gas Analysis (DGA).

Oil analysis is such a powerful diagnostic and condition assessment technique that combining it with background information related to the specification, operating history, loading conditions and system-related issues of a transformer provides a very effective means of assessing condition and helps to identify units at high risk of failure. It is the ideal platform on which to base an ongoing management strategy for aging transformers. The analysis helps to identify units that warrant consideration for continued use, makes consideration of remedial measures to extend life and identifies transformers that should be considered for replacement within a defined time frame.

Other condition assessment techniques for power transformers include the use of online monitors capable of monitoring specific parameters, e.g. dissolved gas monitors, continuous moisture measurement or temperature monitoring, winding continuity checks, DC insulation resistance measurements and no load loss measurements. Dielectric measurements that attempt to give an indication of the condition of the insulation system include dielectric loss, dielectric spectroscopy, polarization index and recovery voltage measurements. Doble testing is a procedure that falls within this general group. Other techniques that are commonly applied to transformers include infrared surveys, partial discharge detection and location using ultrasonic and/or electromagnetic detection and frequency response analysis.

Under-load tap changers are prone to failures resulting from either mechanical or electrical degradation. Active maintenance is required for tap changers in order to manage these issues. It is normal practice to maintain tap changers either at a fixed time interval or after a number of operations. During operation, wear of contacts and buildup of oil degradation products, resulting from arcing activity during make and break of contacts, are the primary degradation processes. Maintenance, cleaning/replacement of contacts, defective components in the mechanism and changing/reprocessing of oil are the primary maintenance activities that deal with these issues. Oil analysis for tap changers is considered less useful than oil analysis for transformers due to the generation of gases and general degradation of the oil during arcing under normal ULTC operation.

There are a number of contributory factors to the long life of transformers. In the 1950s and 1960s transformers were designed and manufactured conservatively such that the thermal and electrical stresses, even at high load, were relatively low compared to modern designs. In addition, the loading of many of these transformers has been relatively light during their working life.

Consequences of power transformer failure include customer interruptions over significantly long durations. Catastrophic failure of a transformer may also result in injury or death, fire and damage to property. There are also environmental risks due to oil spills during tank failures. These risks are more pronounced where transformers are located near water bodies or contain PCBs.

1.2 Substation Transformers Health Index Formulation

This section presents the Health Index Formula that was developed and used for Horizon Utilities Substation Transformers. The Health Index equation is shown in Section II.1; the condition, sub-condition parameters, weights, and condition criteria are as follows.

Assume a parameter scoring system of 0 through 4, where 0 and 4 represent the "worst" and "best" scores respectively. Thus, the maximum score for any condition or sub-condition parameter (maximum CPS and CPF) is "4".

1.2.1 Substation Transformers Condition and Sub-Condition Parameters

Table 1-1 Condition Weights and Maximum CPS

m	Condition parameter	WCP_m	CPS Lookup Table
1	Insulation	6	Table 1-2
2	Cooling	1	Table 1-3
3	Sealing & connection	3	Table 1-4
4	Service Record	3	Table 1-5

Table 1-2 Insulation (m=1) Weights and Maximum CPF

n	Sub-Condition Parameter	CPF Lookup table	$WCPF_n$	$CPF_{n.max}$
1	Oil Quality	Table 1-6	1	4
2	Oil DGA	Table 1-7	2	4
3	Bushings	Table 1-8	1	4

Table 1-3 Cooling (m=2) Weights and Maximum CPF

n	Sub-Condition Parameter	CPF Lookup table	$WCPF_n$	$CPF_{n.max}$
1	Cooling Fan	Table 1-8	1	4
2	Cooling Radiators	Table 1-8	2	4

Table 1-4 Sealing & Connection (m=3) Weights and Maximum CPF

n	Sub-Condition Parameter	CPF Lookup table	$WCPF_n$	$CPF_{n.max}$
1	Tank/Conservator	Table 1-8	2	4
2	Gauges	Table 1-8	2	4
3	Oil Leaks	Table 1-8	5	4
4	Silica Gel	Table 1-8	2	4

Table 1-5 Service Record (m=4) Weights and Maximum CPF

n	Sub-Condition Parameter	CPF Lookup table	$WCPF_n$	$CPF_{n.max}$
1	Performance Record	Table 1-8	1	4
2	Age	Figure 1-1	3	4

1.2.2 Substation Transformers Condition Parameter Criteria

<u>**Oil Quality**</u>

Table 1-6 Oil Quality Test Criteria

CPF	Description
4	Overall factor is less than 1.2
3	Overall factor between 1.2 and 1.5
2	Overall factor is between 1.5 and 2.0
1	Overall factor is between 2.0 and 3.0
0	Overall factor is greater than 3.0

Where the Overall factor is the weighted average of the following gas scores:

Oil Quality Test	Voltage Class [kV]	Scores				
		1	2	3	4	Weight
Water Content (D1533) [ppm]	V ≤ 69	< 30	30-35	35-40	> 40	5
	69 < V < 230	< 20	20-25	25-30	> 35	
	V ≥ 230	< 15	15-20	20-25	> 25	
Dielectric Strength (D1816 - 2 mm gap) [kV]	V ≤ 69	> 40	35-40	30-35	< 30	4
	69 < V < 230	> 47	42-47	35-42	< 35	
	V ≥ 230	> 50	50-45	40-45	< 40	
Dielectric Strength (D877) [kV]	All	> 40	30-40	20-30	< 20	
IFT (D971) [dynes/cm]	V ≤ 69	> 25	20-25	15-20	< 15	4
	69 < V < 230	> 30	23-30	18-23	< 18	
	V ≥ 230	> 32	25-32	20-25	< 20	
Color	All	< 1.5	1.5-2.0	2.0-2.5	> 2.5	1
Acid Number (D974) [mg KOH/g]	V ≤ 69	< 0.05	0.05-0.01	0.1-0.2	> 0.2	4
	69 < V < 230	< 0.04	0.04-0.1	0.1-0.15	> 0.15	

Oil Quality Test	Voltage Class [kV]	Scores				
		1	2	3	4	Weight
	$V \geq 230$	< 0.03	0.03-0.07	0.07-0.1	> 0.1	
Dissipation Factor (D924 - 25^{0}C)	All	< 0.5%	0.5%-1%	1-2%	> 2%	5
Dissipation Factor (D924 - 100^{0}C)	All	< 5%	5%-10%	10%-20%	> 20%	

Overall Factor = $\dfrac{\sum Score_i \times Weight_i}{\sum Weight}$

For example if all data is available, overall Factor = $\dfrac{\sum Score_i \times Weight_i}{12}$

Oil DGA

Table 1-7 Oil DGA Criteria

CPF	Description
4	DGA overall factor is less than 1.2
3	DGA overall factor between 1.2 and 1.5
2	DGA overall factor is between 1.5 and 2.0
1	DGA overall factor is between 2.0 and 3.0
0	DGA overall factor is greater than 3.0

*In the case of a score other than 4, check the variation rate of DGA parameters. If the maximum variation rate (among all the parameters) is greater than 30% for the latest 3 samplings or 20% for the latest 5 samplings, overall Health Index is multiplied by 0.9 for score 3, 0.85 for score 2, 0.75 for score 1 and 0.5 for score 0 where the DGA overall factor is the weighted average of the following gas scores:

2.5 MVA to 10 MVA

Dissolved Gas	Scores						
	1	2	3	4	5	6	Weight
H2	<=70	<=100	<=200	<=400	<=1000	>1000	**4**
CH4(Methane)	<=70	<=120	<=200	<=400	<=600	>600	**3**
C2H6(Ethane)	<=75	<=100	<=150	<=250	<=500	>500	**3**
C2H4(Ethylene)	<=60	<=100	<=150	<=250	<=500	>500	**3**
C2H2(Acetylene)	<=3	<=7	<=35	<=50	<=100	>100	**5**
CO2/CO	3 to 10	<=10to 12	<=12 to 15	15 to 18	18 to 20	>20	**4**

Overall Factor = $\dfrac{\sum Score_i \times Weight_i}{\sum Weight}$

Age

Assume that the failure rate for Substation Transformers exponentially increases with age and that the failure rate equation is as follows:

$$f = e^{\beta(t-\alpha)}$$

f	= failure rate of an asset (percent of failure per unit time)
t	= time
α, β	= constant parameters that control the rise of the curve

The corresponding survivor function is therefore:

$$S_f = 1 - \ P_f = e^{-(f-e^{-\alpha\beta})/\beta}$$

S_f	= survivor function
P_f	= probability of failure

Assuming that at the ages of 45 and 60 years the probability of failures (P_f) for this asset are 20% and 85% respectively results in the survival curve shown below. It follows that the CPF for Age is the survival curve normalized to the maximum CPF score of 4 (i.e. 4*Survival Curve). The CPF vs. Age is also shown in the figure below.

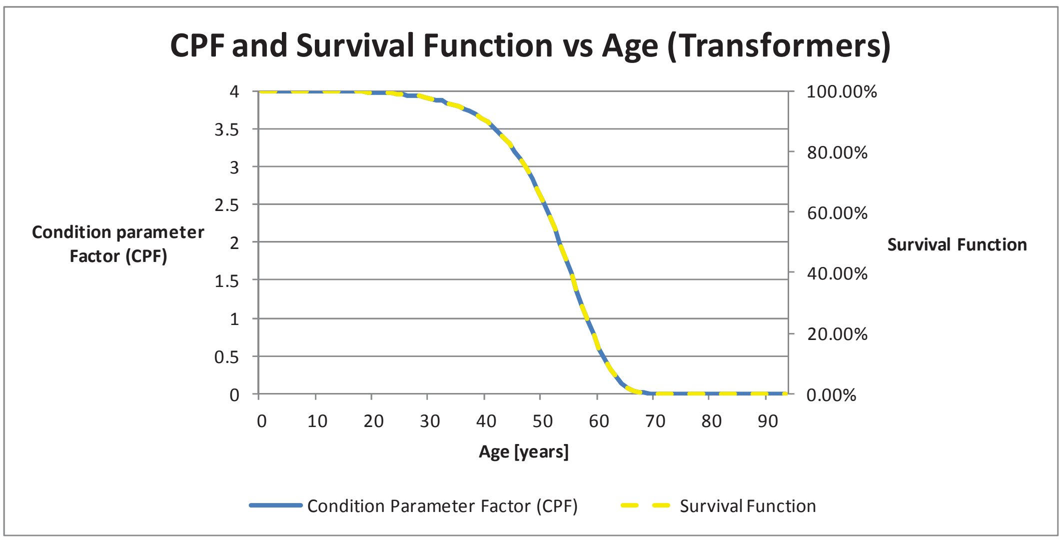

Figure 1-1 Substation Transformers Age Condition Criteria

Station Inspections

Table 1-8 Inspection Condition Criteria

CPF	Condition Description (Horizon Grading)
4	Good
2	Fair
0	Poor

1.3 Substation Transformers Age Distribution

The age distribution is shown in the figure below. Age was available for 100% of the population. The average age was found to be 44 years.

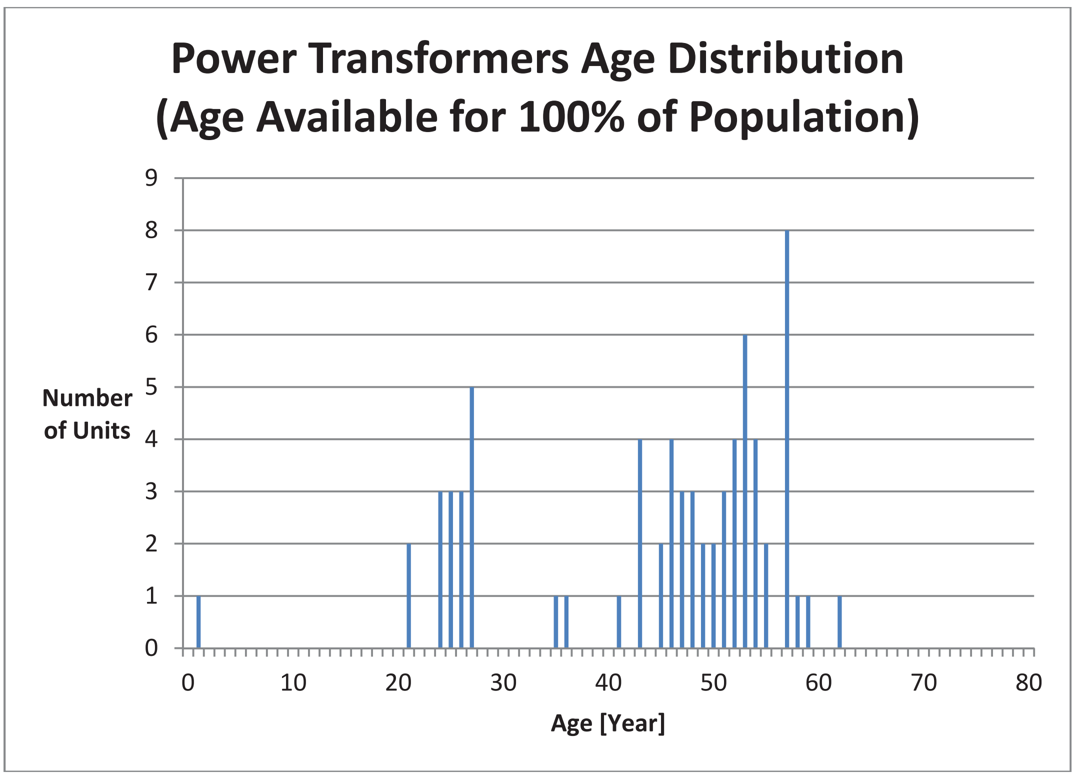

Figure 1-2 Substation Transformers Age Distribution

1.4 Substation Transformers Health Index Results

There are 70 in-service Substation Transformers at Horizon Utilities. Of these, 70 units had sufficient data for assessment.

The average Health Index for this asset group is 86%. None of the units were found to be in poor condition.

The Health Index Distribution is shown in Figure 1-3 and Figure 1-4.

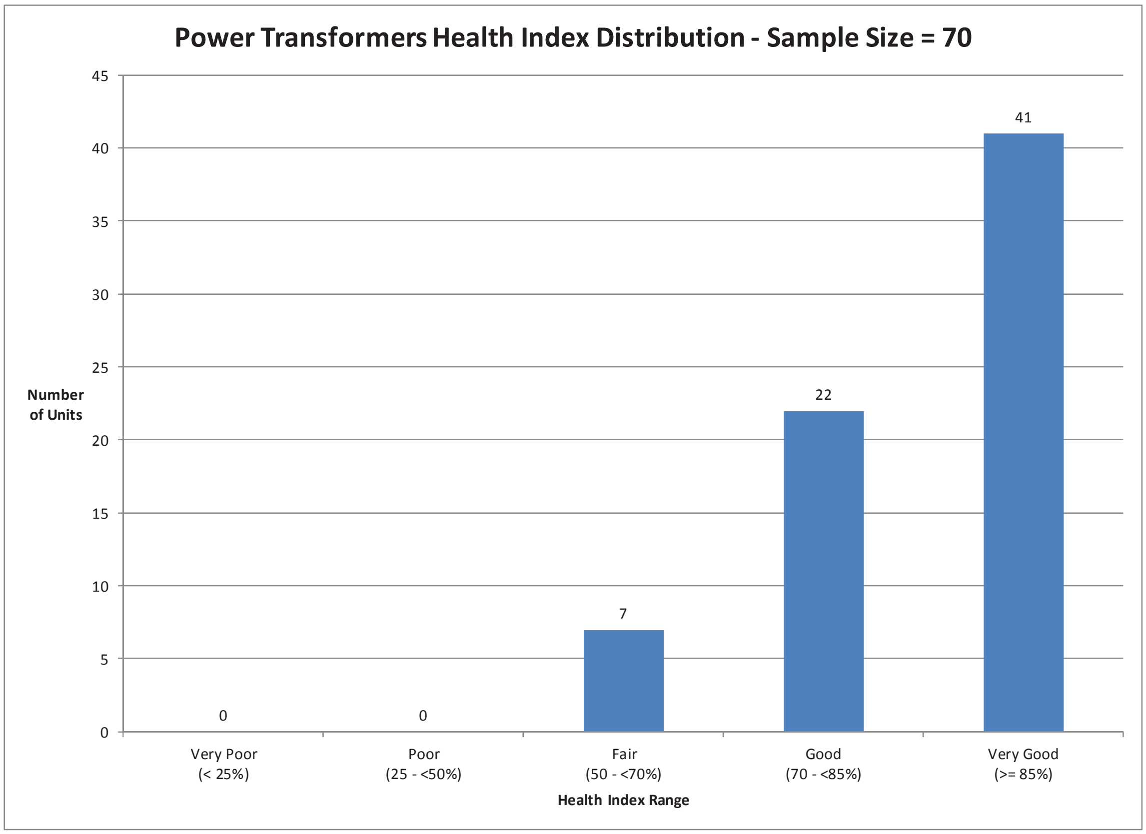

Figure 1-3 Substation Transformers Health Index Distribution (Number of Units)

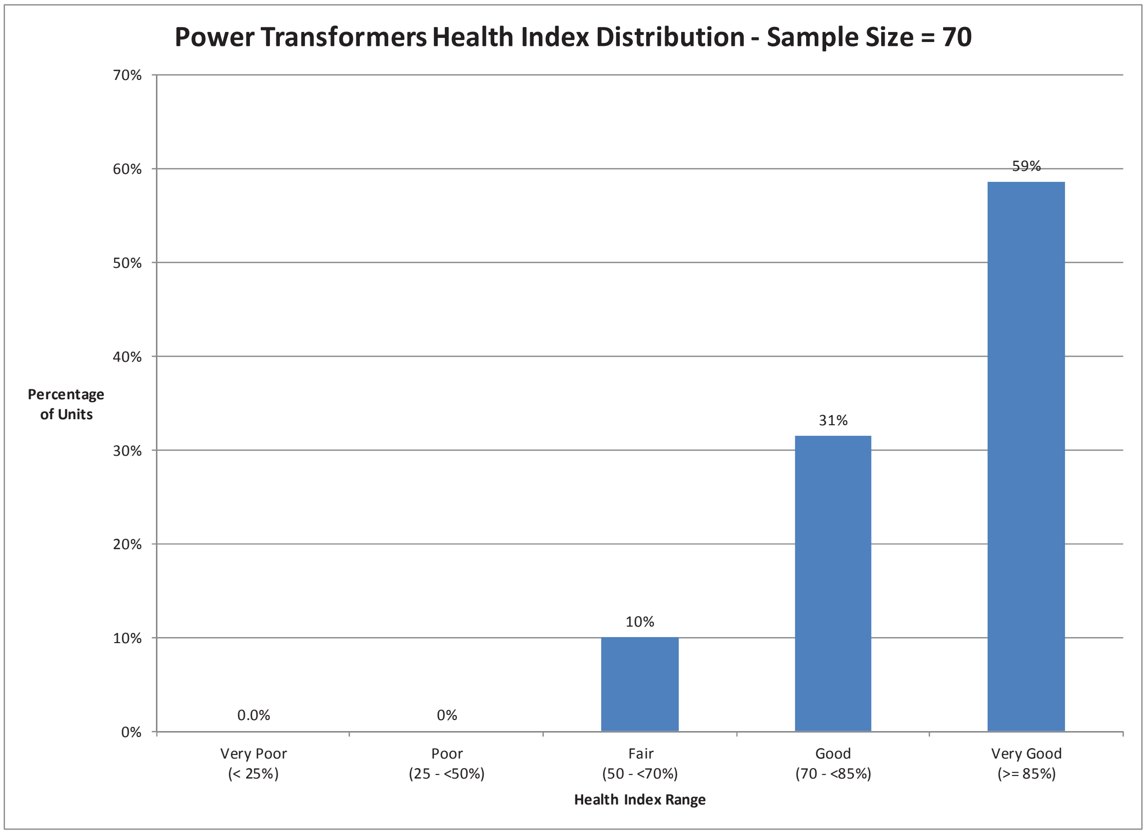

Figure 1-4 Substation Transformers Health Index Distribution (Percentage of Units)

The detailed results, from lowest to highest Health Index are shown in section VII.

1.5 Substation Transformers Condition-Based Flagged-For-Action Plan

As it is assumed that Substation Transformers are proactively replaced, the risk assessment and replacement procedure described in Section II.2.3 was applied for this asset class.

As noted in Section II.2.3, a unit becomes a candidate for replacement when its risk, product of its *probability of failure* and *criticality*, is greater than or equal to a calculated risk limit. The probability of failure is as determined by the Health Index. Criticality is determined as shown in the following section.

1.5.1 Substation Transformers Criticality

The minimum criticality, $Criticality_{min}$, is 1.25. . The maximum criticality, $Criticality_{max,}$ is twice the base criticality ($Criticality_{max,}$ = 1.25*2 = 2.5).

Each unit's criticality is defined as follows:

$$Criticality = (Criticality_{max} – Criticality_{min})*Criticality\_Multiple + Criticality_{min}$$

where the Criticality_Multiple (CM) is defined by criticality factors, weights, and scores:

$$CM = \frac{\sum_{CF=1}^{\forall CF} (CFS_{CF} \times WCF_{CF})}{\sum_{CF=1}^{\forall CF} (WCF_{CF})}$$

Where

CFS	Criticality Factor Score
WCF	Weight of Condition Factor

The factors, weights and the score system of each factor are as follows:

Table 1-9 Criticality Factors

Criticality Factor (CF)	Description	Weight (WCF)	Score (CFS)	
Load criticality	--- Number of customers --- Customer importance (e.g. hospitals, provincial buildings, restoration time sensitive customers)	30	Low	0
			High	1
Physical Protection	oil containment, blast wall, deluge system	15	Yes	0
			No	1
Location	public exposure, environmental impact	15	No	0
			Yes	1
Expected Outage Duration	Back-up unit unavailable, alternate feeds unavailable	20	No	0
			Yes	1
Operation & Maintenance	--- obsolescence of spare parts (e.g. manufacturers cease to produce old types of spare parts) --- known issues (e.g. not economical to have routine maintenance)	20	No	0
			Yes	1

1.5.2 Substation Transformers Flagged-For-Action Plan

The following diagram shows the flagged for action plan in the next 20 years.

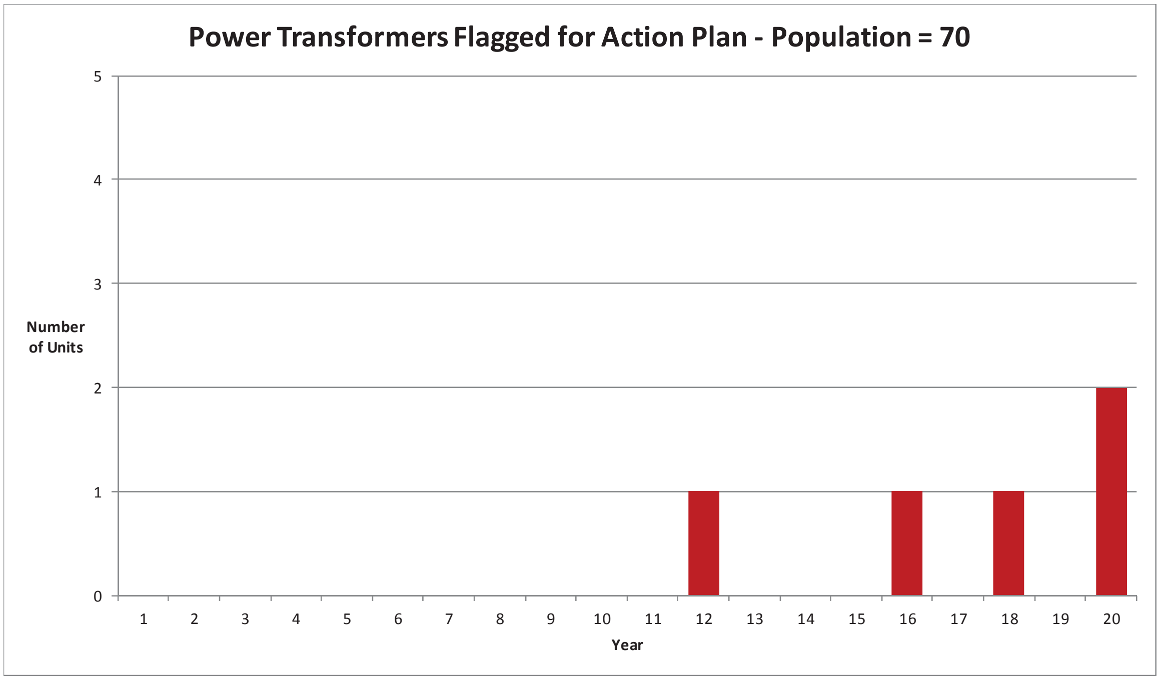

Figure 1-5 Substation Transformers Condition-Based Flagged-For-Action Plan

1.6 Substation Transformers Data Analysis

The data available for Substation Transformers includes age, routine inspection results, oil quality, dissolved gas analysis (DGA), and third party inspection records.

Horizon Utilities should start collecting DGA data for individual gases in order to be able to establish the rate of increase in them which, in addition to the absolute values of gasses in oil, serves as a good indicator of transformer's insulation condition. This will also allow Horizon Utilities to modify formulation and flag-for-action units where only quantities of some specific gases have shown a higher than acceptable rate of increase.

2 Substation Circuit Breakers

Circuit breakers used in transmission and distribution power systems to sectionalize and isolate circuits are often categorized by the insulation medium used in the breaker and the interruption process. The common breaker types include oil circuit breakers, air circuit breakers, vacuum circuit breakers, and SF6 circuit breakers.

Oil circuit breakers (OCB) have been in use for over 70 years. OCBs interrupt current under oil and use the gas generated by the decomposition of the oil to assist in arc extinguishing. They are available in single or multi-tank configurations. Two types of designs exist among OCBs: bulk oil breakers (in which oil serves as the insulating and arc quenching medium), and minimum oil breakers (in which oil provides the arc quenching function only). OCBs are available from 25kV class and up, with continuous currents up to 1200A and interrupting capacities up to 40kA.

Air insulated breakers are generally used at distribution system voltages and below. Air-type circuit breakers fall into two classifications: air- blast and air- magnetic. Air-blast breakers use compressed air as the quenching, insulating and actuating mechanism. In a typical device a blast of air carries the arc into an arc chute to be extinguished. Air blast breakers at distribution voltages are often in metal-enclosed switchgear. Continuous current ratings of these devices are in the range of 1200 to 5000 A, and fault interrupting from 20 to 140kA.

Air magnetic breakers use the magnetic effect of the current undergoing interruption to draw an arc into an arc chute for cooling, splitting and extinction. Sometimes, an auxiliary puffer or air blast piston may help interrupt low-level currents. These designs are commonly used in metal-clad switchgear applications. Air magnetic breakers are available in voltages ratings up to 15kV, with continuous currents up to 3000A, and interrupting ratings as high as 40 kA. These breakers are relatively inexpensive and relatively easy to maintain. The air magnetic breakers have short duty cycles, require frequent maintenance and approach their end-of-life at much faster rates than either SF6 or vacuum breakers. They also have limited transient recovery voltage capabilities and can experience re-strike when switching capacitive currents.

In vacuum breakers, the parting contacts are placed in an evacuated chamber (i.e. bottle). There is generally one fixed and one moving contact in a butting configuration. A bellows attached to the moving contact permits the required short stroke to occur while maintaining the vacuum. Arc interruption occurs at current zero after withdrawal of the moving contact. Utilities typically install vacuum breakers indoors in metal-clad switchgear. Current medium voltage vacuum breakers require low mechanical drive energy, have high endurance, can interrupt fully rated short circuits up to 100 times, and operate reliably over 30,000 or more switching operations. Vacuum breakers also are safe and protective of the environment.

SF6 Circuit breakers were first developed in the late 1960s and based on air blast technology. SF6 breakers interrupt currents by opening a blast valve and allowing high pressure SF6 to flow through a nozzle along the arc drawn between fixed and moving contacts. This process rapidly deionizes, cools and interrupts the arc. After interruption, low-pressure gas is compressed for re-use in the next operation.

2.1 Substation Circuit Breakers Degradation Mechanism

In general, circuit breakers have many moving parts that are subject to wear and stress. They frequently “make” and “break” high currents and experience the erosion caused by arcing accompanying these operations. All circuit breakers undergo some contact degradation every time they open to interrupt an arc. Also, arcing produces heat and decomposition products that degrade surrounding insulation materials, nozzles, and interrupter chambers. The mechanical energy needed for the high contact velocities of these assets adds mechanical deterioration to their degradation processes.

The rate and severity of degradation depends on many factors, including insulating and conducting materials, operating environments, and a breaker’s specific duties. Outdoor circuit breakers may experience adverse environmental conditions that influence their rate and severity of degradation. For outdoor mounted circuit breakers, the following represent additional degradation factors:

- Corrosion
- Effects of moisture
- Bushing/insulator deterioration
- Mechanical

Corrosion and moisture commonly cause degradation of internal insulation, breaker performance mechanisms, and major components like bushings, structural components, and oil seals. Corrosion presents problems for almost all circuit breakers, irrespective of their location or housing material. Rates of corrosion degradation, however, vary depending on exposure to environmental elements. Underside tank corrosion causes problem in many types of breakers, particularly those with steel tanks. Another widespread problem involves corrosion of operating mechanism linkages that result in eventual link seizures. Corrosion also causes damage to metal flanges, bushing hardware and support insulators.

Moisture causes degradation of the insulating system. Outdoor circuit breakers experience moisture ingress through defective seals, gaskets, pressure relief and venting devices. Moisture in the interrupter tank can lead to general degradation of internal components. Also, sometimes free water collects in tank bottoms, creating potential catastrophic failure conditions.

For circuit breakers, mechanical degradation presents greater end-of-life concerns than electrical degradation. Generally, operating mechanisms, bearings, linkages, and drive rods represent components that experience most mechanical degradation problems. Oil leakage also occurs. Contacts, nozzles, and highly stressed components can also experience electrical-related degradation and deterioration. Other effects that arise with aging include:

- Loose primary and grounding connections
- Oil contamination and/or leakage
- Deterioration of concrete foundation affecting stability of breaker

For OCBs, the interruption of load and fault currents involves the reaction of high pressure with large volumes of hydrogen gas and other arc decomposition products. Thus, both contacts and oil degrade more rapidly in OCBs than they do in vacuum designs, especially when the OCB undergoes frequent switching operations. Generally, 4 to 8 fault interruptions with contact erosion and oil carbonization will lead to the need maintenance, including oil filtration. Oil breakers can also experience restrike when switching low load or line charging currents with high recovery voltage values. Sometimes this can lead to catastrophic breaker failures.

The diagnostic tests to assess the condition of circuit breakers include:

- Visual inspections
- Travel time tests
- Contact resistance measurements
- Bushing - Doble Test
- Stored energy tests (Air/Hydraulic/Spring Recharge Time)
- Insulating medium tests

As indicated above, the useful life of circuit breakers can vary significantly depending on the duty cycle and typically lies within a broad range of 25 to 50 years.

In some cases, the end of life for circuit breakers may not be governed by technical considerations but rather by operational, maintenance and obsolescence issues. The International Council on Large Electric Systems' (CIGRE) has identified the following factors that lead to end-of-life for this asset class:

- Decreasing reliability, availability and maintainability
- High maintenance and operating costs
- Changes in operating conditions, rendering the existing asset obsolete;
- Maintenance overhaul requirements; and

Consequences of circuit breaker failure may be significant as they can directly lead to catastrophic failure of the protected equipment, leading to customer interruptions, health and safety consequences and adverse environmental impacts.

2.2 Substation Circuit Breakers Health Index Formula

This section presents the Health Index Formula that was developed and used for Horizon Utilites' Circuit Breakers. The Health Index equation is shown in Section II.1; the condition, sub-condition parameters, weights, and condition criteria are as follows.

Assume a parameter scoring system of 0 through 4, where 0 and 4 represent the "worst" and "best" scores respectively. Thus, the maximum score for any condition or sub-condition parameter (maximum CPS and CPF) is "4".

2.2.1 Substation Circuit Breakers Condition and Sub-Condition Parameters

Table 2-1 Substation Circuit Breakers Condition Weights and Maximum CPS

m	Condition parameter	WCP_m		CPS Lookup Table
		Oil	Air	
1	Contact performance	7	7	Table 2-2
2	Arc extinction	9	5	Table 2-3
3	Service Record	5	5	Table 2-4
	Derating Factor	As a multiplier for overall HI		Table 2-6

Table 2-2 Substation Circuit Breakers Contact Performance (m=1) Weights and Maximum CPF

n	Sub-Condition Parameter	CPF lookup table	$WCPF_n$	$CPF_{n.max}$
1	Primary contact	Table 2-5	1	4
2	Trip coil	Table 2-5	2	4
3	Contact Resistance	Table 2-5	1	4

Table 2-3 Substation Circuit Breakers Arc Extinction (m=2) Weights and Maximum CPF

n	Sub-Condition Parameter	CPF lookup table	$WCPF_n$		$CPF_{n.max}$
			Oil	Air	
1	Tank	Table 2-5	1	1	4
3	Arc chute	Table 2-5	2	2	4
4	Oil condition	Table 2-5	4		4

Table 2-4 Substation Circuit Breakers Service Record (m=3) Weights and Maximum CPF

n	Sub-Condition Parameter	CPF lookup table	$WCPF_n$	$CPF_{n.max}$
1	CB operation	Table 2-5	2	4
2	CB performance record	Table 2-5	1	4
3	Age	Figure 2-1	1	4

2.2.2 Substation Circuit Breakers Condition Parameter Criteria

Station Inspections

Table 2-5 Substation Circuit Breakers Inspection Condition Criteria

CPF	Condition Description (Horizon Grading)
4	Good
2	Fair
0	Poor

Age

Assume that the failure rate for circuit breakers exponentially increases with age and that the failure rate equation is as follows:

$$f = e^{\beta(t-\alpha)}$$

f = failure rate of an asset (percent of failure per unit time)
t = time
α, β = constant parameters that control the rise of the curve

The corresponding survivor function is therefore:

$$S_f = 1 - \ P_f = e^{-(f-e^{-\alpha\beta})/\beta}$$

S_f = survivor function
P_f = probability of failure

Assuming that at the ages of 45 and 60 years the probabilities of failure (P_f) are 20% and 85% result in the survival curves shown below. It follows that the CPF for Age is the survival curve normalized to the maximum CPF score of 4 (i.e. 4*Survival Curve). The CPF vs. Age is also shown in the figure below.

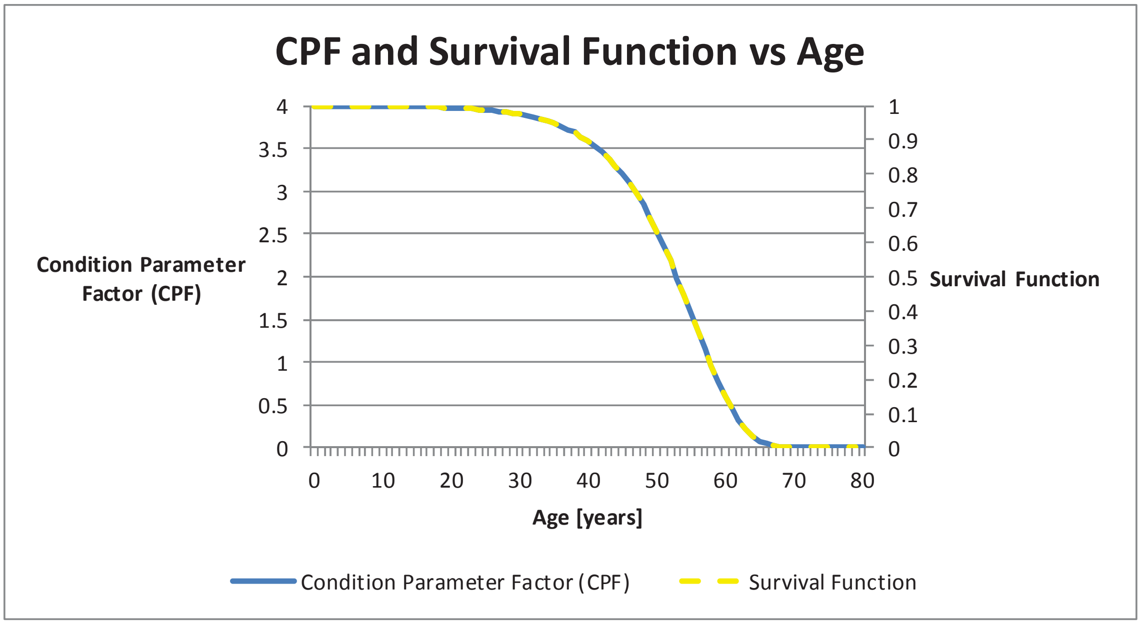

Figure 2-1 CPF and Survival Function vs. Age (Circuit Breakers)

Derating Factor

The de-rating is based on the following equation:

$$DR = DRF_1$$

Equation 2-1

Where DRF are as described in Table 2-6

Table 2-6 Substation Circuit Breakers De-Rating Factors

De-Rating Factor (DRF)	De-Rating Factor	Description
DRF_1	0.3	All the oil circuit breakers, due to closing timing and safety issues

2.3 Substation Circuit Breakers Age Distribution

The age distribution is shown in the figure below. Age was available for 100% of the population. The average age was found to be 28 years.

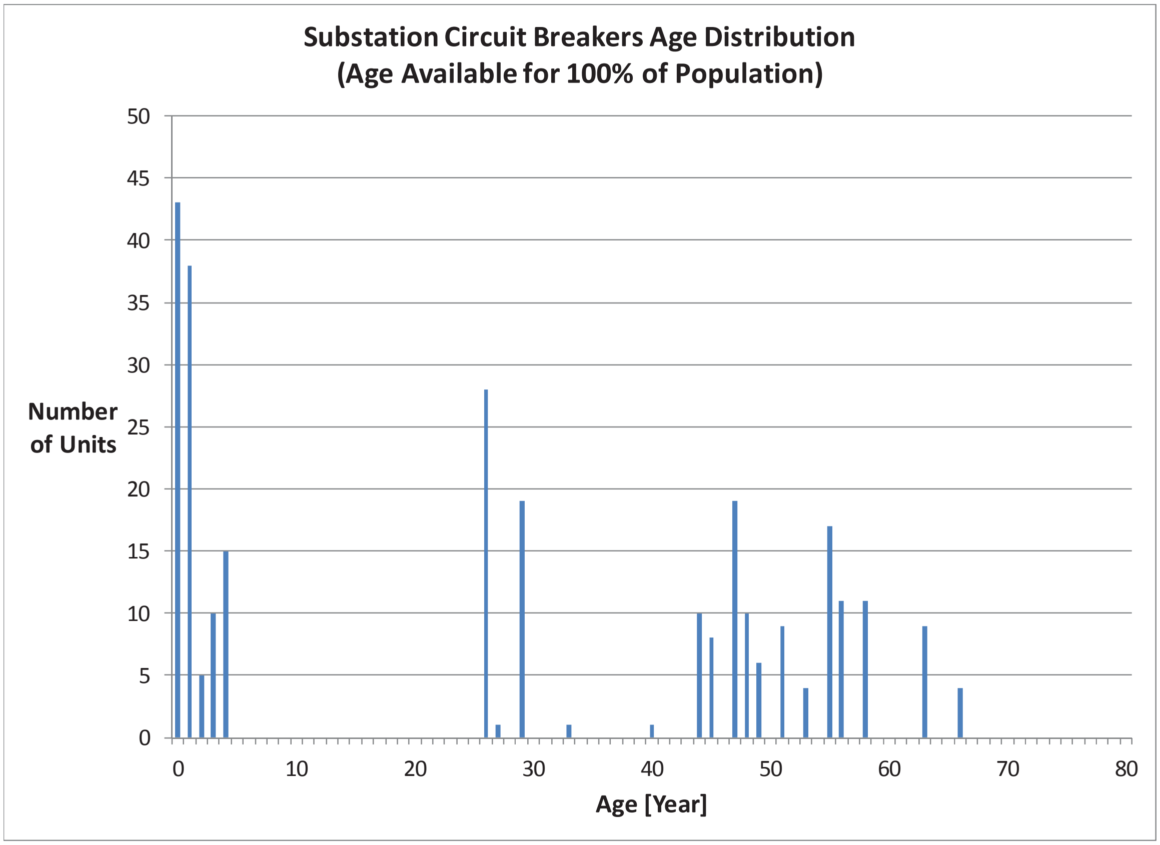

Figure 2-2 Substation Circuit Breakers Age Distribution

2.4 Substation Circuit Breakers Health Index Results

There are 279 in-service Substation Circuit Breakers at Horizon Utilities. All of them have data for assessment.

The average Health Index for this asset group is 77%. Approximately 23% of the units were found to be in poor or very poor condition.

The Health Index Distribution is shown in Figure 1-3 and Figure 1-4.

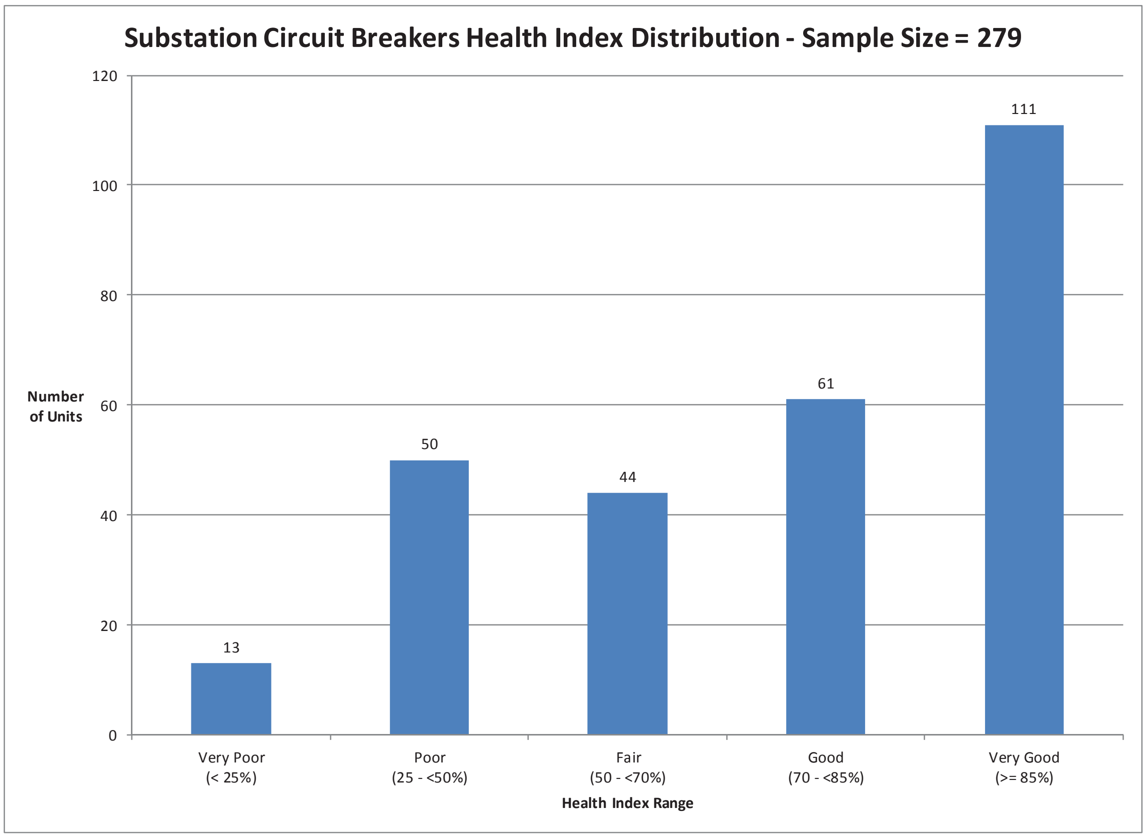

Figure 2-3 Substation Circuit Breakers Health Index Distribution (Number of Units)

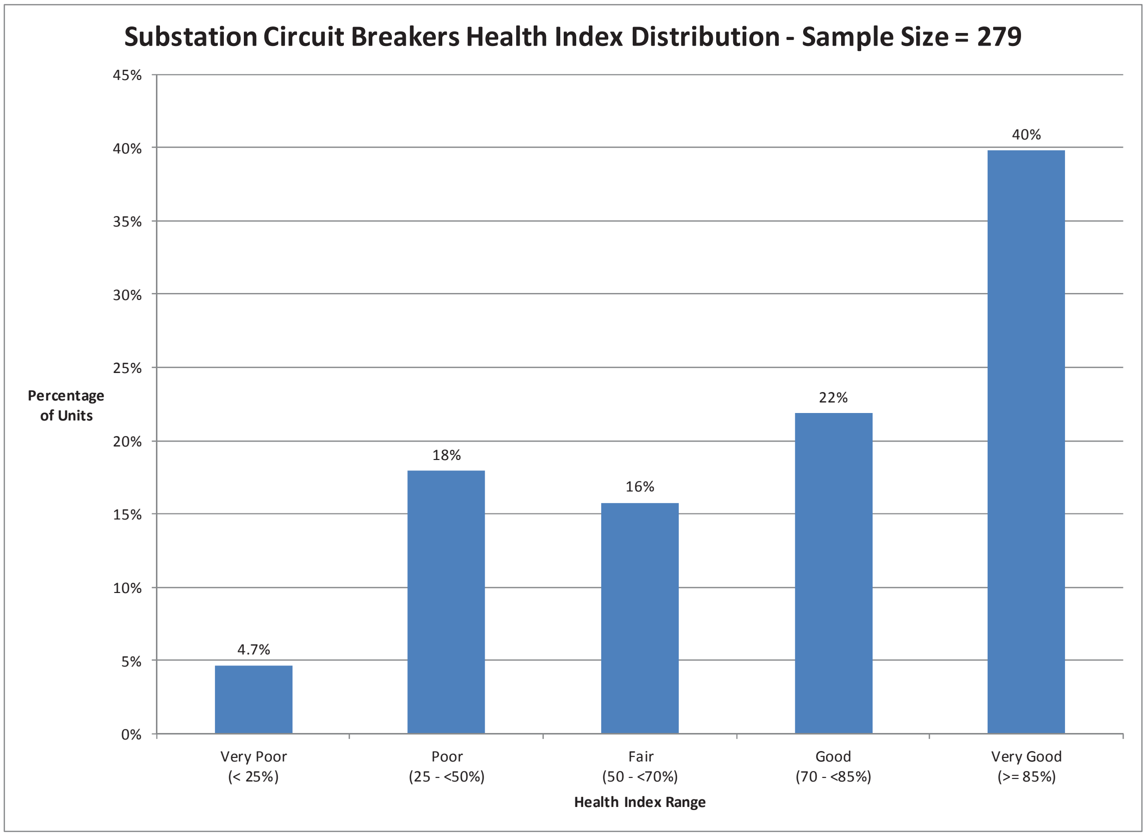

Figure 2-4 Substation Circuit Breakers Health Index Distribution (Percentage of Units)

The detailed results, from lowest to highest Health Index are shown in section VII.

2.5 Substation Circuit Breakers Condition-Based Flagged-For-Action Plan

As it is assumed that Substation Circuit Breakers are proactively replaced, the risk assessment and replacement procedure described in Section II.2.3 was applied for this asset class.

As noted in Section II.2.3, a unit becomes a candidate for replacement when its risk, product of its *probability of failure* and *criticality*, is greater than or equal to a calculated risk limit. The probability of failure is as determined by the Health Index. Criticality is determined as shown in the following section.

2.5.1 Substation Circuit Breakers Criticality

The minimum criticality, $Criticality_{min}$, is 1.25. The maximum criticality, $Criticality_{max,}$ is twice the base criticality ($Criticality_{max,}$ = 1.25*2 = 2.5).

Each unit's criticality is defined as follows:

Criticality = (Criticality$_{max}$ – Criticality$_{min}$)*Criticality_Multiple + Criticality$_{min}$

where the Criticality_Multiple (CM) is defined by criticality factors, weights, and scores:

$$CM = \frac{\sum_{CF=1}^{\forall CF}(CFS_{CF} \times WCF_{CF})}{\sum_{CF=1}^{\forall CF}(WCF_{CF})}$$

Where

CFS	Criticality Factor Score
WCF	Weight of Condition Factor

The factors, weights and the score system of each factor are as follows:

Table 2-7 Substation Circuit Breakers Criticality Factors

Criticality Factor (CF)	Description	Weight (WCF)	Score (CFS)	
Load criticality	--- Number of customers --- Customer importance (e.g. hospitals, provincial buildings, restoration time sensitive customers)	25	Low	0
			High	1
Long-term Development	system upgrading (e.g. higher voltage level, higher fault duty to be implemented)	20	No	0
			Yes	1
Operation & Maintenance	--- obsolescence of spare parts (e.g. manufacturers cease to produce old types of spare parts) --- known issues (e.g. not economical to have routine maintenance)	20	No	0
			Yes	1
Environmental & Safety	--- Legislation/standard requirement (e.g. replace SF6, oil CBs) --- Safety concern (e.g. arc resistance feature, remote racking feature)	35	No	0
			Yes	1

2.5.2 Substation Circuit Breakers Flagged-For-Action Plan

The condition-based Flagged-For-Action Plan for Substation Circuit Breakers is plotted in Figure 2-5.

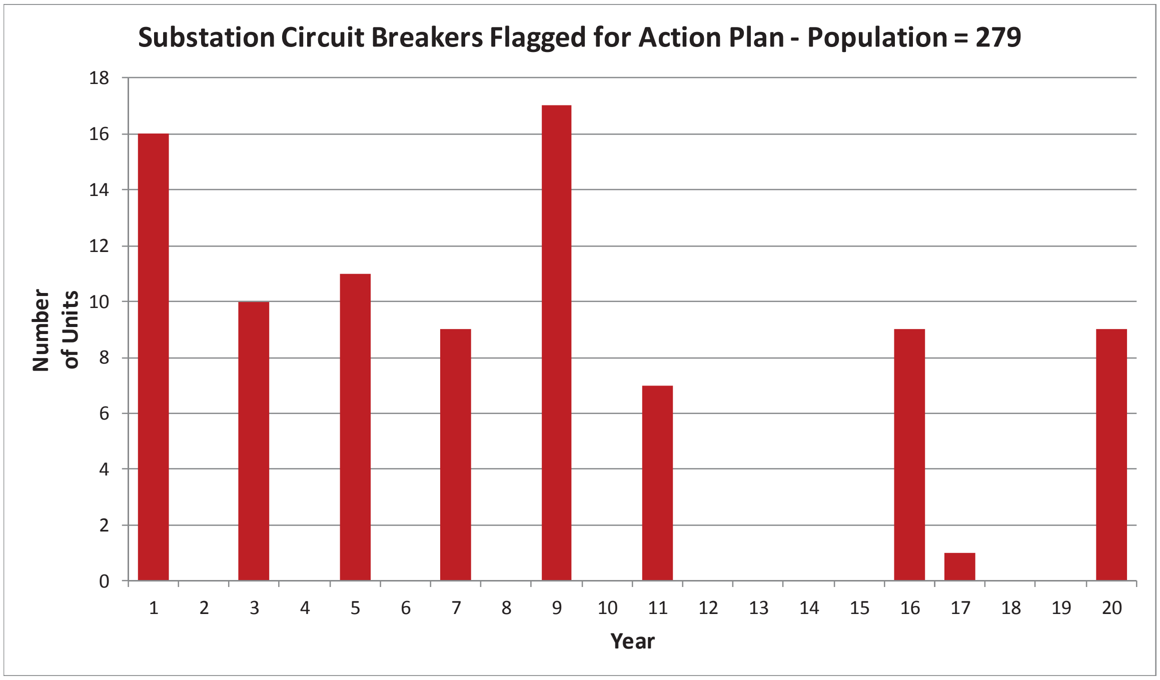

Figure 2-5 Substation Circuit Breakers Condition-Based Flagged-For-Action Plan

2.6 Substation Circuit Breakers Data Analysis

The data available for Substation Circuit Breakers includes age and third party inspection.

While keeping with data acquisition from the existing maintenance program, it is suggested that Horizon Utilities resume collecting and storing in electronic format breaker timing test results while continuing with qualitative assessment of resistance performed by a third party.

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3 Substation Switchgear

Substation Switchgear consists of an assembly of retractable/racked switchgear devices that are totally enclosed in a metal envelope (metal-enclosed). These devices operate in the medium voltage range, from 4.16 to 34 kV. The switchgear includes breakers, disconnect switches, or fuse gear, current transformers (CTs), potential transformers (PTs) and occasionally some or all of the following: metering, protective relays, internal DC and AC power, battery charger(s), and AC station service transformation. The gear is modular in that each breaker is enclosed in its own metal envelope (cell). The gear also is compartmentalized with separate compartments for breakers, control, incoming/outgoing cables or bus duct, and bus-bars associated with each cell.

3.1 Substation Switchgear Degradation Mechanism

Switchgear degradation is a function of a number of different factors: mechanism operation and performance, degradation of solid insulation, general degradation/corrosion, environmental factors, or post fault maintenance (condition of contacts and arc control devices). Degradation of the breaker used is also a factor. However the degradation mechanism differs slightly between switchgear types: air insulated and gas insulated.

Correct operation of the mechanism is critical in devices that make or break fault currents, i.e. the contact opening and closing characteristics must be within specified limits. The greatest cause of mal-operation of switchgear is related to mechanism malfunction. Deterioration due to corrosion or wear due to lubrication failure may compromise mechanism performance by either preventing or slowing down the operation of the breaker. This is a serious issue for all types of switchgear.

In older air filled equipment, degradation of active solid insulation (for example drive links) has been a significant problem for some types of switchgear. Some of the materials used in this equipment, particularly those manufactured using cellulose-based materials (pressboard, SRBP, laminated wood) are susceptible to moisture absorption. This results in a degradation of their dielectric properties that can result in thermal runaway or dielectric breakdown. An increasingly significant area of solid insulation degradation relates to the use of more modern polymeric insulation. Polymeric materials, which are now widely used in switchgear, are very susceptible to discharge damage. These electrical stresses must be controlled to prevent any discharge activity in the vicinity of polymeric material. Failures of relatively new switchgear due to discharge damage and breakdown of polymeric insulation have been relatively common over the past 15 years.

Temperature, humidity and air pollution are also significant degradation factors, so indoor units tend to have better long-term performance. The safe and efficient operation of switchgear and its longevity may all be significantly compromised if the station environment is not adequately controlled. In addition, the air switchgear can tolerate less number of full fault operations before maintenance is required.

3.2 Substation Switchgear Health Index Formula

This section presents the Health Index Formula that was developed and used for Horizon Utilities Substation Switchgear. The Health Index equation is shown in Section II.1; the condition, sub-condition parameters, weights, and condition criteria are as follows.

Assume a parameter scoring system of 0 through 4, where 0 and 4 represent the "worst" and "best" scores respectively. Thus, the maximum score for any condition or sub-condition parameter (maximum CPS and CPF) is "4".

3.2.1Substation Switchgear Condition and Sub-Condition Parameters

Table 3-1 Substation Switchgear Condition and Weights

m	Condition Parameter	WCP_m	Sub-Condition Parameters
1	Enclosure Condition	2	Table 3-2
2	Bus & cable compartment	3	Table 3-3
3	Low voltage compartment	2	Table 3-4
4	Service record	3	Table 3-5

Table 3-2 Substation Switchgear Breaker Compartment (m=1) Sub-Conditions and Weights

n	Sub-condition parameter	$WCPF_n$	Condition Criteria Table
1	Metal Clad	1	Table 3-6
2	Partial Discharge	2	Table 3-6

Table 3-3 Substation Switchgear Bus & Cable Compartment (m=2) Sub-Conditions and Weights

n	Sub-condition parameter	$WCPF_n$	Condition Criteria Table
1	Cable Terminations	2	Table 3-6
2	Instrument Transformers	3	Table 3-6
3	Bus & Insulator	2	Table 3-6

Table 3-4 Substation Switchgear Low Voltage Compartment (m=3) Sub-Conditions and Weights

n	Sub-condition parameter	$WCPF_n$	Condition Criteria Table
1	Relays	3	Table 3-6
2	RTU	2	Table 3-6
3	Batteries	1	Table 3-6
4	Charger	1	Table 3-6

Table 3-5 Substation Switchgear Service Record (m=3) Sub-Conditions and Weights

n	Sub-condition parameter	$WCPF_n$	Condition Criteria Table
1	Switchgear performance record	2	Table 3-6
2	Age	1	Figure 3-1

3.2.2 Substation Switchgear Condition Parameter Criteria

Station Inspection

Table 3-6 Substation Switchgear Inspection criteria

CPF	Condition Description (Horizon Grading)
4	Good
2	Fair
0	Poor

Age

Assume that the failure rate for circuit breakers exponentially increases with age and that the failure rate equation is as follows:

$$f = e^{\beta(t-\alpha)}$$

f = failure rate of an asset (percent of failure per unit time)
t = time
α, β = constant parameters that control the rise of the curve

The corresponding survivor function is therefore:

$$S_f = 1 - P_f = e^{-(f-e^{-\alpha\beta})/\beta}$$

S_f = survivor function
P_f = probability of failure

Assuming that at the ages of 45 and 60 years the probabilities of failure (P_f) are 20% and 85% result in the survival curves shown below. It follows that the CPF for Age is the survival curve normalized to the maximum CPF score of 4 (i.e. 4*Survival Curve). The CPF vs. Age is also shown in the figure below.

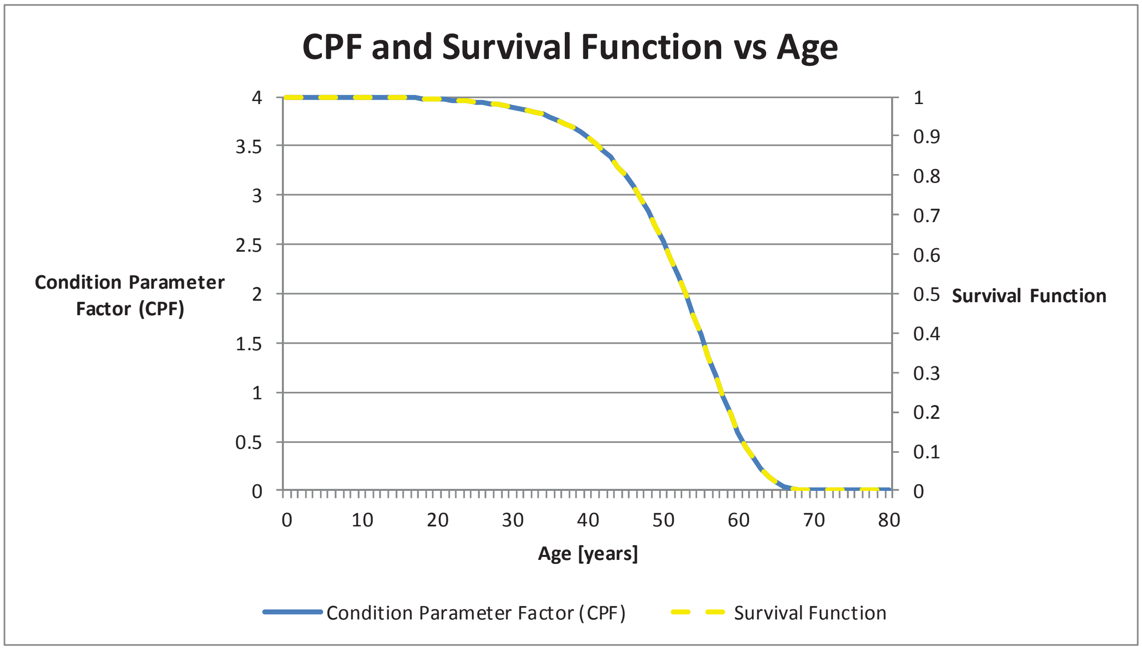

Figure 3-1 CPF and Survival Function vs. Age (Station Switchgear)

3.3 Substation Switchgear Age Distribution

The age distribution is shown in the figure below. Age was available for 97% of the population. The average age was found to be 44 years.

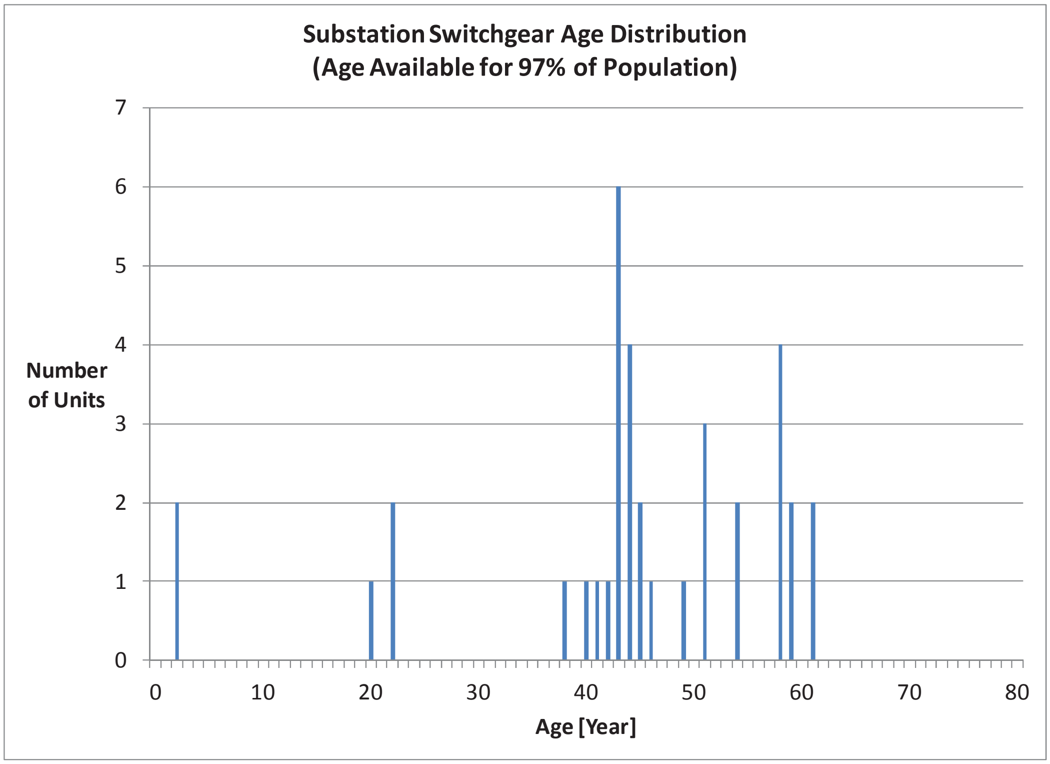

Figure 3-2 Substation Switchgear Age Distribution

3.4 Substation Switchgear Health Index Results

There are 42 in-service Substation Switchgear at Horizon Utilities. All of them have data for assessment.

The average Health Index for this asset group is 59%. None of the units were in very poor condition. Approximately 32% of the units were found to be in poor condition.

The Health Index Distribution is shown in Figure 3-3 and Figure 3-4.

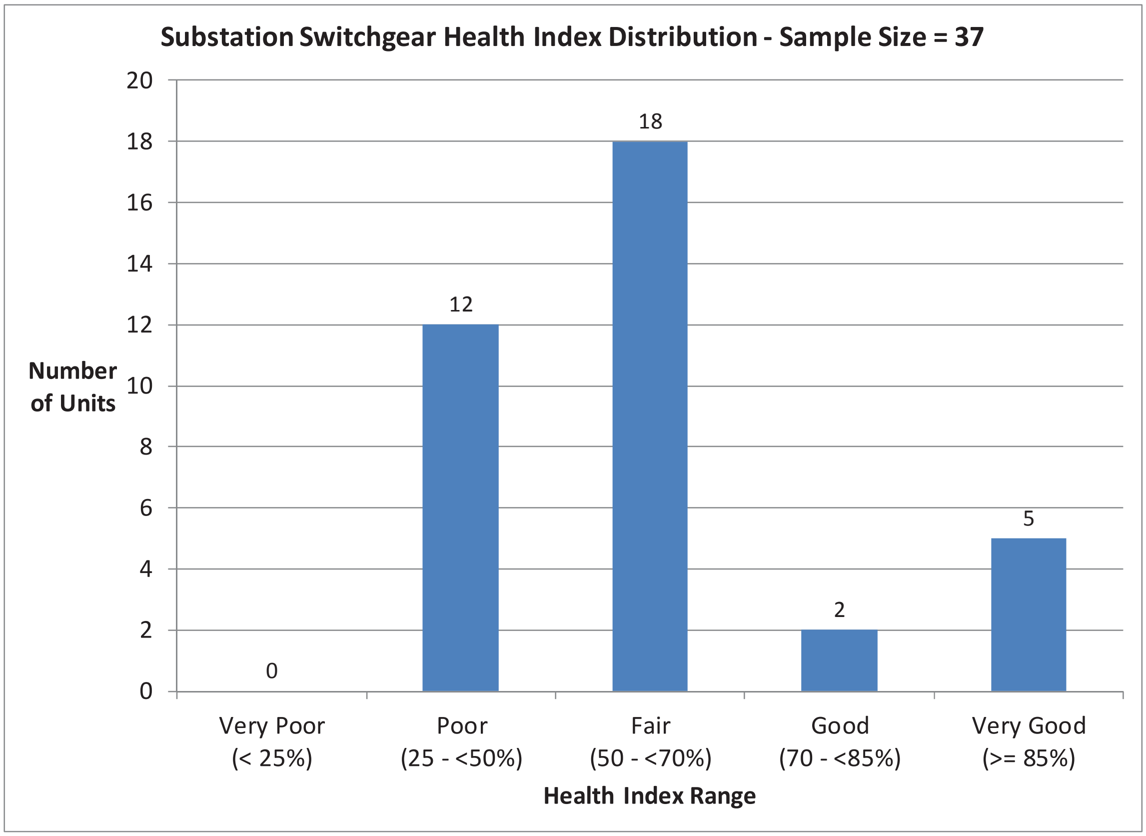

Figure 3-3 Substation Switchgear Health Index Distribution (Number of Units)

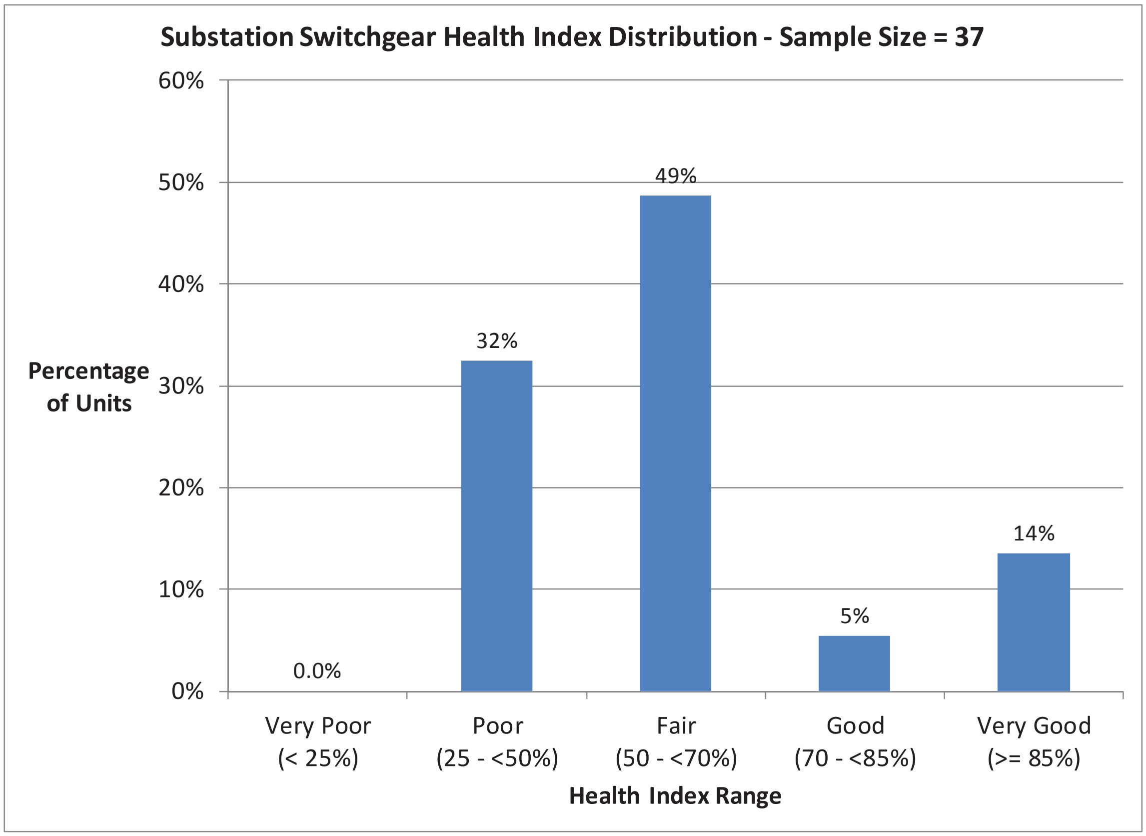

Figure 3-4 Substation Switchgear Health Index Distribution (Percentage of Units)

3.5 Substation Switchgear Condition-Based Flagged-For-Action Plan

As it is assumed that Substation Switchgear is proactively replaced, the risk assessment and replacement procedure described in Section II.2.3 was applied for this asset class based on Health Index only, i.e. not including criticality assessment.

The Flagged-For-Action Plan is based on the years when the Health Index based probability of failure reaches 80% for asset units. In this case, the number refers to the bus-section assembly, which consists of multiple switch cells or cabinets. The following diagram shows such a flagged-for-action plan.

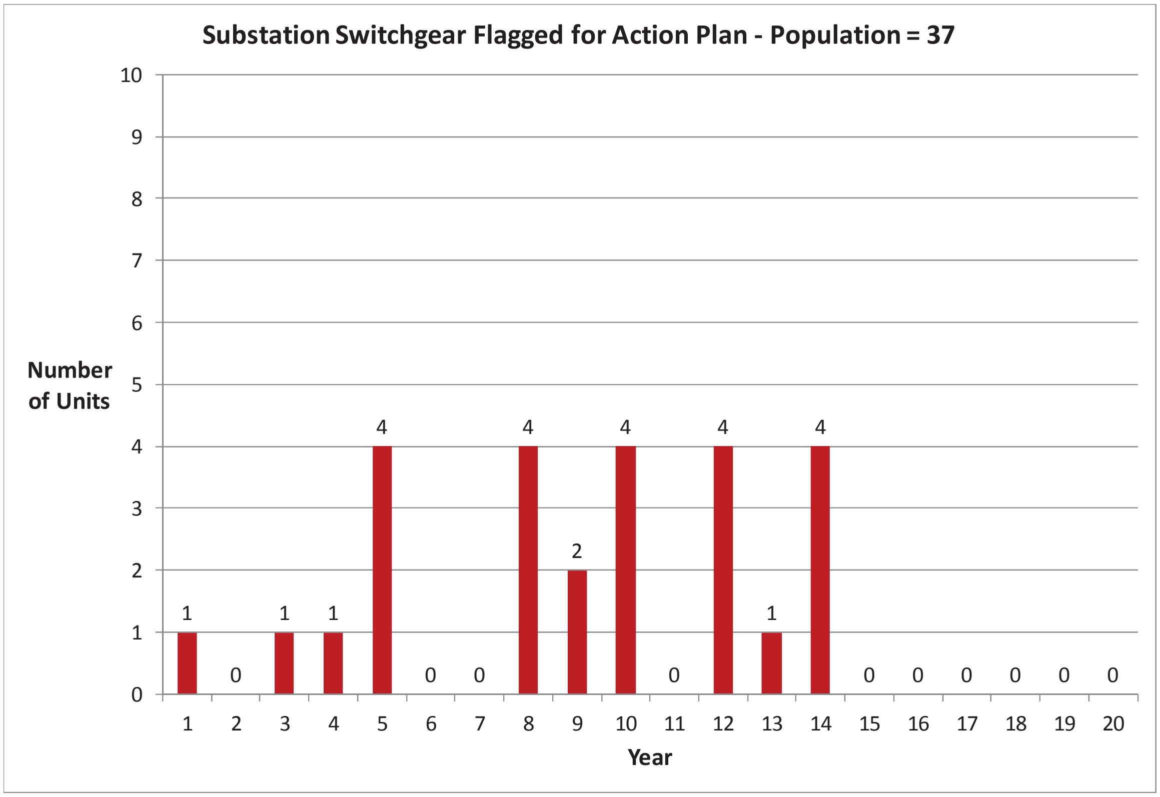

Figure 3-5 Substation Switchgear Condition-Based Flagged-For-Action Plan

3.6 Substation Switchgear Data Analysis

The data available for Substation Switchgear includes age and third party inspection records. Horizon Utilities should continue with the existing data collection practices.

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4 Pole Top Transformers

Pole-mounted distribution transformers convert power from the distribution primary line voltage to 120\240V utilization voltage employed by the customer. Single-phase pole-mounted transformers are commonly available in ratings from 5kVA to 167kVA but can be as high as 500kVA. They are available in voltages from 4.16\2.4kV to 34.5\19kV. Pole-mounted transformers are generally contained in cylindrical cans filled with insulating oil. The connection to the high voltage source is via a bushing, usually on the top of the unit. The transformer core is generally a wrapped sheet-type steel. Wound copper high voltage windings and sheet-type low voltage windings are wound concentrically on the core. Distribution transformers are self-cooled by air and occasionally have external cooling fins. Typically, pole-mounted transformers of size 100kVA and below are attached directly to the pole whereas higher ratings are mounted on cross-beams.

4.1 Pole Top Transformers Degradation Mechanism

Degradation of pole top transformers can occur due to the following mechanisms:

- Corrosion of the tank
- Deterioration or breakage of the bushings
- Deterioration of internal switching or fusing devices
- Degradation of internal insulating material
- Degradation of oil

Tank corrosion can be problematic for overhead transformers particularly in areas of high contamination. Porcelain bushings can develop mechanical cracks or can be subject to breakage due to mechanical vibration and forces. Deterioration of the pole-mounted transformer can also be due to problems such as: breakage of switches and leakage of under-oil fuses.

The life of the transformer's internal insulation is related to temperature-rise and duration. Therefore, transformer life is affected by electrical loading profiles and length of service life. The impacts of loading profiles, load growth, and ambient temperature on asset condition, loss-of-life, and life expectancy can be assessed using methods outlined in ANSI\IEEE Loading Guides. This also provides an initial baseline for the size of transformer that should be selected for a given number and type of customers to obtain optimal life. Insulation condition can also be affected by voltage and current surges.

Distribution pole-mounted transformers sometimes require replacement because of non-condition related factors such as customer load growth, pole replacement or road widening. If a transformer is simply overloaded, a decision is required whether to keep the transformer as spare or to scrap it. Many utilities make this decision through a cost-benefit analysis, by taking into consideration anticipated remaining life of transformer, cost of equivalent-sized new transformer, labour cost for transformer replacement and rated losses of the older transformer in comparison to the newer designs.

Visual inspections provide considerable information on transformer asset condition. Leaks, rusting, and deteriorated connectors can all be established by visual inspections. Transformer oil testing can be employed for distribution transformers to assess the condition of solid and liquid insulation.

The consequences of distribution transformer degradation can be severe if it results in an eventful failure. Though rare, pole-mounted transformers can fail with sufficient energy release to rupture the tank and release oil into the surrounding environment.

4.2 Pole Top Transformers Health Index Formulation

This section presents the Health Index Formula that was developed and used for Horizon Utilities Pole Top Transformers. The Health Index equation is shown in Section II.1; the condition, sub-condition parameters, weights, and condition criteria are as follows.

Assume a parameter scoring system of 0 through 4, where 0 and 4 represent the “worst” and “best” scores respectively. Thus, the maximum score for any condition or sub-condition parameter (maximum CPS and CPF) is “4”.

4.2.1 Pole Top Transformers Condition and Sub-Condition Parameters

Table 4-1 Pole Top Transformers Condition Weights and Maximum CPS

m	Condition Parameter	WCP_m	CPS Lookup Table
1	Service Record	1	Table 4-2

Table 4-2 Pole Top Transformers Service Record (m=1) Weights and Maximum CPF

n	Sub-Condition Parameter	CPF Lookup Table	$WCPF_n$	$CPF_{n.max}$
1	Loading	Table 4-3	1	4
2	Age	Figure 4-1	2	4

4.2.2 Pole Top Transformers Condition Parameter Criteria

<u>**Age**</u>

Assume that the failure rate for Pole Top Transformers exponentially increases with age and that the failure rate equation is as follows:

$$f = e^{\beta(t-\alpha)}$$

f = failure rate of an asset (percent of failure per unit time)

t = time
α, β = constant parameters that control the rise of the curve

The corresponding survivor function is therefore:

$$S_f = 1 - P_f = e^{-(f-e^{-\alpha\beta})/\beta}$$

S_f = survivor function
P_f = probability of failure

Assuming that at the ages of 40 and 55 years the probability of failure (P_f) for this asset are 10% and 90% respectively results in the survival curve shown below. It follows that the CPF for Age is the survival curve normalized to the maximum CPF score of 4 (i.e. 4*Survival Curve). The CPF vs. Age is also shown in the figure below:

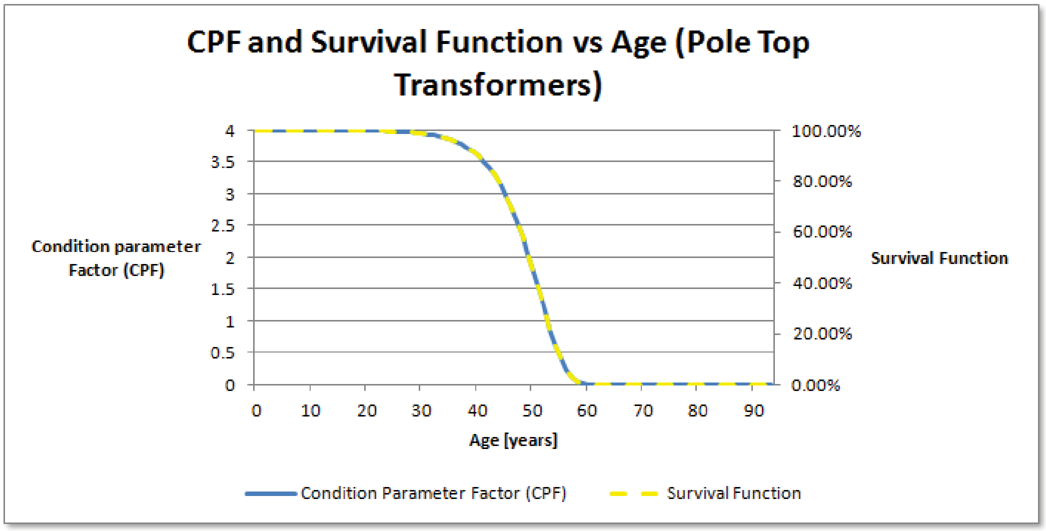

Figure 4-1 Age Condition Criteria (Pole Top Transformers)

<u>Loading</u>

Table 4-3 Pole Top Transformers Loading History

Data: S1, S2, S3, ..., SN recorded data (monthly 15 min peak)
SB= rated MVA NA=Number of Si/SB which is lower than 1.0 NB= Number of Si/SB which is between 1 and 1.2 NC= Number of Si/SB which is greater than 1.2 CPF = $\frac{NA \times 4 + NB \times 1 + NC \times 0}{N}$

Hourly transformer loading was used to determine overloading occurrences leading to a loss of life and thereby increasing the effective age of the transformer. Transformer loading was not determined to decrease the effective age of the transformer in the absence of overloading occurrences. Therefore, loading condition was incorporated only when the loading CPF score was less than age CPF score for a transformer. In the cases when age CPF score was lower than that of loading, Health Index was calculated based on age only.

4.3 Pole Top Transformers Age Distribution

The age distribution is shown in the figure below. Age was available for 100% of the population. The average age was found to be 24 years.

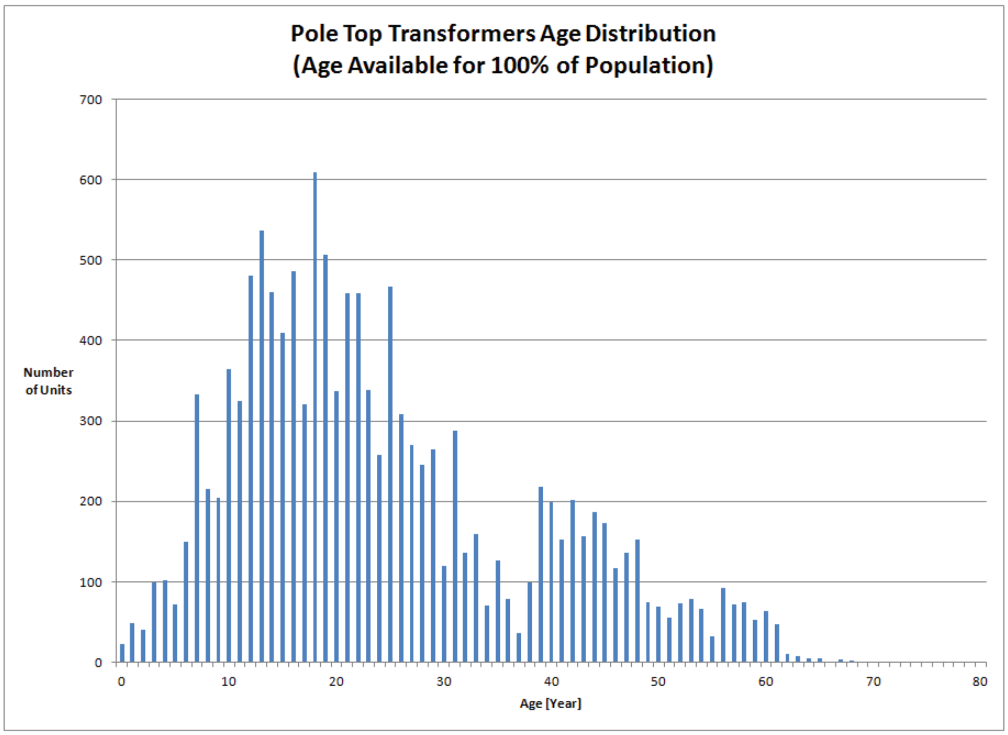

Figure 4-2 Pole Top Transformers Age Distribution

4.4 Pole Top Transformers Health Index Results

There are 12886 in-service Pole Top Transformers at Horizon Utilities. The condition assessment is based on age, together with overloading condition calculated using hourly data obtained from Horizon Utilities Smart Meters.

The average Health Index for this asset group is 91%. About 6% of the units were found to be in poor or very poor condition.

The Health Index Results are as follows:

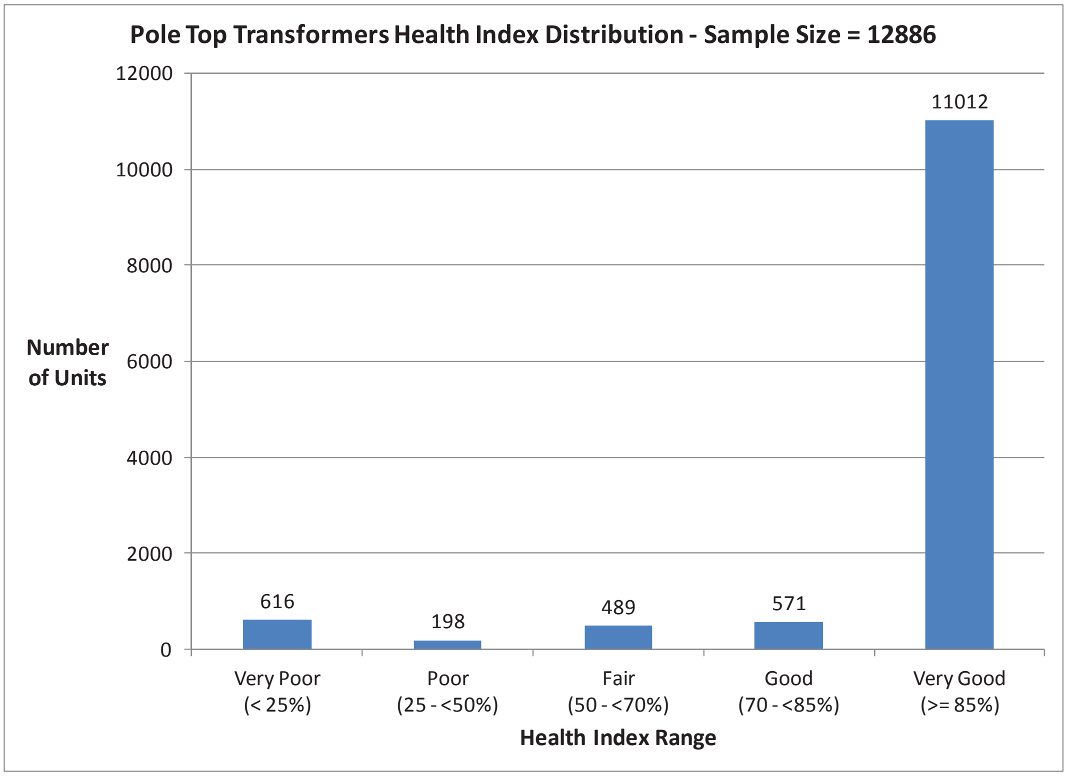

Figure 4-3 Pole Top Transformers Health Index Distribution (Number of Units)

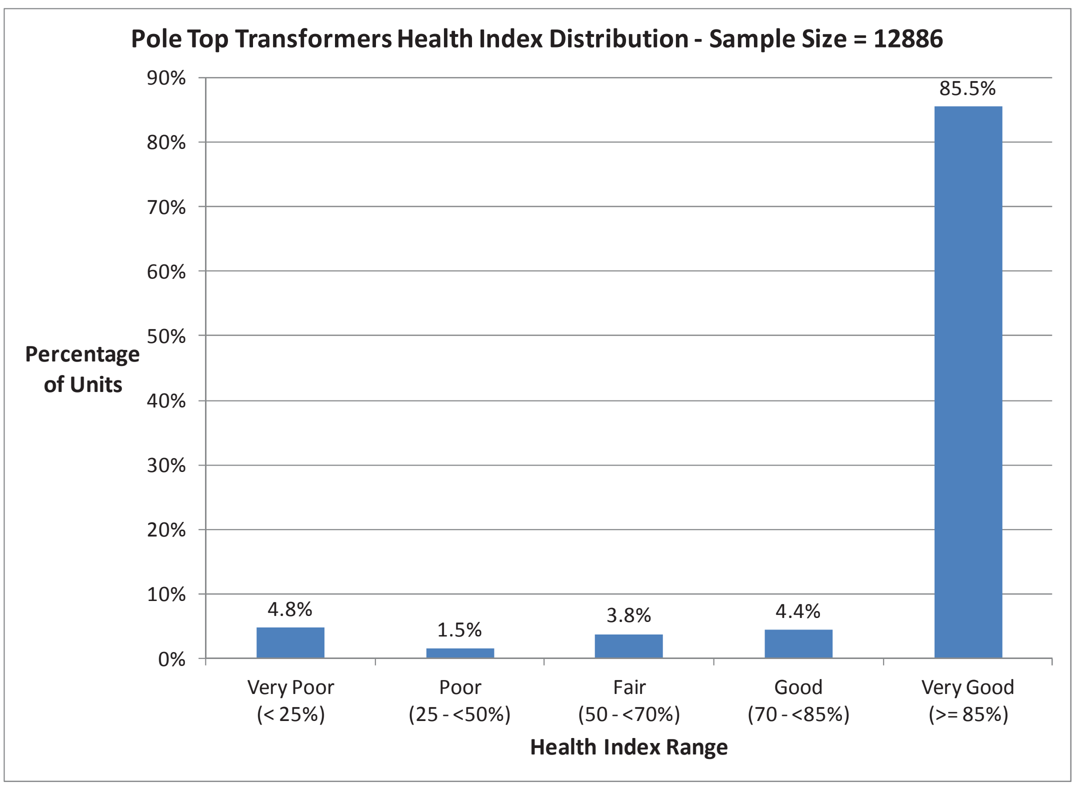

Figure 4-4 Pole Top Transformers Health Index Distribution (Percentage of Units)

4.5 Pole Top Transformers Condition-Based Flagged-For-Action Plan

As it is assumed that Pole Top Transformers are reactively replaced, the Flagged-For-Action Plan is based on asset failure rate f (t), as described in Section II.2.2.

The Flagged-For-Action Plan is based on the number of expected failures in a given year.

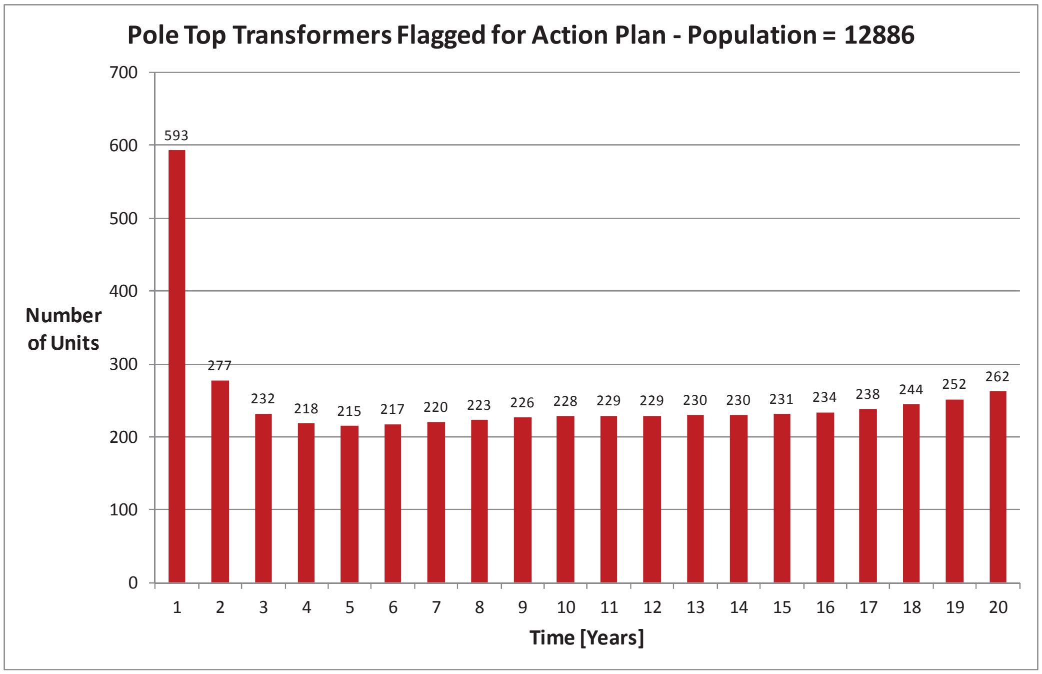

Figure 4-5 Pole Top Transformers Condition-Based Flagged-For-Action Plan

4.6 Pole Top Transformers Data Analysis

The data available for Pole Top Transformers includes age and loading determined using hourly data obtained from Horizon Utilities Smart Meter data.

5 Overhead Conductors

Electrical current flows through distribution line conductors facilitating the movement of power throughout the distribution system. These conductors are supported by either metal, wood or concrete structures to which they are attached by insulator strings selected based on operating voltage. The conductors are sized for the maximum amount of current to be carried and other design requirements. In this study, there are three types of overhead conductor system:

- Primary overhead conductors
- Secondary overhead conductors
- Service overhead conductors

5.1 Overhead Conductors Degradation Mechanism

Conductors used on most distribution lines have high tensile strength, enabling them to be strung over long spans. As electrical current passes through a conductor, its temperature rises. The temperature change is proportional to the square of the current passing through the conductor. The rise in temperature causes the conductor to expand and sag more between points of support, reducing the height of the conductor above ground. This may reduce the line's clearance from ground by 10 feet or more, depending on the conductor's span length, temperature increase, ambient temperature, and wind and solar conditions. The minimum allowable clearance (thermal rating), as per Canadian Standards Association (CSA) C22.3 No. 1-Overhead Systems, limits the amount of loading of a line.

To work properly, conductors must retain both their conductive properties and their mechanical (i.e., tensile) strength. Aluminum-based conductors have three primary modes of degradation - corrosion, fatigue and creep. The rate of each degradation mode depends on several factors, including the size and construction of the conductor, the amount of steel in the cross-section, and the environmental and operating conditions. Most utilities find that corrosion and fatigue present the most critical forms of degradation to their conductors.

Generally, corrosion represents the most critical life-limiting factor for conductors. Visual inspection cannot detect corrosion readily in conductors. Environmental conditions affect degradation rates from corrosion. Both aluminum and zinc-coated steel core conductors are particularly susceptible to corrosion from chlorine-based pollutants, even in low concentrations. ACSR used in extreme marine environments may have a useful life of only 30 years, even with the use of anti-corrosion measures (e.g., greasing). Under minor marine-type pollution, aluminum-based conductors still may have a relatively short life of about 50 years.

Fatigue degradation presents an even greater detection and assessment challenge than corrosion degradation. In extreme circumstances, under high tensions or inappropriate vibration or galloping control, fatigue can occur in very short timeframes (i.e., less than 20 years). However, under normal operating conditions, with proper design and application of vibration control devices such as dampers, fatigue degradation rates are relatively slow. Under normal circumstances, widespread fatigue degradation is not commonly seen in conductors less than 70 years of age. Also, in many cases, detectable indications of fatigue may only exist during the last 10% of a conductor's life.

The tensile strength of conductors gradually decreases over time. When aluminum-based conductors experience unexpectedly large mechanical loads (for example, when heavily ice-coated) and experience tensions beyond 50% of their RTS, they can begin to undergo permanent stretching with noticeable increases in sagging. After conductor stretching has occurred, one can estimate damage severity by measuring sag in the affected spans and then comparing the measured sag to that predicted based on the "as constructed" sag charts.

Overloading lines beyond their thermal capacity causes elevated operating temperatures. When operating at elevated temperatures, aluminum conductors begin to anneal and lose tensile strength. Each elevated temperature event adds further damage to the conductor. Because of their steel cores, ACSR can withstand substantially greater annealing degradation than all-aluminum (e.g. ACAR) conductors.

Phase to phase power arcs can result from conductor galloping during severe ice and wind storm events. This can cause localized burning and melting of a conductor's aluminum strands, reducing strength at those sites and potentially leading to conductor failures if not repaired. Visual inspection from a helicopter readily detects severe arcing damage.

Forms of conductor damage include:

- Broken strands due to fatigue cracking (i.e. outer and/or inner strands)
- Vandalism (gunshot) damage
- Strand abrasion at or near clamping points
- Elongation (i.e. changes in sags and tensions)
- Burn damage (i.e. lightning strikes or power arcs/wire clashing)
- Birdcaging (ballooning) of the outer, aluminum strands

5.2 Overhead Conductors Health Index Formulation

This section presents the Health Index Formula that was developed and used for Horizon Utilities Overhead Conductors. The Health Index equation is shown Section II.1; the condition, sub-condition parameters, weights, and condition criteria are as follows.

Assume a parameter scoring system of 0 through 4, where 0 and 4 represent the "worst" and "best" scores respectively. Thus, the maximum score for any condition or sub-condition parameter (maximum CPS and CPF) is "4".

5.2.1 Overhead Conductors Condition and Sub-Condition Parameters

Table 5-1 Overhead Conductors Condition Weights and Maximum CPS

m	Condition Parameter	WCP_m	CPS Lookup Table
1	Service Record	1	Table 5-2
	De-rating multiplier (DR)		Table 5-3

Table 5-2 Overhead Conductors Service Record (m=1) Weights and Maximum CPF

n	Sub-Condition Parameter	CPF Lookup Table	$WCPF_n$	$CPF_{n.max}$
1	Age	Figure 5-1	1	4

5.2.2 Overhead Conductors Condition Parameter Criteria

<u>**Age**</u>

Assume that the failure rate for Overhead Conductors exponentially increases with age and that the failure rate equation is as follows:

$$f = e^{\beta(t-\alpha)}$$

f = failure rate of an asset (percent of failure per unit time)
t = time
α, β = constant parameters that control the rise of the curve

The corresponding survivor function is therefore:

$$S_f = 1 - P_f = e^{-(f-e^{-\alpha\beta})/\beta}$$

S_f = survivor function
P_f = probability of failure

Assuming that for primary/secondary/service overhead conductors, at the ages of 60 and 77 years the probability of failure (P_f) for this asset are 20% and 95% respectively results in the survival curve shown below. It follows that the CPF for Age is the survival curve normalized to the maximum CPF score of 4 (i.e. 4*Survival Curve). The CPF vs. Age is also shown in the figure below:

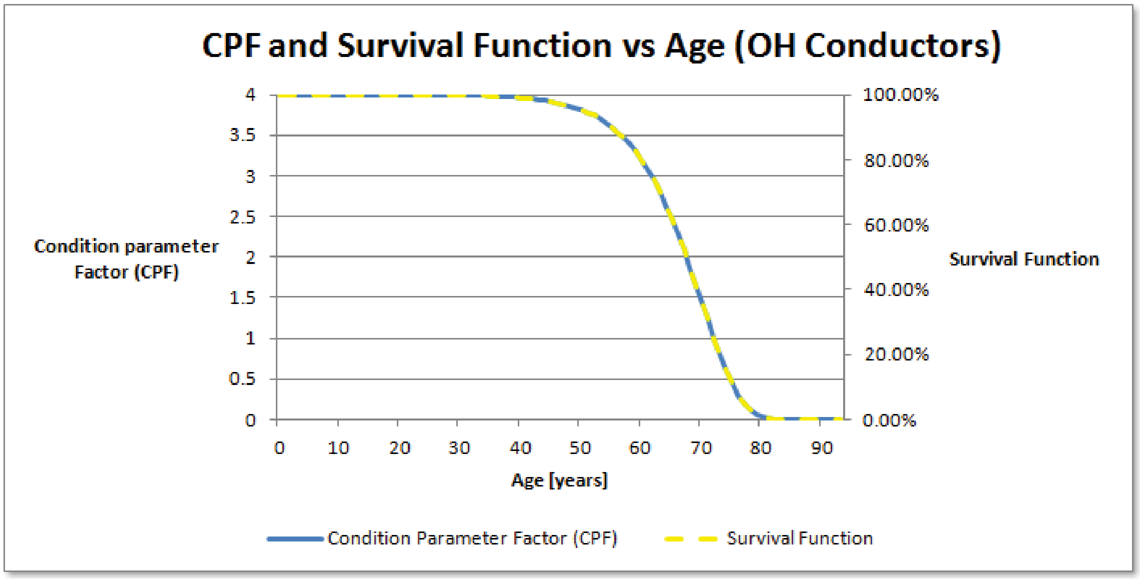

Figure 5-1 Overhead Conductors Age Condition Criteria

De-Rating (DR) Multiplier

Table 5-3 Overhead Conductors De-Rating Factors

De-Rating Factor	Description
0.3	#6 copper conductor for primary conductor

5.3 Overhead Conductors Age Distribution

The age distribution is shown in the figures below. Age was available for 100% of the population. The average age was found to be 28, 38 and 40, for primary, secondary and service overhead conductors respectively.

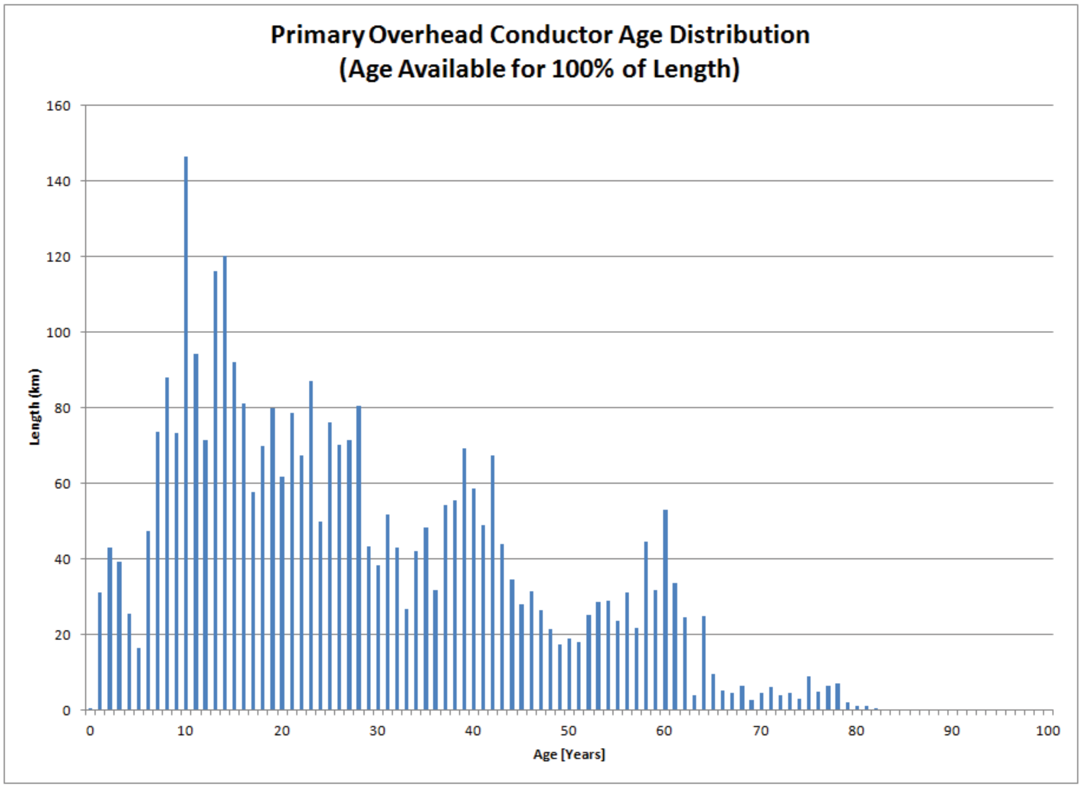

Figure 5-2 Overhead Conductors Age Distribution (Primary)

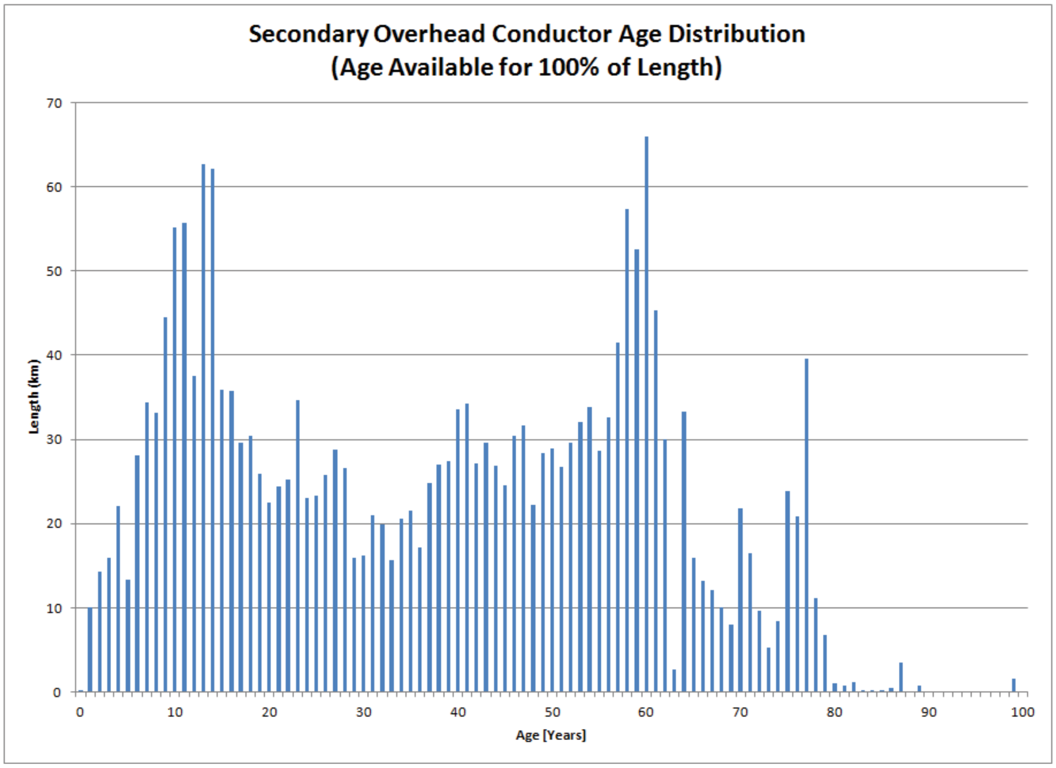

Figure 5-3 Overhead Conductors Age Distribution (Secondary)

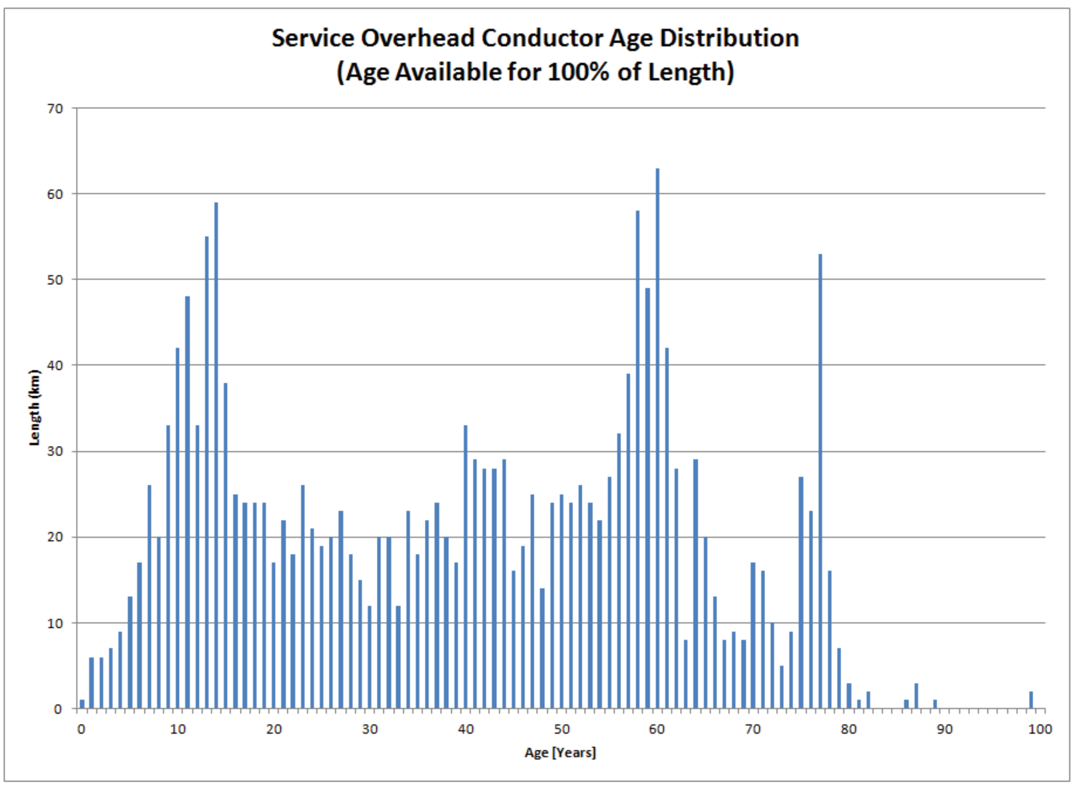

Figure 5-4 Overhead Conductors Age Distribution (Service)

5.4 Overhead Conductors Health Index Results

There are 3385 km, 2196 km and 1897 km in-service Overhead Conductors at Horizon Utilities, for primary, secondary and service systems respectively. The condition assessment is mainly age-driven, together with de-rating based on #6 copper conductor type for primary conductors only.

The average Health Index for this asset group is 90%, 86% and 84% for primary, secondary and service systems respectively.

The Health Index Results are as follows:

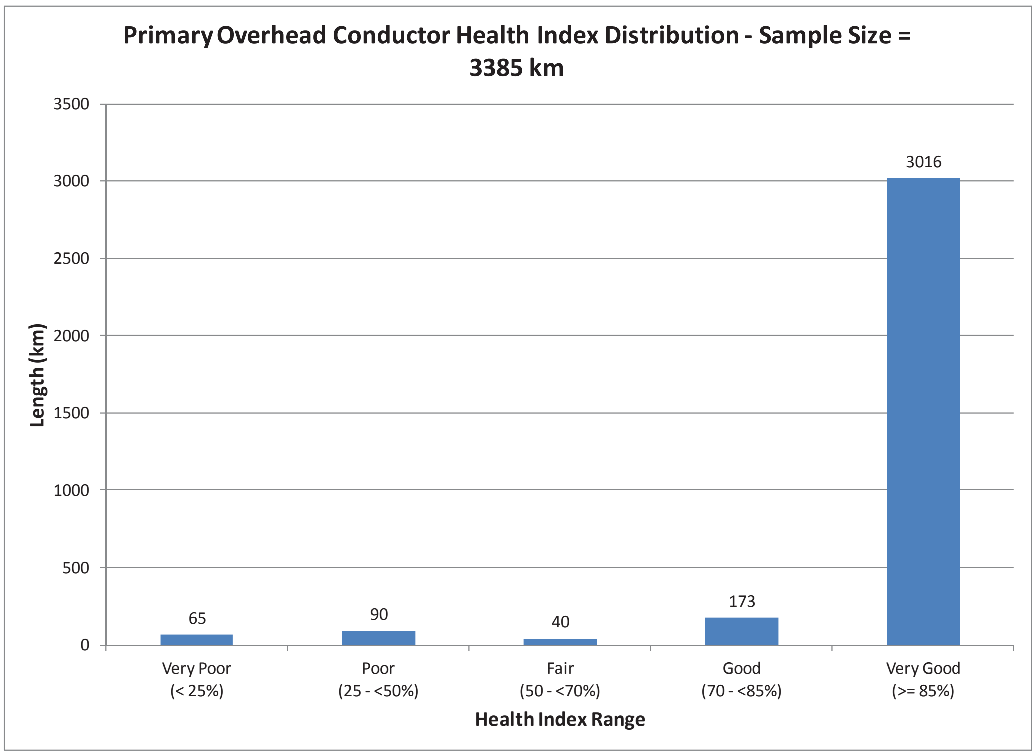

Figure 5-5 Overhead Conductors Health Index Distribution (Length, Primary)

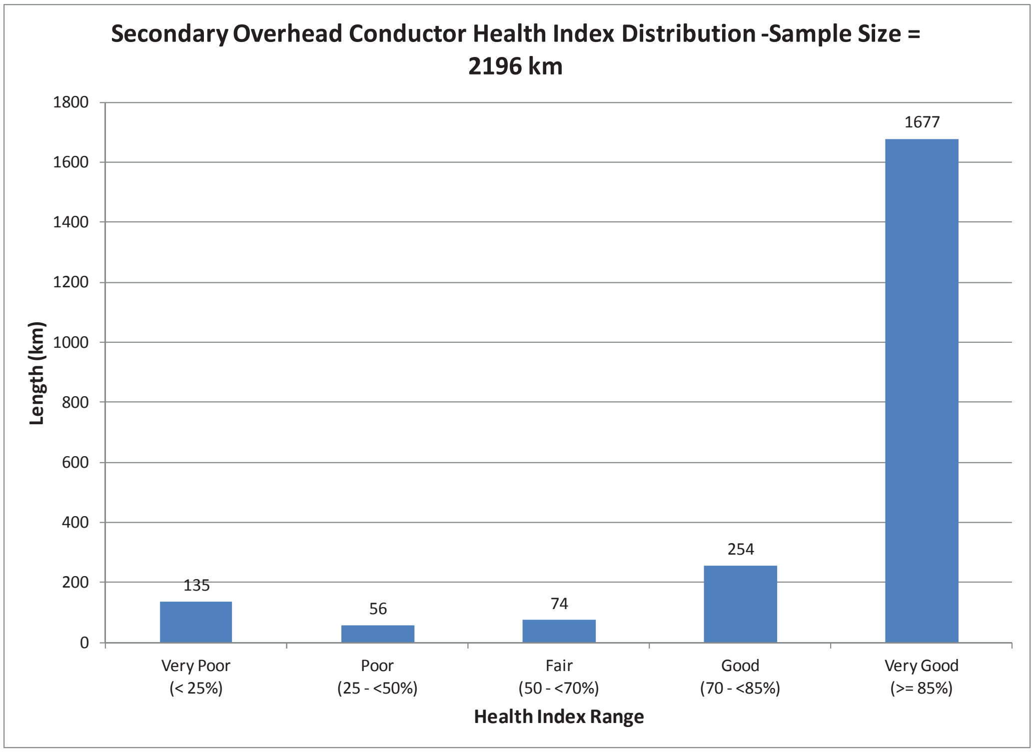

Figure 5-6 Overhead Conductors Health Index Distribution (Length, Secondary)

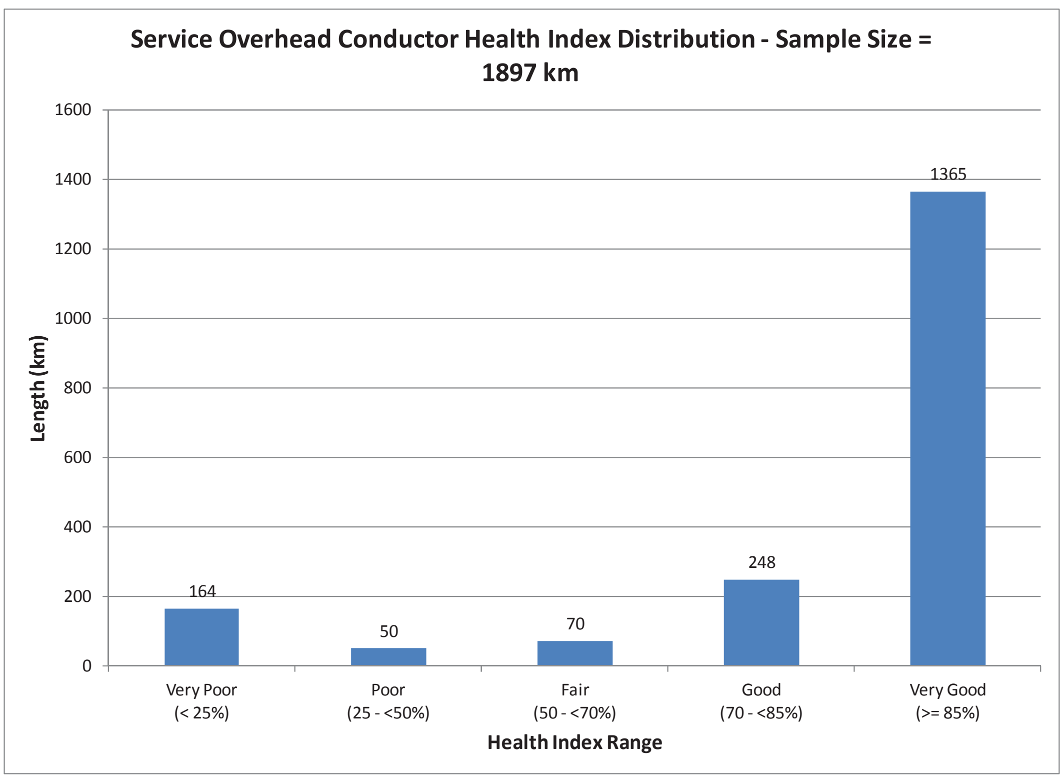

Figure 5-7 Overhead Conductors Health Index Distribution (Length, Service)

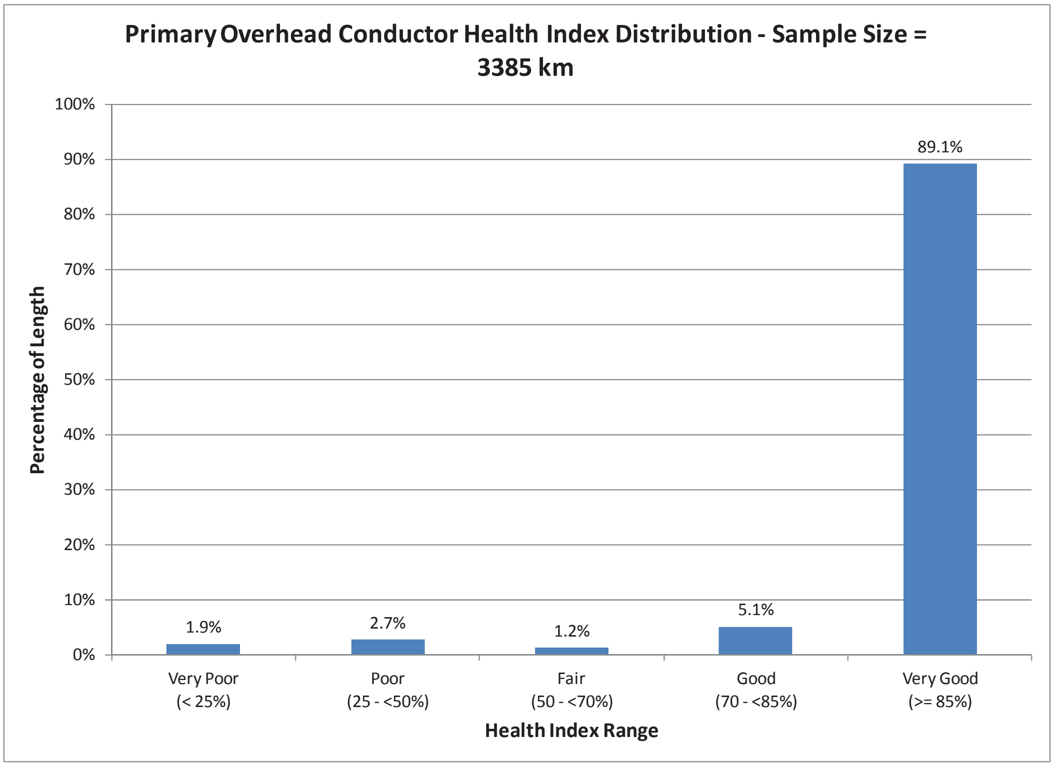

Figure 5-8 Overhead Conductors Health Index Distribution (Percentage, Primary)

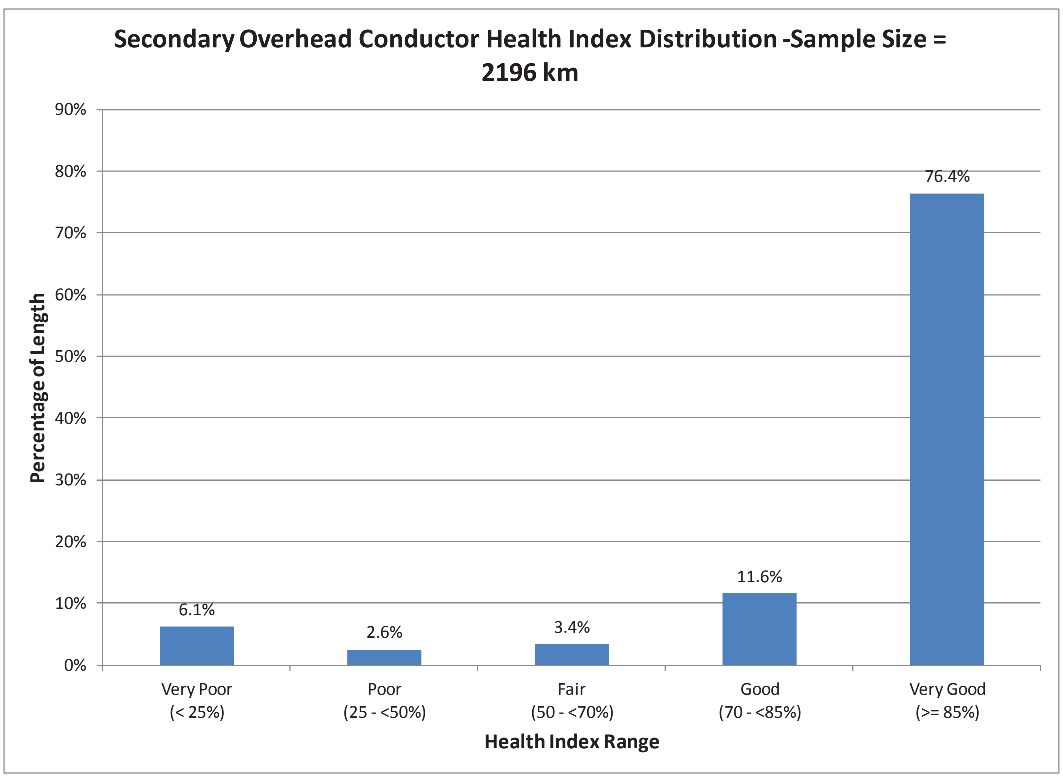

Figure 5-9 Overhead Conductors Health Index Distribution (Percentage, Secondary)

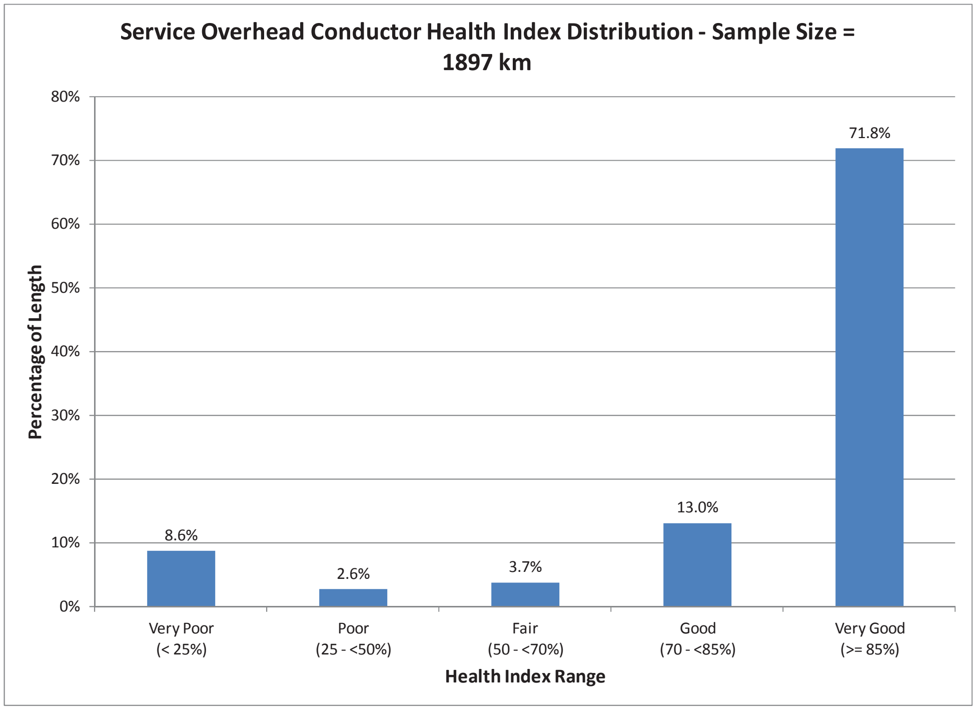

Figure 5-10 Overhead Conductors Health Index Distribution (Percentage, Service)

The following diagrams show the primary Overhead Conductors Health Index distribution by different voltage levels.

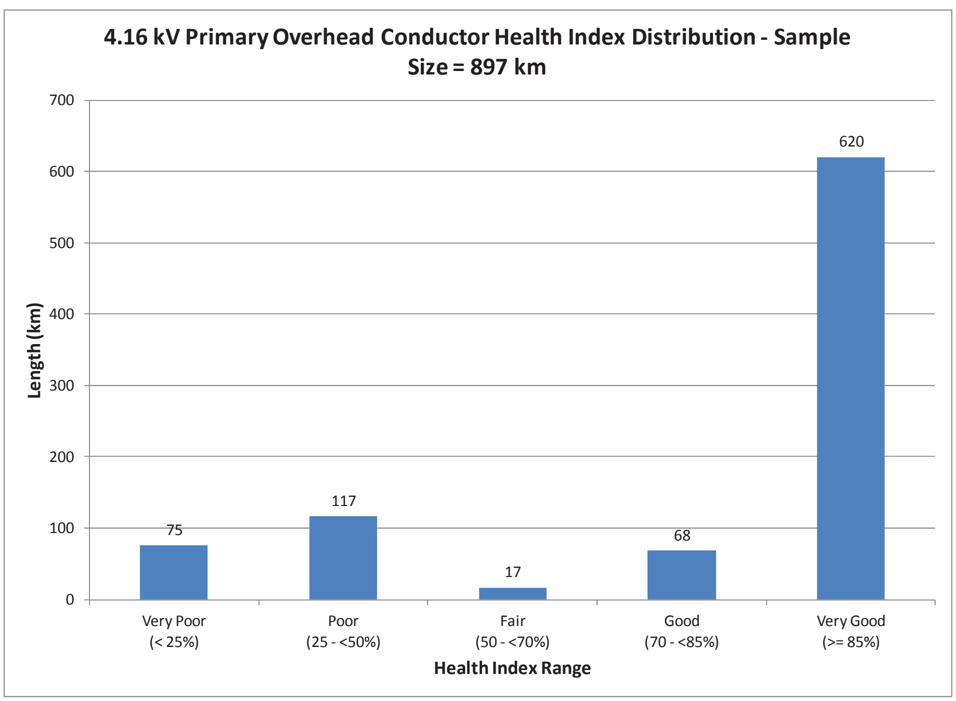

Figure 5-11 Overhead Conductors Health Index – Primary 4.16 kV

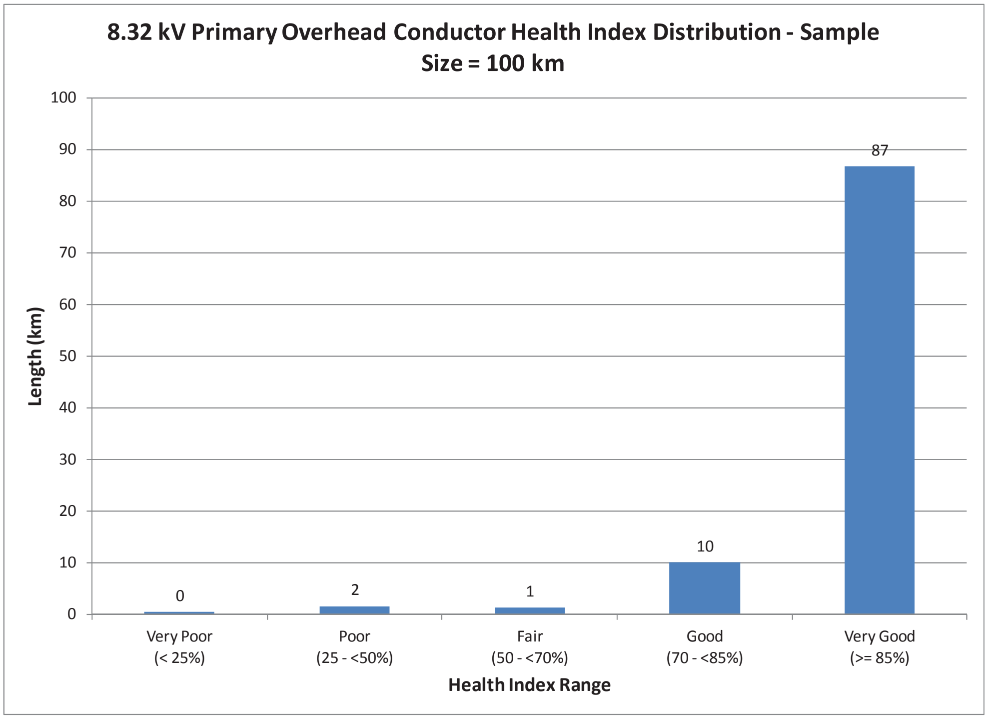

Figure 5-12 Overhead Conductors Health Index – Primary 8.32 kV

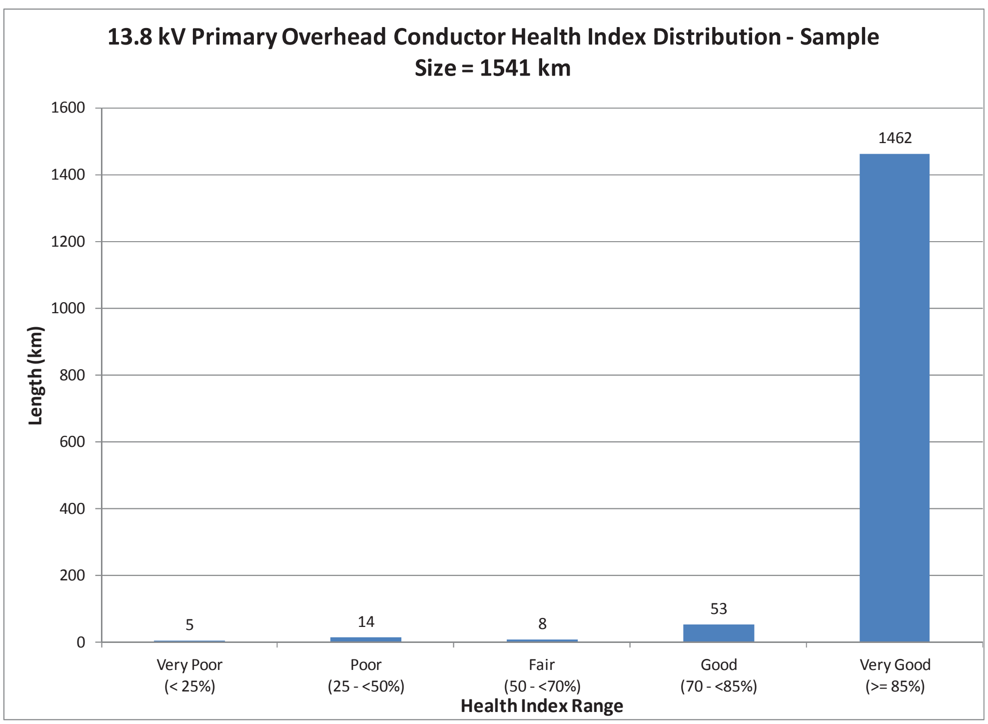

Figure 5-13 Overhead Conductors Health Index – Primary 13.8 kV

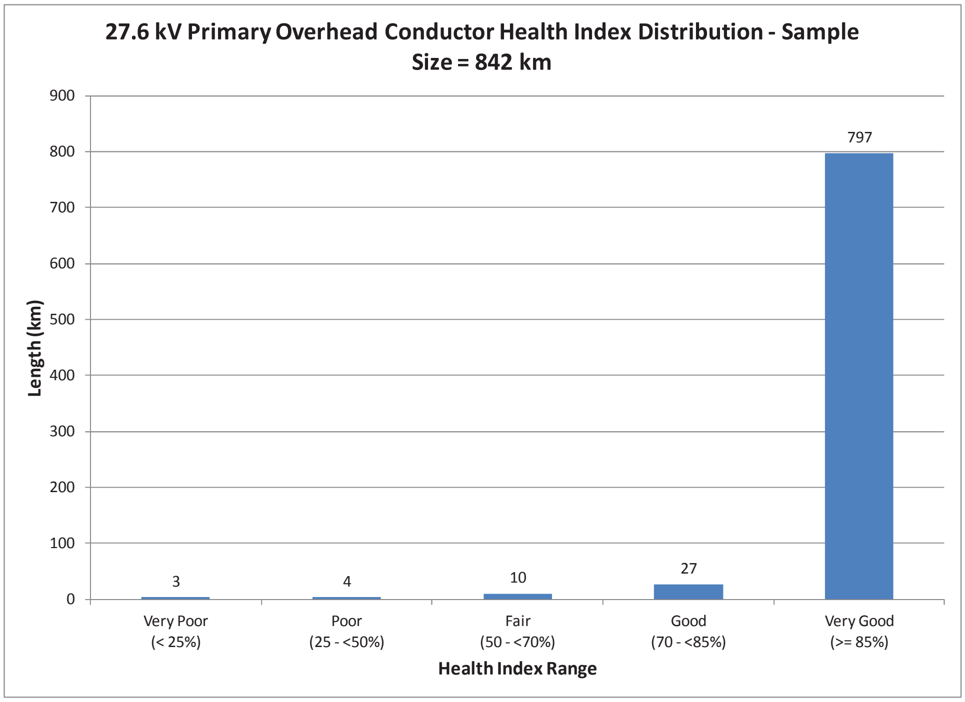

Figure 5-14 Overhead Conductors Health Index – Primary 27.6 kV

5.5 Overhead Conductors Condition-Based Flagged-For-Action Plan

As it is assumed that Overhead Conductors are reactively replaced, the Flagged-For-Action Plan is based on asset failure rate f (t), as described in Section II.2.2.

The optimal Flagged-For-Action Plan is based on the number of expected failures in a given year.

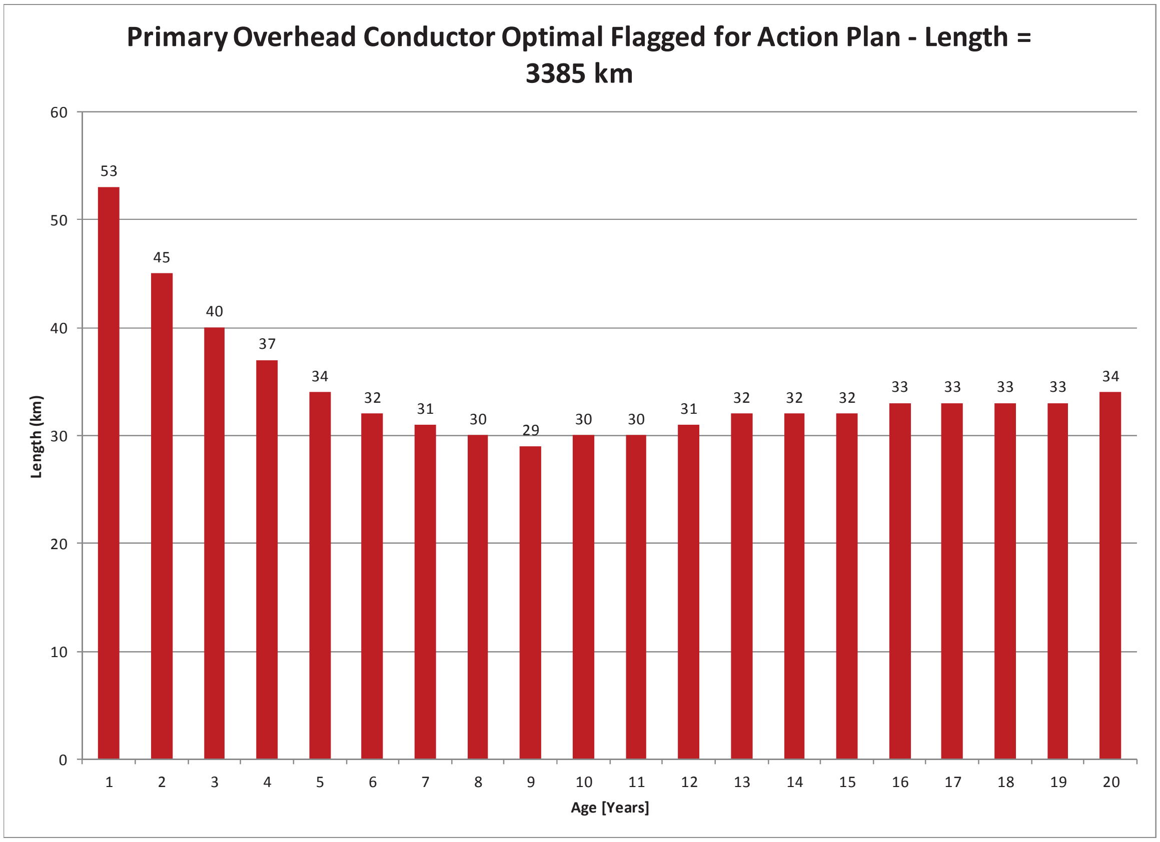

Figure 5-15 Overhead Conductors Condition-Based Flagged-For-Action Plan (Primary)

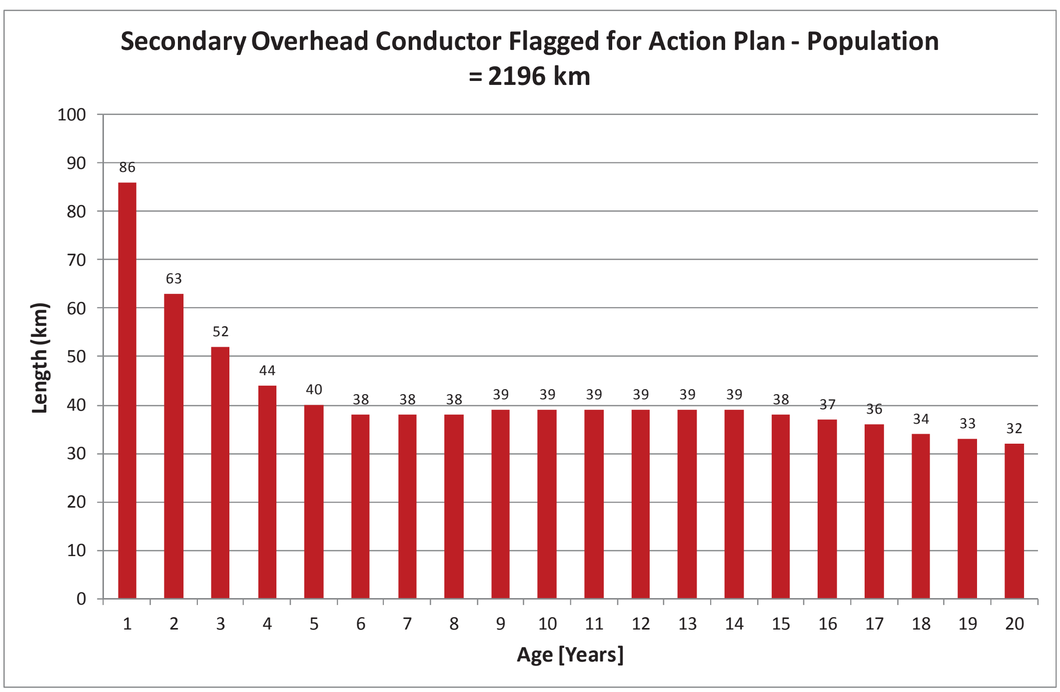

Figure 5-16 Overhead Conductors Condition-Based Flagged-For-Action Plan (Secondary)

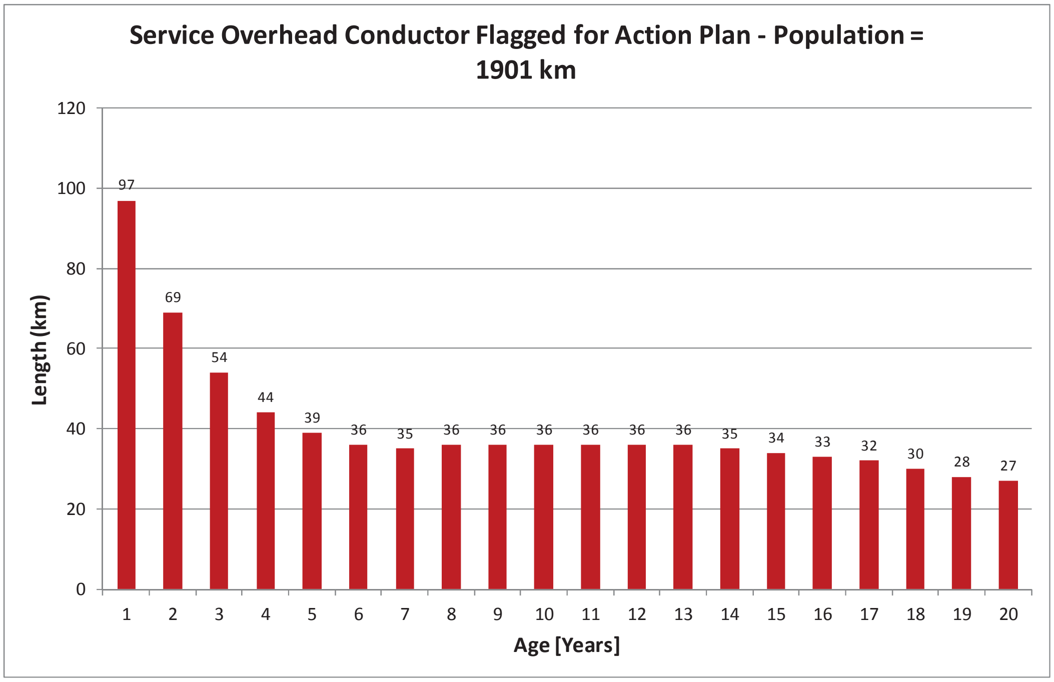

Figure 5-17 Overhead Conductors Condition-Based Flagged-For-Action Plan (Service)

5.6 Overhead Conductors Data Analysis

The data available for Overhead Conductors includes age and material. Horizon Utilities should continue with the existing practices. It is also recommended that some of the removed primary conductors or primary conductors at some critical locations suspected to be at the end of their lives be tested.

6 Overhead Line Switches

The primary function of switches is to allow isolation of line sections or equipment for maintenance, safety or other operating requirements. Disconnect switches are relatively simple in design compared to circuit breakers, since they are not typically required to interrupt fault current.

In general, line switches consist of mechanically movable copper blades supported on insulators and mounted on metal bases. Their operating mechanism can be either a simple hook stick or a manually driven mechanical mechanism to move the ganged contacts. Air serves as the insulating medium between contacts when these switches are in the open position. Air break switches must have the capability of providing visual confirmation of the open/close position. Disconnect switches are sometimes provided with padlocks to allow staff to obtain work permit clearance with switch handle locked in open position.

Most distribution line switches are rated 600 A continuous rating. While some categories of the switches are rated for load interruption, others are designed to operate under no load conditions. Non-load break switches operate only when the current through the switch is zero. When used in conjunction with cutout fuses, switches provide short circuit interruption rating.

6.1 Overhead Line Switches Degradation Mechanism

The main degradation processes associated with line switches include:

- Corrosion of steel hardware or operating rod
- Mechanical deterioration of linkages
- Switch blades falling out of alignment, which may result in excessive arcing during operation
- Loose connections
- Nonfunctioning padlocks
- Insulators damage
- Missing ground connections

The rate and severity of these degradation processes depends on a number of inter-related factors including the operating duties and environment in which the equipment is installed. In most cases, corrosion or rust represents a critical degradation process.

Corrosion typically occurs around the mechanical linkages of these switches. Corrosion can cause seizing. When lubrication dries out the switch operating mechanism may seize making the disconnect switch inoperable. While a lesser mode of degradation, air pollution also can affect support insulators. Typically, this occurs in heavy industrial areas or where road salt is used.

The condition assessment of overhead switches involves visual inspections which would reveal the extent of wear or corrosion on main contacts, condition of stand-off insulators and operating mechanism. Thermographic surveys using infrared cameras represent one of the easiest and most cost-effective tests to locate hot spots.

Consequences of overhead line switch failure may include customer interruption and health and safety consequences for operators.

6.2 Overhead Line Switches Health Index Formulation

This section presents the Health Index Formula that was developed and used for Horizon Utilities Overhead Line Switches. The Health Index equation is shown in Section II.1; the condition, sub-condition parameters, weights, and condition criteria are as follows.

Assume a parameter scoring system of 0 through 4, where 0 and 4 represent the "worst" and "best" scores respectively. Thus, the maximum score for any condition or sub-condition parameter (maximum CPS and CPF) is "4".

6.2.1 Overhead Line Switches Condition and Sub-Condition Parameters

Table 6-1 Condition Weights and Maximum CPS

m	Condition Parameter	WCP_m	CPS Lookup Table
1	Service Record	1	Table 6-2

Table 6-2 Service Record (m=1) Weights and Maximum CPF

n	Sub-Condition Parameter	CPF Lookup table	$WCPF_n$	$CPF_{n.max}$
1	Age	Figure 6-1	1	4

6.2.2 Condition Parameter Criteria

<u>**Age**</u>

Assume that the failure rate for Overhead Line Switches exponentially increases with age and that the failure rate equation is as follows:

$$f = e^{\beta(t-\alpha)}$$

f = failure rate of an asset (percent of failure per unit time)
t = time
α, β = constant parameters that control the rise of the curve

The corresponding survivor function is therefore:

$$S_f = 1 - P_f = e^{-(f - e^{-\alpha\beta})/\beta}$$

S_f = survivor function
P_f = probability of failure

Assuming that at the ages of 40 and 50 years the probability of failure (P_f) for this asset are 50% and 80% respectively results in the survival curve shown below. It follows that the CPF for Age is the survival curve normalized to the maximum CPF score of 4 (i.e. 4*Survival Curve). The CPF vs. Age is also shown in the figure below:

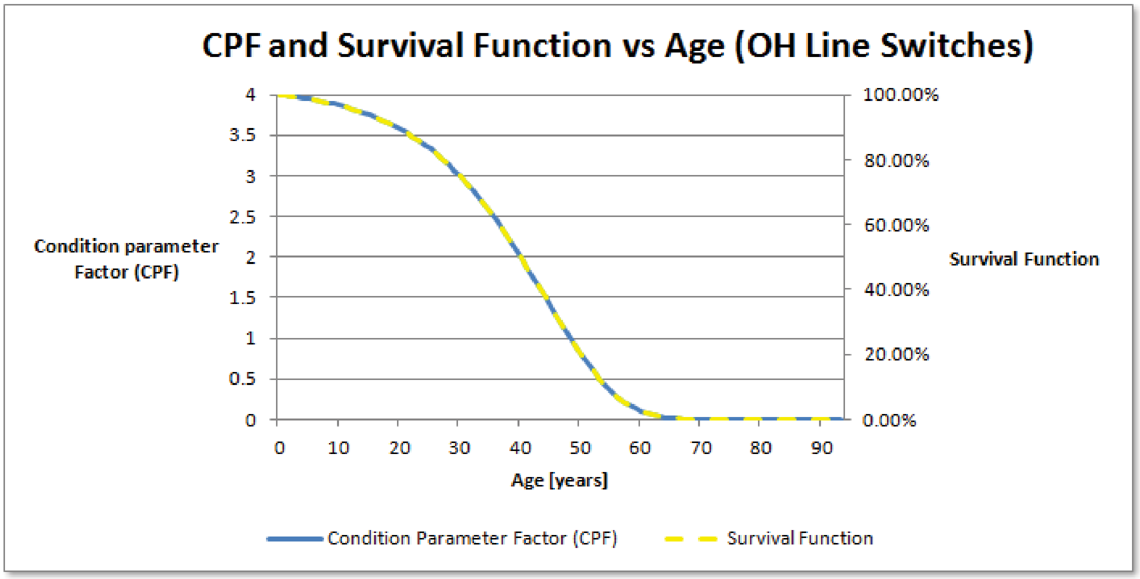

Figure 6-1 Overhead Line Switches Age Condition Criteria (Overhead Line Switches)

6.3 Overhead Line Switches Age Distribution

The age distribution is shown in the figure below. Age was available for 100% of the population. The average age was found to be 26 years.

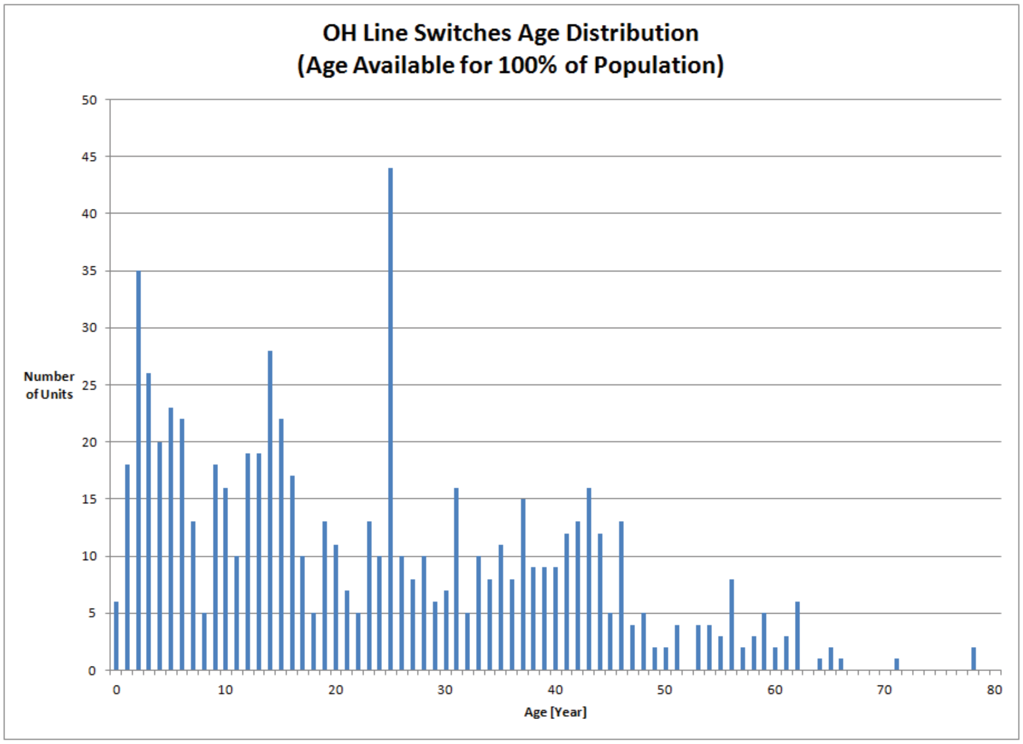

Figure 6-2 Overhead Line Switches Age Distribution

6.4 Overhead Line Switches Health Index Results

There are 712 in-service Overhead Line Switches at Horizon Utilities. The condition assessment is age-driven.

The average Health Index for this asset group is 76%. Approximately 20% of the units were found to be in poor or very poor condition.

The Health Index Results are as follows:

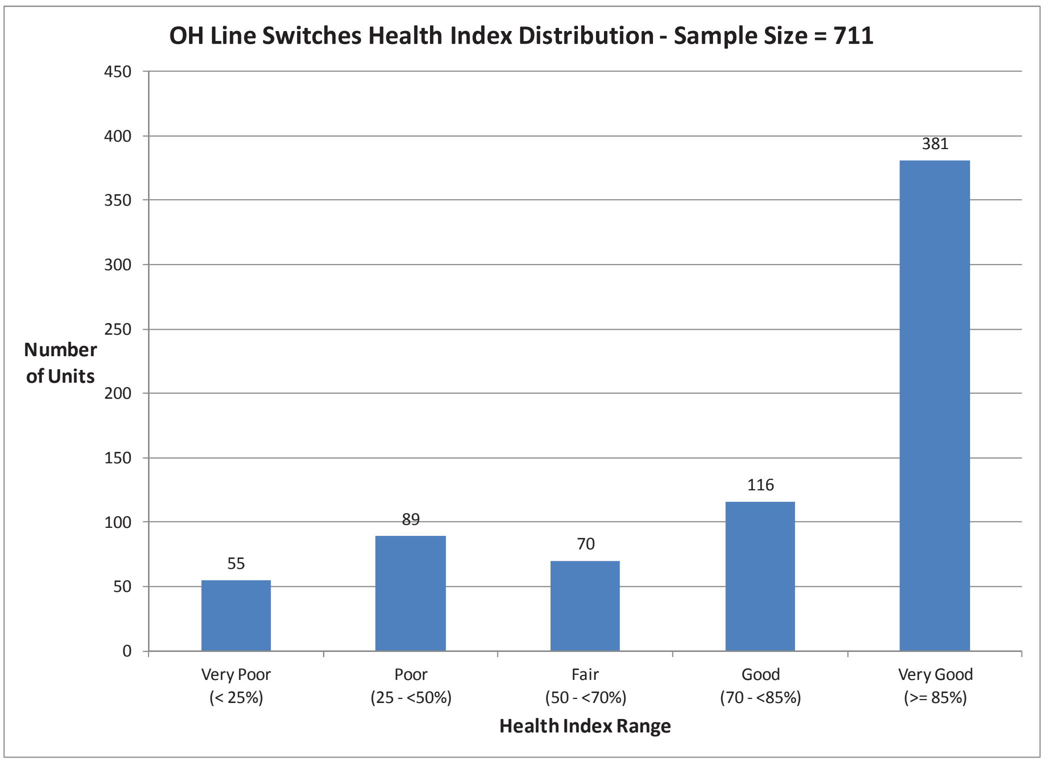

Figure 6-3 Overhead Line Switches Health Index Distribution (Number of Units)

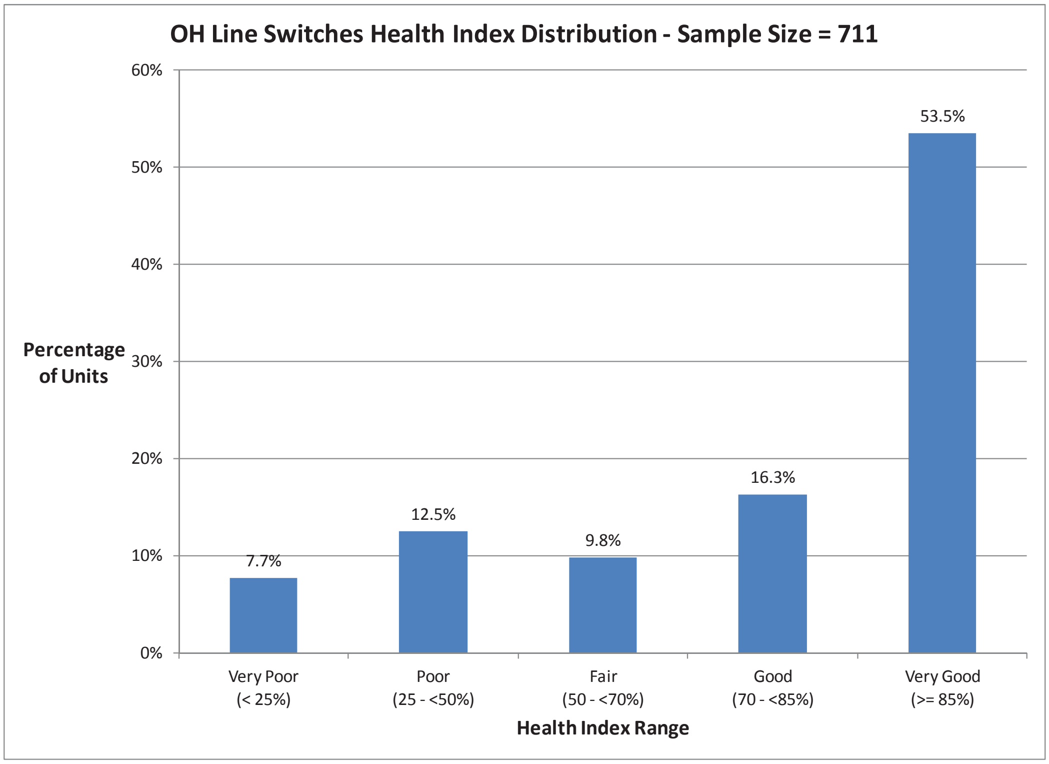

Figure 6-4 Overhead Line Switches Health Index Distribution (Percentage of Units)

6.5 Overhead Line Switches Condition-Based Flagged-For-Action Plan

As it is assumed that Overhead Line Switches are reactively replaced, the Flagged-For-Action Plan is based on asset failure rate f (t), as described in Section II.2.2.

The Flagged-For-Action Plan is based on the number of expected failures in a given year.

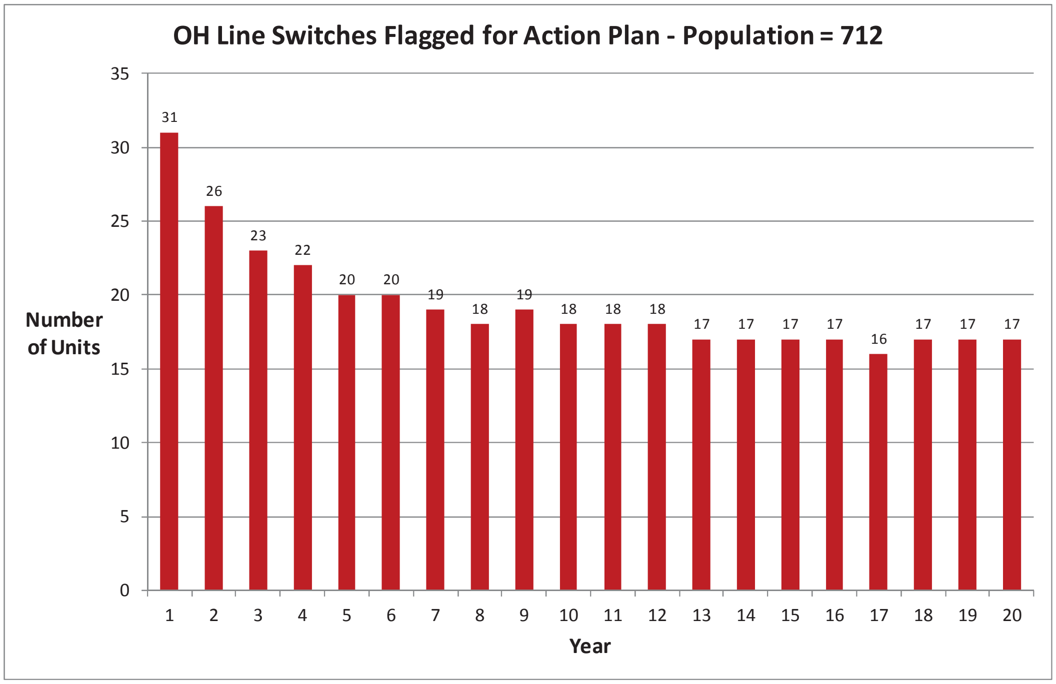

Figure 6-5 Overhead Line Switches Condition-Based Flagged-For-Action Plan

6.6 Overhead Line Switches Data Analysis

The data available for Overhead Line Switches includes age only.

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7 Wood Poles

Wood poles are used to support primary distribution lines at voltages from 4.16 kV to 44 kV. The wood species commonly used for distribution wood poles predominantly include Red Pine, Jack Pine and Western Red Cedar (WRC), either butt-treated or full-length treated. Smaller numbers of Larch, Fir, White Pine and Southern Yellow Pine have also been used.

Distribution line design standards dictate usage of poles of varying height and strength, depending upon the number and size of conductors, the average length of adjacent spans, maximum loadings, line angles, appropriate loading factors and the mass of installed equipment. Poles are categorized into Classes (1 to 7) which reflect the relative strength of the pole. Stronger poles (lower numbered classes) are used for supporting equipment and handling stresses associated with corner structures and directional changes in the line. The height of a pole is determined by a number of factors, such as the number of conductors it must support, equipment-mounting requirements, clearances below the conductors for roads and the presence of coaxial cable and/or other telecommunications facilities.

7.1 Wood Poles Degradation Mechanism

Since wood is a natural material, the degradation processes are somewhat different to those which affect other physical assets on electricity distribution systems. The critical processes are biological involving naturally occurring fungi that attack and degrade wood, resulting in decay. The nature and severity of the degradation depends both on the type of wood and the environment. Certain species of fungi are known to attack the external surfaces of the pole and some the internal heartwood. Therefore, the mode of degradation can be split into either external rot or internal rot. As the decay processes requires the presence of water and oxygen, the area of the pole most susceptible to degradation is at and around the ground line or at the top of the pole. Although it is possible in some circumstances for decay to occur in other locations, it is normal to concentrate inspection and assessment of poles in the most critical areas. In addition to the natural degradation processes, external damage to the pole by wildlife can also be a significant problem. Examples may include attack by termites, small mammals or woodpeckers.

To prevent attack and decay, wood poles are treated with preservatives prior to being installed. The preservatives have two functions; firstly, to keep out moisture vital to fungal attacks, and, secondly, as a biocide to kill off fungus spores. As wood pole use has evolved in the electricity industry, the nature of the preservatives used to treat the wood has also evolved, as the chemicals used previously have become unacceptable from an environmental viewpoint.

As a structural item, the sole concern when assessing the condition of a wood pole is the native reduction in mechanical strength due to degradation or damage. A particular problem when assessing wood poles is the potentially large variation in their original mechanical properties. Depending on the species, the mechanical strength of a new wood pole can vary greatly. Typically, the first standard deviation has a width of ±15% for poles nominally in the same class.

However, in some test programs, the minimum measured strength has been as low as 50% of the average.

Assessment techniques start with simple visual inspection of poles. This is often accompanied by basic physical tests such as prodding tests and hammer tests to detect evidence of internal decay. Over the past 20 years, electricity companies have sought more objective and accurate means of determining condition and estimating remaining life. This has led to the development of a wide range of condition assessment and diagnostic tools and techniques for wood poles. These include techniques that are designed to apply the traditional probing or hammer tests in a more controlled, repeatable and objective manner. Devices are available that measure the resistance of a pin fired into the pole to determine the severity of external rot and instrumented hammers that record and analyze the vibration caused by a hammer blow to identify patterns that indicate the presence of decay. Direct assessment of condition by using a decay resistance drill or an auger to extract a sample through the pole, are also widely used. Indirect techniques, ultrasonic, X-rays, electrical resistance measurement have also been widely used.

Although wood pole condition assessment is driven by the condition of the wood pole itself, replacement of the ancillary components, foundations, cross-arms, guys, anchors and insulators may also be required. The poles, foundations and cross-arms support the required insulators and phase conductors. The guys and anchors maintain the mechanical integrity of the structure and the insulators electrically insulate the conductors from ground potential.

There are many factors considered by utilities when establishing condition for wood poles. These include species of wood, historic rates of decay and average lifetimes, environment, perceived effectiveness of available techniques and cost. However, perhaps the most significant is the policy of routine line inspections. A foot patrol of overhead lines undertaken on a regular cycle is extremely effective in addressing the required safety and security obligations.

Consequences of an in-service pole failure are quite serious, as they could lead to a serious accident involving the public. Depending on the number of circuits supported, a pole failure may also lead to a power interruption for a significant number of customers.

7.2 Wood Poles Health Index Formulation

This section presents the Health Index Formula that was developed and used for Horizon Utilities Wood Poles. The Health Index equation is shown in Section II.1; the condition, sub-condition parameters, weights, and condition criteria are as follows.

Assume a parameter scoring system of 0 through 4, where 0 and 4 represent the “worst” and “best” scores respectively. Thus, the maximum score for any condition or sub-condition parameter (maximum CPS and CPF) is “4”.

7.2.1 Wood Poles Condition and Sub-Condition Parameters

Table 7-1 Wood Poles Condition Weights and Maximum CPS

m	Condition Parameter	WCP_m	CPS Lookup Table
1	Pole Strength	5	Table 7-2
2	Service Record	3	Table 7-3

Table 7-2 Wood Pole Strength (m=1) Weights and Maximum CPF

n	Sub-Condition Parameter	CPF Lookup table	$WCPF_n$	$CPF_{n.max}$
1	Pole Strength	Table 7-5	1	4

Table 7-3 Wood Poles Service Record (m=4) Weights and Maximum CPF

n	Sub-Condition Parameter	CPF Lookup table	$WCPF_n$	$CPF_{n.max}$
1	Age	Figure 7-1	2	4
2	Overall	Table 7-4	1	4

7.2.2 Wood Poles Condition Parameter Criteria

Overall Condition

Table 7-4 Wood Poles Overall Condition Criteria

CPF	Description
4	Good
2	Fair
0	Poor

Pole Strength

Table 7-5 Pole Strength Condition Criteria

CPF	Description (percentage of original strength at installation)
4	100
3	90
2	75
1	66
0	33

Age

Assume that the failure rate for Wood Poles exponentially increases with age and that the failure rate equation is as follows:

$$f = e^{\beta(t-\alpha)}$$

f	= failure rate of an asset (percent of failure per unit time)
t	= time
α, β	= constant parameters that control the rise of the curve

The corresponding survivor function is therefore:

$$S_f = 1 - P_f = e^{-(f-e^{-\alpha\beta})/\beta}$$

S_f	= survivor function
P_f	= probability of failure

Assuming that at the ages of 50 and 65 years the probability of failures (P_f) for this asset are 20% and 80% respectively results in the survival curve shown below. It follows that the CPF for Age is the survival curve normalized to the maximum CPF score of 4 (i.e. 4*Survival Curve). The CPF vs. Age for wood poles is also shown in the figure below:

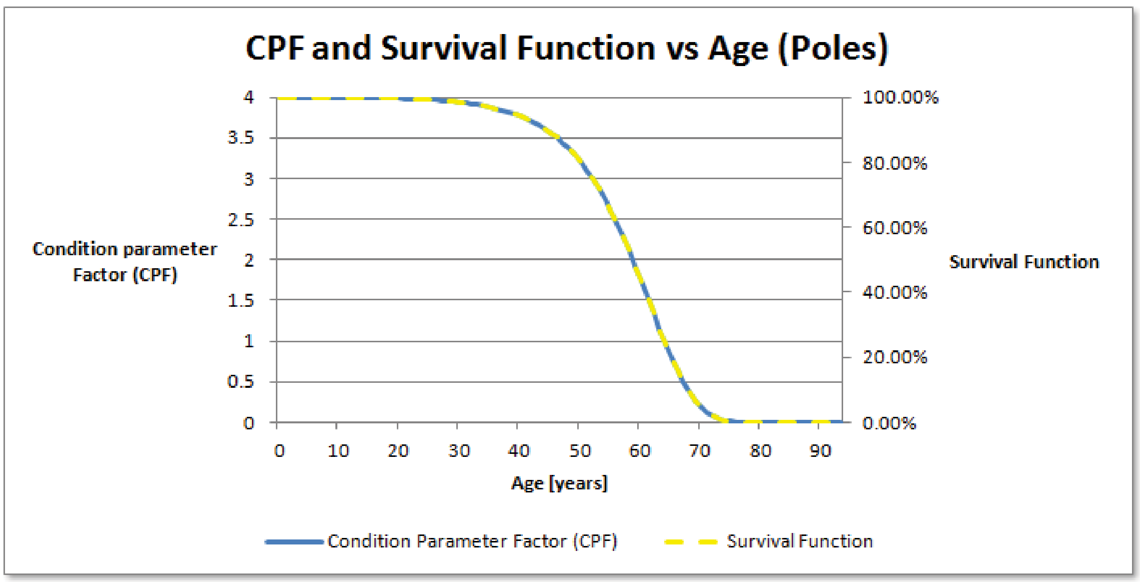

Figure 7-1 Wood Pole Age Condition Criteria (Wood Poles)

7.3 Wood Poles Age Distribution

The age distribution is shown in the figure below. Age was available for all the population. The average age was found to be 32 years.

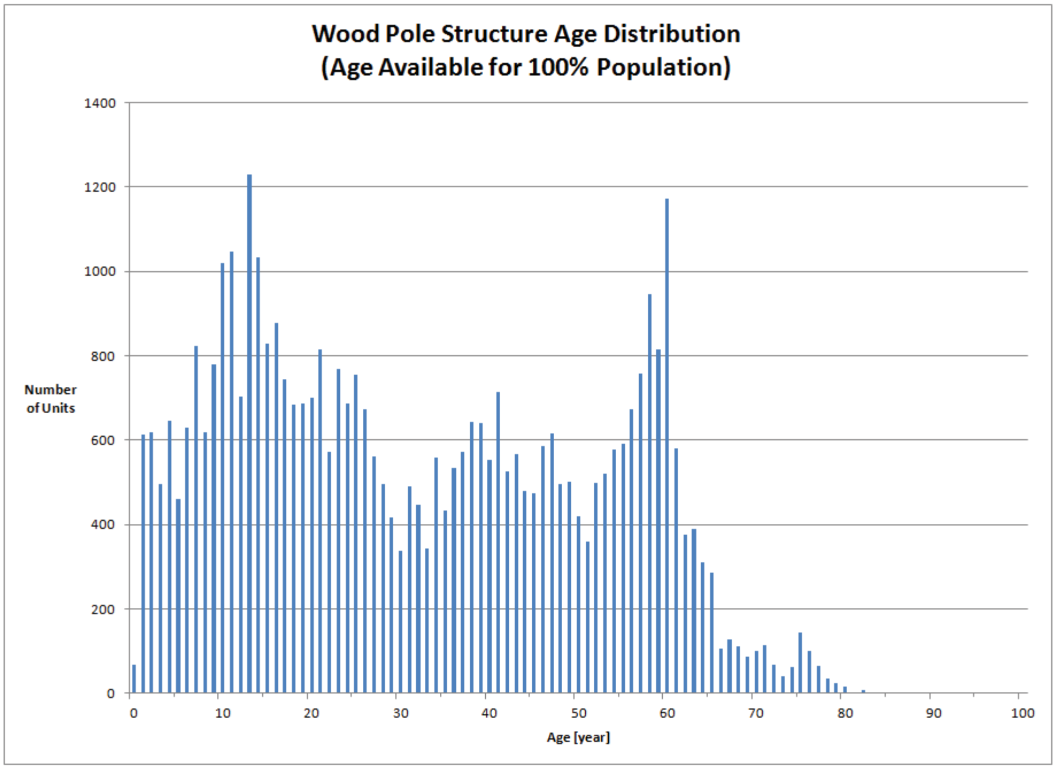

Figure 7-2 Wood Poles Age Distribution

7.4 Wood Poles Health Index Results

There are 42037 in-service Wood Poles at Horizon Utilities.

The average Health Index for this asset group is 86%. Approximately 11% of the units were found to be in poor or very poor condition.

The Health Index Results are as follows:

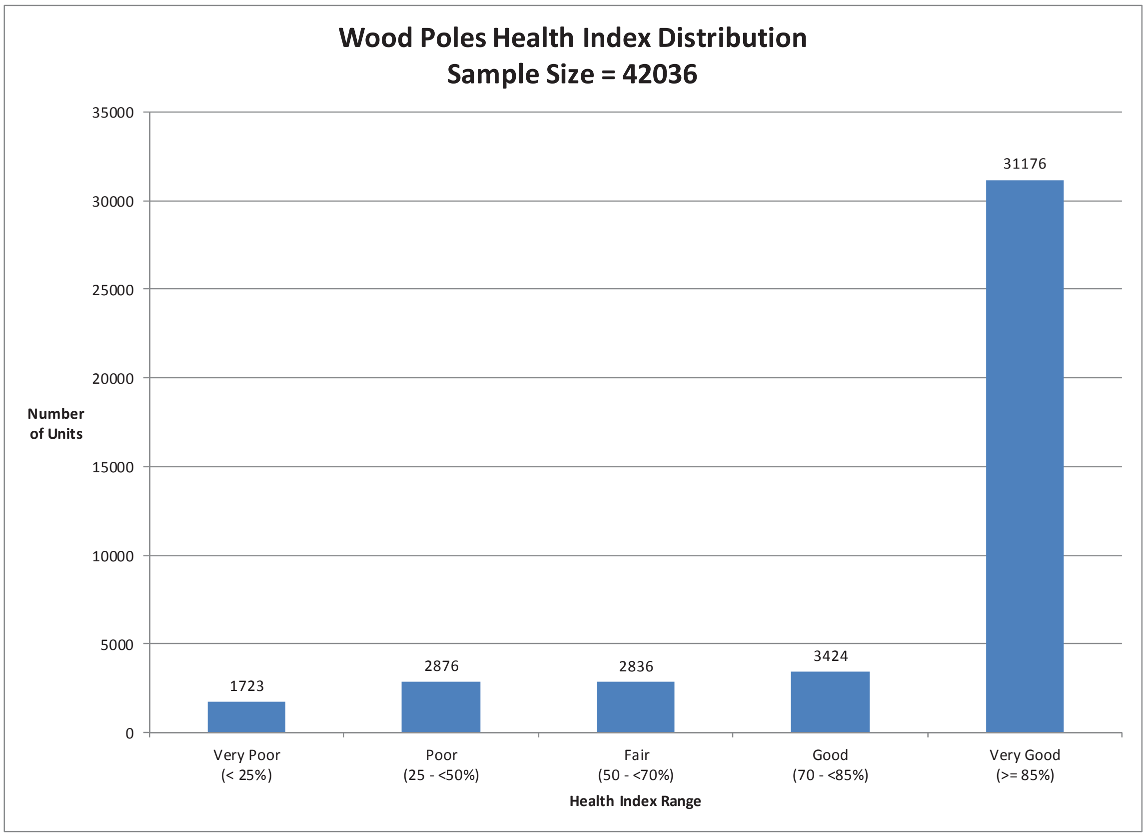

Figure 7-3 Wood Poles Health Index Distribution (Number of Units)

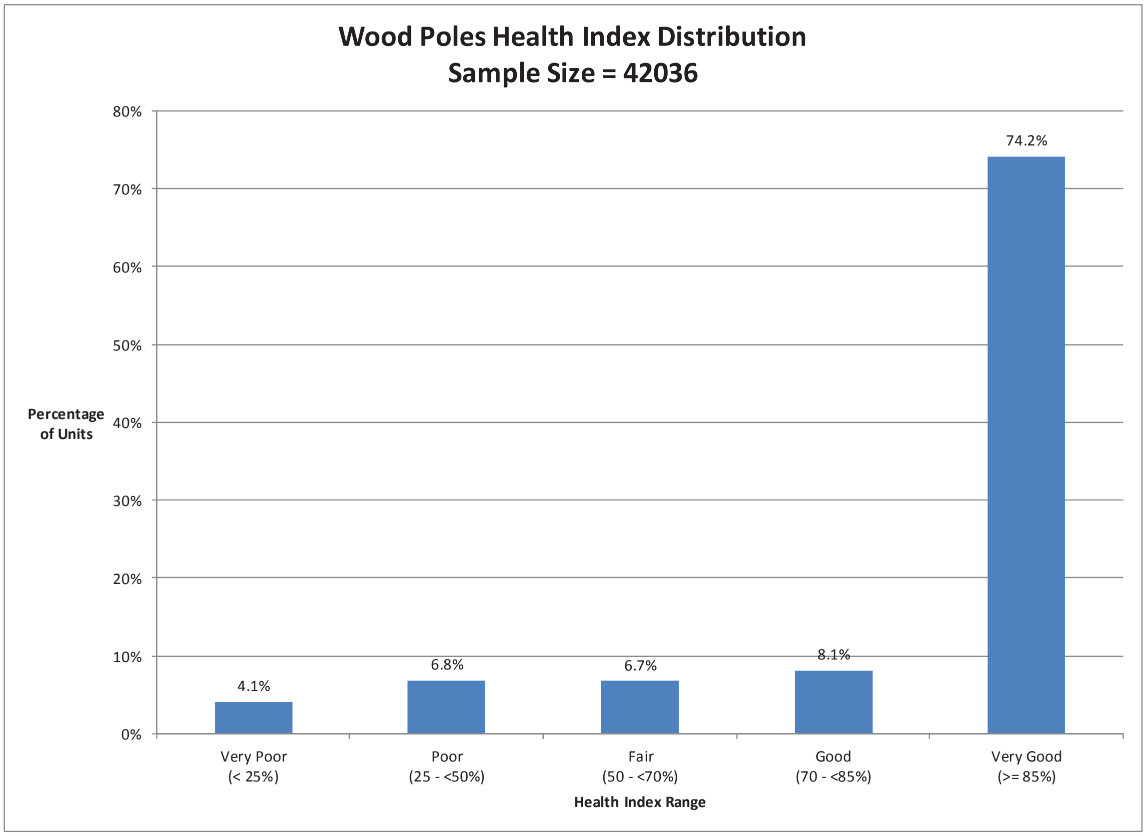

Figure 7-4 Wood Poles Health Index Distribution (Percentage of Units)

7.5 Wood Poles Condition-Based Flagged-For-Action Plan

As it is assumed that Wood Poles are reactively replaced, the Flagged-For-Action Plan is based on asset failure rate f (t), as described in Section II.2.2.

The Flagged-For-Action Plan is based on the number of expected failures in a given year.

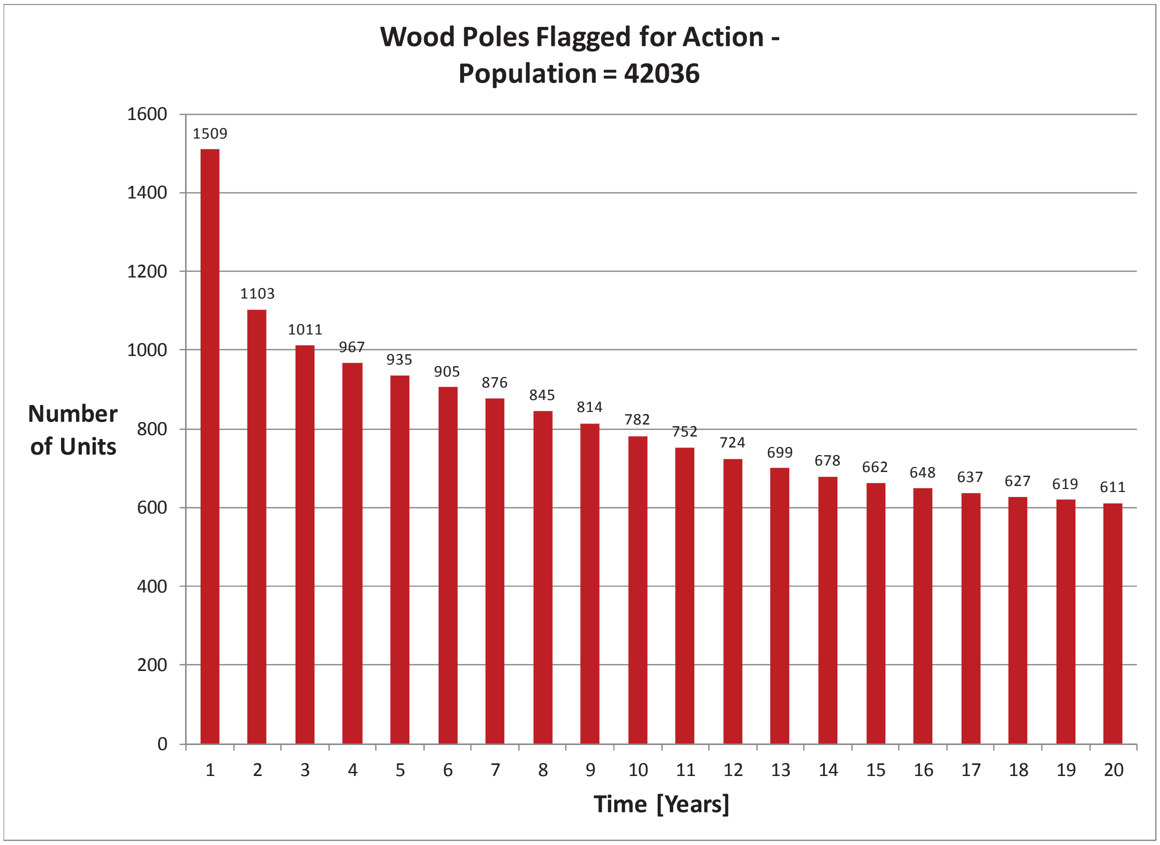

Figure 7-5 Wood Poles Condition-Based Flagged-For-Action Plan

7.6 Wood Poles Data Analysis

It is recommended that Horizon Utilities continues with the existing wood pole testing and inspection practices.

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8 Concrete Poles

Concrete poles are used primarily in the construction of higher voltage distribution or sub-transmission overhead lines. They are available with round, square and octagonal cross-sections in lengths up to 60 feet. The strength of the pole is specified by a Class from A to D indicating light to heavy duty. They are supplied with a variety of pre-determined attachment patterns. Concrete poles are a relatively expensive option compared to wood or steel poles. They are heavy to transport and install. They have a clean matte appearance that is stable over long time periods and blends in to most environments. They have a longer expected service life than wood or steel. They are harder to climb and to make attachments to once they are in service.

8.1 Concrete Poles Degradation Mechanism

Concrete poles age in the same manner as any other concrete structure. Any moisture ingress inside the concrete pores would result in freezing during the winter and damage to concrete surface. Road salt spray can further accelerate the degradation process and lead to concrete spalling. Typical concrete mixes employ a washed-gravel aggregate and have extremely high resistance to downward compressive stresses (about 3,000 lb./sq. in); however, any appreciable stretching or bending (tension) will break the microscopic rigid lattice resulting in cracking and separation of the concrete. The spun concrete process used in manufacture of poles prevents moisture entrapment inside the pores. Spun, pre-stressed concrete is particularly resistant to corrosion problems common in a water-and-soil environment.

8.2 Concrete Poles Health Index Formulation

This section presents the Health Index Formula that was developed and used for Horizon Utilities Concrete Poles. The Health Index equation is shown in Section II.1; the condition, sub-condition parameters, weights, and condition criteria are as follows.

Assume a parameter scoring system of 0 through 4, where 0 and 4 represent the “worst” and “best” scores respectively. Thus, the maximum score for any condition or sub-condition parameter (maximum CPS and CPF) is “4”.

8.2.1 Concrete Poles Condition and Sub-Condition Parameters

Table 8-1 Concrete Poles Condition Weights and Maximum CPS

m	Condition Parameter	WCP_m	CPS Lookup Table
1	Service Record	1	Table 7-3

Table 8-2 Concrete Poles Service Record (m=1) Weights and Maximum CPF

n	Sub-Condition Parameter	CPF Lookup table	$WCPF_n$	$CPF_{n.max}$
1	Age	Table 8-1	1	4

8.2.2 Concrete Poles Condition Parameter Criteria

Age

Assume that the failure rate for Concrete Poles exponentially increases with age and that the failure rate equation is as follows:

$$f = e^{\beta(t-\alpha)}$$

f = failure rate of an asset (percent of failure per unit time)
t = time
α, β = constant parameters that control the rise of the curve

The corresponding survivor function is therefore:

$$S_f = 1 - \ P_f = e^{-(f-e^{-\alpha\beta})/\beta}$$

S_f = survivor function
P_f = probability of failure

Assuming that at the ages of 65 and 80 years the probability of failures (P_f) for this asset are 50% and 85% respectively results in the survival curve shown below. It follows that the CPF for Age is the survival curve normalized to the maximum CPF score of 4 (i.e. 4*Survival Curve). The CPF vs. Age for concrete poles is also shown in the figure below:

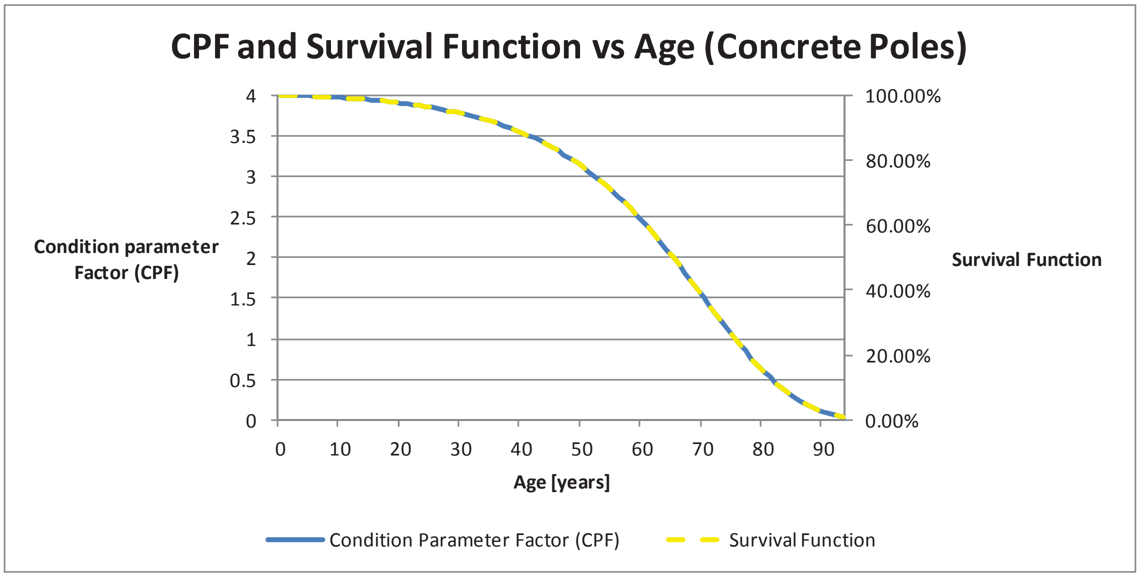

Figure 8-1 Concrete Pole Age Condition Criteria (Concrete Poles)

8.3 Concrete Poles Age Distribution

The age distribution is shown in the figure below. Age was available for all the population. The average age was found to be 27 years.

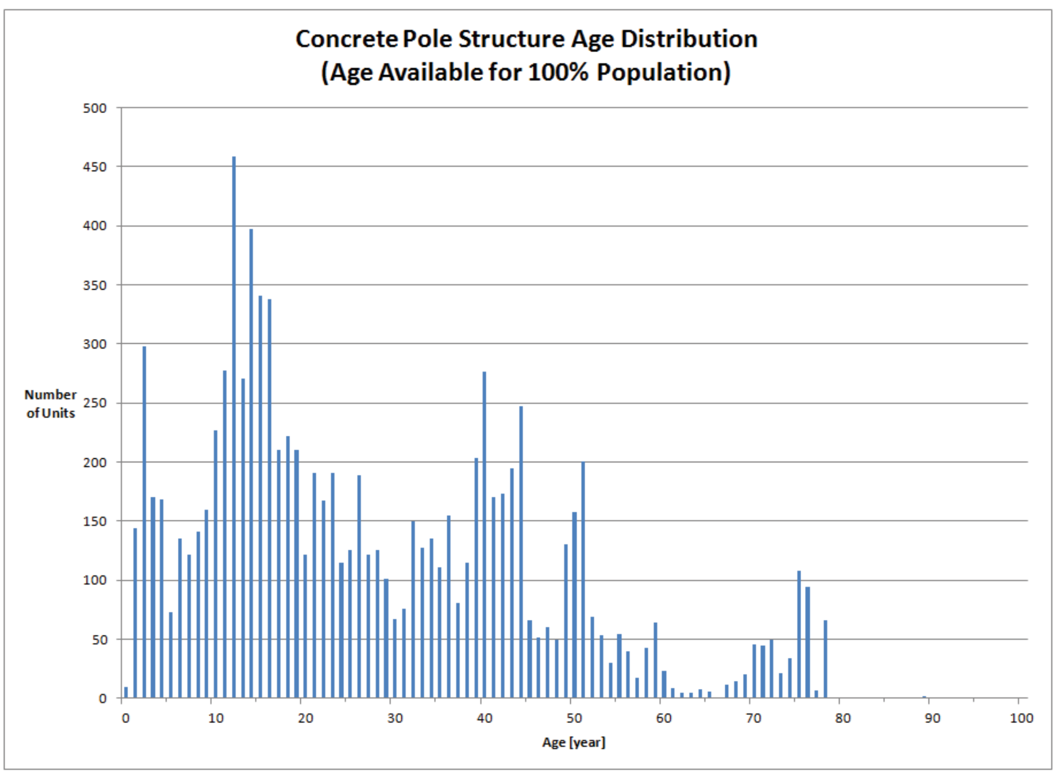

Figure 8-2 Concrete Poles Age Distribution

8.4 Concrete Poles Health Index Results

There are 9761 in-service Concrete Poles at Horizon Utilities. The HI is based on age only.

The average Health Index for this asset group is 90%. Approximately 31% of the units were found to be in poor or very poor condition.

The Health Index Results are as follows:

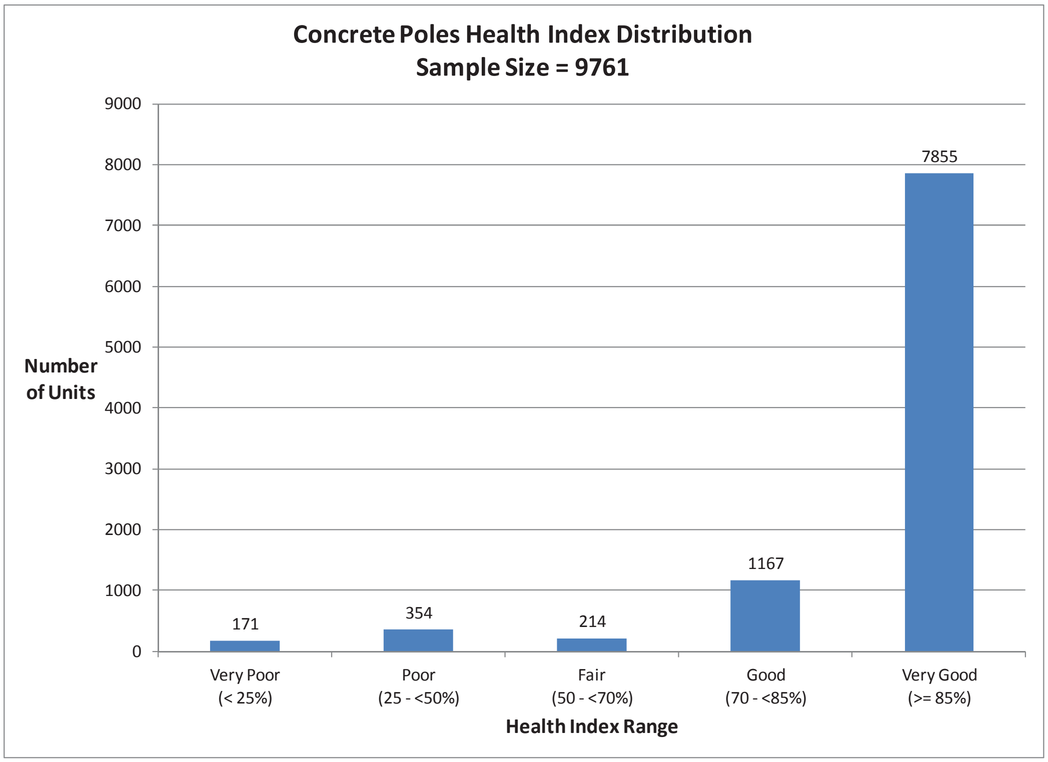

Figure 8-3 Concrete Poles Health Index Distribution (Number of Units)

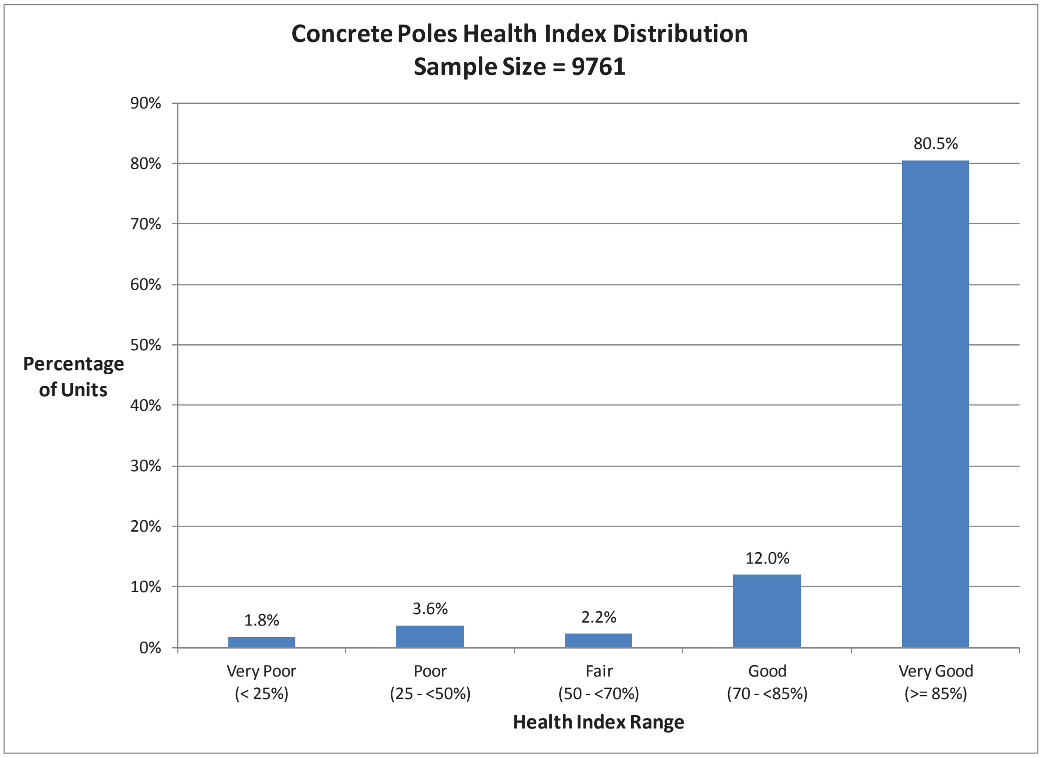

Figure 8-4 Concrete Poles Health Index Distribution (Percentage of Units)

8.5 Concrete Poles Condition-Based Flagged-For-Action Plan

As it is assumed that Concrete Poles are proactively replaced, the Flagged-For-Action Plan is based on asset failure rate f (t), as described in Section II.2.2.

The Flagged-For-Action Plan is based on the number of expected failures in a given year.

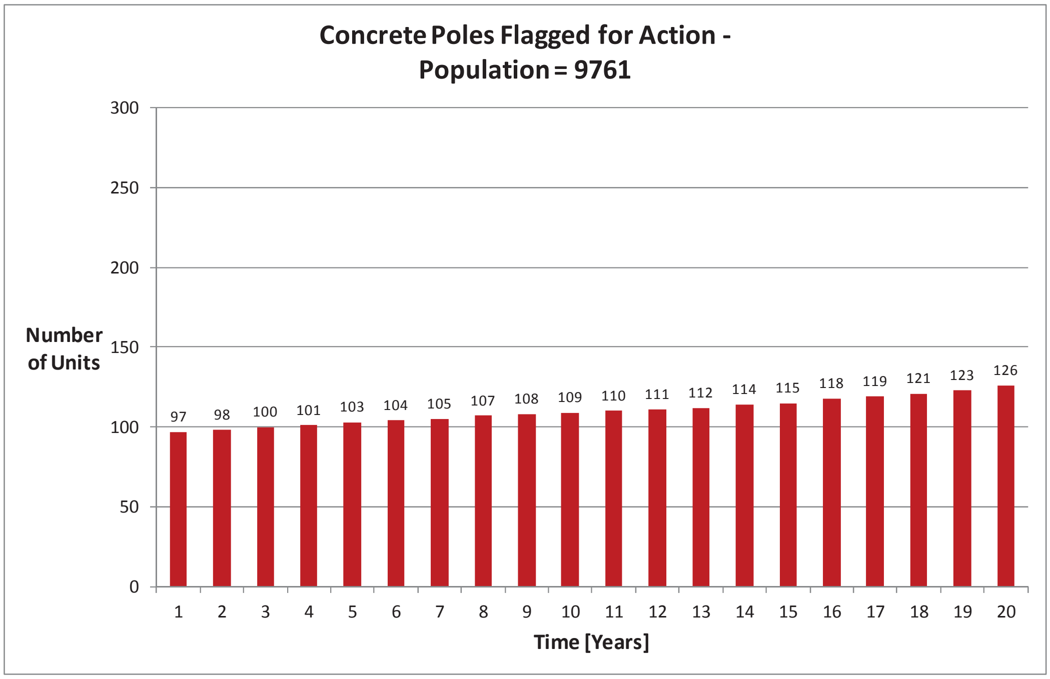

Figure 8-5 Concrete Poles Condition-Based Flagged-For-Action Plan

8.6 Concrete Poles Data Analysis

The data available for Concrete Poles includes age only.

9 Underground Cables

The asset category of distribution system underground cables includes underground cross-link-polyethylene (XLPE) cables, paper insulated lead covered (PILC) cables, splices/joints, elbows, potheads and terminators at voltage levels 44 kV and below. It includes direct buried and installed-in-duct feeder cables, underground cable sections running from stations to overhead lines and from overhead lines to customer stations and switches.

The use of insulated cables on distribution feeders has virtually become a standard in most North American jurisdictions for urban residential areas where it is either impossible or extremely difficult to build overhead lines due to aesthetic, legal, environmental or safety reasons. The initial capital cost of a distribution underground feeder cable circuit is approximately three times the cost of an overhead line of equivalent capacity and voltage.

Distribution underground feeder cables are one of the more challenging assets for electricity systems from a condition assessment and asset management viewpoint. Underground cables are a relatively expensive asset. However, it is very difficult and therefore very expensive to obtain meaningful condition information for buried cables. Underground cable systems, unlike overhead lines, do not suffer from weather induced faults and have better reliability records.

In this study, there are three types of underground cable system:

- Primary underground cable
- Secondary underground cable
- Service underground cable

9.1 Underground Cables Degradation Mechanism

Faults on underground feeder cables are usually caused by insulation failure within a localized area and when failures do occur they can be repaired at much lower cost than replacement of the entire cable. Thus, the standard approach to cable system management has been based on reliability rather than the balance between repair and replacement costs. As long as the reliability is within acceptable levels, it is virtually always cheaper to repair than replace cables.

Many utilities with high proportions of over 40 years old underground cables have concerns about reliability. Condition assessment programs enable utilities to prioritize the cable replacement programs based on available budgets.

Over the past 30 years XLPE insulated cables, due to their lower costs and easier splicing have all but replaced paper-insulated cables in new installations. The existing population of XLPE cables is still relatively young in terms of normal cable lifetimes. Therefore, failures that have occurred can be classified as early life failures. In the early days of polymeric insulated cables, their reliability was questionable. Many of the problems were associated with joints and accessories or defects introduced during manufacturing. Over the past 30 years many of these problems have been addressed, and modern XLPE cables and accessories are generally considered very reliable if manufactured and installed through competent workmanship.

Polymeric insulation is very sensitive to discharge activity, thus, cable, joints and accessories must be discharge free when installed. Water penetration into the insulation/conductor barrier, existence of impurities within the semiconducting layer and presence of high dielectric stress are the principal causes of insulation treeing and the most significant degradation processes for earlier generation of polymeric cables. The rate of water tree growth depends on the quality of the polymeric insulation and the manufacturing process. In addition to manufacturing improvements, development of tree retardant XLPE cables and designs with metal foil barriers and water migration controls have further reduced the rate of deterioration from treeing.

Examining recovered failed cable samples to detect and quantify treeing serves as an effective means to assess the general condition and estimate the future life of XLPE cables. Alternatively, accelerated electrical testing of recovered cables can also be used to determine condition.

Most utilities are beginning to determine the condition of their cables through lab testing and in-situ testing. In the absence of testing, the only other indicators of cable health are:

- Number of failures per unit length of installation
- Age of Cables

At this time, the precise life expectancy of XLPE cables is difficult to ascertain. XLPE cable life expectancy is less than PILC cable. The life expectancy of early generation XLPE cables is expected to be less than 40 years while the newer, tree-retardant (TR) XLPE cables is expected to be in service in excess of 40 years.

The major consequences of cable failure are adverse impacts on reliability. Fundamentally, end of life cannot be predicted since most insulation system failures are related to the occurrence of a transient event such as an overvoltage caused by breaker operations, lightning strikes or flashovers, etc. However, diagnostic testing can indicate the status of insulation and therefore show the likelihood of failure at external factors.

9.2 Underground Cables Health Index Formulation

This section presents the Health Index Formula that was developed and used for Horizon Utilities Underground Cables. The Health Index equation is shown in Section II.1; the condition, sub-condition parameters, weights, and condition criteria are as follows.

Assume a parameter scoring system of 0 through 4, where 0 and 4 represent the “worst” and “best” scores respectively. Thus, the maximum score for any condition or sub-condition parameter (maximum CPS and CPF) is “4”.

9.2.1 Underground Cables Condition and Sub-Condition Parameters

Table 9-1 Condition Weights and Maximum CPS

m	Condition Parameter	WCP_m	CPS Lookup Table
1	Service Record	1	Table 9-2
	De-rating multiplier (DR)		Table 9-3

Table 9-2 Service Record (m=1) Weights and Maximum CPF

n	Sub-Condition Parameter	CPF Lookup table	$WCPF_n$	$CPF_{n.max}$
1	Age	Figure 9-1 to Figure 9-3	1	4

9.2.2 Condition Criteria

Age

Assume that the failure rate for Underground Cables exponentially increases with age and that the failure rate equation is as follows:

$$f = e^{\beta(t-\alpha)}$$

f	= failure rate of an asset (percent of failure per unit time)
t	= time
α, β	= constant parameters that control the rise of the curve

The corresponding survivor function is therefore:

$$S_f = 1 - P_f = e^{-(f-e^{-\alpha\beta})/\beta}$$

S_f	= survivor function
P_f	= probability of failure

--- Primary XLPE and Unknown

Assuming that at the ages of 30 and 40 years the probability of failures (P_f) for this asset are 50% and 80% respectively results in the survival curve shown below. It follows that the CPF for Age is the survival curve normalized to the maximum CPF score of 4 (i.e. 4*Survival Curve). The CPF vs. Age is also shown in the figure below:

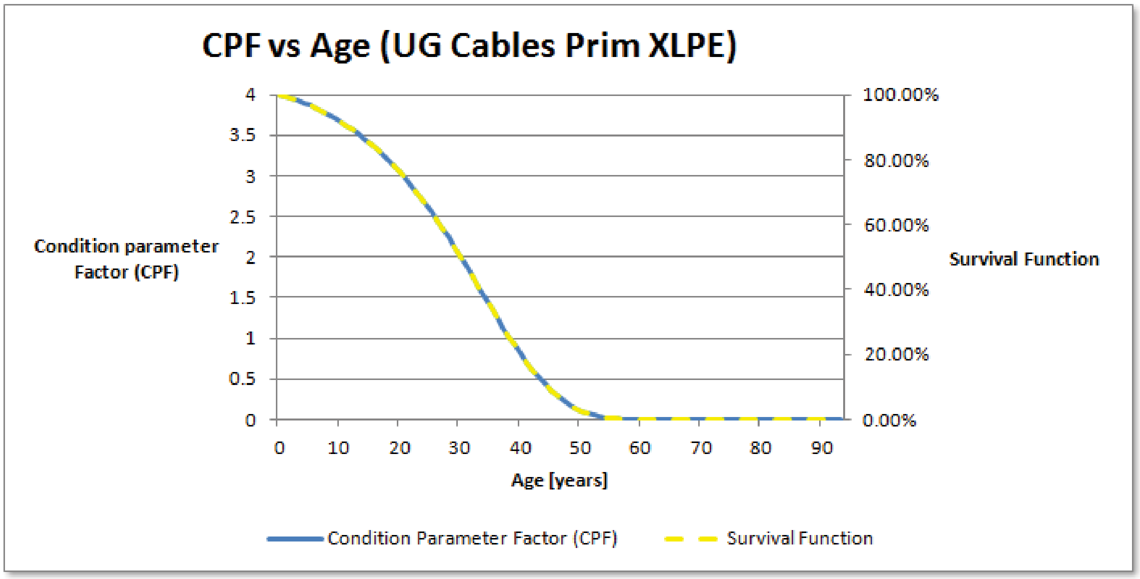

Figure 9-1 Age Condition Criteria (Underground Cables – Primary XLPE)

--- Primary PILC

Assuming that at the ages of 60 and 70 years the probability of failures (P_f) for this asset are 25% and 50% respectively results in the survival curve shown below. It follows that the CPF for Age is the survival curve normalized to the maximum CPF score of 4 (i.e. 4*Survival Curve). The CPF vs. Age is also shown in the figure below:

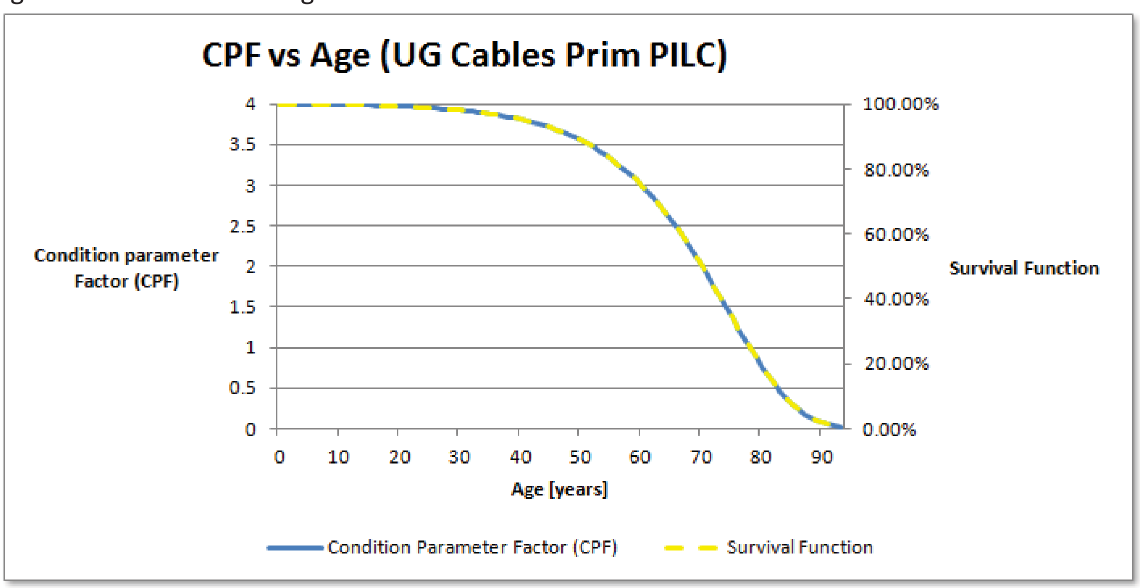

Figure 9-2 Age Condition Criteria (Underground Cables – Primary PILC)

--- Secondary/Service In-Duct and Direct Buried

Assuming that at the ages of 40 and 60 years the probability of failures (P_f) for this asset are 60% and 90% respectively results in the survival curve shown below. It follows that the CPF for Age is the survival curve normalized to the maximum CPF score of 4 (i.e. 4*Survival Curve). The CPF vs. Age is also shown in the figure below:

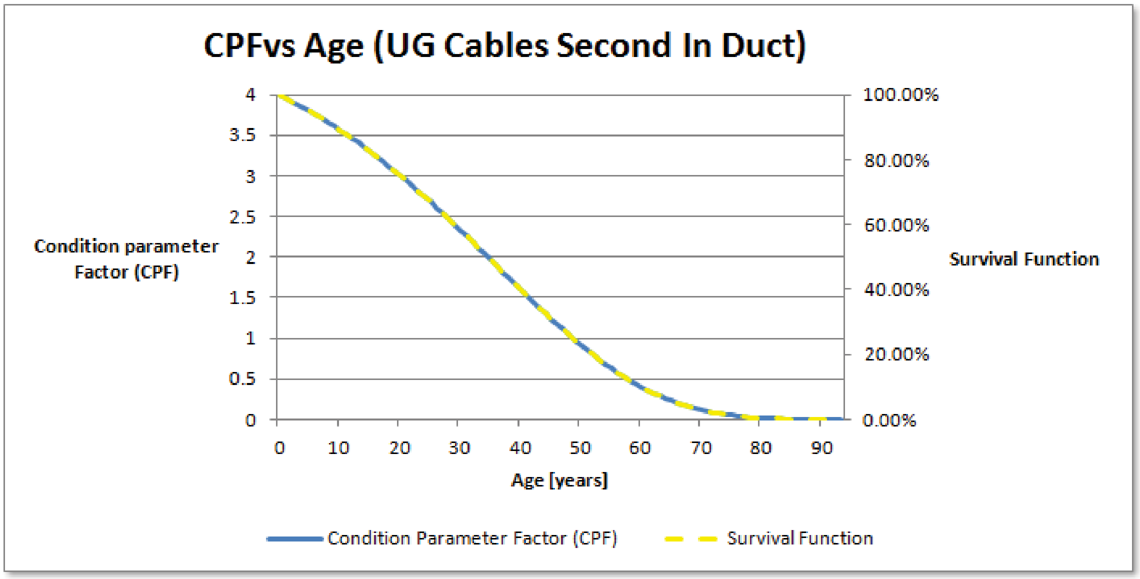

Figure 9-3 Age Condition Criteria (Underground Cables – Secondary/Service)

De-Rating (DR) Multiplier

The de-rating is based on the following equation:

$$DR = \min(DRF_1, DRF_2, DRF_3)$$

Equation 9-1

Where DRF are as described in Table 9-3

Table 9-3 De-Rating Factors

De-Rating Factor (DRF)	De-Rating Factor	Description
DRF_1	0.7	Aluminum secondary and service cables older than year 1985
DRF_2	0.7	Stoney Creek Mountain primary cables (direct buried)

9.3 Underground Cables Age Distribution

The age distribution is shown in the figures below. Age was available for 100% of the population. The average age was found to be 22 and 34 years, for primary underground XLPE and PILC cables respectively. For both secondary underground direct buried and in-duct cables, the average age was found to be 29 years. For service underground direct buried and in-duct cables, the average age was found to be 33 and 13 years respectively.

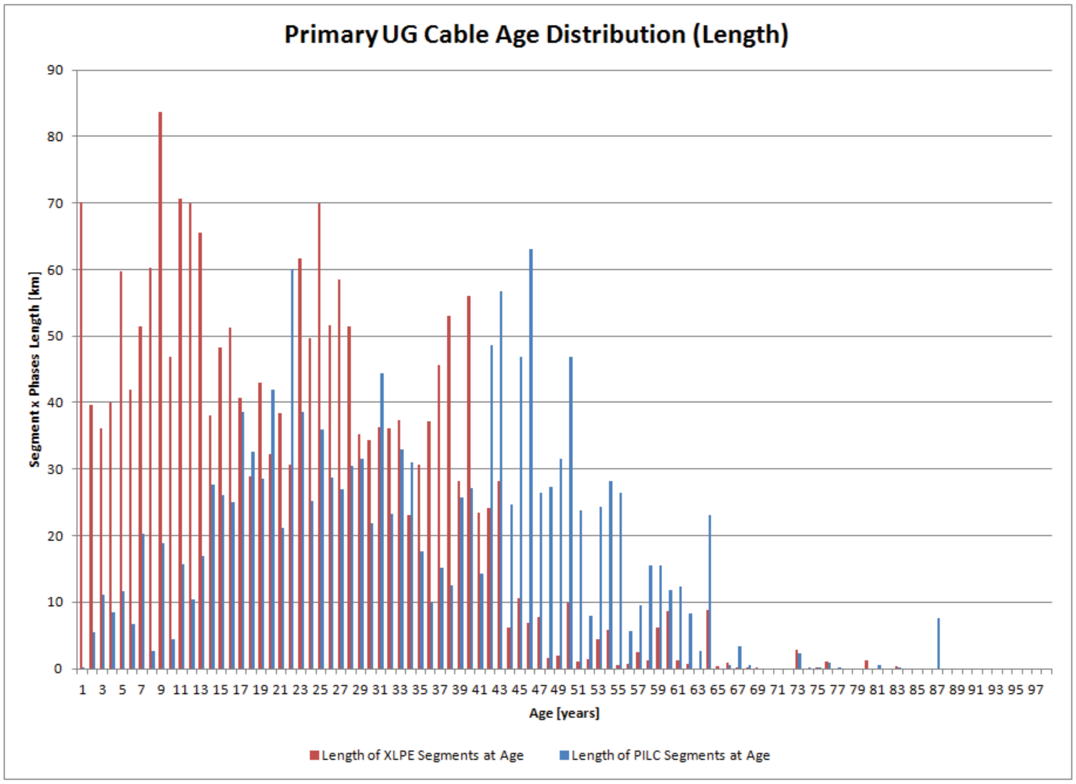

Figure 9-4 Underground Cables Age Distribution (Primary)

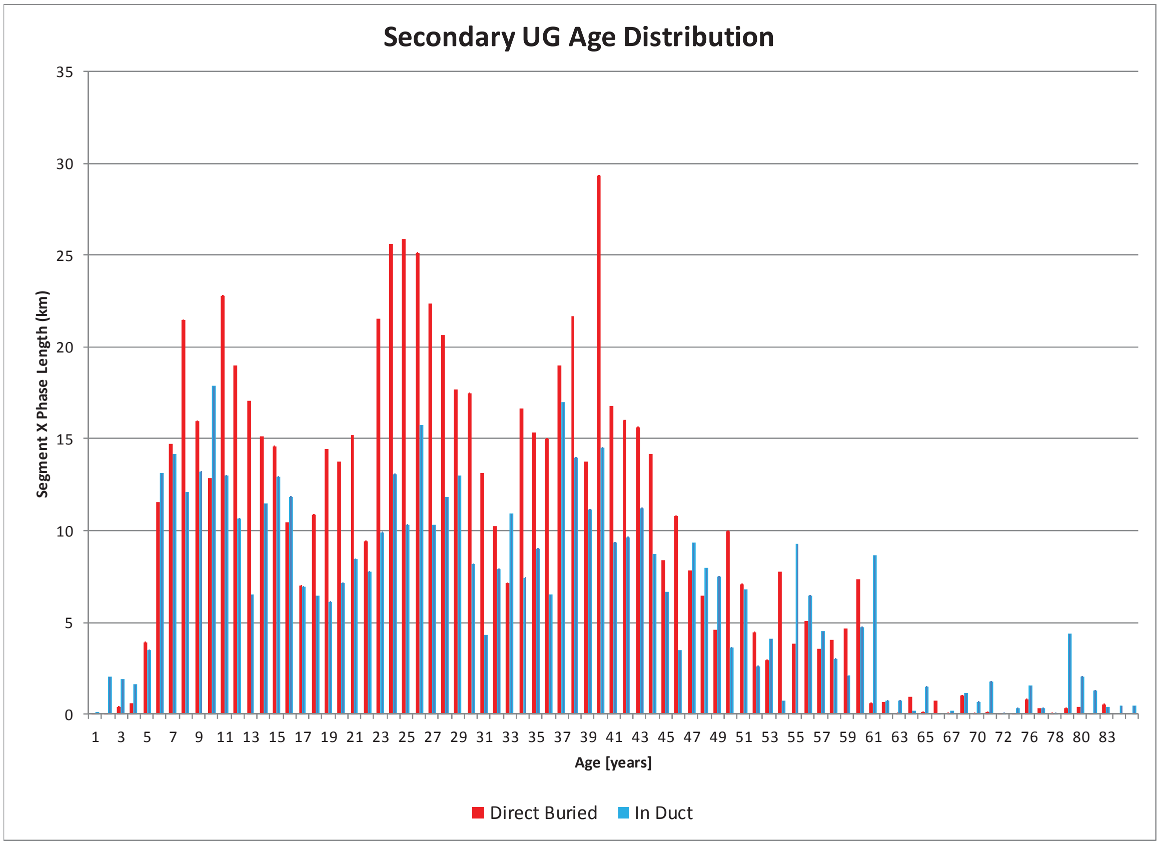

Figure 9-5 Underground Cables Age Distribution (Secondary)

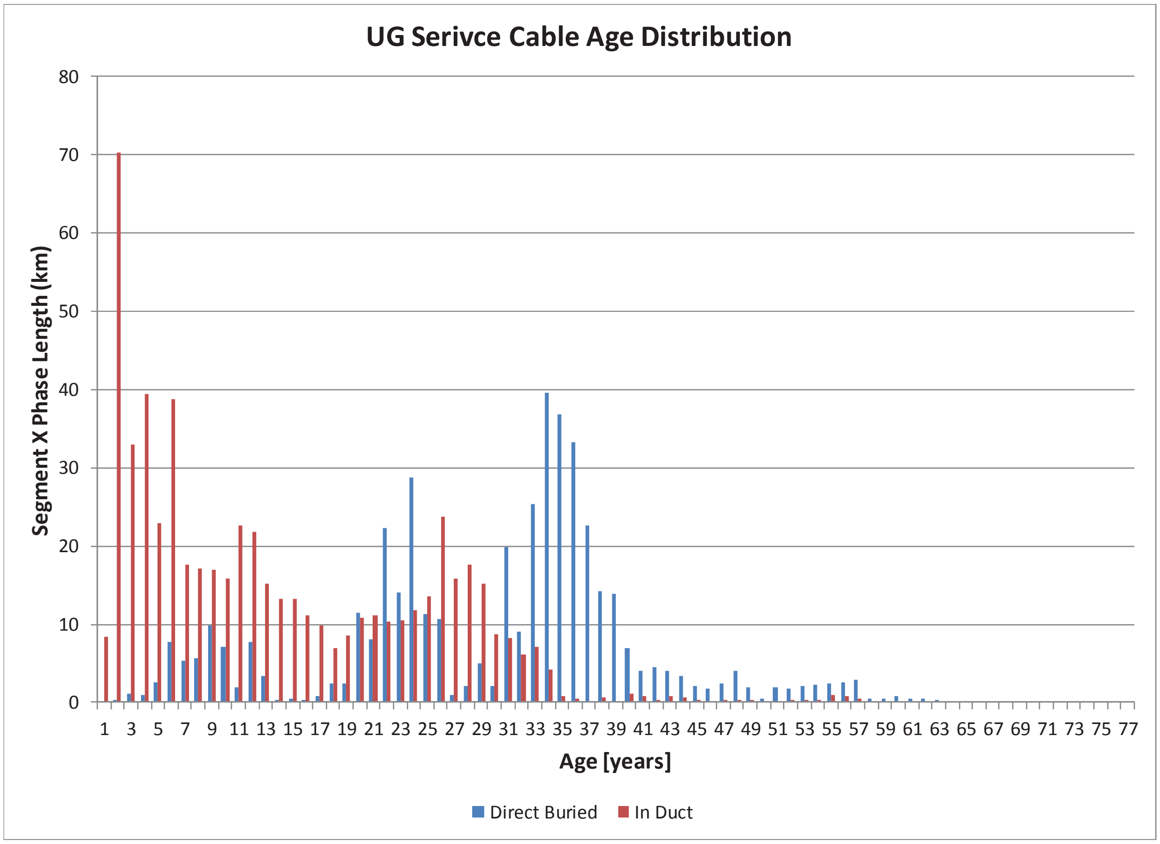

Figure 9-6 Underground Cables Age Distribution (Service)

9.4 Underground Cables Health Index Results

There are 3592 km, 1290 km and 1035 km in-service Underground Cables at Horizon Utilities, for primary, secondary and service systems respectively. The condition assessment is mainly age-driven, together with some de-ratings based on locations and conductor types.

The Health Index Results are as follows:

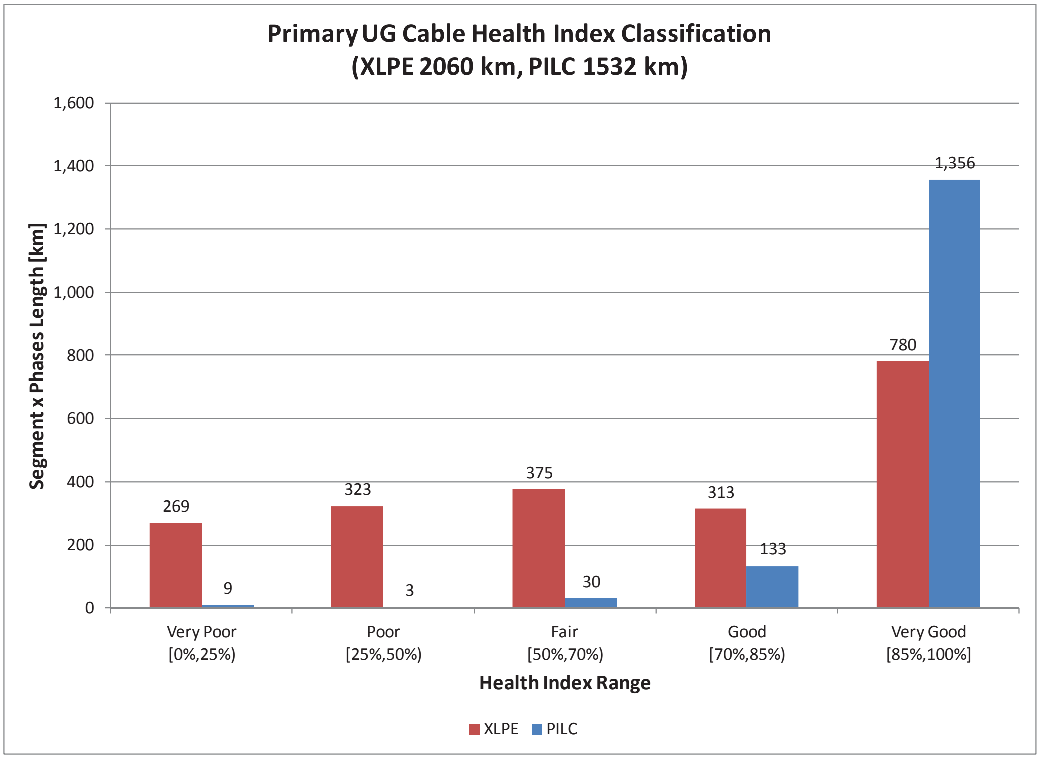

Figure 9-7 Underground Cables Health Index Distribution (Length, Primary)

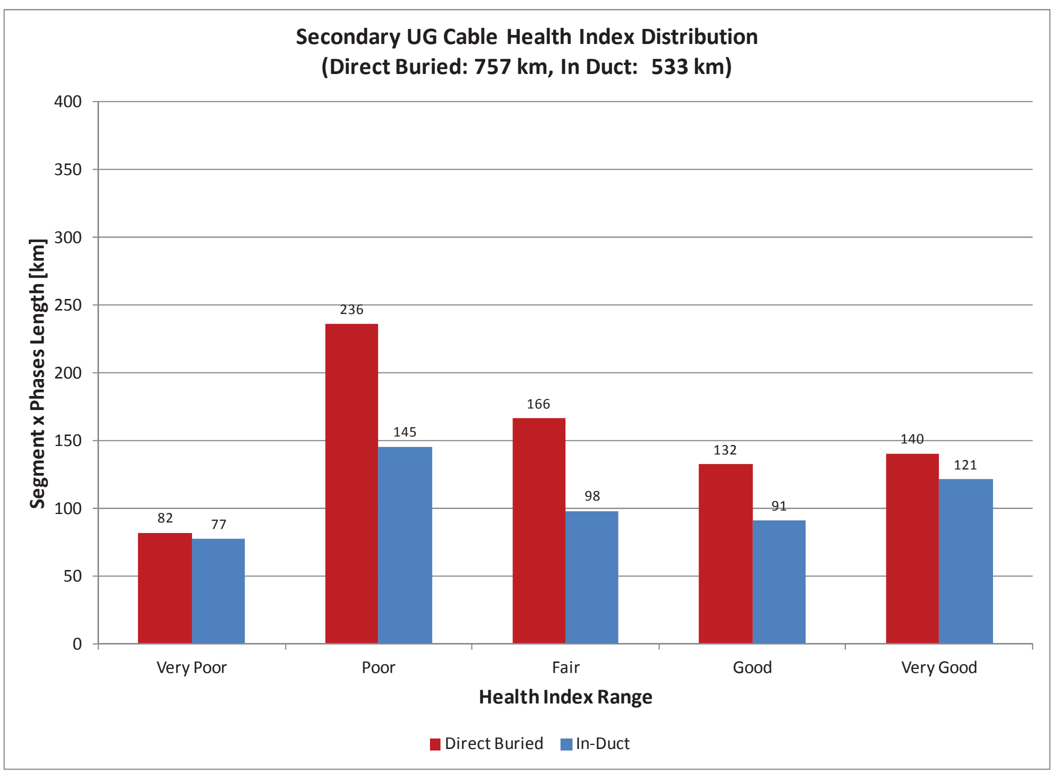

Figure 9-8 Underground Cables Health Index Distribution (Length, Secondary)

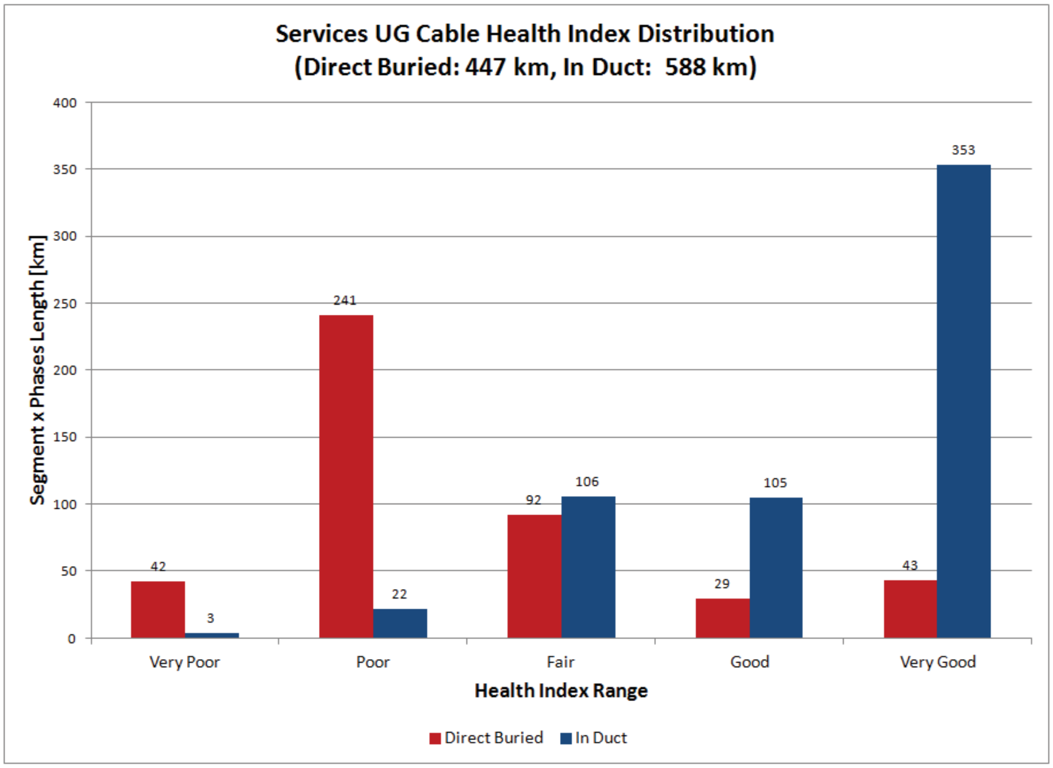

Figure 9-9 Underground Cables Health Index Distribution (Length, Service)

The following diagrams show the primary UG cables health index at different voltage level.

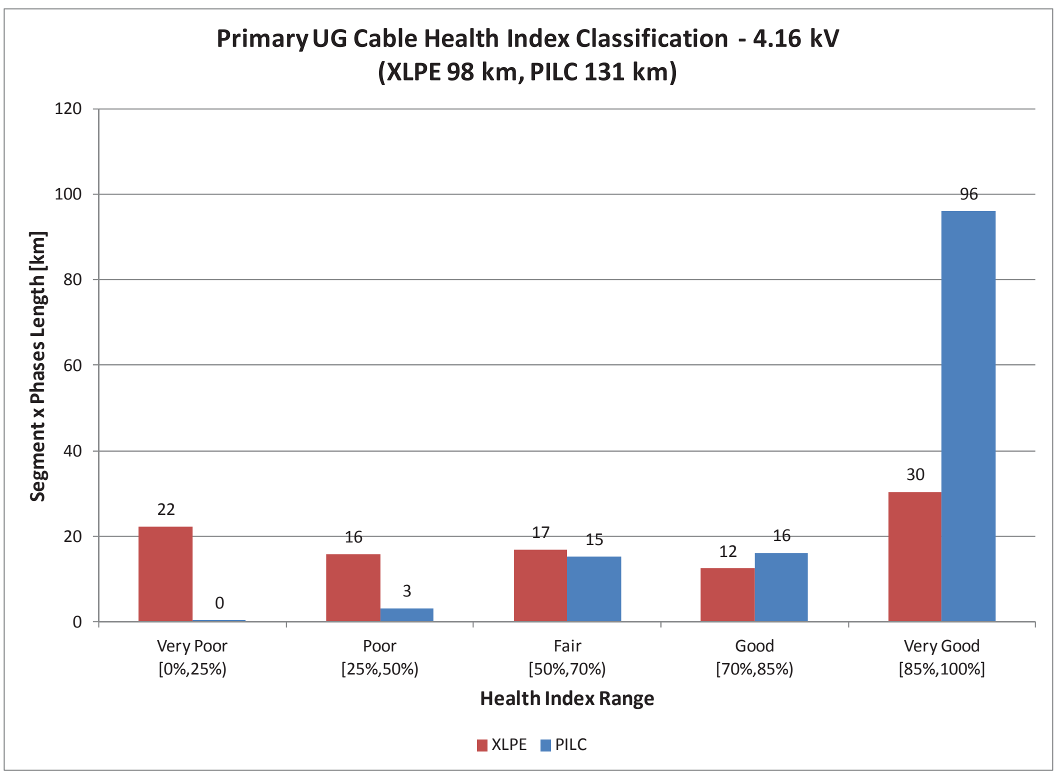

Figure 9-10 Underground Cables Health Index Distribution (Primary, 4.16 kV)

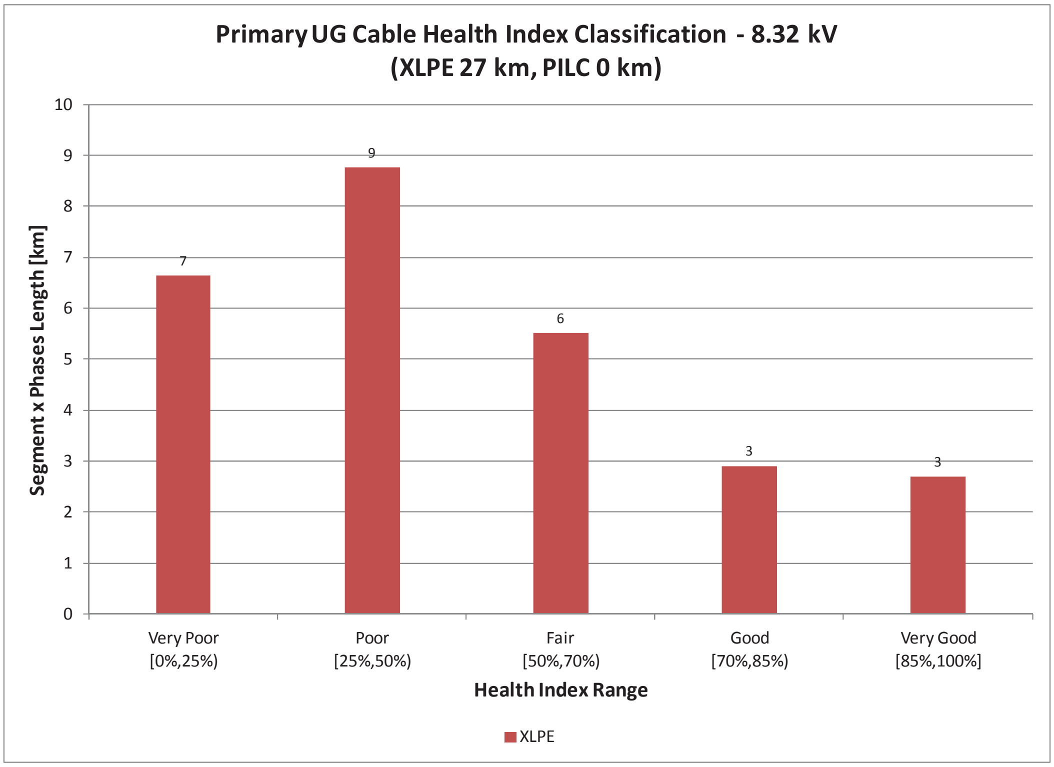

Figure 9-11 Underground Cables Health Index Distribution (Primary, 8.32 kV)

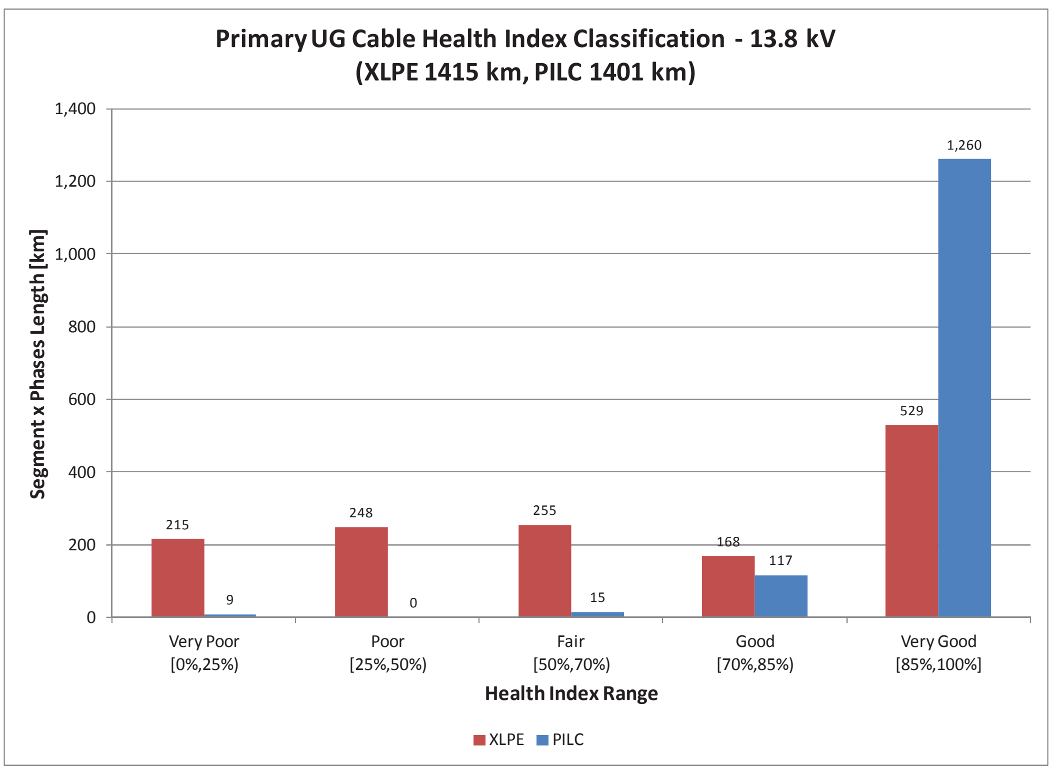

Figure 9-12 Underground Cables Health Index Distribution (Primary, 13.8 kV)

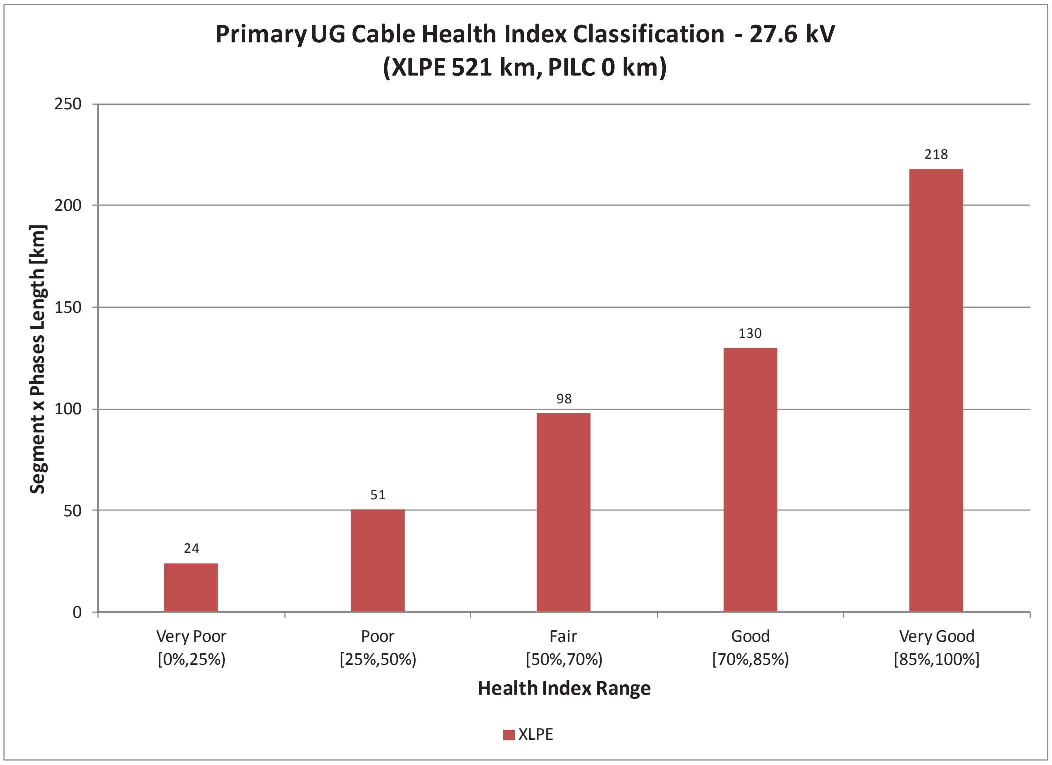

Figure 9-13 Underground Cables Health Index Distribution (Primary, 27.6 kV)

The following diagrams show the percentage health index distribution.

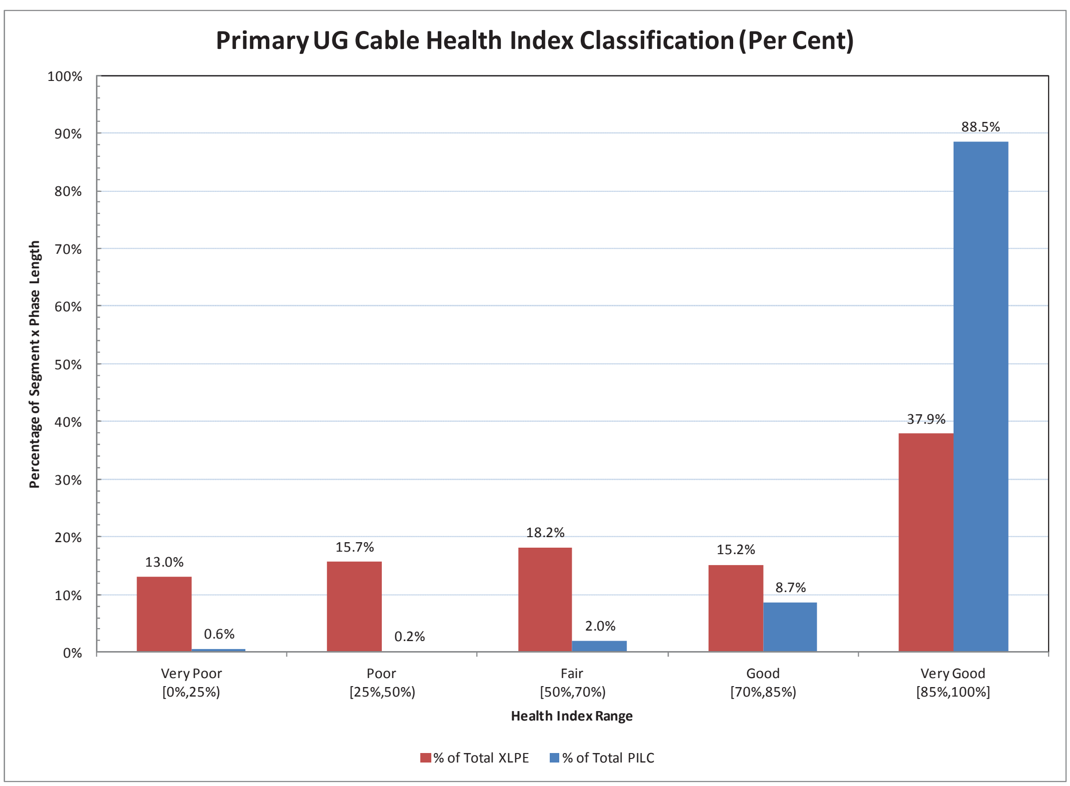

Figure 9-14 Underground Cables Health Index Distribution (Percentage, Primary)

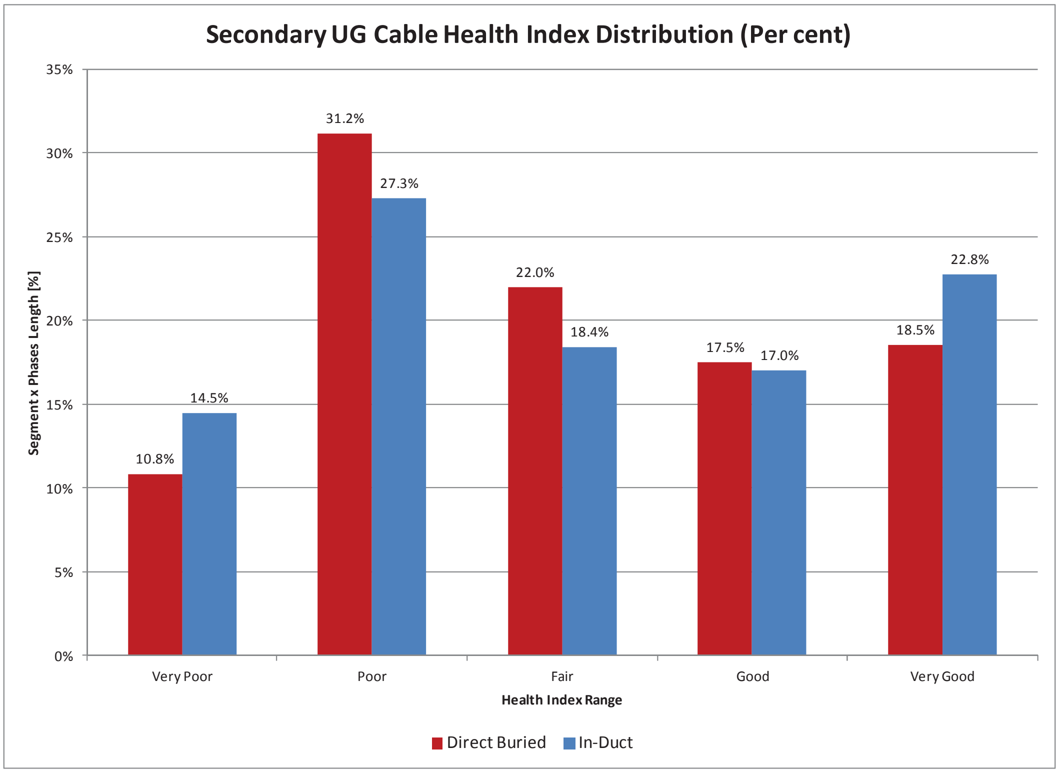

Figure 9-15 Underground Cables Health Index Distribution (Percentage, Secondary)

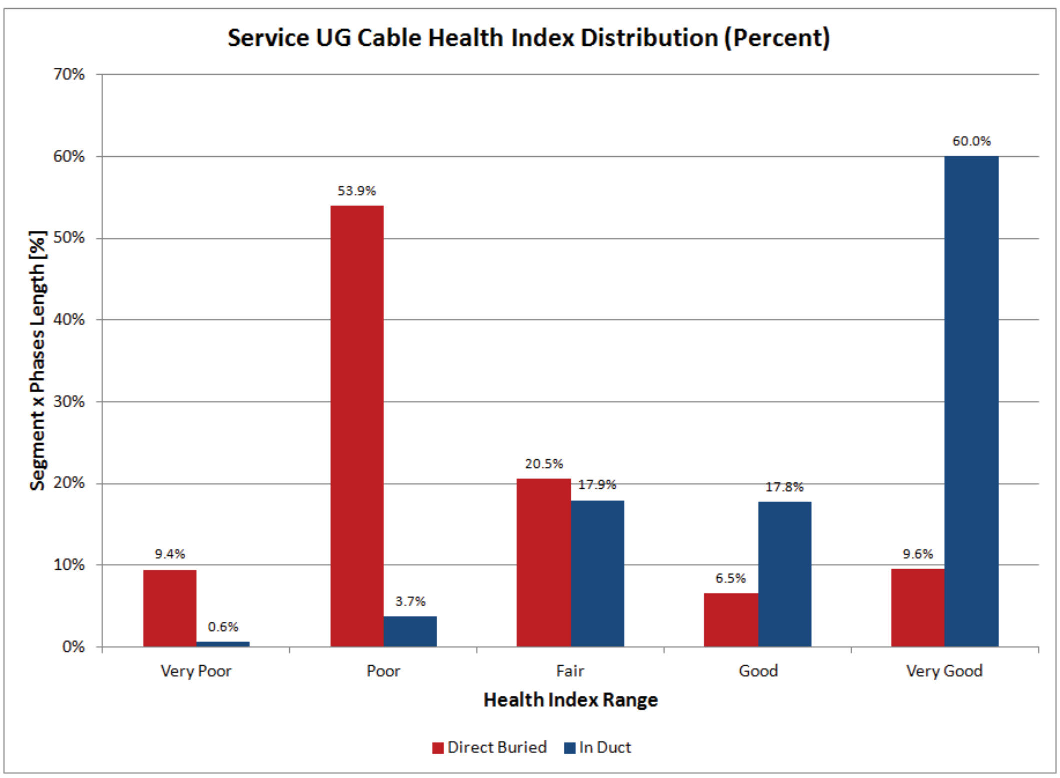

Figure 9-16 Underground Cables Health Index Distribution (Percentage, Service)

9.5 Underground Cables Condition-Based Flagged-For-Action Plan

As it is assumed that primary Underground Cables are proactively replaced while secondary and service cable is primary replaced reactively. The Flagged-For-Action Plan is based on asset failure rate f (t), as described in Section II.2.2.

The optimal Flagged-For-Action Plan is based on the number of expected failures in a given year.

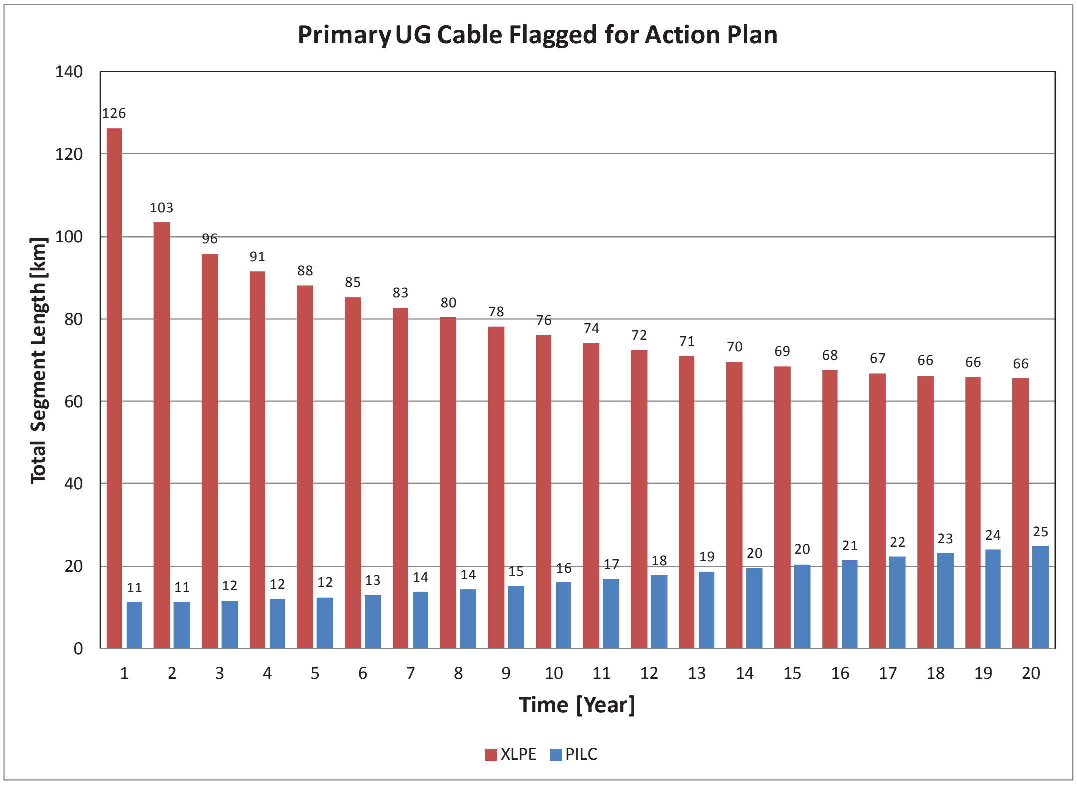

Figure 9-17 Underground Cables Condition-Based Flagged-For-Action Plan (Primary)

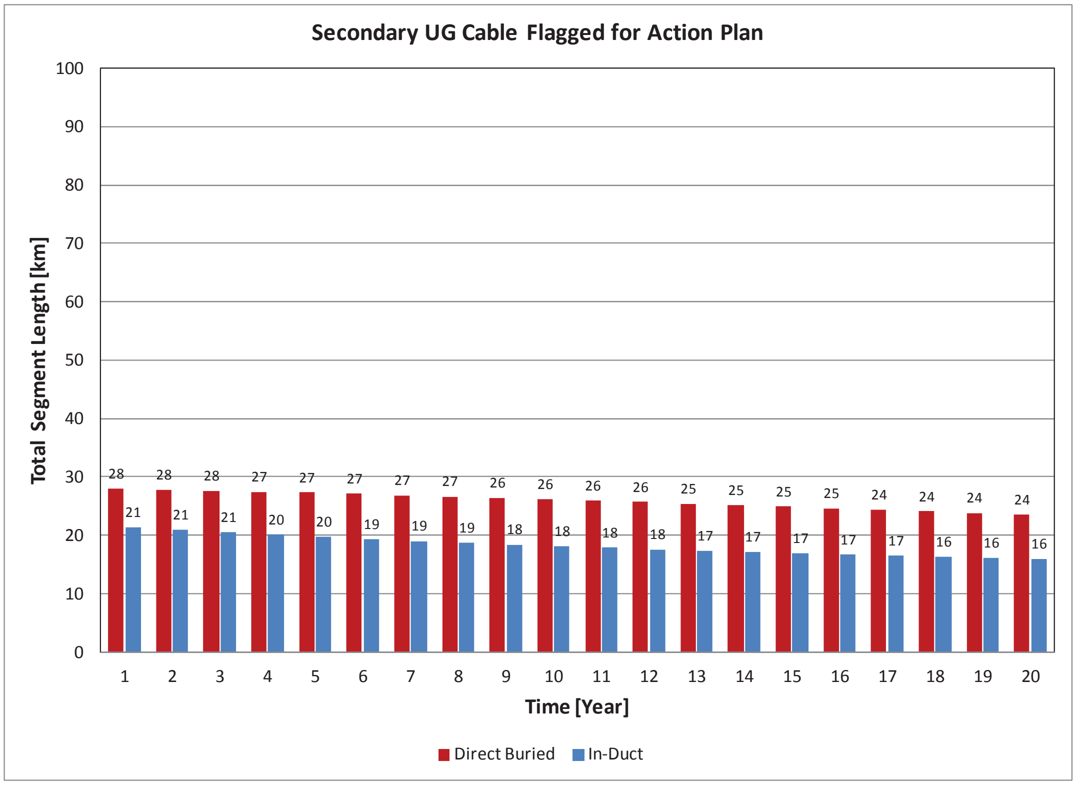

Figure 9-18 Underground Cables Condition-Based Flagged-For-Action Plan (Secondary)

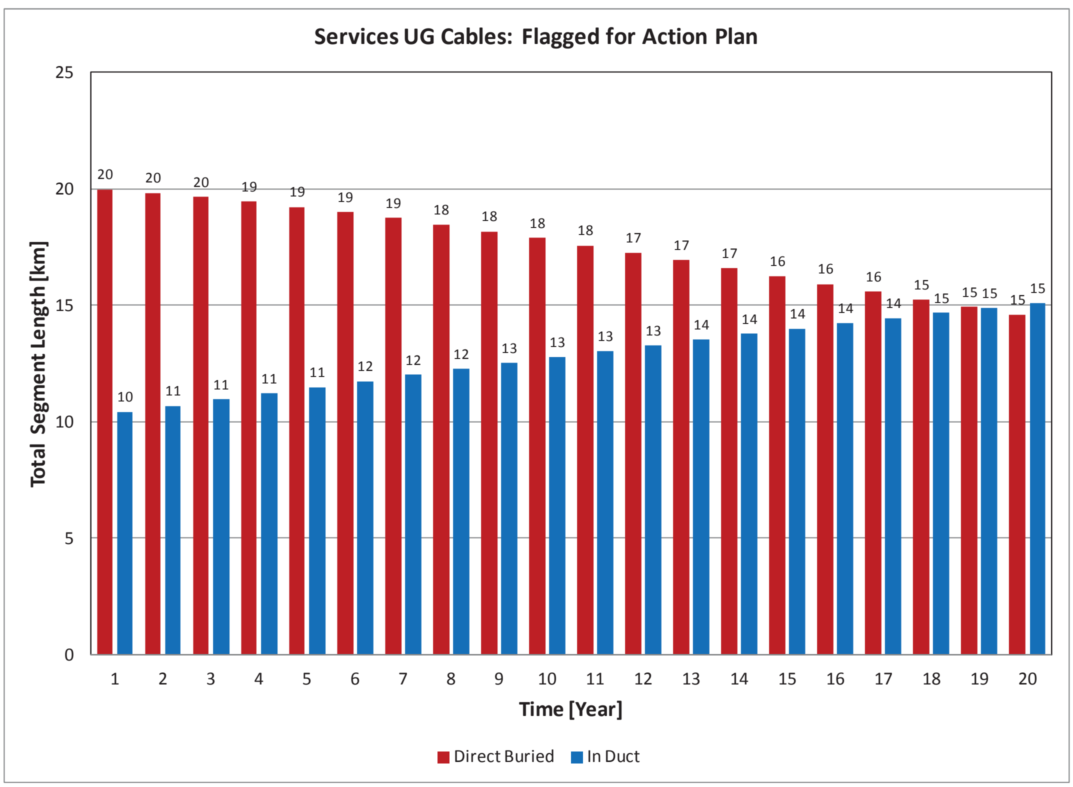

Figure 9-19 Underground Cables Condition-Based Flagged-For-Action Plan (Service)

9.6 Underground Cables Data Analysis

The data available for Underground Cables includes age, cable material and cable location.

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10 Pad-Mounted Transformers

Pad-mounted transformers are used in underground distribution systems to step voltages down from primary system voltages (34.5kV to 4.2kV) to utilization voltages such as 120/240V and 600/347V.

Pad-mounted transformers are housed in low-profile metal enclosures which generally have an oil-filled compartment for the transformer windings and under-oil switches and protection as well as an air compartment under a hinged door for access to connections, switching and protection. The enclosure is placed on top of a concrete foundation which allows access for incoming cables. Foundations of 6'x6' by 3 feet deep are commonly utilized. Modern pad-mounted transformers are dead-front, with incoming and feed-through connections made using separable insulated connectors.

Fuses and switches are housed in the oil-filled compartment. Single-phase pad-mounted distribution transformers have ratings from 10 to 167kVA. Three-phase pad-mounted transformers are often used in industrial and commercial applications and are generally available in ratings from 45 to 2500kVA. Pad-mounted transformers are self-cooled and may have external cooling fins; however these are occasionally avoided because of potentially sharp external edges.

10.1 Pad-Mounted Transformers Degradation Mechanism

Degradation of pad-mounted transformers can occur due to the following mechanisms:

- Corrosion of the pad-mounted enclosure and tank
- Deterioration of foundations
- Deterioration of separable insulated connectors
- Deterioration of switching or fusing devices
- Degradation of internal insulating material
- Degradation of oil

Pad-mounted transformers located in corrosive environments, such as next to major roads that are salted, are particularly prone to enclosure corrosion. Foundation shifting of pad-mounted transformers has been known to be problematic. Deep frost areas or unstable soil conditions can lead to movement of the foundation. Rubber encapsulated separable insulated connectors will deteriorate with multiple operations and are known to degrade if they are coated with transformer oil. Deterioration of the pad-mounted transformer can also be due to problems such as: switch breakage, leakage of under-oil fuses, and deterioration of dry-well canisters.

The life of the transformer's internal insulation is related to temperature-rise and duration. Therefore, transformer life is affected by electrical loading profiles and length of service life. The impacts of loading profiles, load growth, and ambient temperature on asset condition, loss-of-life, and life expectancy can be assessed using methods outlined in ANSI\IEEE Loading Guides. This also provides an initial baseline for the size of transformer that should be selected for a given number and type of customers to obtain optimal life.

Insulation condition can also be affected by voltage and current surges. Therefore, a combination of condition, age and load-based criteria is commonly used to determine the useful remaining life of distribution transformers.

Distribution transformers sometimes need to be replaced because of non-condition related factors such as mechanical damage by vehicles or customer load growth. If a transformer is simply overloaded, a decision is required whether to keep the transformer as spare or to scrap it. Many utilities make this decision through a cost benefit analysis, by taking into consideration anticipated remaining life of transformer, cost of equivalent sized new transformer, labour cost for transformer replacement and rated losses of the older transformer in comparison to the newer designs.

Visual inspections provide considerable information on transformer asset condition. Leaks, rusting, and deteriorated connectors can all be established by visual inspections. Transformer oil testing can be employed for distribution transformers to assess the condition of solid and liquid insulation.

The consequences of distribution transformer failure can be severe because of the street level location of this equipment. Though rare, pad-mounted transformers can fail with sufficient energy release to rupture the tank and release oil into the surrounding environment. Many utilities treat residential pad-mounted transformers as run-to-failure assets.

10.2 Pad-Mounted Transformers Health Index Formulation

This section presents the Health Index Formula that was developed and used for Horizon Utilities Pad-Mounted Transformers. The Health Index equation is shown in Section II.1; the condition, sub-condition parameters, weights, and condition criteria are as follows:

Assume a parameter scoring system of 0 through 4, where 0 and 4 represent the “worst” and “best” scores respectively. Thus, the maximum score for any condition or sub-condition parameter (maximum CPS and CPF) is “4”.

Health Index condition and sub-condition parameters and condition criteria are as follows:

10.2.1 Pad-Mounted Transformers Condition and Sub-Condition Parameters

Table 10-1 Pad-Mounted Transformers Condition Weights and Maximum CPS

m	Condition Parameter	WCP_m	CPS Lookup Table
1	Service Record	1	Table 10-2

Table 10-2 Pad-Mounted Transformers Service Record (m=1) Weights and Maximum CPF

n	Sub-Condition Parameter	CPF Lookup Table	$WCPF_n$	$CPF_{n.max}$
1	Loading	Table 10-3	1	4
2	Age	Figure 10-1	2	4

10.2.2 Pad-Mounted Transformers Condition Parameter Criteria

<u>**Age**</u>

Assume that the failure rate for Pad-Mounted Transformers exponentially increases with age and that the failure rate equation is as follows:

$$f = e^{\beta(t-\alpha)}$$

f = failure rate of an asset (percent of failure per unit time)
t = time
α, β = constant parameters that control the rise of the curve

The corresponding survivor function is therefore:

$$S_f = 1 - \ P_f = e^{-(f-e^{-\alpha\beta})/\beta}$$

S_f = survivor function
P_f = probability of failure

Assuming that at the ages of 40 and 55 years the probability of failure (P_f) for this asset are 10% and 90% respectively results in the survival curve shown below. It follows that the CPF for Age is the survival curve normalized to the maximum CPF score of 4 (i.e. 4*Survival Curve). The CPF vs. Age is also shown in the figure below:

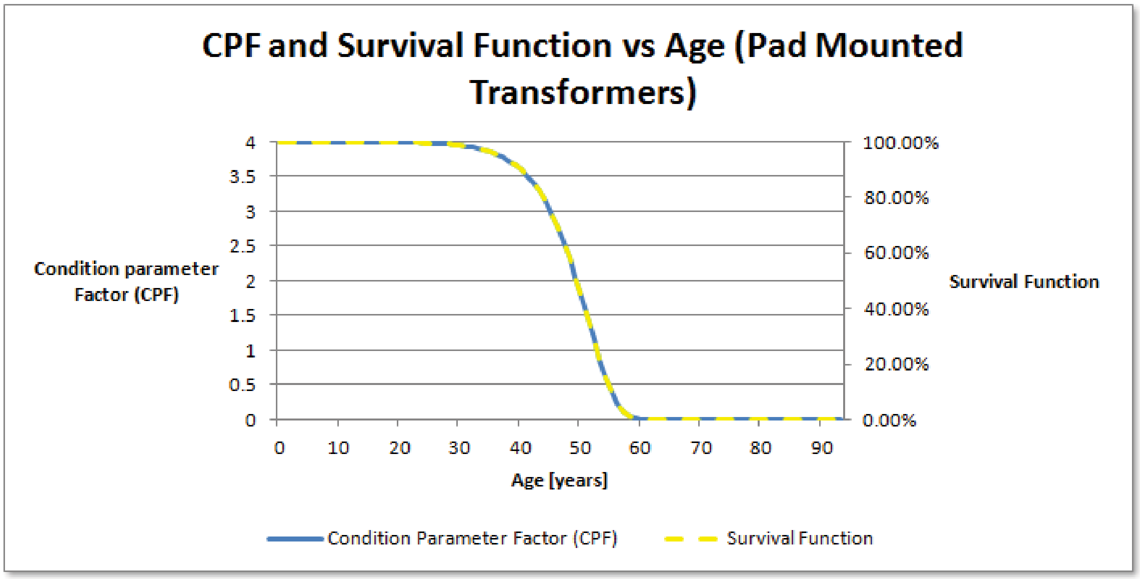

Figure 10-1 Age Condition Criteria (Pad-Mounted Transformers)

Loading

Table 10-3 Pad-Mounted Transformers Loading History

Data: S1, S2, S3, …, SN   recorded data (monthly 15 min peak)
SB= rated MVA NA=Number of Si/SB which is lower than 1.0 NB= Number of Si/SB which is between 1 and 1.2 NC= Number of Si/SB which is greater than 1.2 CPF = $\frac{NA \times 4 + NB \times 1 + NC \times 0}{N}$

Hourly transformer loading was used to determine overloading occurrences leading to a loss of life and thereby increasing the effective age of the transformer.   Transformer loading was not determined to decrease the effective age of the transformer in the absence of overloading occurrences. Therefore, loading condition was incorporated only when the loading CPF score was less than age CPF score for a transformer. In the cases when age CPF score was lower than that of loading, Health Index was calculated based on age only.

10.3 Pad-Mounted Transformers Age Distribution

The age distribution is shown in the figure below. Age was available for the entire population. The average age was found to be 17 years.

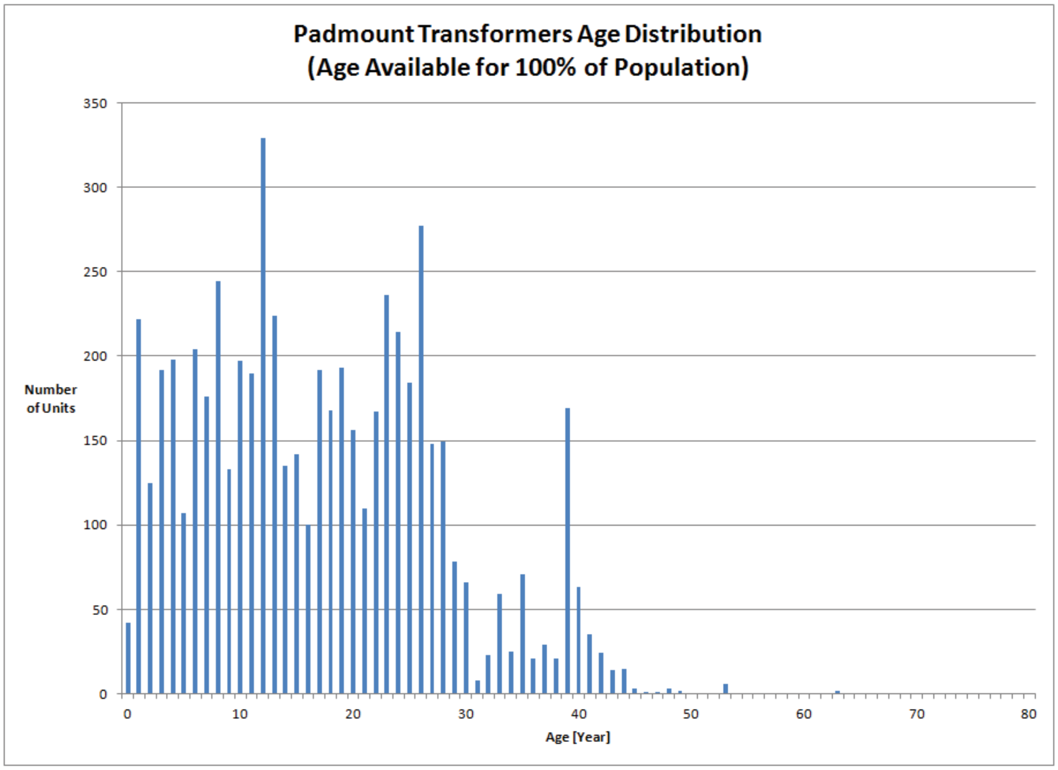

Figure 10-2 Pad-Mounted Transformers Age Distribution

10.4 Pad-Mounted Transformers Health Index Results

There are 5906 in-service Pad-Mounted Transformers at Horizon Utilities. The condition assessment is based on age, together with overloading condition calculated using hourly data obtained from Horizon Utilities Smart Meters.

The average Health Index for this asset group is 99%. Less than 1% of the units were found to be in poor or very poor condition.

The Health Index Results are as follows:

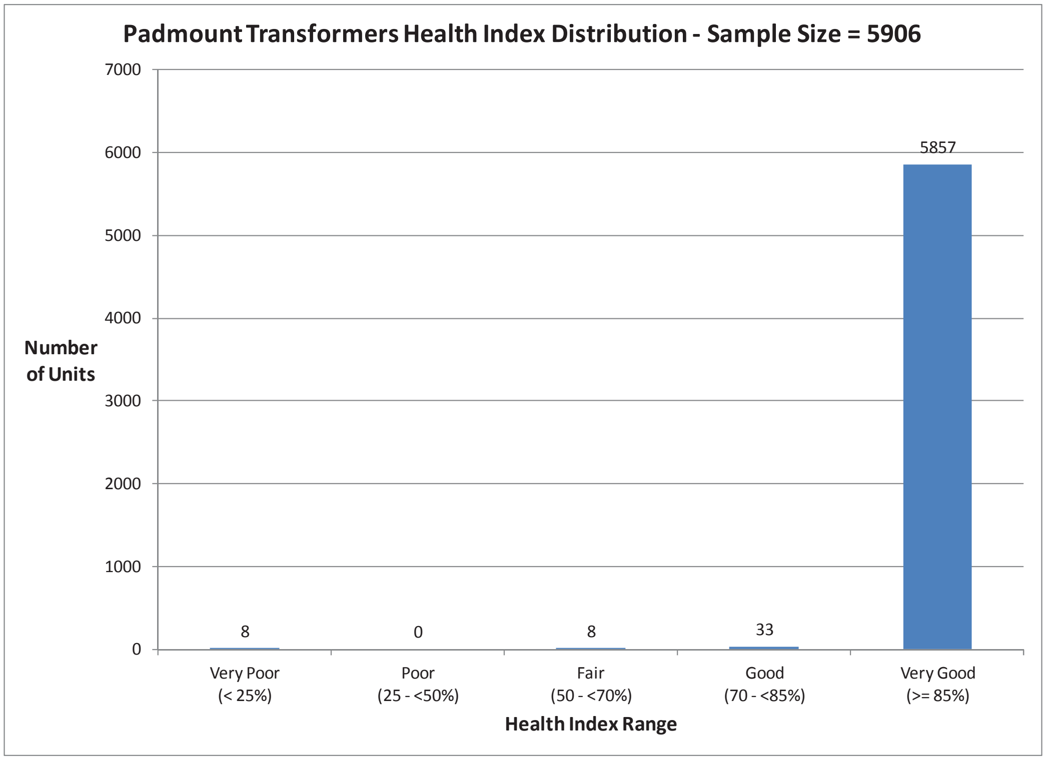

Figure 10-3 Pad-Mounted Transformers Health Index Distribution (Number of Units)

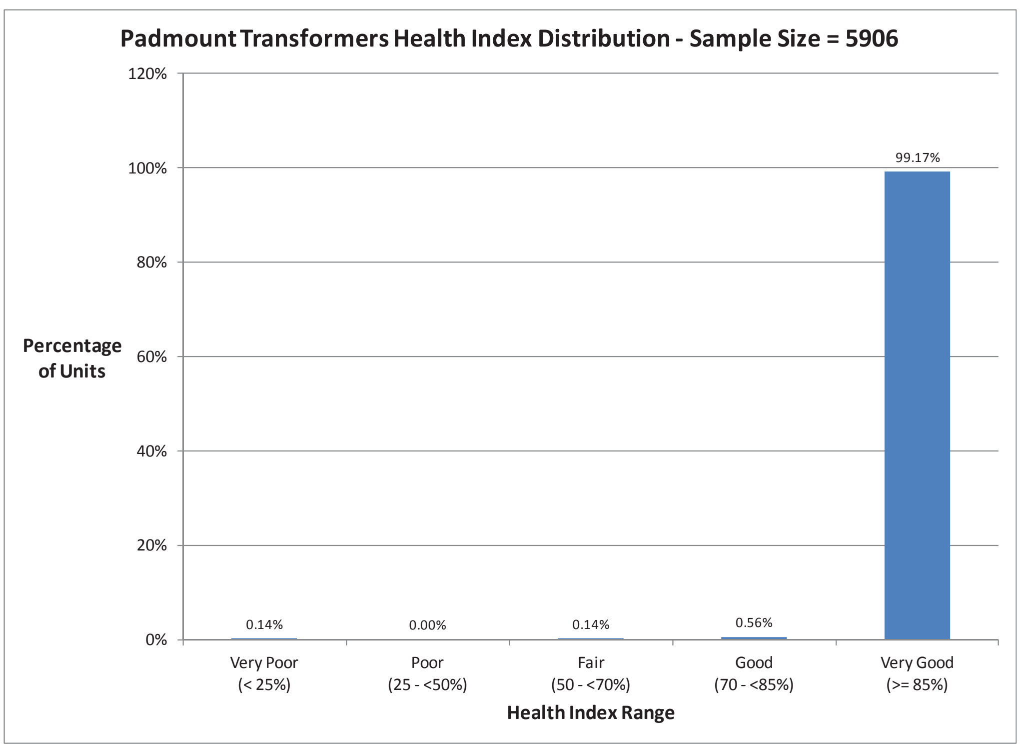

Figure 10-4 Pad-Mounted Transformers Health Index Distribution (Percentage of Units)

The following diagrams show the Pad-Mounted Transformers Health Index distribution by different voltage levels.

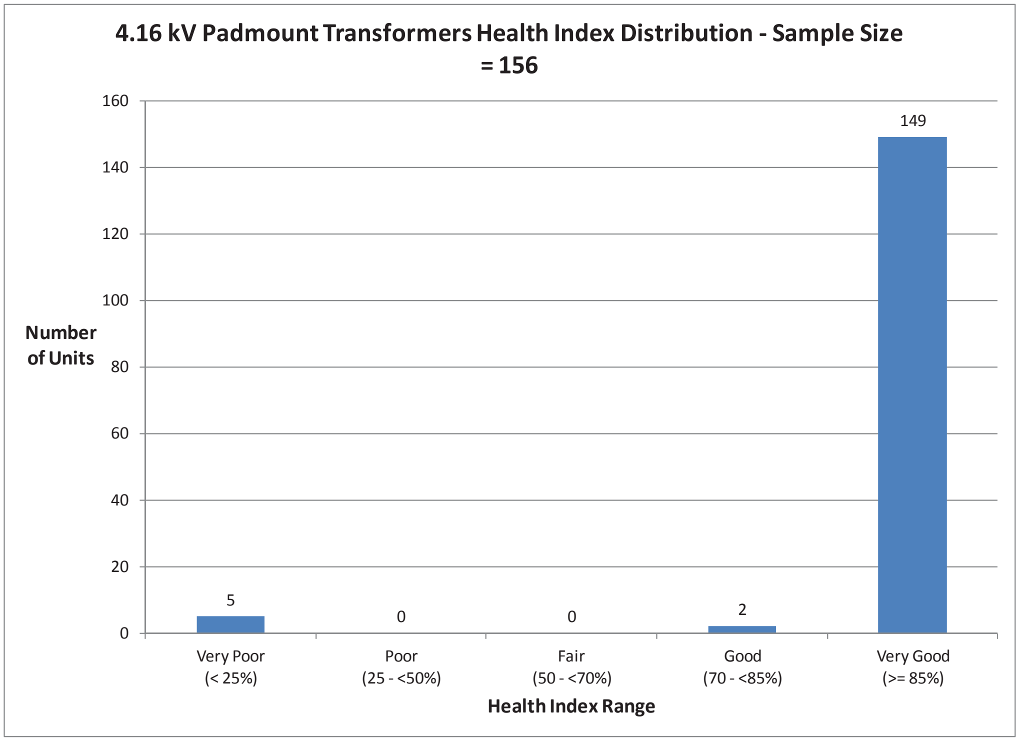

Figure 10-5 Pad-Mounted Transformers Health Index Distribution – 4.16 kV

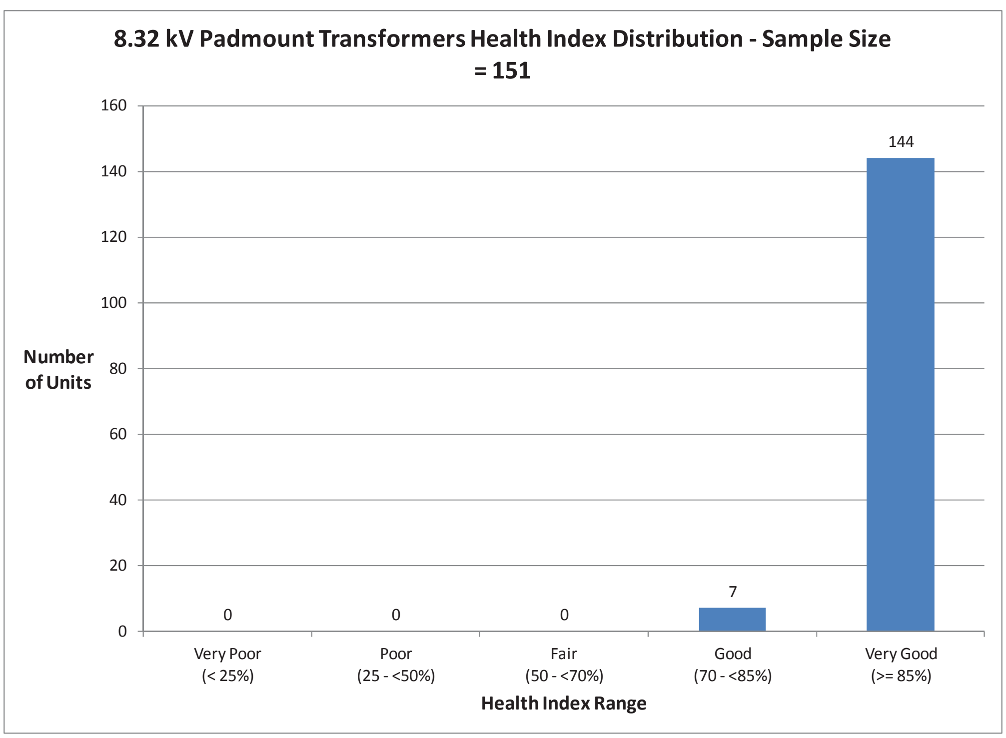

Figure 10-6 Pad-Mounted Transformers Health Index Distribution – 8.32 kV

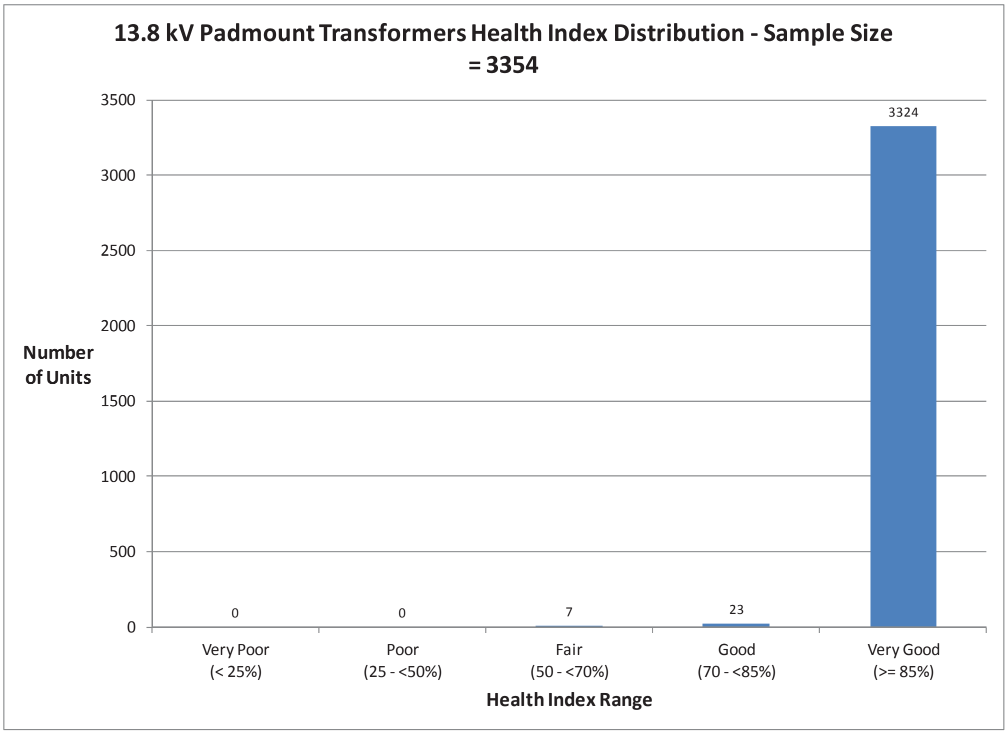

Figure 10-7 Pad-Mounted Transformers Health Index Distribution – 13.8 kV

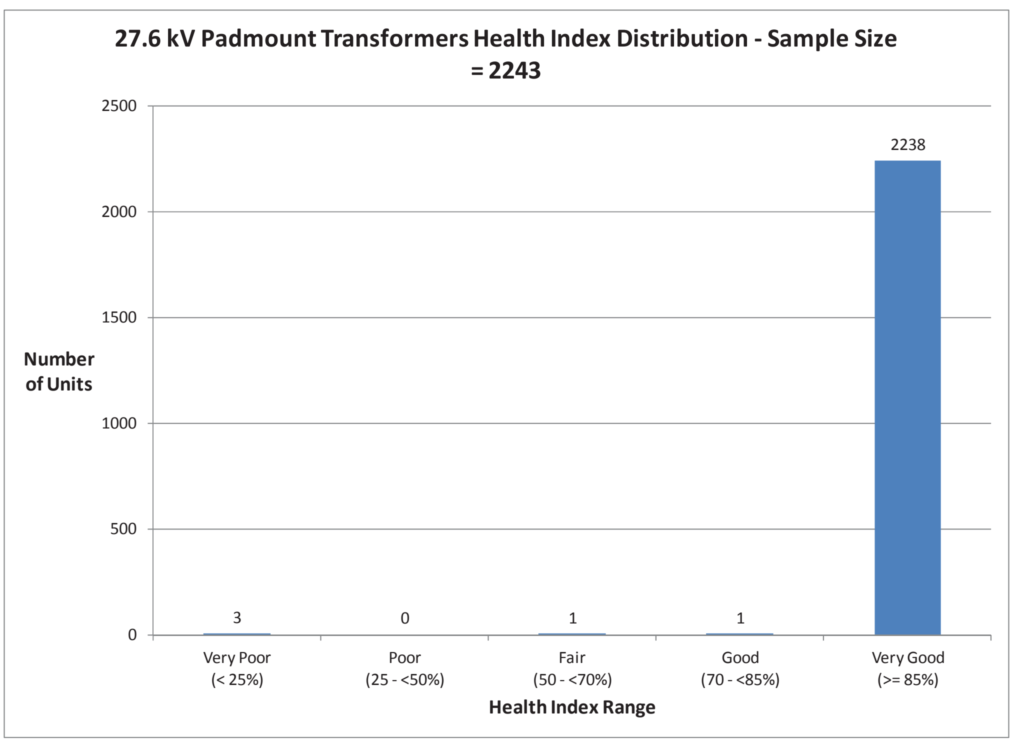

Figure 10-8 Pad-Mounted Transformers Health Index Distribution – 27.6 kV

10.5 Pad-Mounted Transformers Condition-Based Flagged-For-Action Plan

As it is assumed that Pad-Mounted Transformers are reactively replaced, the Flagged-For-Action Plan is based on asset failure rate, f (t), as described in Section II.2.2.

The Flagged-For-Action Plan is based on the number of expected failures in a given year.

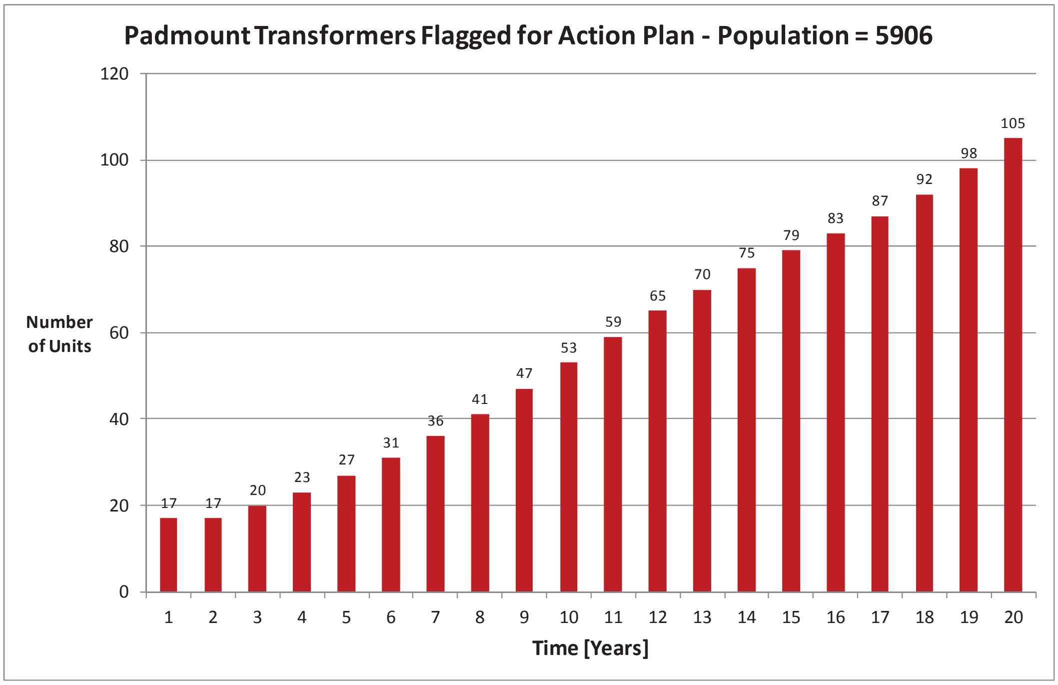

Figure 10-9 Pad-Mounted Transformers Condition-Based Flagged-For-Action Plan

10.6 Pad-Mounted Transformers Data Analysis

The data available for Pad-Mounted Transformers includes age and loading determined using hourly data obtained from Horizon Utilities Smart Meter data.

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11 Pad Mounted Switchgear

This asset class consists of pad-mounted above grade switchgear typically used in underground distribution systems. The switchgear consists of a low profile pad-mounted enclosure with various internal compartments housing cable terminations, switching, and protection equipment.

The pad-mounted gear can be sub-classified as live-front (with exposed electrical components when the doors are opened) or dead-front (with no live parts exposed). The majority of live-front pad mounted switchgear currently in use includes air-insulated gang-operated load-break switches. Dead-front gear utilizes separable insulated connectors and sometimes oil vacuum or SF6 switches.

11.1 Pad Mounted Switchgear Degradation Mechanism

Pad-mounted switchgear degradation can be caused by:

- Mechanical wear and misalignment
- Moisture ingress
- Contamination of internal components
- Corrosion e.g. rusting of the enclosures or operating mechanism
- Degradation of insulated barriers and breakage of insulators
- Failure of internal components such as insulators and fuses

Mechanical wear is impacted by factors such as frequency of switching operations, and the magnitude of continuous and switched load. Moisture and contamination problems are influenced by the dampness of the installation site and the presence of a corrosive environment.

Failures of switchgear can be associated instead with outside influences. For example, pad-mounted switchgear can be damaged by rodents and vehicle accidents. There are other defects that are important and require intervention, but do not result into a failure and can be rectified by field action. For example, graffiti on pad-mounted switchgear is often considered an eyesore and may even conceal important safety and operating signage. Re-painting the outside of the case and replacing the signage can usually be done with no disruption of power. In areas with recurring problems, anti-graffiti paint may be an effective solution.

Some of the degradation modes can be mitigated, failures avoided, and life can be extended with good design and maintenance practices. Rusting of a pad-mounted switchgear enclosure can lead to perforation and a public safety hazard. Touch-up and re-painting may delay the rusting process, but eventually a planned replacement of the equipment will be required. Accumulation of dirt and pollution can often be removed by cleaning. On-line cleaning using CO2 or dry ice is one of the technologies used successfully. Inspection and thermo-graphic analysis can detect loose or degrading connections. If problems or defects are identified during inspection, often the affected component can be replaced or repaired without a total replacement of the switchgear.

The first generation of pad mounted switchgear was first introduced in early 1970's and many of these units are still in good operating condition. In the absence of specifically identified problems, the common industry practice for distribution switchgear is running it to end of life, just short of failure.

Consequences of pad-mounted switchgear failure include customer interruptions, health and safety as well as environmental consequences. For instance failures caused by fuse malfunctions can result in a catastrophic pad-mounted switchgear failure.

11.2 Pad Mounted Switchgear Health Index Formula

This section presents the Health Index Formula that was developed and used for Horizon Utilities Pad Mounted Switchgear. The Health Index equation is shown in Section II.1; the condition, sub-condition parameters, weights, and condition criteria are as follows.

Assume a parameter scoring system of 0 through 4, where 0 and 4 represent the "worst" and "best" scores respectively. Thus, the maximum score for any condition or sub-condition parameter (maximum CPS and CPF) is "4".

11.2.1 Pad Mounted Switchgear Condition and Sub-Condition Parameters

Table 11-1 Condition Parameter and Weights

m	Condition Parameter	WCP_m	Sub-Condition Parameters
1	Physical Condition	4	Table 11-2
2	Switch/Fuse Condition	2	Table 11-3
3	Insulation	2	Table 11-4
4	Service Record	1	Table 11-5

Table 11-2 Physical Condition Sub-Condition Parameters and Weights (m=1)

n	Sub-Condition Parameter	$WCPF_n$	Condition Criteria Table
1	Physical Condition (Rust, Paint etc.)	1	Table 11-6
2	Door Hinges	1	Table 11-6
3	Pad Foundation	1	Table 11-6

Table 11-3 Switch/Fuse Sub-Condition Parameters and Weights (m=2)

n	Sub-Condition Parameter	$WCPF_n$	Condition Criteria Table
1	Switch Blades	3	Table 11-6
2	Arc Suppressor	3	Table 11-6
3	Cable Termination	1	Table 11-6
4	Grounding	1	Table 11-6
5	Hot Spot in IR Scan	2	Table 11-7

Table 11-4 Insulation Sub-Condition Parameters and Weights (m=3)

n	Sub-Condition Parameter	$WCPF_n$	Condition Criteria Table
1	Support/Switch Insulator	2	Table 11-6
2	Barrier Boards	1	Table 11-6

Table 11-5 Service Record Sub-Condition Parameters and Weights (m=4)

n	Sub-Condition Parameter	$WCPF_n$	Condition Criteria Table
1	Other	1	Table 11-6
2	Age	2	Figure 11-1

11.2.2 Pad Mounted Switchgear Condition Criteria

Visual Inspections

Table 11-6 Inspection Condition Criteria

Condition Rating*	CPF	Description
A	4	PASS
C	2	PASS (Not Unique ID)
E	0	Failed

Table 11-7 IR Condition Criteria

Condition Rating*	CPF	Description (Hot Spot Detected)
A	4	FALSE
E	0	TRUE

Age

Assume that the failure rate Pad Mounted Switchgear exponentially increases with age and that the failure rate equation is as follows:

$$f = e^{\beta(t-\alpha)}$$

f = failure rate of an asset (percent of failure per unit time)
t = time
α, β = constant parameters that control the rise of the curve

The corresponding survivor function is therefore:

$$S_f = 1 - P_f = e^{-(f-e^{-\alpha\beta})/\beta}$$

S_f = survivor function
P_f = probability of failure

Assuming that at the ages of 40 and 55 years the probability of failures (P_f) for this asset are 50% and 80% respectively results in the survival curve shown below. It follows that the Score for Age is the survival curve normalized to the maximum Score of 4 (i.e. 4*Survival Curve). The Score vs. Age is also shown in the figure below.

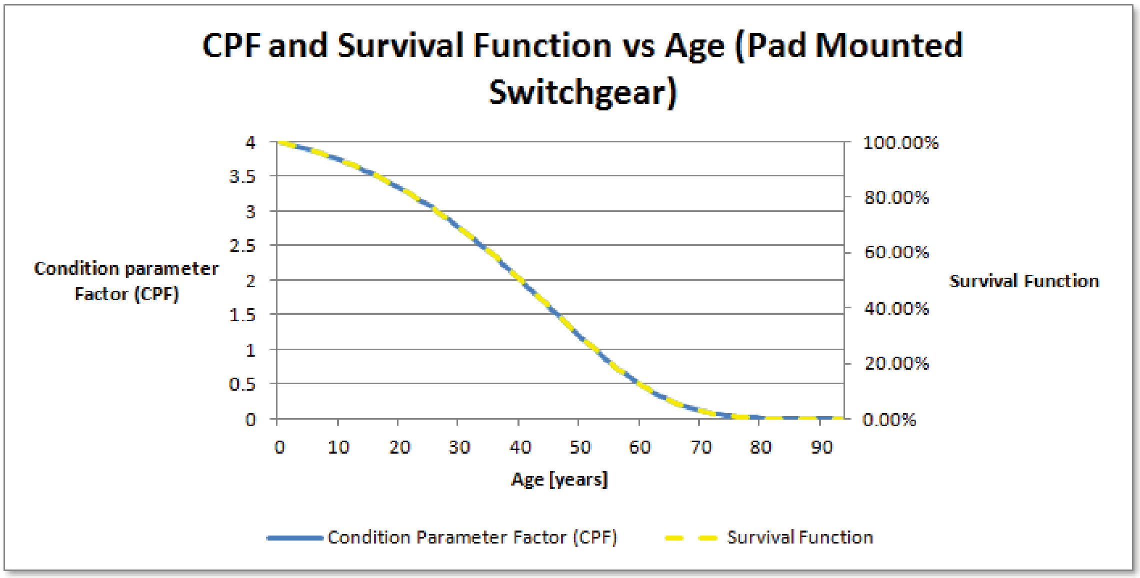

Figure 11-1 Age Criteria (Pad Mounted Switchgear)

11.3 Pad Mounted Switchgear Age Distribution

The age distribution is shown in the figure below. Age was available for the entire population. The average age was found to be 23 years.

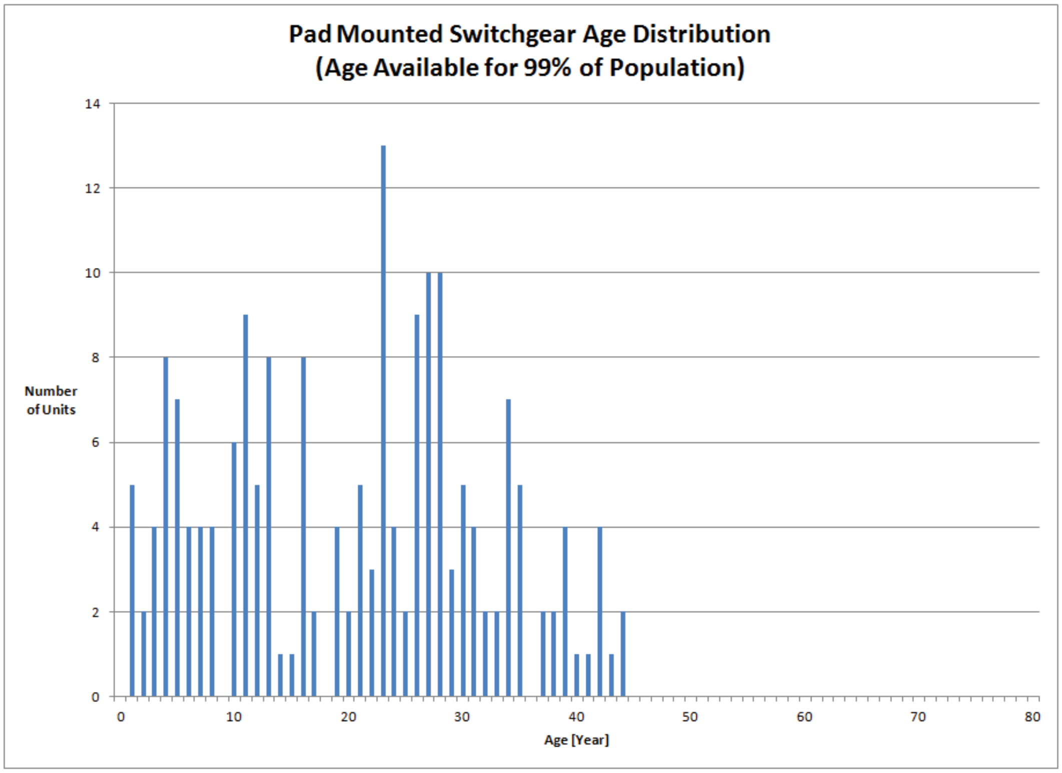

Figure 11-2 Pad Mounted Switchgear Age Distribution

11.4 Pad Mounted Switchgear Health Index Results

There are 186 in-service Pad Mounted Switchgear at Horizon Utilities. Most of them have age and inspection data available for assessment.

The average Health Index for this asset group is 77%. Approximately 4% of the units were found to be in poor condition.

The Health Index Distribution is shown in the following tables.

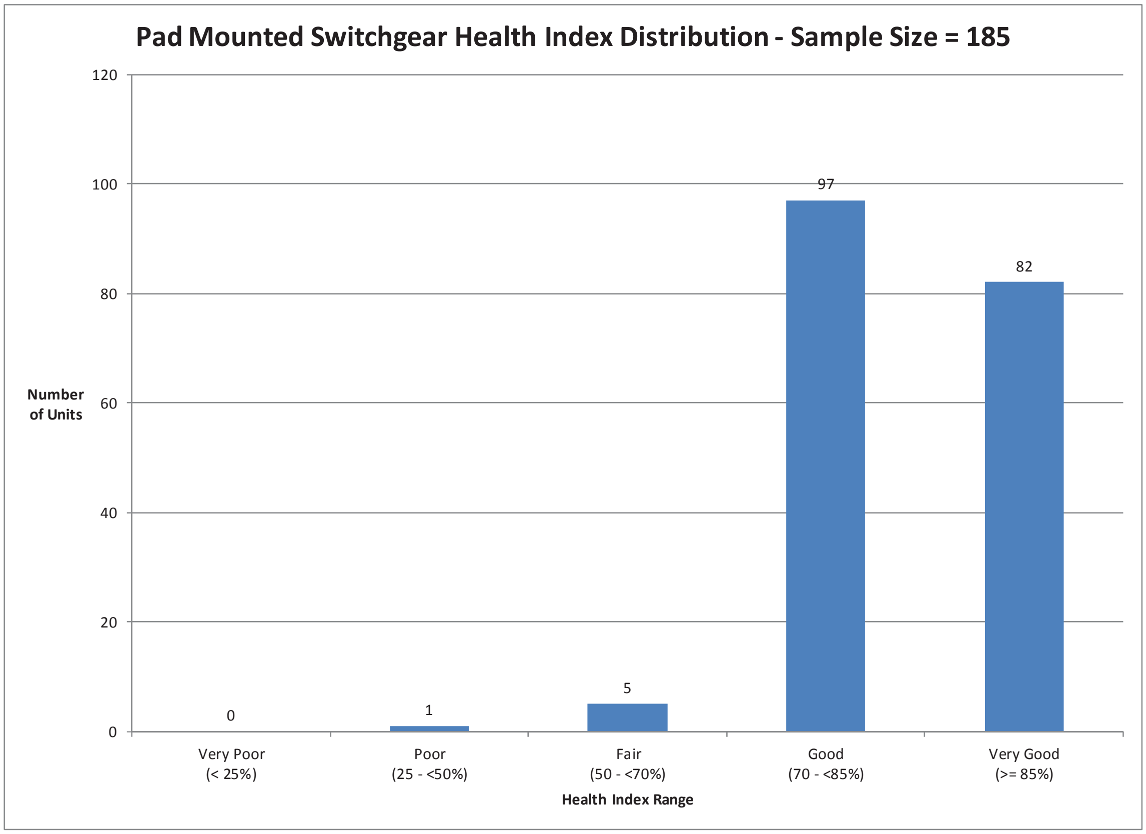

Figure 11-3 Pad Mounted Switchgear Health Index Distribution (Number of Units)

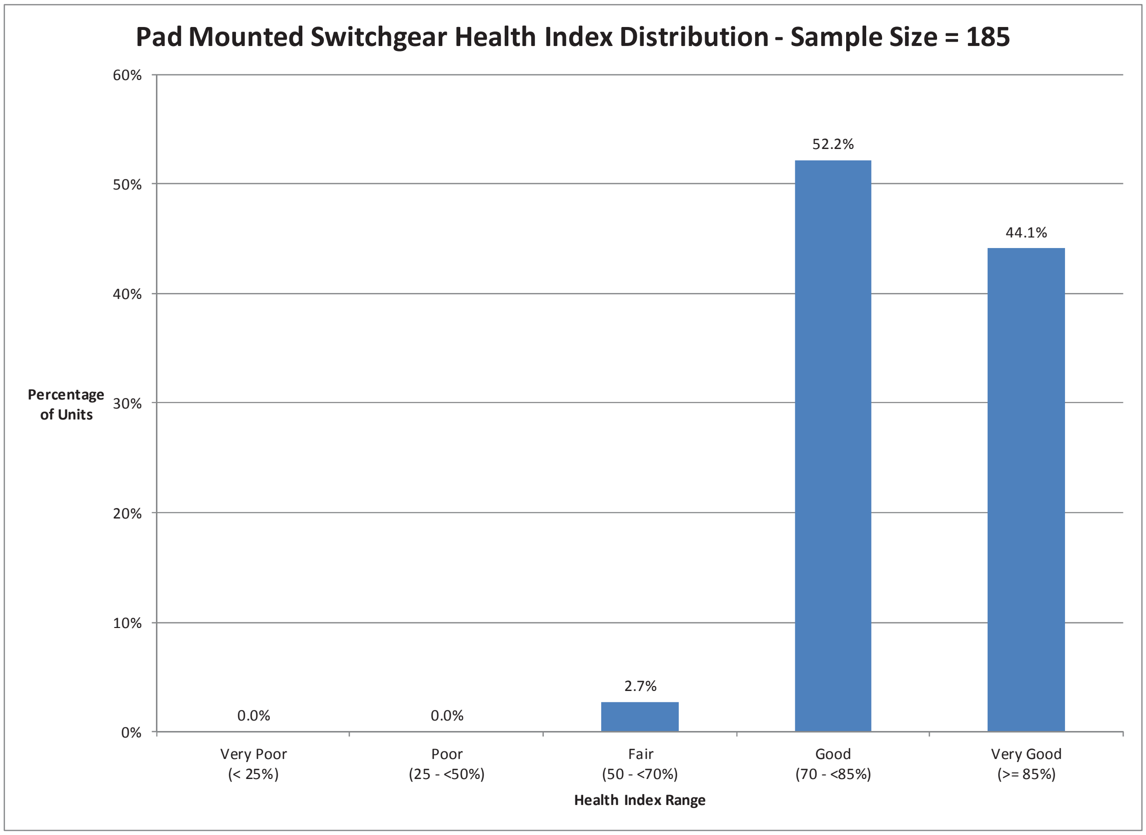

Figure 11-4 Pad Mounted Switchgear Health Index Distribution (Percentage of Units)

11.5 Pad Mounted Switchgear Condition-Based Flagged-For-Action Plan

As it is assumed that Pad Mounted Switchgear is reactively replaced, the risk assessment and replacement procedure described in Section II.2.2 was applied for this asset class.

The optimal Flagged-For-Action Plan is based on the number of expected failures in a given year.

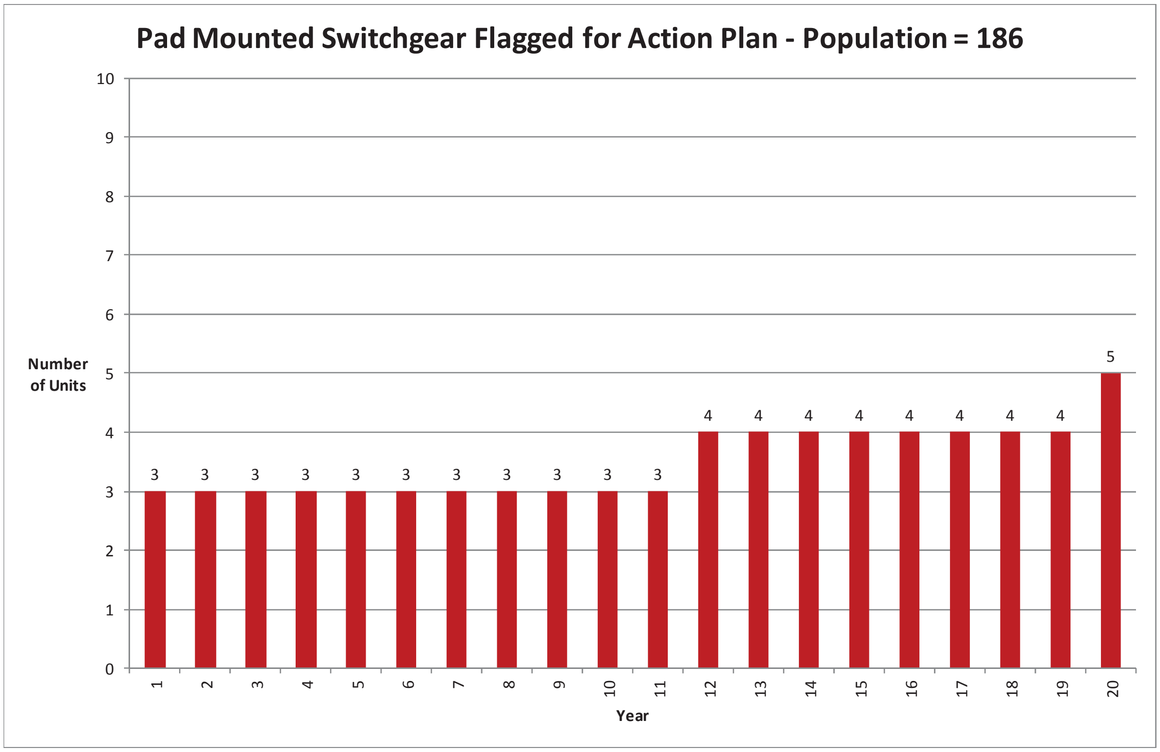

Figure 11-5 Pad Mounted Switchgear Optimal Condition-Based Flagged-For-Action Plan

11.6 Pad Mounted Switchgear Data Analysis

The data available for Pad Mounted Switchgear includes age, location and inspection records. Horizon Utilities should continue with the existing practices.

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12 Vault Transformers

Vault-type distribution transformers are generally installed in a dedicated compartment in a building or under a sidewalk in locations where there is not sufficient room for a pad-mounted transformer. Vault-type transformers are often used in secondary networks and spot networks. They are available for primary voltages from 1.2 to 34.5kV in ratings generally up to 1000kVA.

As vault transformers are often located in harsh environments, vault transformer design often includes enhancements to the protective coatings on the steel walls. Some vault-type transformers may be used in submersible applications.

12.1 Vault Transformers Degradation Mechanism

Degradation of vault-type transformers can occur due to the following mechanisms:

- Corrosion of the tank
- Deterioration of internal switching or fusing devices
- Degradation of internal insulating material
- Degradation of oil

Vault-type transformers are often located in corrosive below-grade environments and are prone to enclosure corrosion. Deterioration of the vault-type transformer can also be due to problems such as: switch breakage and leakage of under-oil fuses.

The life of the transformer’s internal insulation is related to temperature-rise and duration. Therefore, transformer life is affected by electrical loading profiles and length of service life. The impacts of loading profiles, load growth, and ambient temperature on asset condition, loss-of-life, and life expectancy can be assessed using methods outlined in ANSI\IEEE Loading Guides. This also provides an initial baseline for the size of transformer that should be selected for a given number and type of customers to obtain optimal life.

Visual inspections provide considerable information on transformer asset condition. Leaks, rusting, and deteriorated connectors can all be established by visual inspections. Transformer oil testing can be employed for distribution transformers to assess the condition of solid and liquid insulation.

The consequences of vault–type transformer failure can be severe because of the in-building or under side-walk location of this equipment. Though rare, vault-type transformers can fail with sufficient energy release to rupture the tank and release oil into the surroundings.

12.2 Vault Transformers Health Index Formulation

This section presents the Health Index Formula that was developed and used for Horizon Utilities Vault Transformers. The Health Index equation is shown in Section II.1; the condition, sub-condition parameters, weights, and condition criteria are as follows.

Assume a parameter scoring system of 0 through 4, where 0 and 4 represent the "worst" and "best" scores respectively. Thus, the maximum score for any condition or sub-condition parameter (maximum CPS and CPF) is "4".

12.2.1 Vault Transformers Condition and Sub-Condition Parameters

Table 12-1 Vault Transformers Condition Parameter and Weights

m	Condition Parameter	WCP_m	Sub-Condition Parameters
1	Service Record	1	Table 12-2
	De-rating multiplier (DR)		Table 12-4

Table 12-2 Vault Transformers Service Record (m=1) Weights and Maximum CPF

n	Sub-Condition Parameter	CPF Lookup Table	$WCPF_n$	$CPF_{n.max}$
1	Loading	Table 12-3	1	4
2	Age	Figure 12-1	2	4

12.2.2 Vault Transformers Condition Criteria

<u>**Age**</u>

Assume that the failure rate for Vault Transformers exponentially increases with age and that the failure rate equation is as follows:

$$f = e^{\beta(t-\alpha)}$$

f = failure rate of an asset (percent of failure per unit time)
t = time
α, β = constant parameters that control the rise of the curve

The corresponding survivor function is therefore:

$$S_f = 1 - P_f = e^{-(f-e^{-\alpha\beta})/\beta}$$

S_f = survivor function
P_f = probability of failure

Assuming that at the ages of 40 and 45 years the probability of failure (P_f) for this asset are 80% and 90% respectively results in the survival curve shown below. It follows that the CPF for Age is the survival curve normalized to the maximum CPF score of 4 (i.e. 4*Survival Curve). The CPF vs. Age is also shown in the figure below:

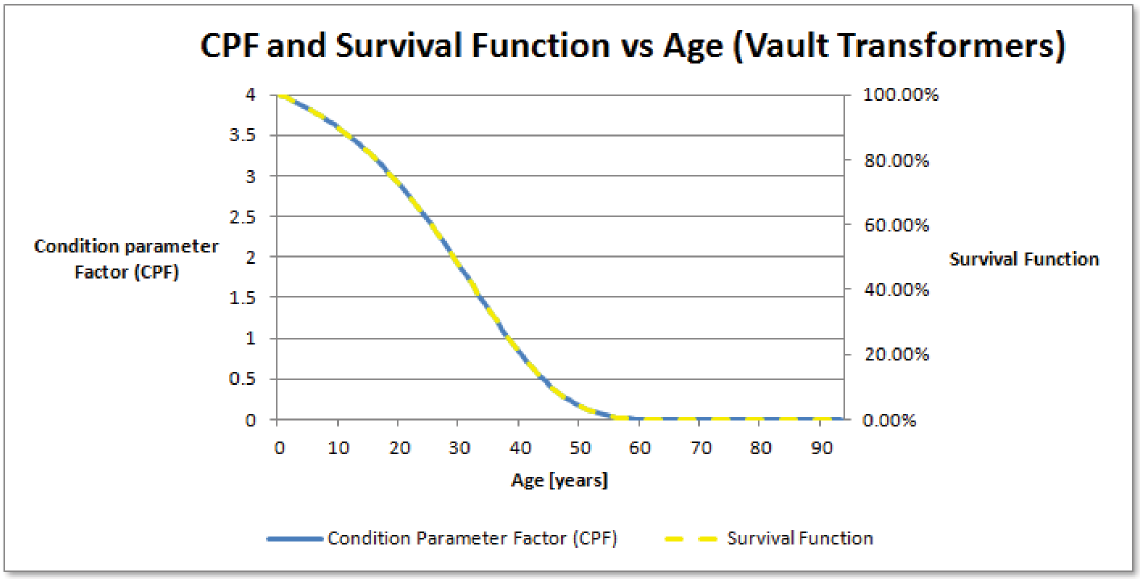

Figure 12-1 Age Condition Criteria (Vault Transformers)

Loading

Table 12-3 Vault Transformers Loading History

Data: S1, S2, S3, …, SN recorded data (monthly 15 min peak)
SB= rated MVA NA=Number of Si/SB which is lower than 1.0 NB= Number of Si/SB which is between 1 and 1.2 NC= Number of Si/SB which is greater than 1.2 CPF = $\frac{NA \times 4 + NB \times 1 + NC \times 0}{N}$

Hourly transformer loading was used to determine overloading occurrences leading to a loss of life and thereby increasing the effective age of the transformer. Transformer loading was not determined to decrease the effective age of the transformer in the absence of overloading occurrences. Therefore, loading condition was incorporated only when the loading CPF score was less than age CPF score for a transformer. In the cases when age CPF score was lower than that of loading, Health Index was calculated based on age only.

De-Rating (DR) Multiplier

Table 12-4 Vault Transformers De-Rating Factors

De-Rating Factor	Description
0.8	All the vault transformers due to obsolescence/safety concerns

12.3 Vault Transformers Age Distribution

The age distribution is shown in the figure below. Age was available for 100% of the population. The average age was found to be 25 years.

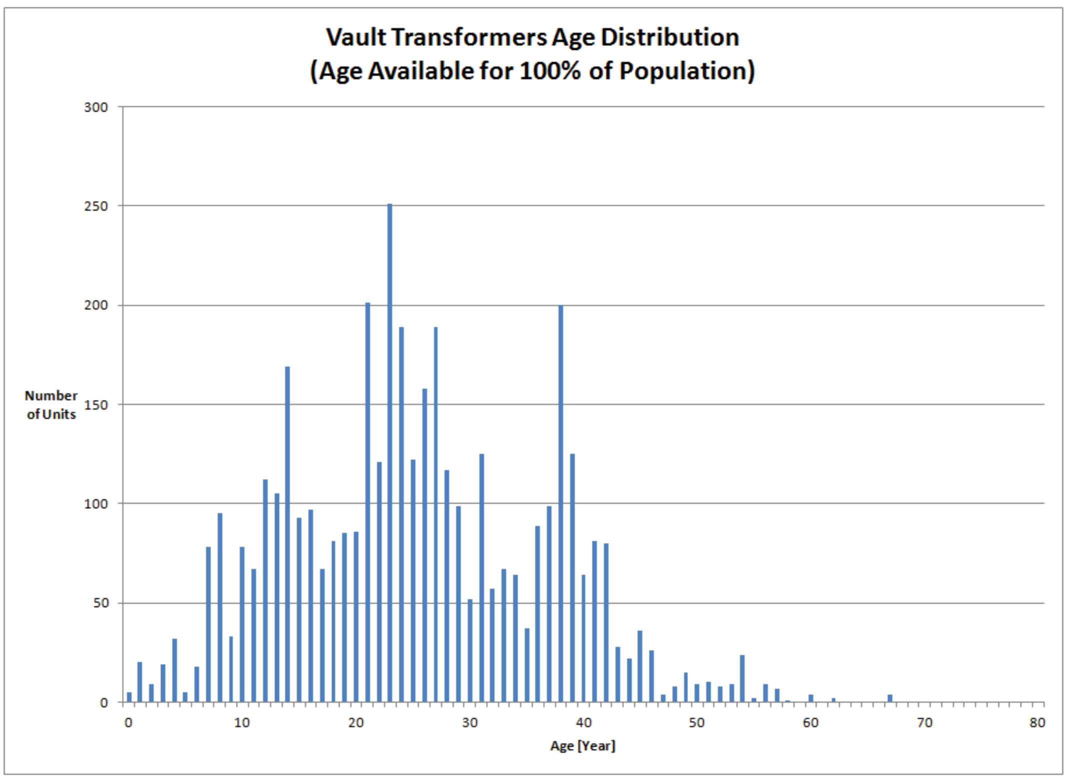

Figure 12-2 Vault Transformers Age Distribution

12.4 Vault Transformers Health Index Results

There are 4169 in-service Vault Transformers at Horizon Utilities. The condition assessment is based on age, together with overloading condition calculated using hourly data obtained from Horizon Utilities Smart Meters. Additionally, all vault transformers were de-rated due to their obsolescence and safety concerns.

The average Health Index for this asset group is 46%. Approximately 20% of the units were found to be in poor or very poor condition due mainly to the de-rating factor applied.

The Health Index Results are as follows:

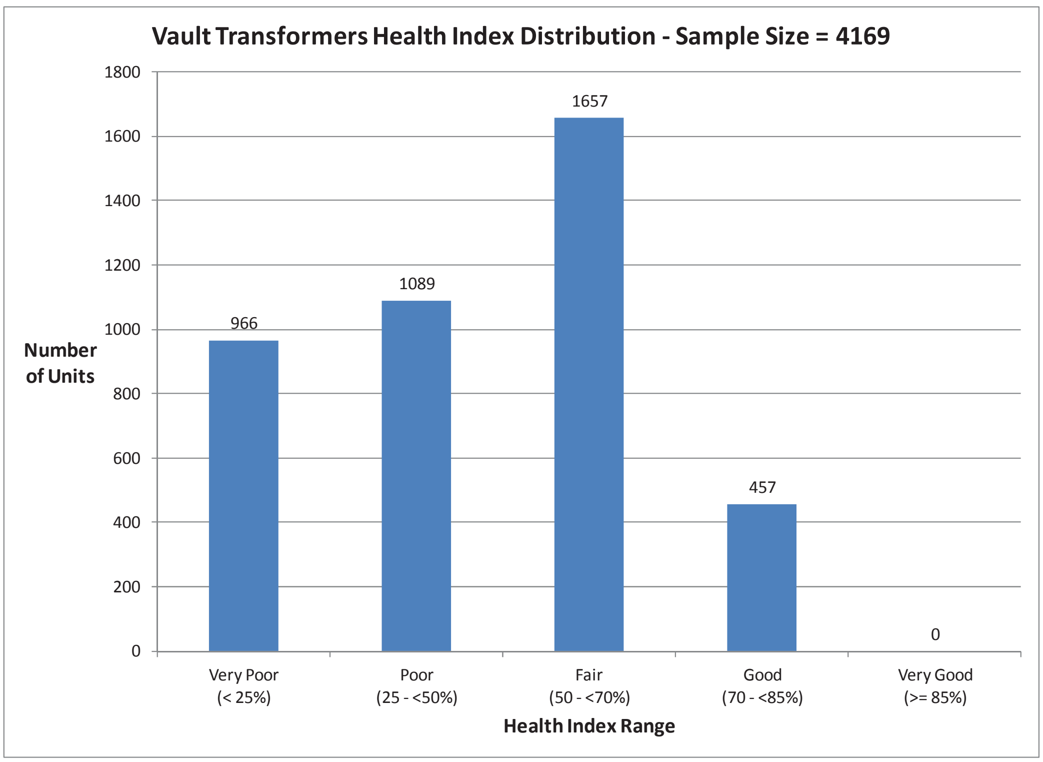

Figure 12-3 Vault Transformers Health Index Distribution (Number of Units)

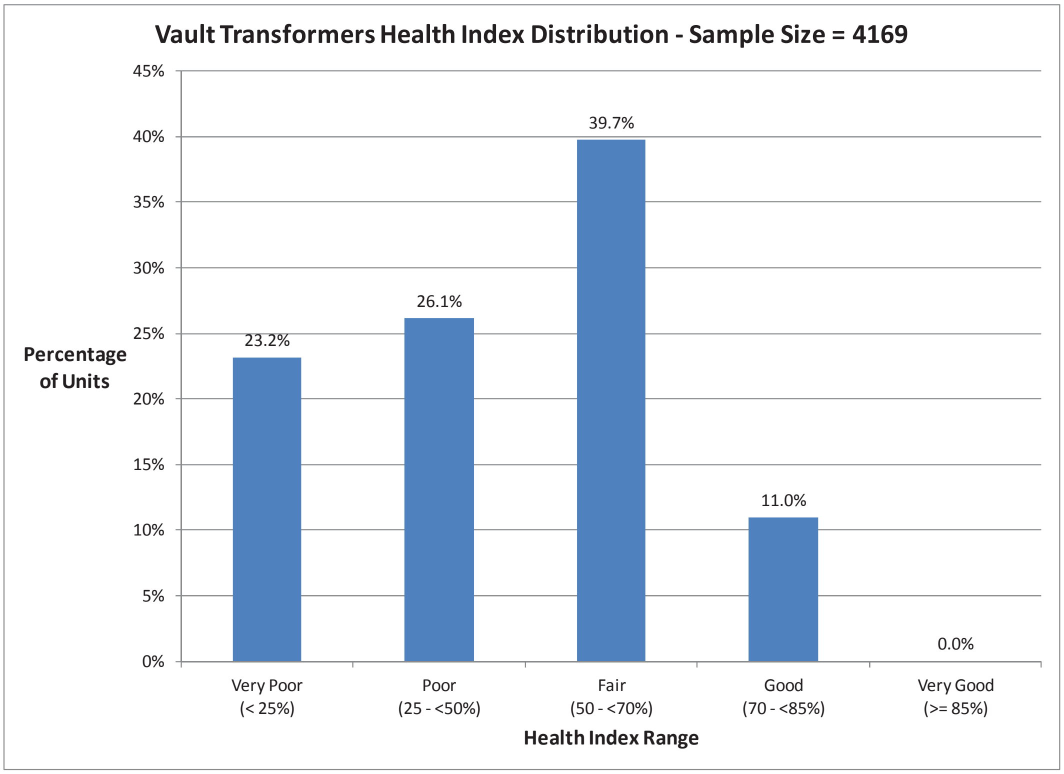

Figure 12-4 Vault Transformers Health Index Distribution (Percentage of Units)

The following diagrams show the Vault Transformers Health Index distribution by different voltage levels.

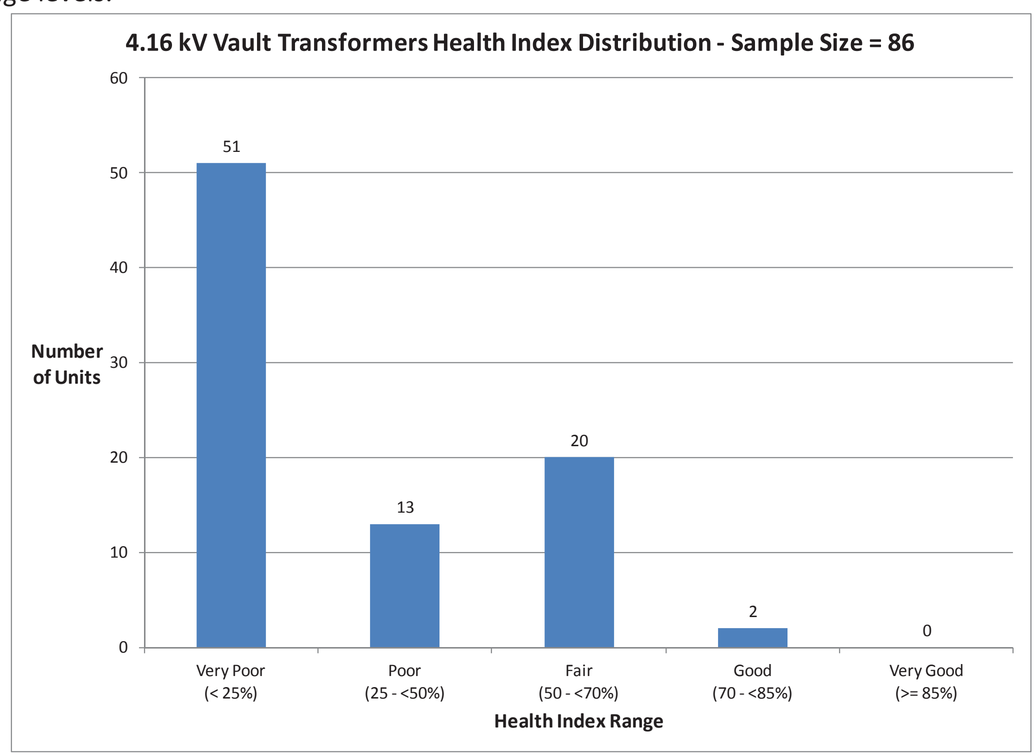

Figure 12-5 Vault Transformers Health Index Distribution – 4.16 kV

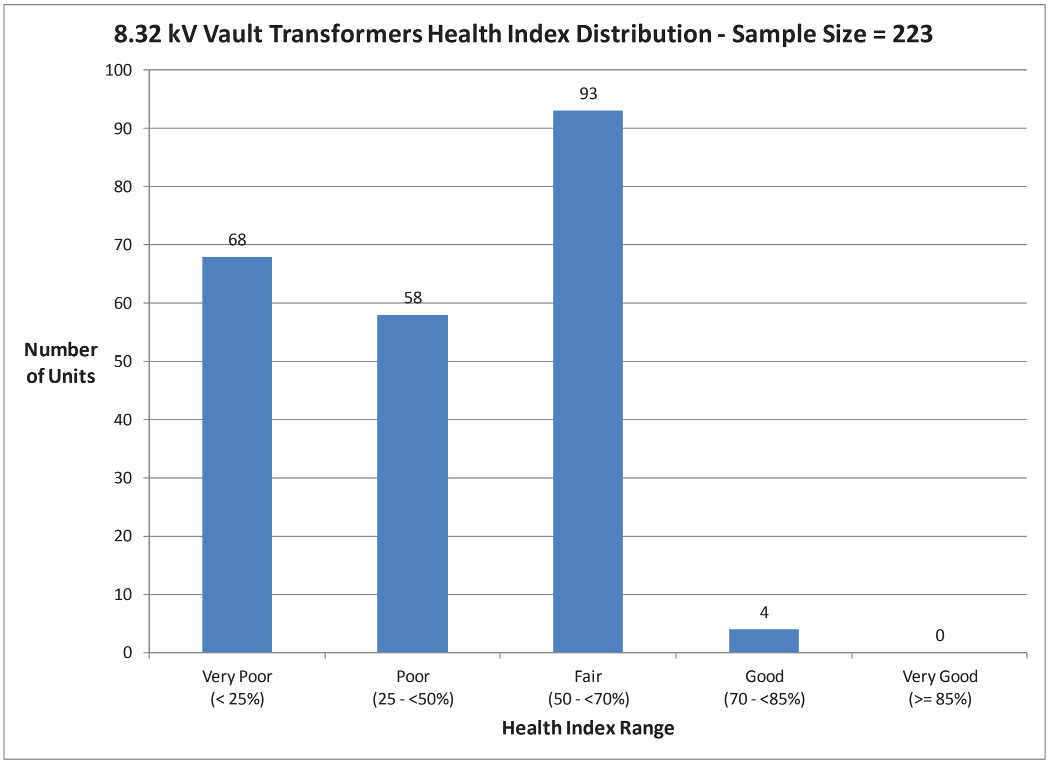

Figure 12-6 Vault Transformers Health Index Distribution – 8.32 kV

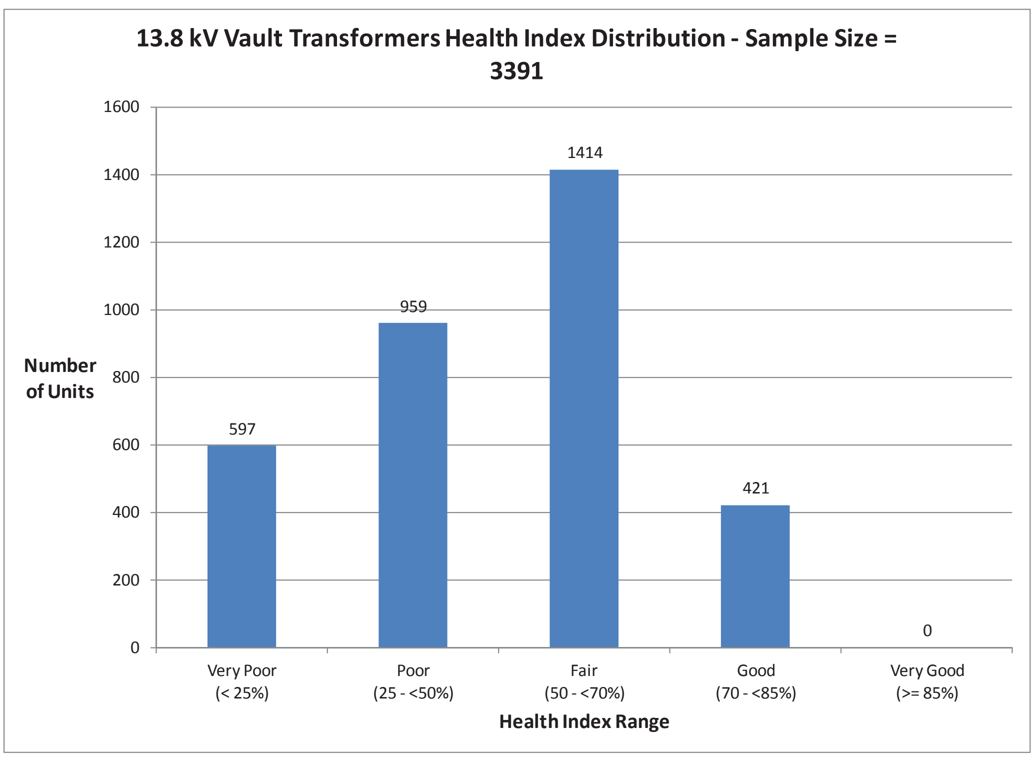

Figure 12-7 Vault Transformers Health Index Distribution – 13.8 kV

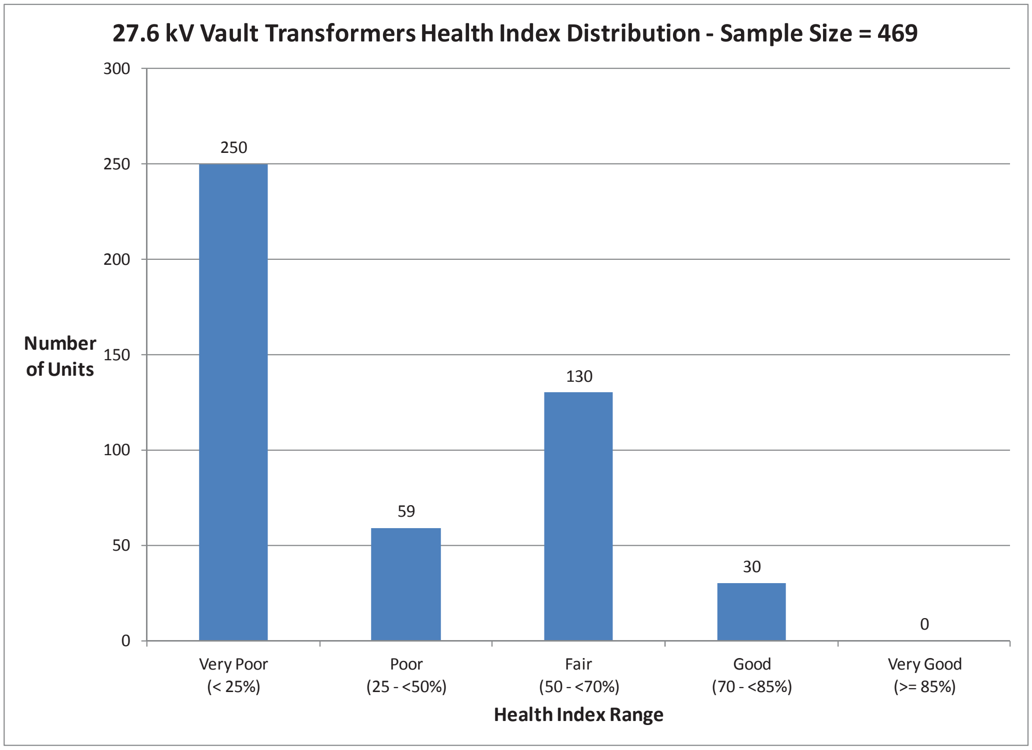

Figure 12-8 Vault Transformers Health Index Distribution – 27.6 kV

12.5 Vault Transformers Condition-Based Flagged-For-Action Plan

As it is assumed that Vault Transformers are reactively replaced, the Flagged-For-Action Plan is based on asset failure rate f (t), as described in Section II.2.2.

The Flagged-For-Action Plan is based on the number of expected failures in a given year.

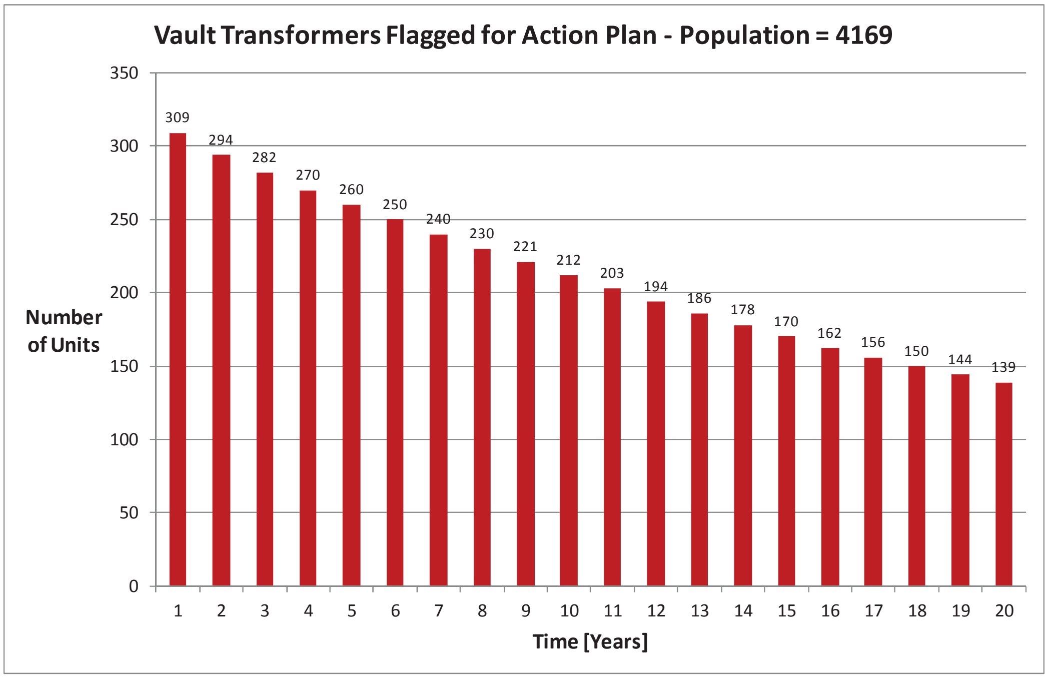

Figure 12-9 Vault Transformers Condition-Based Flagged-For-Action Plan

12.6 Vault Transformers Data Analysis

The data available for Vault Transformers includes age and loading determined using hourly data obtained from Horizon Utilities Smart Meter data.

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13 Utility Chambers

Utility Chambers facilitate cable pulling into underground ducts and provide access to splices and facilities that require periodic inspections or maintenance. Below ground equipment vaults permit installation of transformers, switchgear or other equipment. Vaults used for transformer installation are often equipped with ventilation grates to provide natural or forced cooling.

Underground cable chambers come in different styles, shapes and sizes according to the location and application. For this analysis we identified only the broad categories depending on their use and type of construction. Precast cable chambers are normally installed only outside the traveled portion of the road although some end up under the road surface after road widening. Cast-in-place cable chambers are used under the traveled portion of the road because of their strength and also because they are cheaper to rebuild if they should fail. Customer cable chambers are on customer property and are usually in a more benign environment. Although they supply a specific customer, system cables loop through these chambers so other customers could also be affected by any problems. Sidewalk vaults are most often located in or adjacent to pedestrian walkways.

13.1 Utility Chambers Degradation Mechanism

Utility chambers must withstand the heaviest structural loadings that they might be subjected to. For example, when located in streets, utility chambers must withstand heavy loads associated with traffic in the street. When located in driving lanes, manhole chimney and collar rings must match street grading. Since utility chambers and vaults often experience flooding, they sometimes include drainage sumps and sump pumps. However, environmental regulations in some jurisdictions may prohibit the pumping of utility chambers or vaults into sewer systems, without testing of the water for environmentally hazardous contaminants.

Although age is loosely related to the condition of underground civil structures, it is not a linear relationship. Other factors such as mechanical loading, exposure to corrosive salts, etc. have a stronger effect. Therefore, a condition-based asset management program based on periodic field inspections to identify problems and rate the condition of the structure is used by many utilities. Tracking the results of these inspections will show the rate of deterioration and provide advance notice of impending work to correct any problems. Some underground chambers may only need cleaning or repairs to frames and covers or vault doors and grates, but the others may require major rebuilding of the walls and/or roof.

Utility chamber degradation commonly includes corrosion of reinforcing steel, spalling of concrete, and rusting of covers or rings. Acidic salts (i.e. sulfates or chlorides) affect corrosion rates. Manhole systems also may experience a number of deficiencies or defects. In roadways, defects exist when covers are not level with street surfaces. Conditions that lead to flooding, clogged sumps, and non-functioning sump-pumps also represent major deficiencies in a manhole system. Similarly, manhole systems with lights that do not function properly constitute defective systems. Deteriorating ductwork associated with utility chambers also requires evaluation in assessing the overall condition of a manhole system. In addition to the above, for equipment vaults, the condition of ventilation grates and padlocks need to be considered in assessing overall health.

13.2 Utility Chambers Health Index Formulation

This section presents the Health Index Formula that was developed and used for Horizon Utilities Utility Chambers. The Health Index equation is shown in Section II.1; the condition, sub-condition parameters, weights, and condition criteria are as follows.

Assume a parameter scoring system of 0 through 4, where 0 and 4 represent the “worst” and “best” scores respectively. Thus, the maximum score for any condition or sub-condition parameter (maximum CPS and CPF) is “4”.

13.2.1 Utility Chambers Condition and Sub-Condition Parameters

Table 13-1 Utility Chambers Condition Parameter and Weights

m	Condition Parameter	WCP_m	Sub-Condition Parameters
1	Service Record	2	Table 13-2

Table 13-2 Utility Chambers Service Record (m=5) Weights and Maximum CPF

n	Sub-Condition Parameter	CPF Lookup Table	$WCPF_n$	$CPF_{n.max}$
1	Overall	Table 13-3	1	4
2	Age	Figure 13-1	2	4

13.2.2 Utility Chambers Condition Criteria

__Overall Condition__

Table 13-3 Utility Chambers Overall Condition Criteria

Condition Rating*	CPF	Description (Kinectrics 2011 report)
A	4	A
B	3	B
C	2	C
D	1	D
E	0	E

Age

Assume that the failure rate for Utility Chambers exponentially increases with age and that the failure rate equation is as follows:

$$f = e^{\beta(t-\alpha)}$$

f	= failure rate of an asset (percent of failure per unit time)
t	= time
α, β	= constant parameters that control the rise of the curve

The corresponding survivor function is therefore:

$$S_f = 1 - P_f = e^{-(f-e^{-\alpha\beta})/\beta}$$

S_f	= survivor function
P_f	= probability of failure

Assuming that at the ages of 80 and 95 years the probability of failure (P_f) for this asset are 50% and 85% respectively results in the survival curve shown below. It follows that the CPF for Age is the survival curve normalized to the maximum CPF score of 4 (i.e. 4*Survival Curve). The CPF vs. Age is also shown in the figure below:

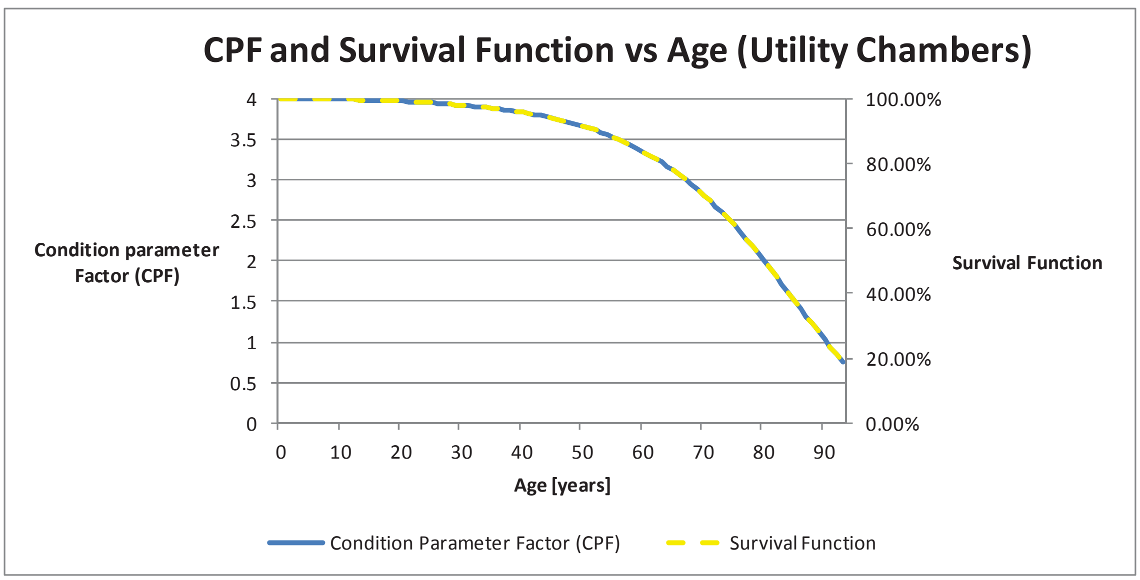

Figure 13-1 Age Condition Criteria (Utility Chambers)

13.3 Utility Chambers Age Distribution

The age distribution is shown in the figure below. Age was available for 100% of the population. The average age was found to be 39 years.

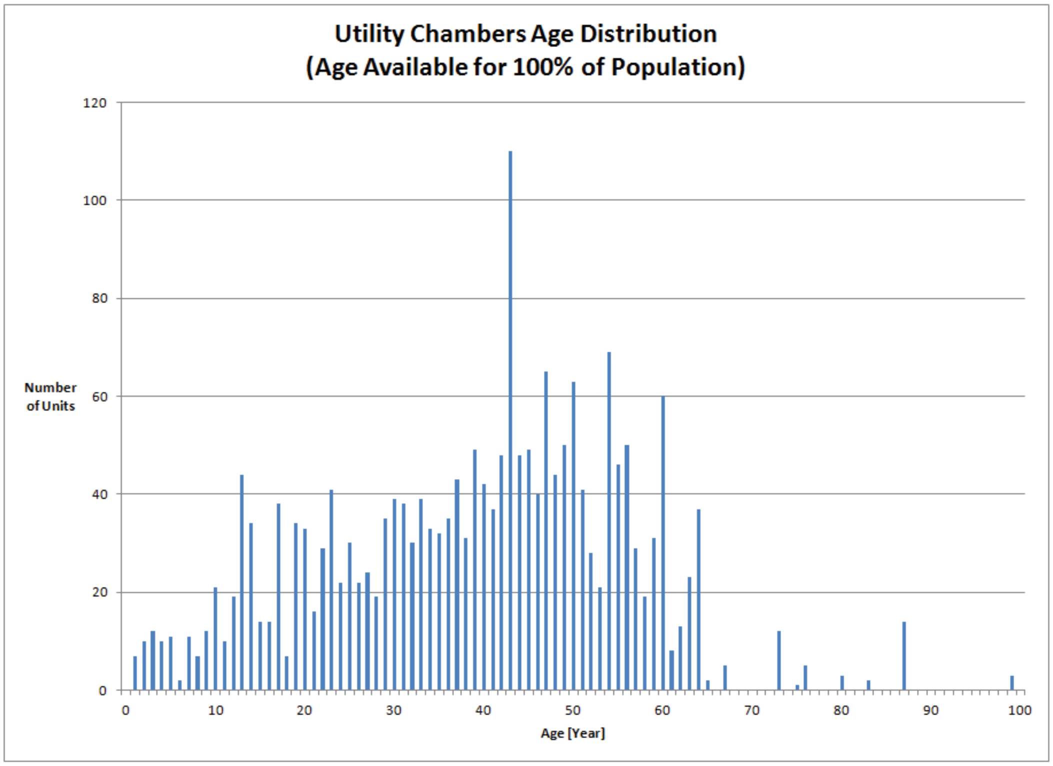

Figure 13-2 Utility Chambers Age Distribution

13.4 Utility Chambers Health Index Results

There are 2075 in-service Utility Chambers at Horizon Utilities. The condition assessment for utility chambers is primarily age-driven. Results of an independent assessment performed on a sample of utility chambers were included in the condition assessment.

The average Health Index for this asset group is 92%.

The Health Index Results are as follows:

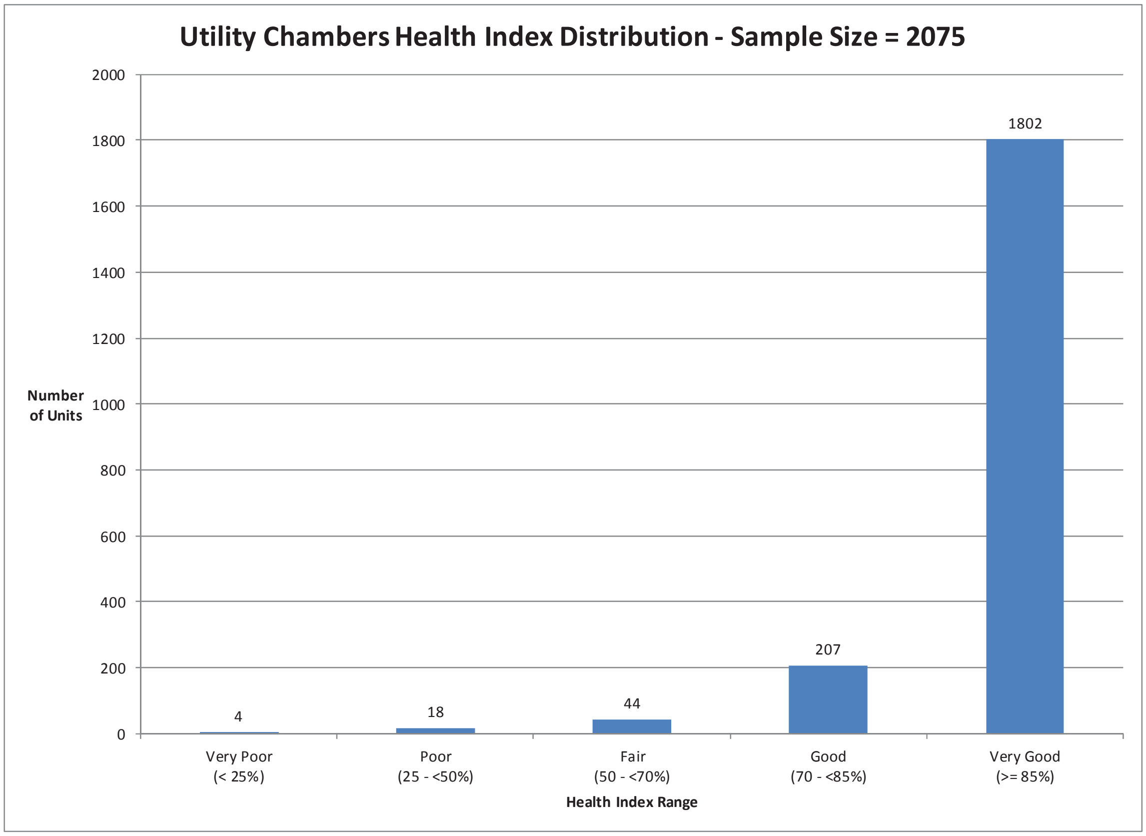

Figure 13-3 Utility Chambers Health Index Distribution (Number of Units)

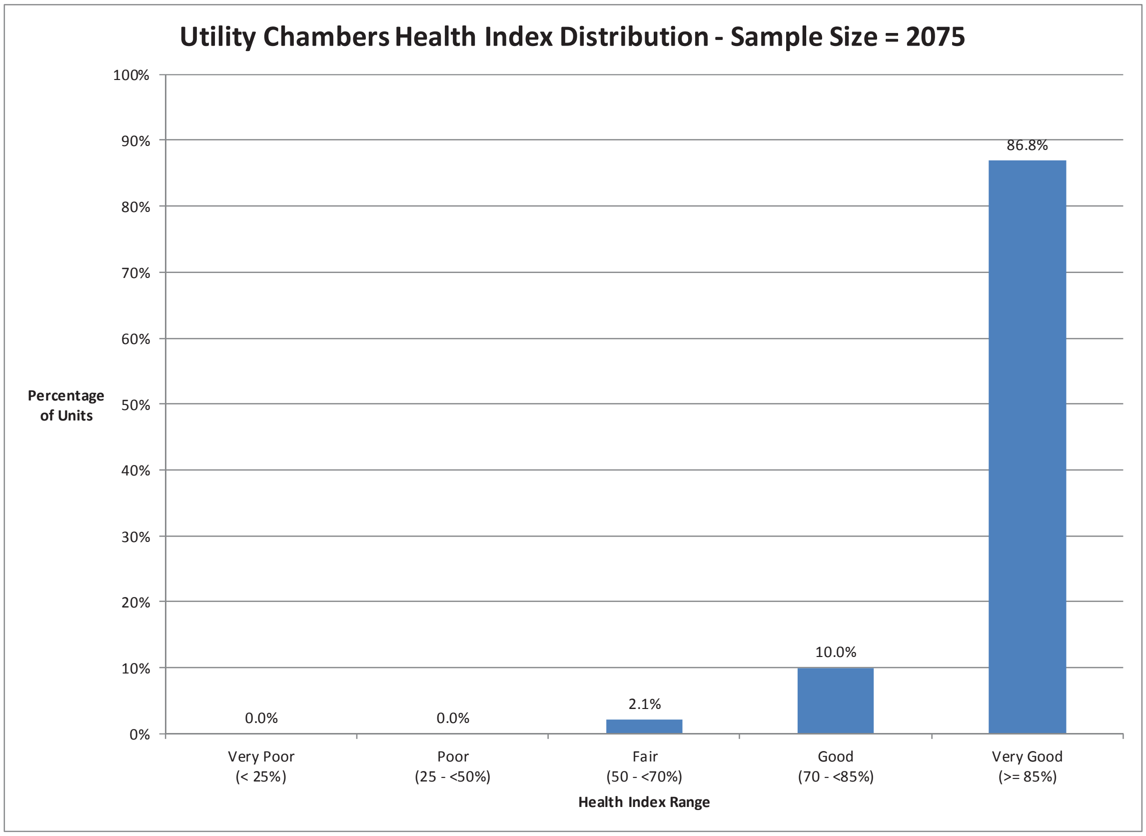

Figure 13-4 Utility Chambers Health Index Distribution (Percentage of Units)

13.5 Utility Chambers Condition-Based Flagged-For-Action Plan

As it is assumed that Utility Chambers are reactively replaced, the Flagged-For-Action Plan is based on asset failure rate f (t), as described in Section II.2.2.

The Flagged-For-Action Plan is based on the number of expected failures in a given year.

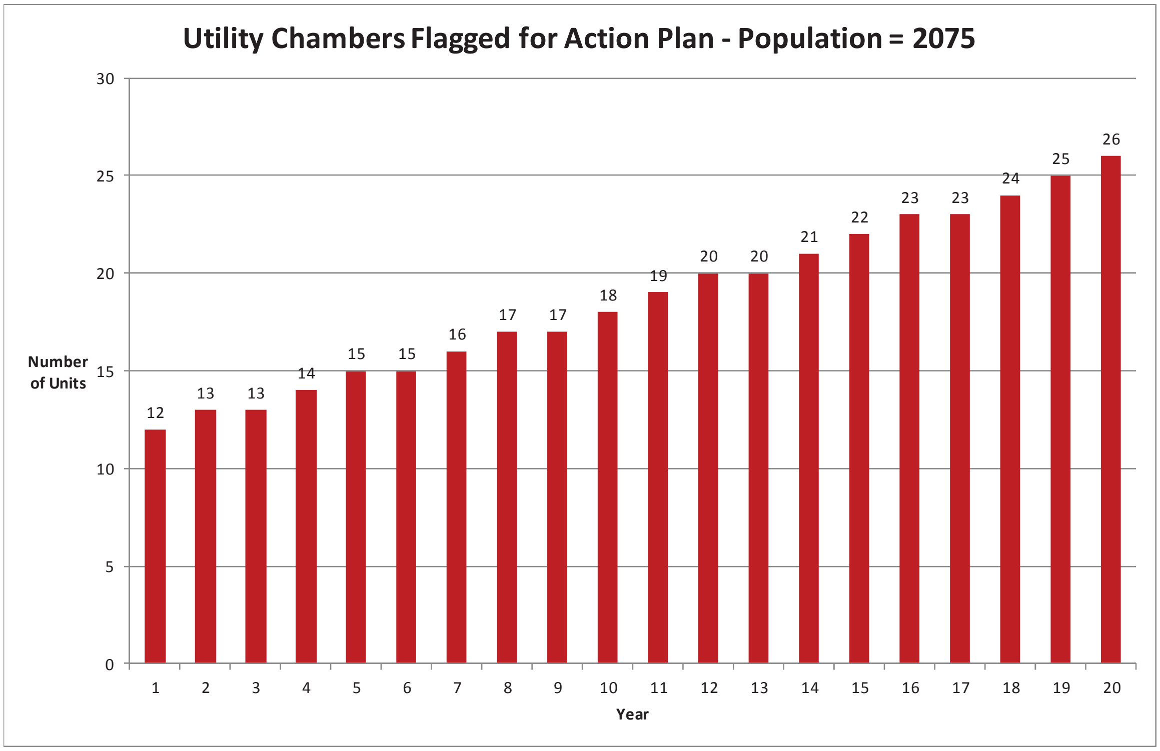

Figure 13-5 Utility Chambers Optimized Condition-Based Flagged-For-Action Plan

13.6 Utility Chambers Data Analysis

The data available for Utility Chambers includes age and Kinectrics assessment sample records (for very few units using remotely controlled camera). It is recommended to conduct periodic assessments to increase the sample size, particularly to include locations deemed to be critical by Horizon Utilities.

14 Vaults

There are 3143 vaults included in this report. Similar to Utility Chambers, vaults facilitate cable pulling into underground ducts and provide access to splices and facilities that require periodic inspections or maintenance. At Horizon Utilities, vaults are typically smaller than Utility Chambers and utilized where regular access for workers is not required.

Underground vaults come in different styles, shapes and sizes according to the location and application. For this analysis we identified only the broad categories depending on their use and type of construction.

14.1 Vaults Degradation Mechanism

Vaults must withstand the heaviest structural loadings that they might be subjected to. For example, when located in streets, vaults must withstand heavy loads associated with traffic in the street. When located in driving lanes, manhole chimney and collar rings must match street grading. Since vaults often experience flooding, they sometimes include drainage sumps and sump pumps. However, environmental regulations in some jurisdictions may prohibit the pumping of vaults into sewer systems, without testing of the water for environmentally hazardous contaminants.

Although age is loosely related to the condition of underground civil structures, it is not a linear relationship. Other factors such as mechanical loading, exposure to corrosive salts, etc. have a stronger effect. Therefore, a condition-based asset management program based on periodic field inspections to identify problems and rate the condition of the structure is used by many utilities. Tracking the results of these inspections will show the rate of deterioration and provide advance notice of impending work to correct any problems. Some underground vaults may only need cleaning or repairs to frames and covers or vault doors and grates, but the others may require major rebuilding of the walls and/or roof.

Vault degradation commonly includes corrosion of reinforcing steel, spalling of concrete, and rusting of covers or rings. Acidic salts (i.e. sulfates or chlorides) affect corrosion rates. Manhole systems also may experience a number of deficiencies or defects. In roadways, defects exist when covers are not level with street surfaces. Conditions that lead to flooding, clogged sumps, and non-functioning sump-pumps also represent major deficiencies in a manhole system. Similarly, manhole systems with lights that do not function properly constitute defective systems. Deteriorating ductwork associated with vaults also requires evaluation in assessing the overall condition of a manhole system. In addition to the above, for equipment vaults, the condition of ventilation grates and padlocks need to be considered in assessing overall health.

14.2 Vaults Health Index Formulation

This section presents the Health Index Formula that was developed and used for Horizon Utilities Vaults. The Health Index equation is shown in Section II.1; the condition, sub-condition parameters, weights, and condition criteria are as follows.

Assume a parameter scoring system of 0 through 4, where 0 and 4 represent the "worst" and "best" scores respectively. Thus, the maximum score for any condition or sub-condition parameter (maximum CPS and CPF) is "4".

14.2.1 Vaults Condition and Sub-Condition Parameters

Table 14-1 Vaults Condition Parameter and Weights

m	Condition Parameter	WCP_m	Sub-Condition Parameters
1	Service Record	1	Table 14-2

Table 14-2 Vaults Service Record (m=1) Weights and Maximum CPF

n	Sub-Condition Parameter	CPF Lookup Table	$WCPF_n$	$CPF_{n.max}$
1	Age	Figure 15-1	1	4

14.2.2 Vaults Condition Criteria

<u>**Age**</u>

Assume that the failure rate for Vaults exponentially increases with age and that the failure rate equation is as follows:

$$f = e^{\beta(t-\alpha)}$$

f = failure rate of an asset (percent of failure per unit time)
t = time
α, β = constant parameters that control the rise of the curve

The corresponding survivor function is therefore:

$$S_f = 1 - P_f = e^{-(f-e^{-\alpha\beta})/\beta}$$

S_f = survivor function
P_f = probability of failure

Assuming that at the ages of 80 and 95 years the probability of failure (P_f) for this asset are 50% and 85% respectively results in the survival curve shown below. It follows that the CPF for Age is the survival curve normalized to the maximum CPF score of 4 (i.e. 4*Survival Curve). The CPF vs. Age is also shown in the figure below:

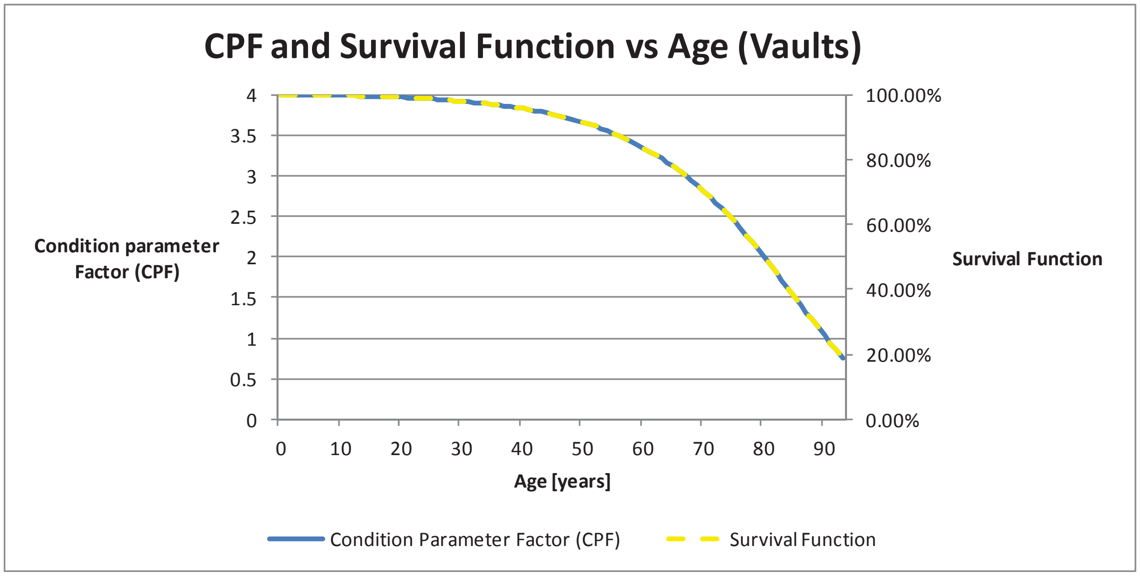

Figure 14-1 Age Condition Criteria (Vaults)

14.3 Vaults Age Distribution

The age distribution is shown in the figure below. Age was available for 100% of the population. The average age was found to be 28 years.

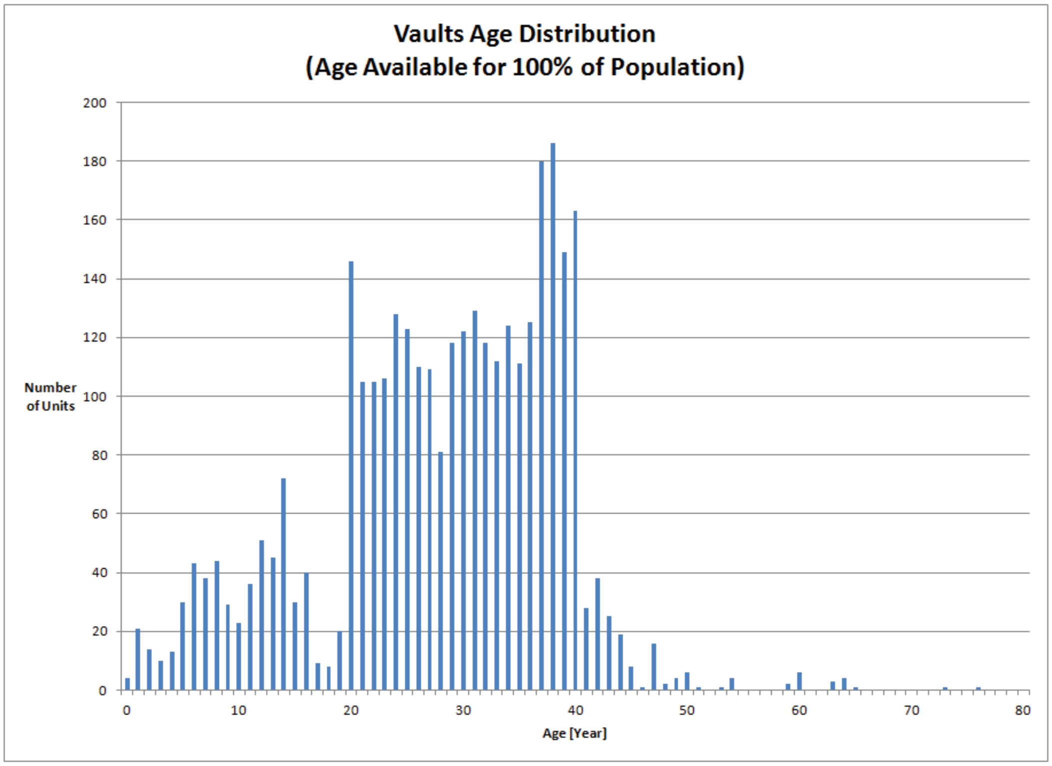

Figure 14-2 Vaults Age Distribution

14.4 Vaults Health Index Results

There are 3143 in-service Vaults at Horizon Utilities. The Health Index is exclusively age driven.

The average Health Index for this asset group is 97%. None of the units was found to be in poor or very poor condition.

The Health Index Results are as follows:

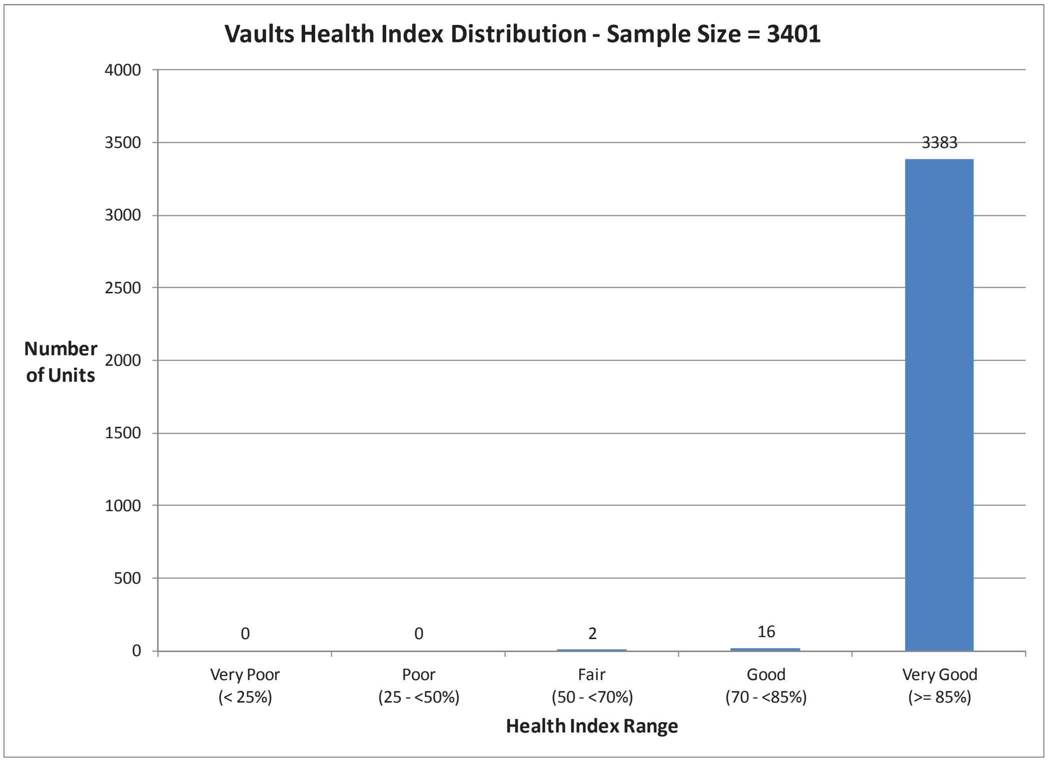

Figure 14-3 Vaults Health Index Distribution (Number of Units)

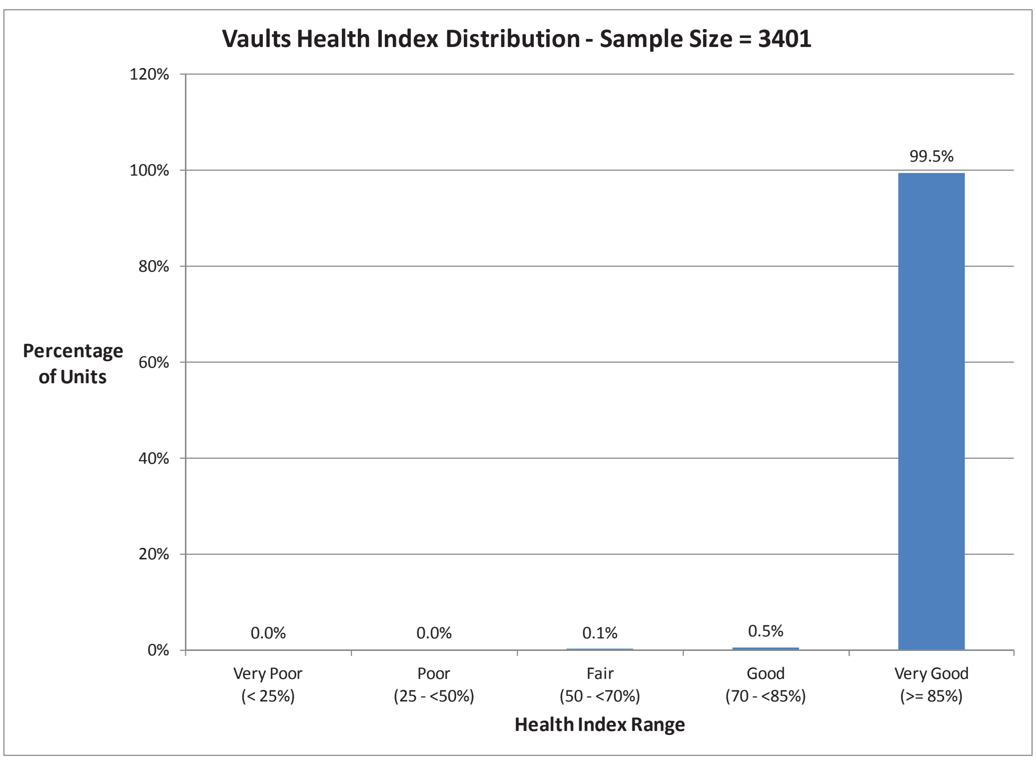

Figure 14-4 Vaults Health Index Distribution (Percentage of Units)

14.5 Vaults Condition-Based Flagged-For-Action Plan

As it is assumed that Vaults are reactively replaced, the Flagged-For-Action Plan is based on asset failure rate f (t), as described in Section II.2.2.

The Flagged-For-Action Plan is based on the number of expected failures in a given year.

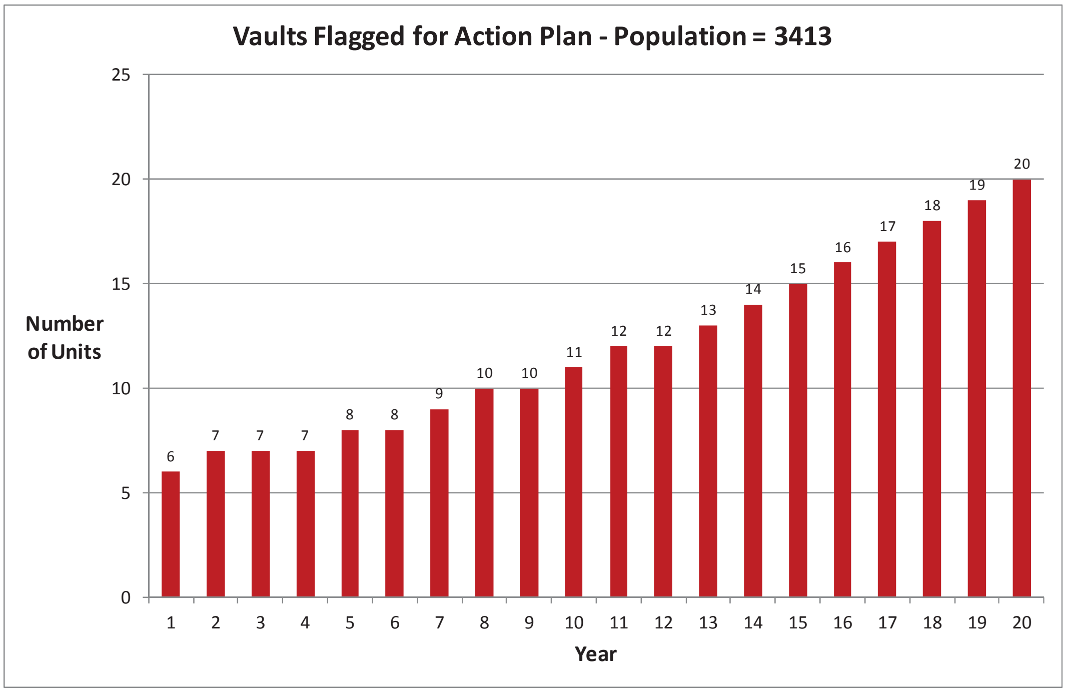

Figure 14-5 Vaults Condition-Based Flagged-For-Action Plan

14.6 Vaults Data Analysis

The data available for Vaults includes age only.

15 Submersible Load Break Switches

This asset group consists of distribution underground three-phase gang operated switches, manually operated as well as motor operated. The primary function of switches is to permit isolation of line sections or equipment for maintenance, safety or other operating requirements. While some categories of switches are rated for load interruption, others are designed to operate under no load conditions, these switches operate only when the current through the switch is zero.

In general, submersible load break switches consist of mechanically movable copper blades supported on insulators and mounted inside a sealed unit. The insulating medium is either oil or SF^6. The operating or control mechanism can be either a simple hook stick or a manual gang. Since they do not typically need to interrupt short circuit currents, disconnect switches are relatively simple in design compared to circuit breakers.

15.1 Submersible Load Break Switches Degradation Mechanism

The main degradation processes associated with line switches include:

- Corrosion of steel hardware or operating rod
- Contamination of oil for oil insulated devices
- Degradation of the separable connectors

The rate and severity of these degradation processes depends on a number of inter-related factors including the operating duties and environment in which the equipment is installed. In most cases, corrosion or rust represents a critical degradation process. The rate of deterioration depends heavily on environmental conditions where the equipment operates.

15.2 Submersible Load Break Switches Health Index Formulation

This section presents the Health Index Formula that was developed and used for Horizon Utilities Submersible Load Break Switches. The Health Index equation is shown in Section II.1; the condition, sub-condition parameters, weights, and condition criteria are as follows.

15.2.1 Submersible Load Break Switches Condition and Sub-Condition Parameters

Table 15-1 Submersible Load Break Switches Condition Weights and Maximum CPS

m	Condition Parameter	WCP_m	CPS Lookup Table
1	Service Record	1	Table 15-1
	De-rating multiplier (DR)		

Table 15-1 Submersible Load Break Switches Service Record (m=3) Weights and Maximum CPF

n	Sub-Condition Parameter	CPF Lookup table	$WCPF_n$	$CPF_{n.max}$
1	Age	Figure 15-1	1	4

15.2.2 Submersible Load Break Switches Condition Parameter Criteria

Age

Assume that the failure rate for Submersible Load Break Switches exponentially increases with age and that the failure rate equation is as follows:

$$f = e^{\beta(t-\alpha)}$$

f = failure rate of an asset (percent of failure per unit time)
t = time
α, β = constant parameters that control the rise of the curve

The corresponding survivor function is therefore:

$$S_f = 1 - P_f = e^{-(f-e^{-\alpha\beta})/\beta}$$

S_f = survivor function
P_f = probability of failure

Assuming that at the ages of 40 and 50 years the probability of failure (P_f) for this asset are 50% and 80% respectively results in the survival curve shown below. It follows that the CPF for Age is the survival curve normalized to the maximum CPF score of 4 (i.e. 4*Survival Curve). The CPF vs. Age is also shown in the figure below:

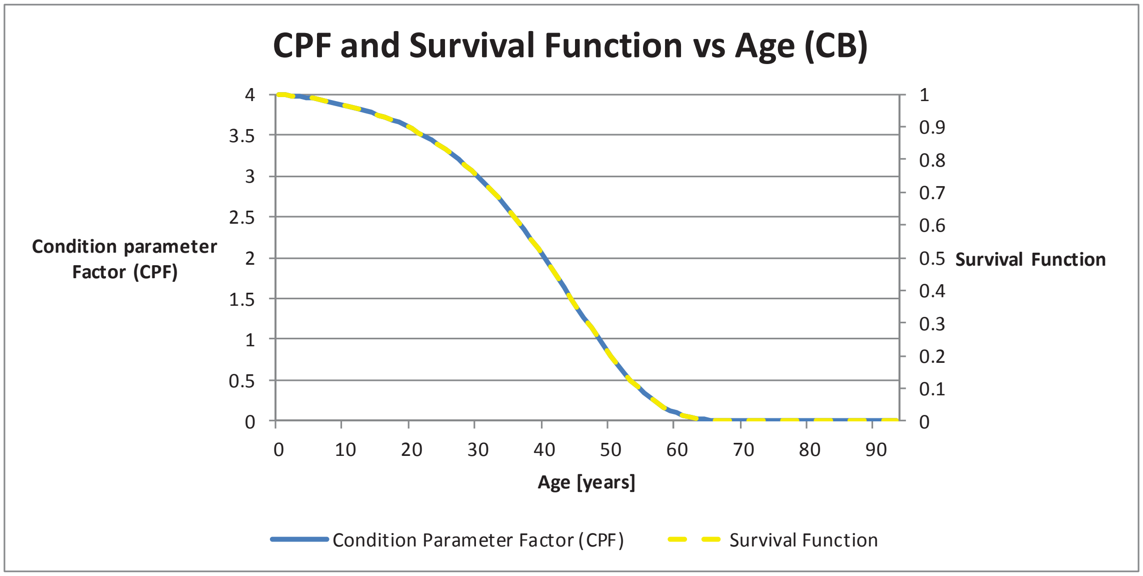

Figure 15-1 Age Condition Criteria (Submersible Load Break Switches)

De-Rating (DR) Multiplier

The de-rating is based on the following equation:

$$DR = \min(DRF_1, DRF_2, DRF_3)$$

Equation 15-1

Where DRF are as described as follows:

Table 15-2 Submersible Load Break Switches De-Rating Factors

De-Rating Factor (DRF)	De-Rating Factor	Description
DRF_1	0.7	Old oil LBDS (older than year 2000)

15.3 Submersible Load Break Switches Age Distribution

The age distribution is shown in the figures below. Age was available for 100% of the population. The average age was found to be 30 years.

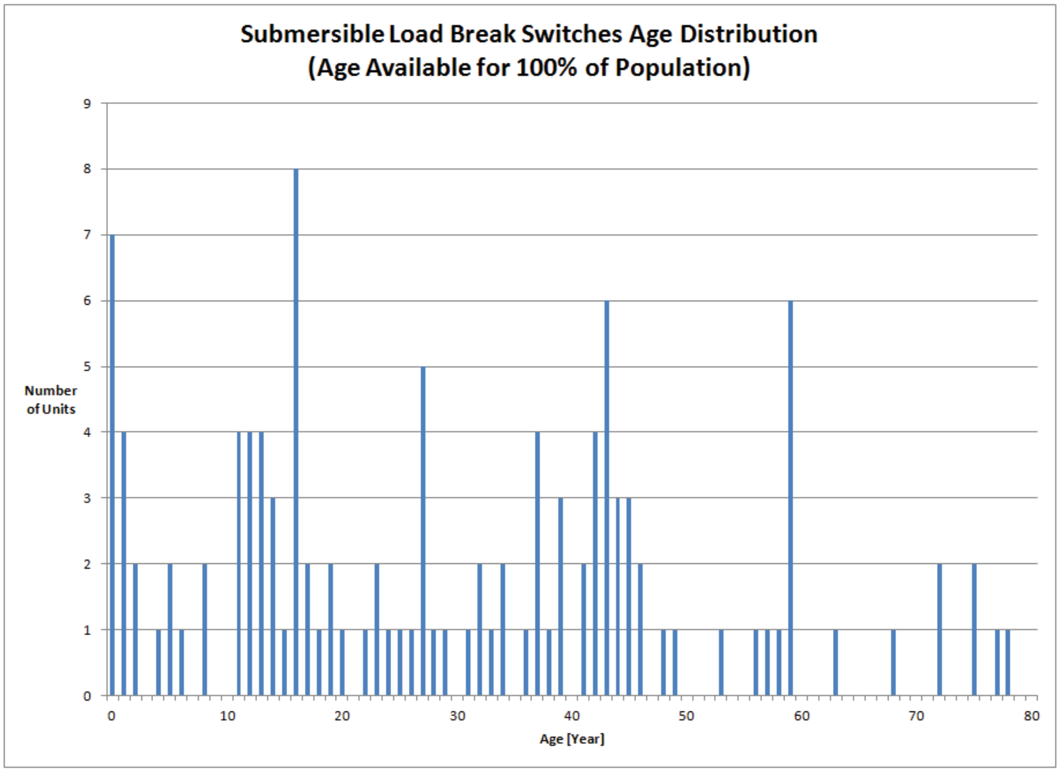

Figure 15-2 Submersible Load Break Switches Age Distribution

15.4 Submersible Load Break Switches Health Index Results

There are 117 in-service Submersible Load Break Switches at Horizon Utilities. The condition assessment is age-driven. The average Health Index for this asset group is 55%. Approximately 46% of the switches were found to be in poor or very poor condition.

The Health Index Results are as follows:

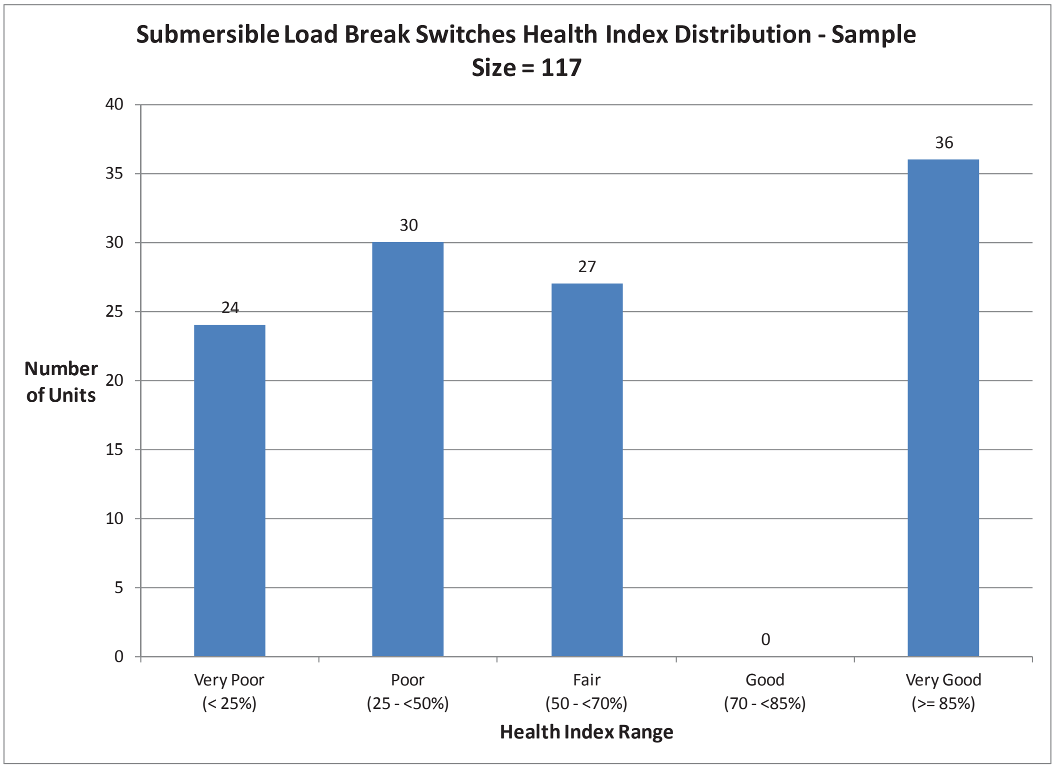

Figure 15-3 Submersible Load Break Switches Health Index Distribution

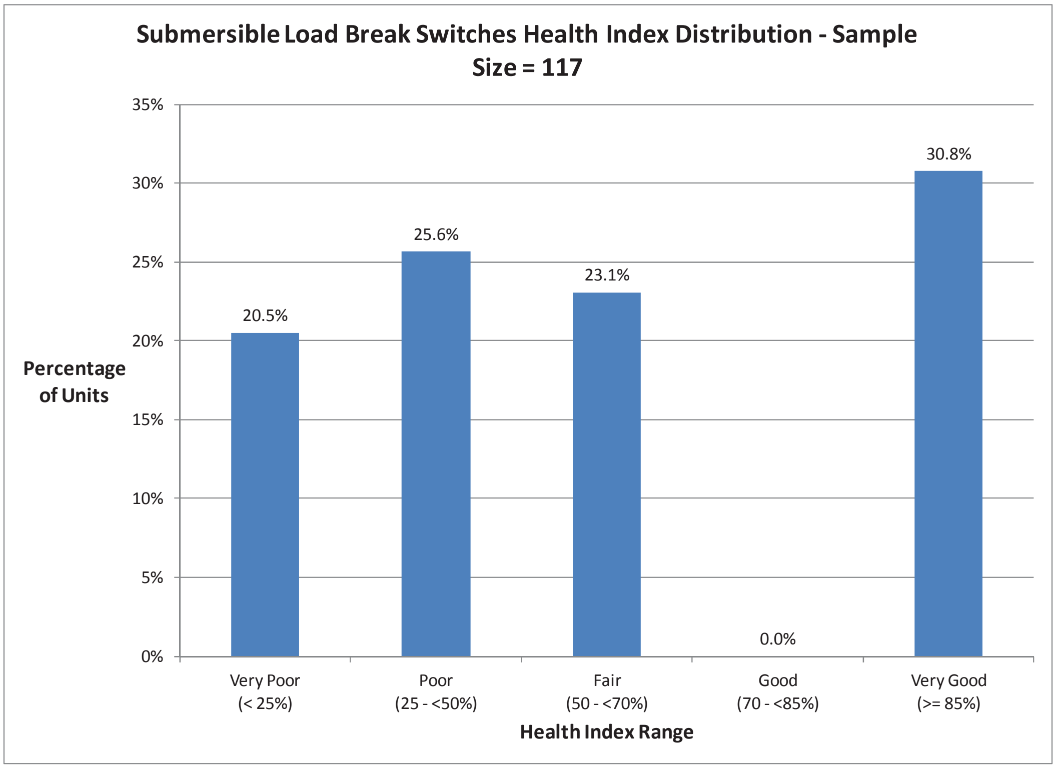

Figure 15-4 Submersible Load Break Switches Health Index Distribution

15.5 Submersible Load Break Switches Condition-Based Flagged-For-Action Plan

As it is assumed that Submersible Load Break Switches are reactively replaced, the Flagged-For-Action Plan is based on asset failure rate f (t), as described in Section II.2.2.

The Flagged-For-Action Plan is based on the number of expected failures in a given year.

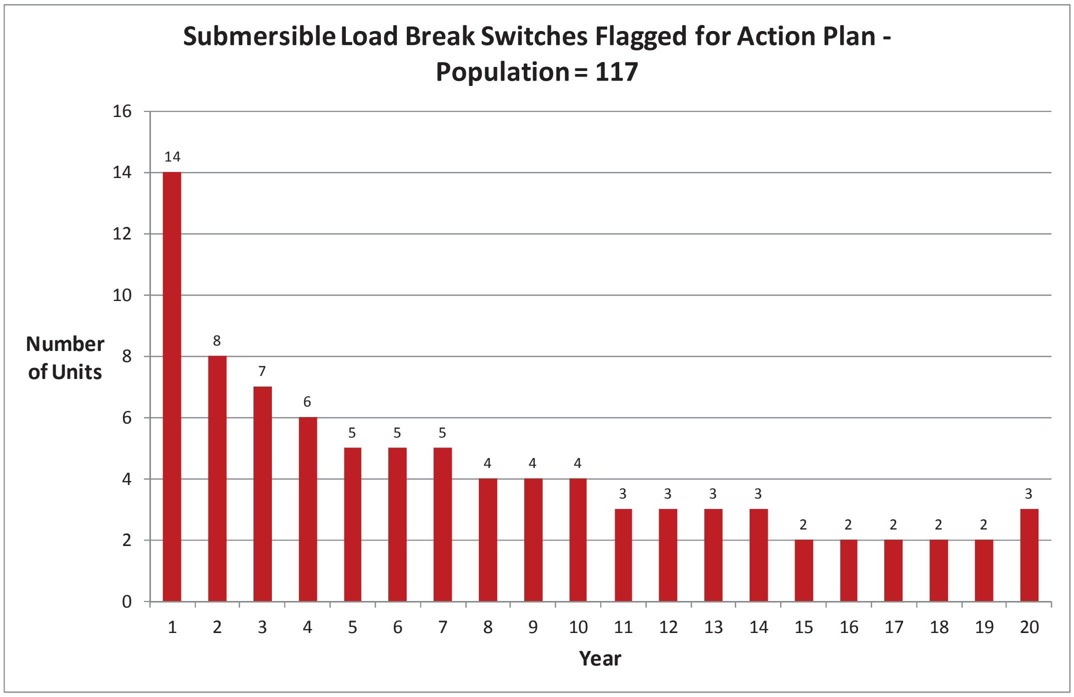

Figure 15-5 Submersible Load Break Switches Condition-Based Flagged-For-Action Plan

15.6 Submersible Load Break Switches Data Analysis

The data available for Submersible Load Break Switches included age only.

VII REFERENCES

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VII References

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Appendix C – KPMG Assurance Review of Kinectrics' Asset Condition Assessment Review

KPMG
cutting through complexity

Horizon Utilities Corporation

Assurance Review of Kinectrics' Asset Condition Assessment Report

Jan 23, 2014

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Version Control

Version	Date	By	Description
0.9	Dec 18, 2013	David Cheng	Original Draft for discussion
1.0	Jan 21, 2014	David Cheng	Incorporated Horizon feedback
1.1	Jan 23, 2014	David Cheng	Incorporated additional Horizon feedback

Glossary

Chronological Age	age of the asset expressed in years since its installation
Health Index	condition of the asset expressed as a percentage score between 0 and 100% with 100% representing an asset that is in new condition
Proactive Replacement	a strategy that will flag assets for action based on the capability of handling a pre-defined stress level, typically resulting in Flagged-for-Action prior to the physical end of life.
Reactive Replacement	a strategy that flags assets for action based on the failure rate of the assets
Flagged-for-Action	a state that identifies assets to be considered for replacement or significant refurbishment

Contents

1 Executive Summary

Kinectrics Inc. ("Kinectrics") was retained by Horizon between 2012 and 2013 to conduct an assessment on Horizon's distribution assets with the goal of identifying future asset replacement or refurbishment needs in order to sustain the existing assets. Kinectrics findings and recommendations were delivered in their final report dated November 27, 2013 (Kinectrics Inc., 2013).

Based on an independent assurance review of the methodology and analytics used in the Kinectrics report titled "Horizon Utilities 2013 Asset Condition Assessment" (Kinectrics Inc., 2013), 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 Utilities Corporation ("Horizon") supplied asset data in order to derive the final Flagged-for-Action (assets flagged for replacement or refurbishment) 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.

KPMG was subsequently retained by Horizon 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 expresses no opinion on financial results, internal control, data quality or other information.

KPMG reviewed the methodology published by Kinectrics in their report and compared it with other methodologies used in utilities for predicting probabilistic life expectancy of assets in order to test the validity of the selected methodology used by Kinectrics. 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. Kinectrics also employed different predictive models for run-to-failure assets (reactively replaced) and for assets that are replaced or rehabilitated before failure occurs (proactively managed assets). This differentiated approach is more advanced than that which is currently in use at most other utilities and in theory should provide more appropriate modelling of remaining asset life for reactively replaced assets and for proactively managed assets.

From the described methodology and from the original asset condition data set provided by Horizon to Kinectrics for their assessment, KPMG was successful in recreating independent analytical models to calculate the health indices, effective ages and Flagged-for-Action plans for the 22 distinct classes of assets (see Appendix 1) and comparing them with Kinectrics' published results.

The results calculated by Kinectrics and independently calculated by KPMG are within an acceptable and reasonable margin of error for the intended purpose of projecting asset replacements or refurbishments over a twenty year period. The numbers of units identified for replacement or refurbishment by the two respective models differ by less than 0.5% for 19 out of the 22 asset classes and the remaining 3 asset classes differ by no more than 4.5%. Using current standard unit costs provided by Horizon, the cumulative anticipated investment over twenty years is projected to be $693.7M for the Kinectrics model and $694.8M for that of KPMG. The projected twenty year difference is 0.02%; this difference is insignificant between the two models. Thus, it is KPMG's opinion that Kinectrics has consistently applied their methodology as published in their report using Horizon's asset data.

To test the reasonableness of the effective age calculations, the effective age distribution for each asset class was compared with the chronological age distribution to identify any potential anomalies in applying the asset condition ratings to the asset population. This test demonstrated relative consistency between chronological age and effective age distributions for 21 out of the 22 asset classes. The Substation Transformers asset class was the only exception found; its average effective age was found to be significantly below the average chronological age. The result of this age reduction is that this asset class would require less capital sustainment investments going forward than if the chronological age was the only criterion used. Using the effective age distribution, the investment impact would be understated when compared to using the chronological age distribution. This lower level of investment is reflected in the resultant Flagged-for-Action plan for Substation Transformers.

To further test the reasonableness of the Kinectrics results, a comparison of their Flagged-for-Action plan was made against an alternative plan generated from accepted asset life expectancies found in the Asset Depreciation Study for the Ontario Energy Board (OEB) report (Kinectrics Inc. Report No: K-418033-RA-001-R000, 2010). Using the published useful life expectancy data for the different asset classes found in the Asset Depreciation Study against the chronological ages of the assets, an alternative twenty year investment plan was created by KPMG. This alternative OEB-based investment plan was compared to the one created by Kinectrics. The twenty year investment plan based on the OEB data projected $706.9M required capital investment versus the $693.7M figure projected by Kinectrics. The marginal differences between these two models validated that Kinectrics' projections are within accepted industry norms and practices for asset replacements or refurbishments.

In conclusion, it is KPMG's opinion that the approach and the calculations used to arrive at the presented results in the Kinectrics report is in line with industry practice and generally accepted methodologies.

2 Introduction

In 2012, Horizon commissioned Kinectrics to conduct an asset condition assessment on Horizon's distribution assets with the goal of identifying future investments needed to sustain Horizon's existing asset base. Kinectrics' findings and recommendations have been published in the Horizon Utilities 2013 Asset Condition Assessment report (the "report") (Kinectrics Inc., 2013). Based on these recommendations, Horizon has prepared a Distribution System Plan ("DSP") that outlines the sustainment capital needed to maintain system performance over the next 20 years. The DSP will be submitted to the Ontario Energy Board ("OEB") in 2014 as part of Horizon's 2015 – 2019 rate application.

To support Horizon's rate application, KPMG was retained as an independent third-party, to complete an independent assurance review of the results contained in the Kinectrics report and provide a written opinion on the reasonableness of Kinectrics' findings and recommendations.

The procedures employed consisted solely of inquiry, observation, comparison and analysis of Horizon supplied information. The findings relied on the completeness and accuracy of the information as provided. KPMG expresses no opinion on financial results, internal control, data quality or other information.

KPMG recognizes this report may be called as evidence during the overall regulatory review process and as such KPMG may be needed to participate as an expert witness as prescribed by the OEB's procedural steps and timelines.

3 Assurance Review Scope

3.1 Scope

As an independent third party, KPMG completed the required data analysis to assess whether the results contained in the Kinectrics report are reasonable and acceptable. KPMG reviewed the methodology and analyses used by Kinectrics to generate the asset health indices, the effective ages and the resulting "Flagged-for-Action" plans for each of the asset classes shown in Table 1 below.

Table 1: Asset Classes in Scope

Asset Class	
Substation Transformers	
Substation Circuit Breakers	
Substation Switchgear	
Pole Mounted Transformers	
Overhead Conductors (in km)	Primary
Overhead Conductors (in km)	Secondary
Overhead Conductors (in km)	Service
Overhead Line Switches	
Wood Poles	
Concrete Poles	
Underground Cables (in km)	Prim. XLPE
Underground Cables (in km)	Prim. PILC
Underground Cables (in km)	Sec. DB
Underground Cables (in km)	Sec. ID
Underground Cables (in km)	Serv. DB
Underground Cables (in km)	Serv. ID
Pad Mounted Transformers	
Pad Mounted Switchgear	
Vault Transformers	
Utility Chambers	
Vaults	
Submersible LBD Switches	

The following inquiry, observation, comparison and analysis were undertaken in the assurance review process:

- Compared the methodology used by Kinectrics to determine the probabilistic remaining asset life expectancy against current methodologies employed by leading practitioners of asset management and against known published standards
- Using the methodology described in the Kinectrics report, created independent calculation engines for health indices, effective age and Flagged-for-Action plans in order to recreate the results contained in the Kinectrics report
- Using standard unit costs provided by Horizon, monetized the respective Flagged-for-Action plans generated by Kinectrics and KPMG in order to test the materiality differences of the two plans
- Compared KPMG calculations against Kinectrics calculations in order to test the validity of the Kinectrics results
- Created an alternative Flagged-for-Action model using the published expected life data contained in the Asset Depreciation Study for the Ontario Energy Board ("OEB") (Kinectrics Inc. Report No: K-418033-RA-001-R000, 2010) in order to test the reasonableness of Kinectrics' results with accepted industry standards

3.2 Not In Scope:

The following items were not in scope as part of the review process:

- Validation of the raw data quality (accuracy and completeness) used by Kinectrics to generate the results
- Validation of the selected failure curves used to estimate future asset failures
- Validation of actual asset conditions as expressed in the asset health indices
- Validation of the standard unit costs used in the determination of the Flagged-for-Action investment plans
- Interpretation of the Flagged-for-Action plans to future replacement or refurbishment investments

4 Assurance Review Methodology

The assurance review was conducted using data and information provided by Horizon and publically available information. These included:

- Horizon Utilities 2013 Asset Condition Assessment (Kinectrics Inc., 2013)
- Asset data including asset age, description, and asset condition for each of the asset classes
- Answers to KPMG's questionnaire requesting clarification or additional information
- Asset Depreciation Study for the Ontario Energy Board (Kinectrics Inc. Report No: K-418033-RA-001-R000, 2010)
- Answers obtained through interviews with Horizon representatives

The approach taken by KPMG to assess the Kinectrics results was to independently recreate the calculations using the data and information presented to KPMG by Horizon and the Kinectrics methodology contained in their report. The intermediate and final outcomes were compared to the published Kinectrics results. The comparisons that were completed included:

- Total population of individual asset classes
- Health indices for each asset class
- Effective ages for each asset class
- Flagged-for-Action profiles for each asset class
- Estimated 20 year monetary capital investment using Horizon supplied standard unit costs

In addition to comparing Kinectrics calculated results with KPMG's results, KPMG also conducted additional tests to confirm the reasonability of Kinectrics' recommendations. The additional tests included:

- Comparison of the calculated effective age distributions against the chronological age distributions for the different asset classes to determine reasonability of the methodology for determining effective age
- Comparison of estimated capital investment required for the Kinectrics' Flagged-for-Action plan and an alternative plan generated from the useful asset life ranges contained in the Depreciation Study for the Ontario Energy Board (Kinectrics Inc. Report No: K-418033-RA-001-R000, 2010)

5 Assurance Review Results

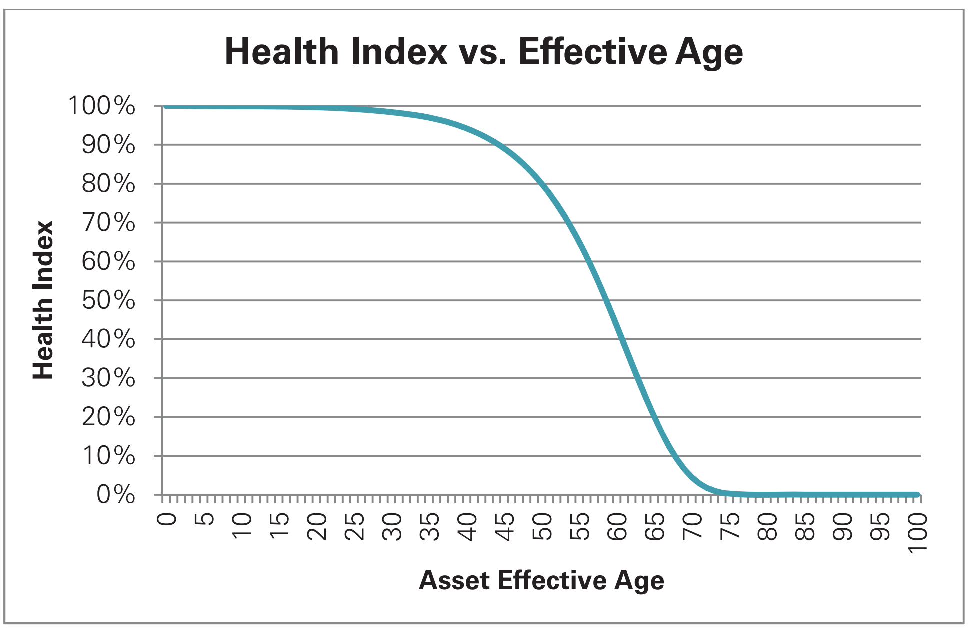
5.1 Kinectrics Methodology

Kinectrics adopted a probabilistic approach to identify expected failures and probable number of units for replacement based on asset condition as represented by the asset health index score. The approach is non-deterministic (i.e. resultant actions are not linked to any specific assets but, rather applies to the asset group as a whole) for reactively replaced assets and deterministic (i.e. actions are directly linked to specific assets) for proactively replaced asset classes. Kinectrics' high-level methodology is shown in Figure 1 below.

Figure 1: Methodology for Determining Flagged-for-Action Plans

The formula used to calculate the health index for each asset class was unique depending on available asset condition data. The health index for each asset was calculated using weighted averages of known asset age and known asset condition parameters and their associated weighting factors. The health index was then used to determine the asset effective age as demonstrated in Figure 2 below using the appropriate survival curve determined jointly by Kinectrics and Horizon for that asset class.

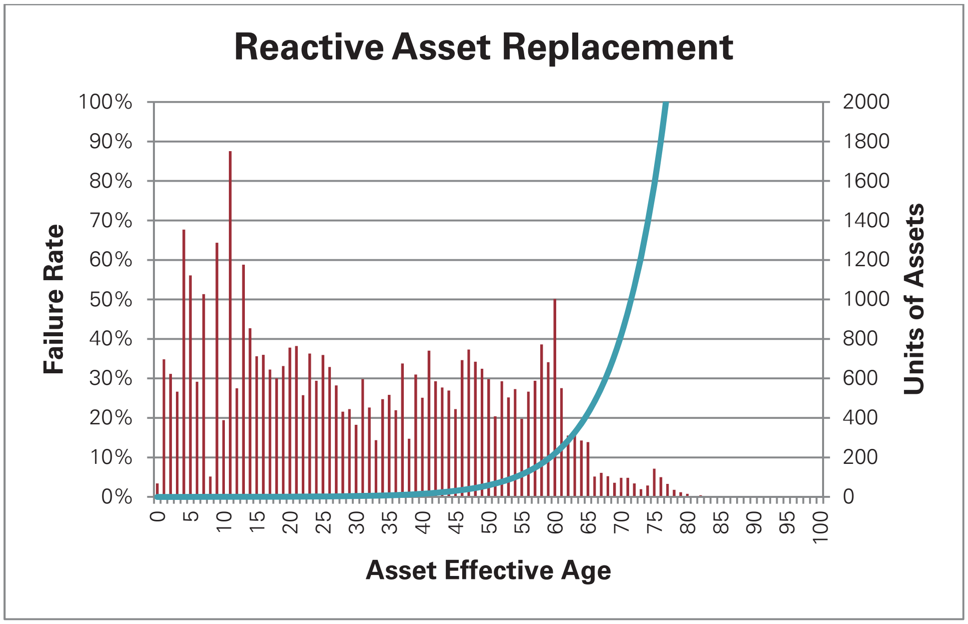
Figure 2: Determining Effective Age from Health Index



This method takes into account known asset condition in order to modify the actual chronological age into an effective age prior to calculating the probability of failure. For example, an asset that is well maintained would have an effective age that is lower than its actual chronological age indicating a lower probability of failure. Conversely, an asset that is overloaded or that is situated in adverse conditions would be de-rated to have a higher effective age as compared to its chronological age leading to a higher probability of failure. This method of predicting asset failure is a more representative method for predicting probability of failure over using only the chronological age.

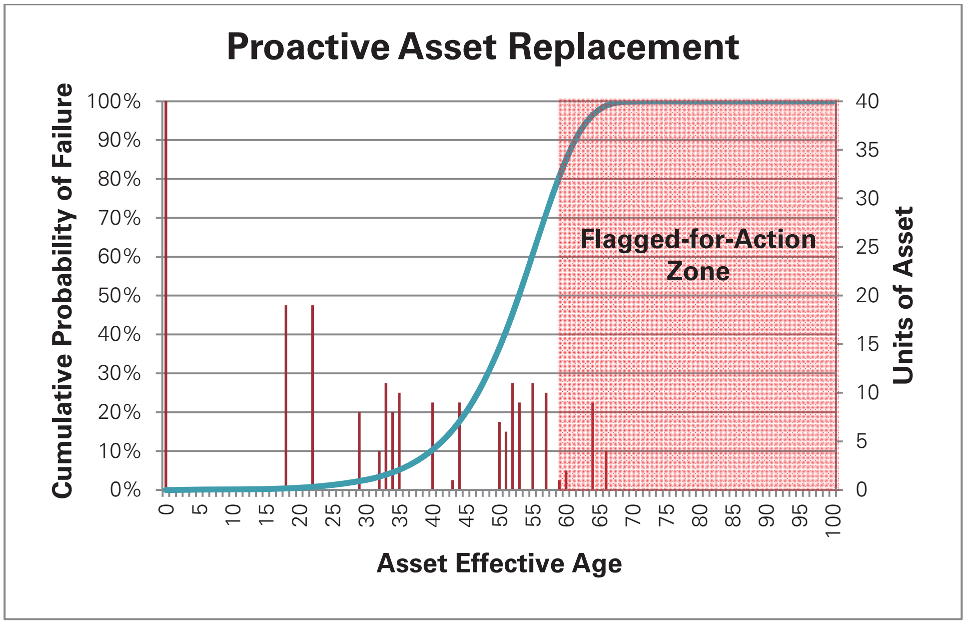
Once the effective age distribution of an asset class is known, it is used to determine probable failure rates. For reactively replaced assets, the effective age distribution is mapped against the assigned failure rate curve for each asset class to determine the quantity of assets projected to fail over the next twenty years (see Figure 3 below).

Figure 3: Flagged-for-Action Methodology used for Reactively Replaced Assets



For proactively replaced assets, the effective age is mapped against the cumulative probability of failure curve and assets with an effective age that returns a cumulative probability of failure of greater than or equal to 80% are flagged for replacement. Figure 4 represents the methodology used to flag proactively replaced assets.

Figure 4: Flagged-for-Action Methodology used for Proactively Replaced Assets



The twenty year Flagged-for-Action plan is developed by progressively advancing the effective age of the assets yearly and any assets flagged for replacement are subtracted from the population and replaced with new assets for that year.

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 actuary science and by other utilities. The inclusion of asset condition in these calculations provides a more sophisticated approach than using just chronological age alone. Kinectrics also employed different predictive models for run to failure assets (reactively replaced) and for assets that are replaced or rehabilitated before failure occurs (proactively managed assets). This differentiation approach is more advanced than what is currently in use at most other utilities and in practice should provide more appropriate modelling of remaining asset life for reactively replaced assets and for proactively managed assets.

KPMG's assurance review of Kinectrics methodologies for calculating Flagged-for-Action plans for both reactively and proactively replaced asset classes confirmed that the respective methodologies were consistently applied across the asset classes. The selected methodology for estimating asset replacement for sustainment purposes is deemed to be reasonable and is an accepted practice within the utilities industry.

5.2 Kinectrics Analytics

The results of the assurance review on the analytics used to determine the Kinectrics results are shown in the following sections.

5.2.1 Asset Populations Comparison

The total population of the individual asset classes were summed and compared to the population cited by Kinectrics in their report. Table 2 summarizes the results of the population comparison.

Table 2: Comparison of Asset Population

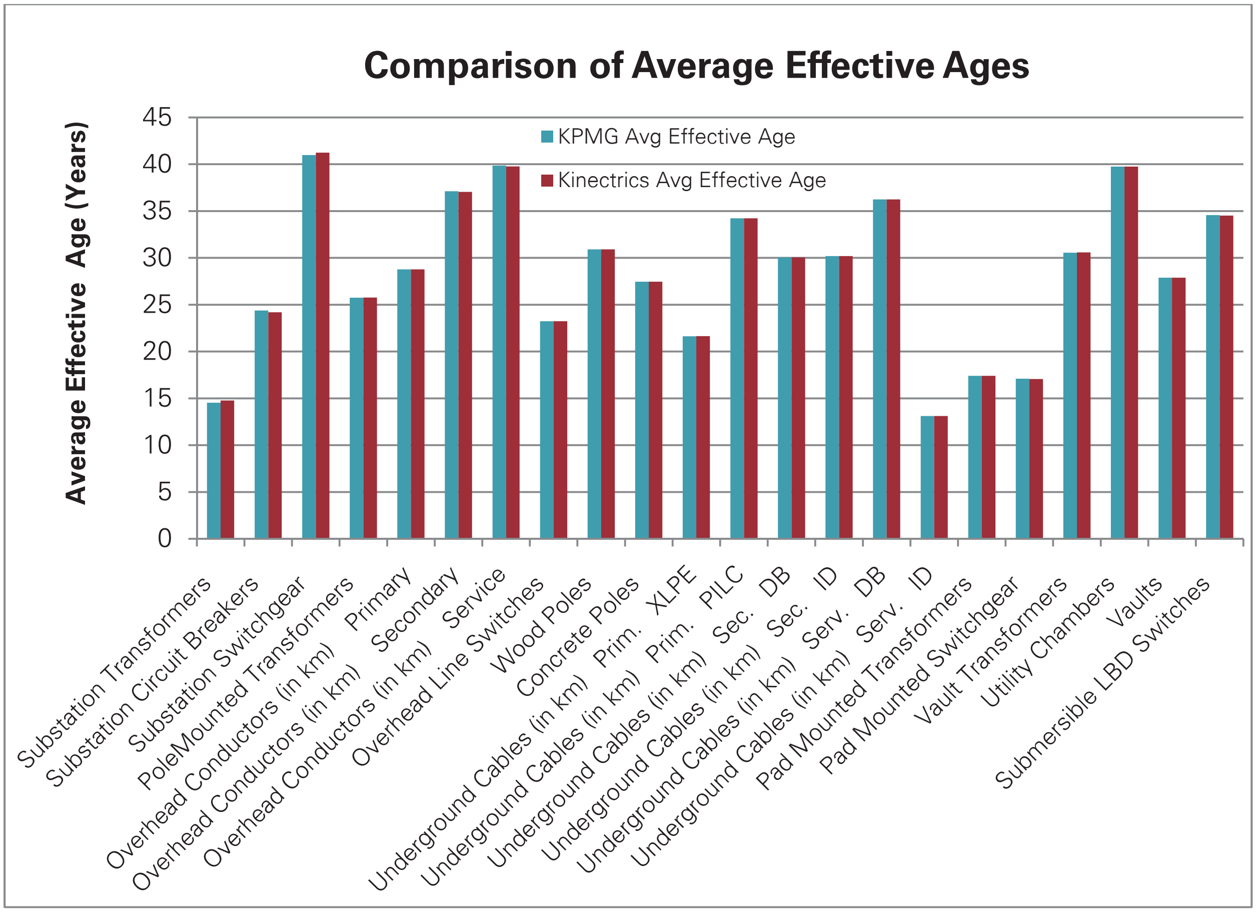
Asset Class		KPMG Total Asset Population	Kinectrics Total Asset Population	Population Difference	Percentage Population Difference
Substation Transformers		70	70	0	0.0%
Substation Circuit Breakers		279	279	0	0.0%
Substation Switchgear		37	37	0	0.0%
Pole Mounted Transformers		12886	12886	0	0.0%
Overhead Conductors (in km)	Primary	3386	3386	0	0.0%
Overhead Conductors (in km)	Secondary	2196	2196	0	0.0%
Overhead Conductors (in km)	Service	1897	1897	0	0.0%
Overhead Line Switches		711	712	-1	-0.1%
Wood Poles		42037	42037	0	0.0%
Concrete Poles		9761	9761	0	0.0%
Underground Cables (in km)	Prim. XLPE	2060	2060	0	0.0%
Underground Cables (in km)	Prim. PILC	1532	1532	0	0.0%
Underground Cables (in km)	Sec. DB	757	757	0	0.0%
Underground Cables (in km)	Sec. ID	533	533	0	0.0%
Underground Cables (in km)	Serv. DB	447	447	0	0.0%
Underground Cables (in km)	Serv. ID	588	588	0	0.0%
Pad Mounted Transformers		5906	5906	0	0.0%
Pad Mounted Switchgear		186	186	0	0.0%
Vault Transformers		4169	4169	0	0.0%
Utility Chambers		2075	2075	0	0.0%
Vaults		3413	3413	0	0.0%
Submersible LBD Switches		117	117	0	0.0%

With one exception, the asset population in each asset class matches with Kinectrics' published results. The only difference observed is with the Overhead Line Switches where there is a 1 unit difference; however the overall impact to the analysis is immaterial. This comparison confirms that the data population is identical to the data population used by Kinectrics in their analysis.

5.2.2 Health Indices and Effective Age Comparisons

Health index calculations were recreated independently by KPMG using Kinectrics' published methodology found in their report (KPMG was not privy to Kinectrics' proprietary calculation models). The calculated health indices were then used to determine the effective ages. When the calculated health indices were compared to Kinectrics results, there were no significant differences identified and the calculated values were then used to determine the effective ages for each asset class. The results of the effective ages are summarized in Figure 5 below.

Figure 5: Comparison of Average Effective Ages

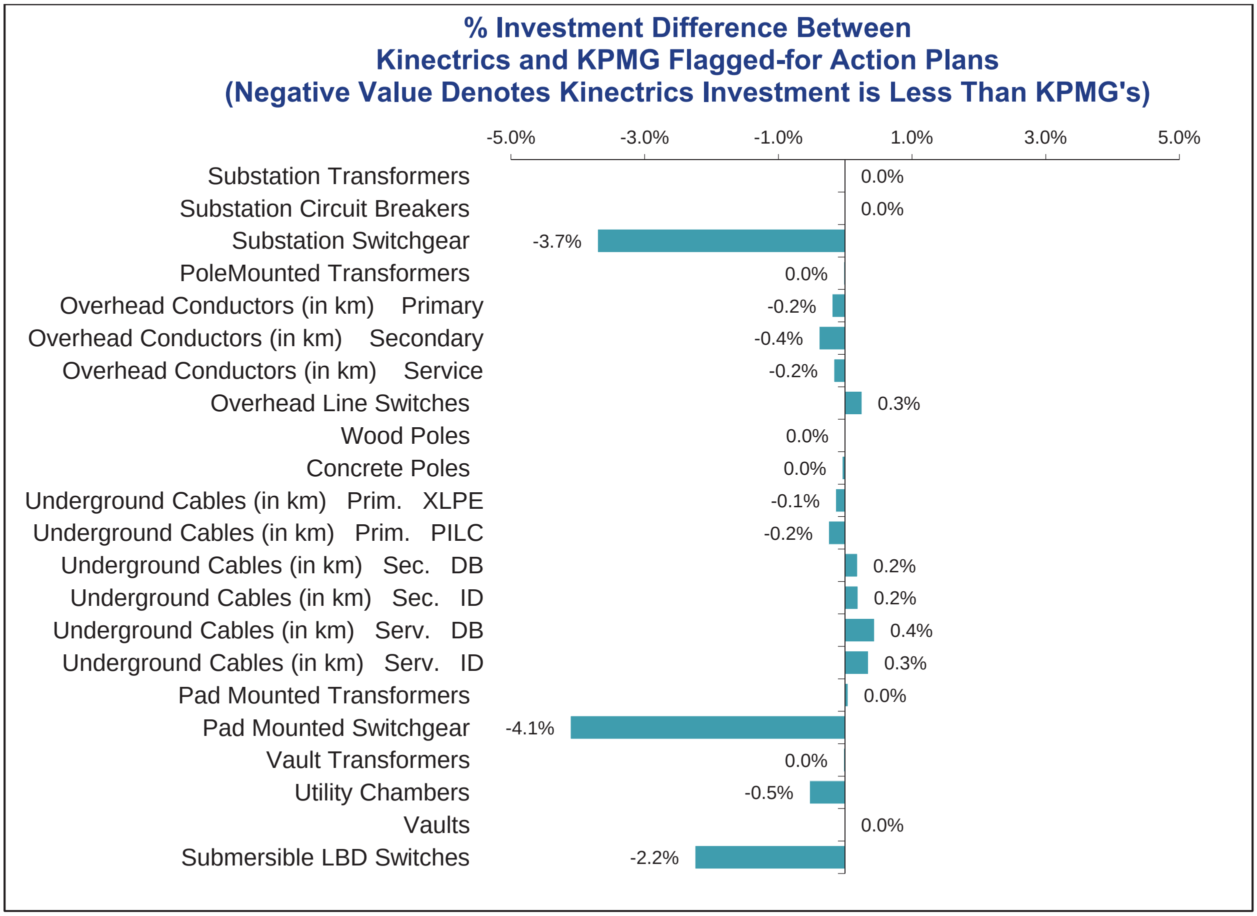


As evidenced by Figure 5 , the average effective age distributions for the different asset classes are virtually identical for both Kinectrics calculations and KPMG's calculations. Minor differences were observed for the proactively replaced assets (Substation Transformers, Substation Circuit Breakers and Substation Switchgear) but as the subsequent Flagged-for-Action analysis shows, these minor differences did not result in material differences in the Flagged-for-Action plans for these asset classes.

5.2.3 Flagged-for-Action Comparisons

Based on KPMG's calculated effective age distribution for each asset class, the Flagged-for-Action plans for the next twenty years were calculated based on whether the asset was deemed to be proactively replaced or reactively replaced. A detailed summary of the units Flagged-for-Action are shown in Appendix 1. The differences in the Flagged-for-Action plans are minor and are deemed to be immaterial. A summary of the percentage differences is shown in Figure 6, below.

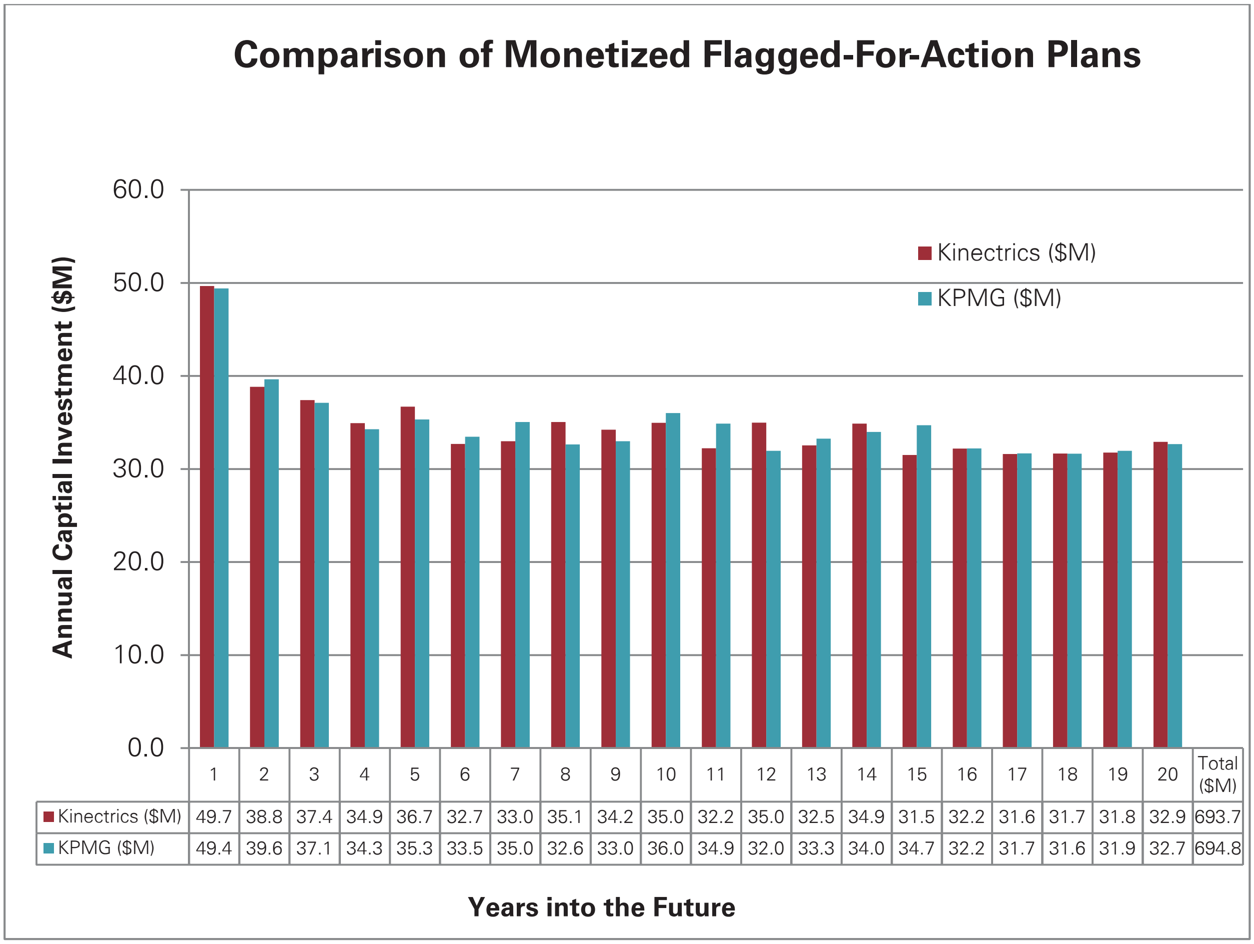
Figure 6: Percentage Difference in Flagged-for-Action Plans between Kinectrics and KPMG



The most significant percentage differences are in the Substation Switchgear, the Pad Mounted Switchgear and the Submersible LBD Switches asset classes. These asset classes have a small number of units in their population (less than 100 in each instance) and any small discrepancies in numeric values result in larger percentage differences when compared to other asset classes. The numerical differences can be found in Appendix 1. The impact of these differences to the Flagged-for-Action plan at the distribution network level over twenty years is immaterial.

Flagged-for-Action unit plans were monetized using standard unit costs in order to effectively allow comparison of the business impact of the identified differences. The standard unit costs used were provided by Horizon for each asset class. The resultant estimated investment over twenty years for the respective plans is shown in Figure 7 below.

Figure 7: Comparison of Monetized Flagged-for-Action Plans

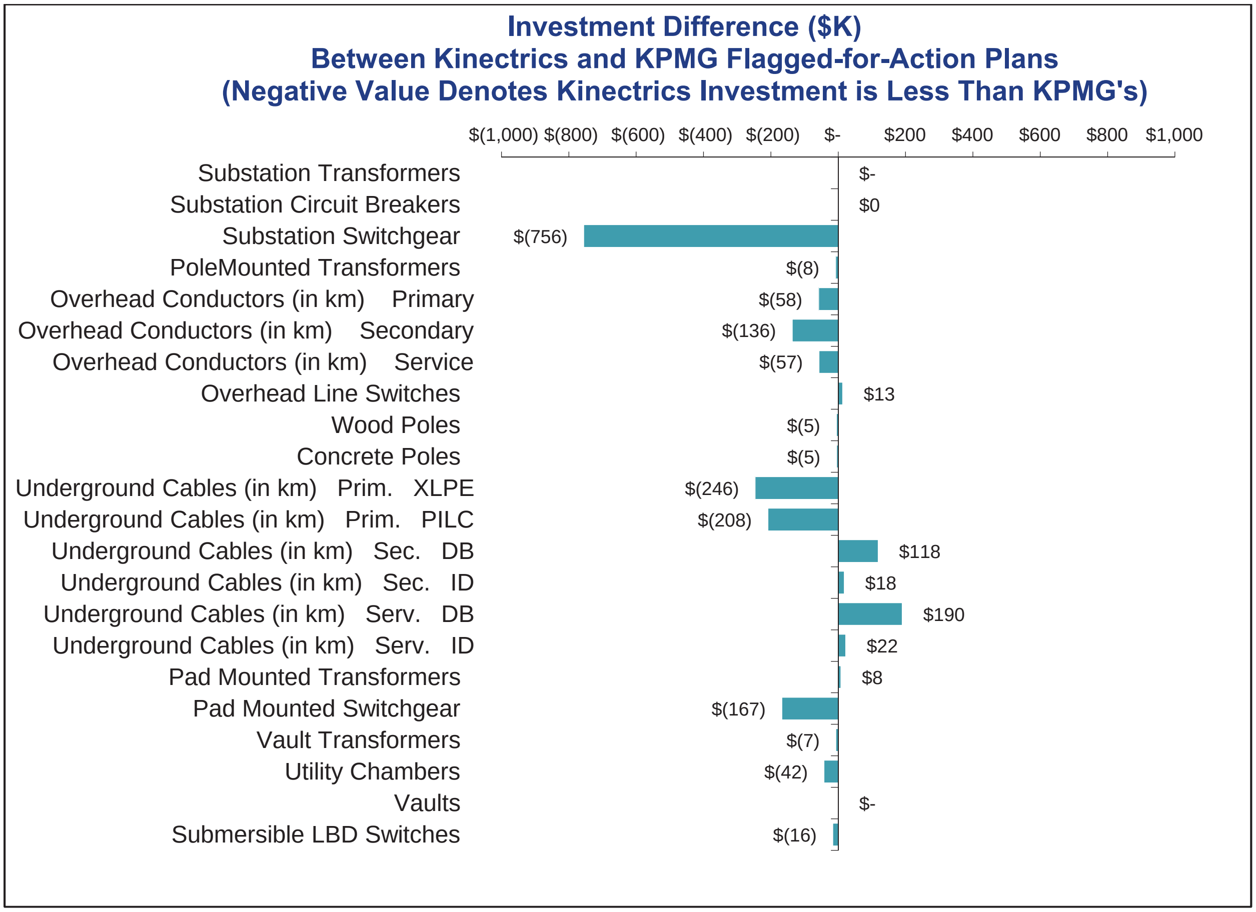


	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	Total ($M)
Kinectrics ($M)	49.7	38.8	37.4	34.9	36.7	32.7	33.0	35.1	34.2	35.0	32.2	35.0	32.5	34.9	31.5	32.2	31.6	31.7	31.8	32.9	693.7
KPMG ($M)	49.4	39.6	37.1	34.3	35.3	33.5	35.0	32.6	33.0	36.0	34.9	32.0	33.3	34.0	34.7	32.2	31.7	31.6	31.9	32.7	694.8

This monetized plan is meant to serve as a normalized comparison in dollar terms between the two respective Flagged-for-Action plans and it is not meant to be used as the definitive guide for Horizon's future capital investments. The two plans returned very similar total investment values over the twenty year span supporting the reasonableness of the calculations presented in the Kinectrics report. The total investment differs by only $1.1 million over twenty years or 0.02% for the period. The estimated monetary differences for each asset class are summarized in Figure 8, below.

When comparing Kinectrics and KPMG's results for the first five years of the monetized investment plan, the total investment portfolio difference found during this time period was $1.8 million or 0.09% of the five year plan. This investment difference was found to be primarily caused by the Substation Switchgear asset class. Due to the relatively low number of Substation Switchgear assets involved, the different values returned by the respective lookup methods employed by Kinectrics and KPMG resulted in slight variations in the timing of the Flagged-for-Action profile (See Appendix 1 for details). This variation was deemed to be insignificant to the overall five year Flagged-for-Action plan.

Figure 8: Comparison of Estimated Value of Flagged-for-Action Plans between Kinectrics and KPMG



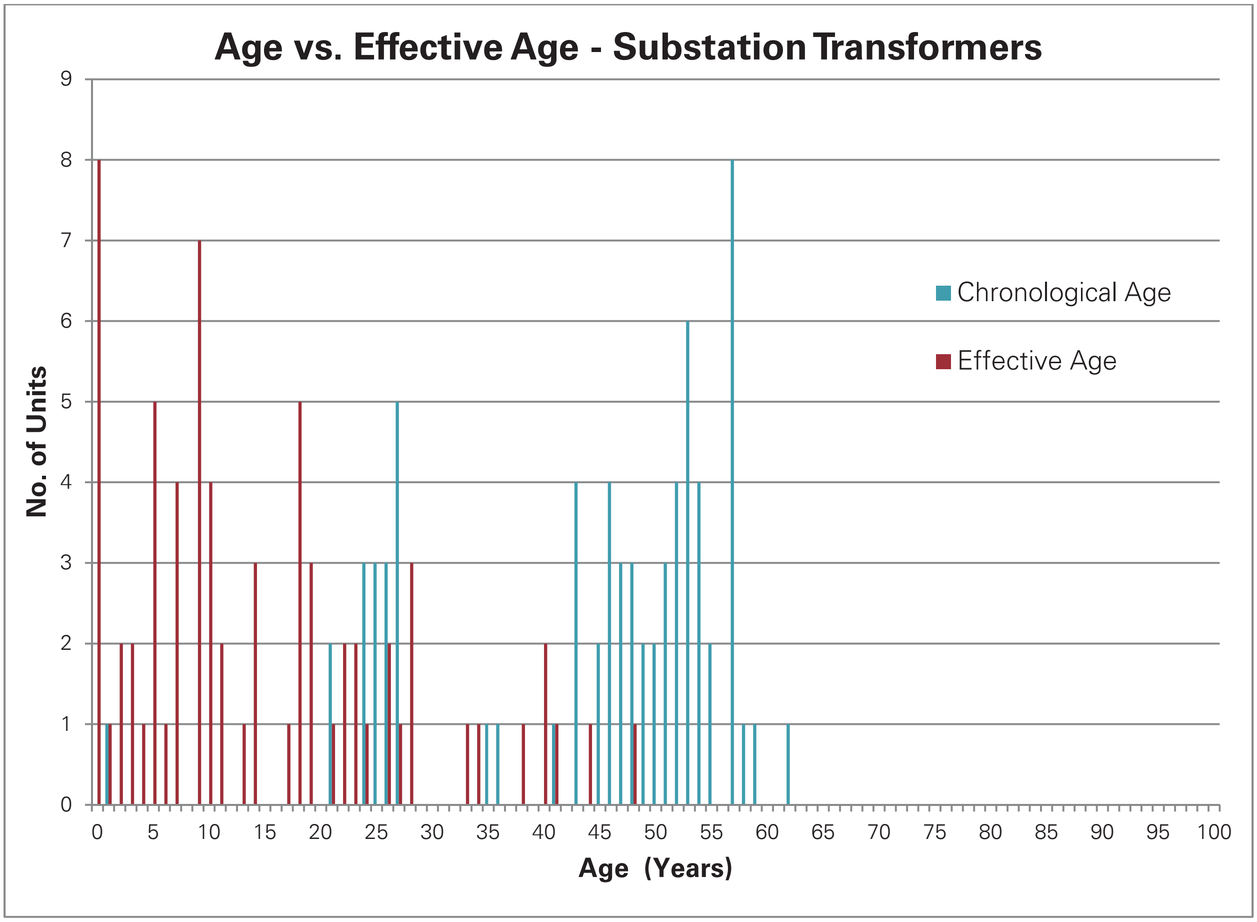
The results of the analysis show that Kinectrics' resulting end calculations can be replicated independently within a very small margin of error. It is KPMG's opinion that Kinectrics has accurately applied their published methodology and formulas contained in their report against the Horizon supplied asset data set.

5.3 Tests for Reasonableness

5.3.1 Comparison of Effective Age against Chronological Age

In order to test whether the health indices and the associated effective ages of assets were reasonable, the calculated effective age was compared to the chronological age in terms of age distribution and overall average age for each of the asset classes. The age distribution comparison test was meant to reveal whether the incorporation of the asset condition parameters played a major role in altering the chronological age in a material way. Figure 9 below is an example of the comparison conducted for each asset class.

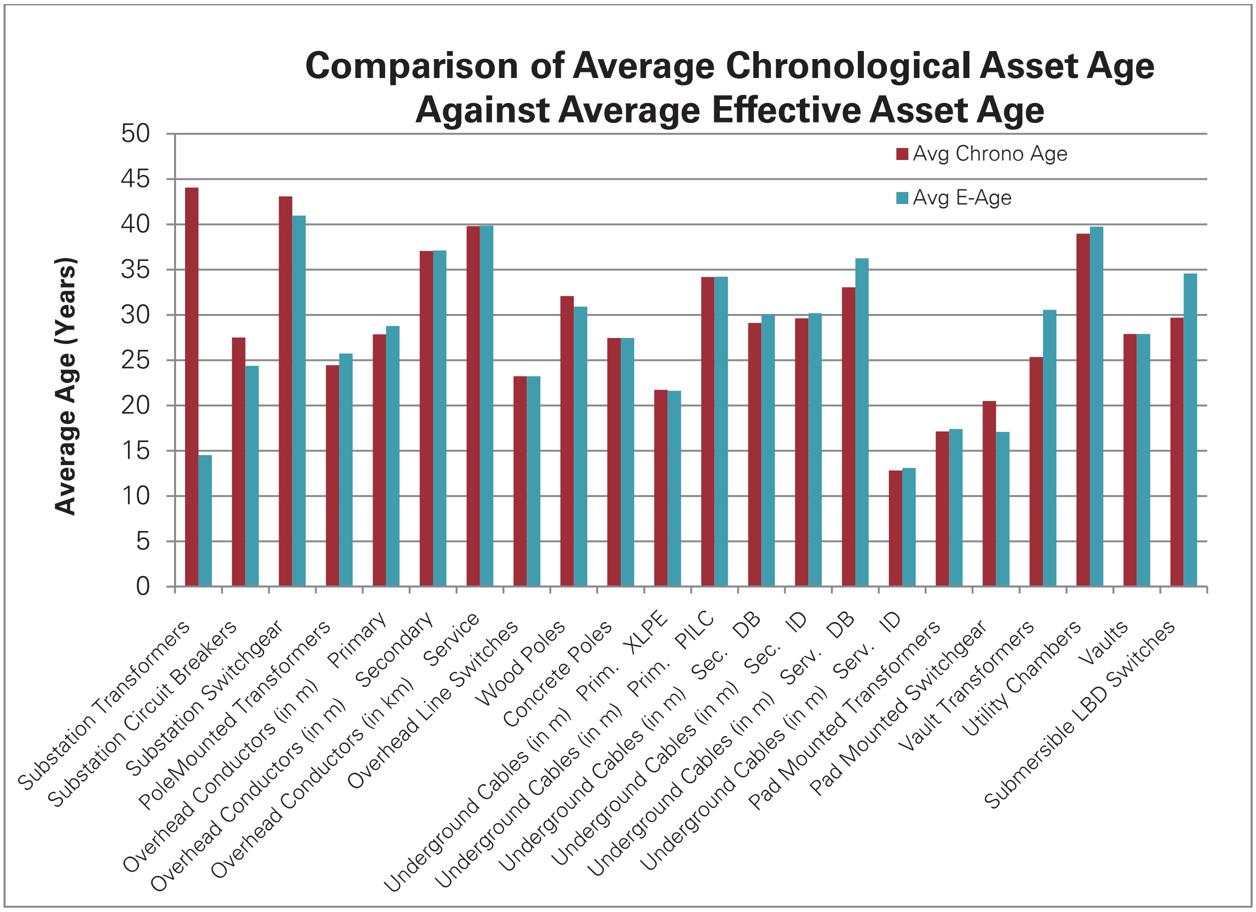
Figure 9: Example of Chronological Age versus Effective Age Comparison



The conversion of chronological age to effective age as a result of having asset condition parameters applied did shift the age distribution significantly for some asset classes. The differences between the average effective ages and the average chronological ages can be seen in Figure 10 below. The most significant shift is in the Substation Transformer asset class as the average effective age is significantly below the average chronological age. This phenomenon, as explained by Horizon representatives is the result of having significant maintenance and testing programs in place for this relatively old asset class to ensure their performance and reliability as these assets are key core components of the distribution system.

This test revealed that the use of effective ages to calculate the Flagged-for-Action plans would generate different end results than plans generated from chronological ages. However, the Flagged-for-Action differences in all the asset classes with the exception of the Substation Transformers would be reasonably close between the two different age profiles. For the Substation Transformers, the Flagged-for-Action plan using the assets' effective ages would significantly understate the number of units to be Flagged-for-Action when compared with a plan generated by the use of chronological age alone. Using effective ages to determine the Flagged-for-Action plan was deemed to be more reflective of actual asset conditions than using just chronological age.

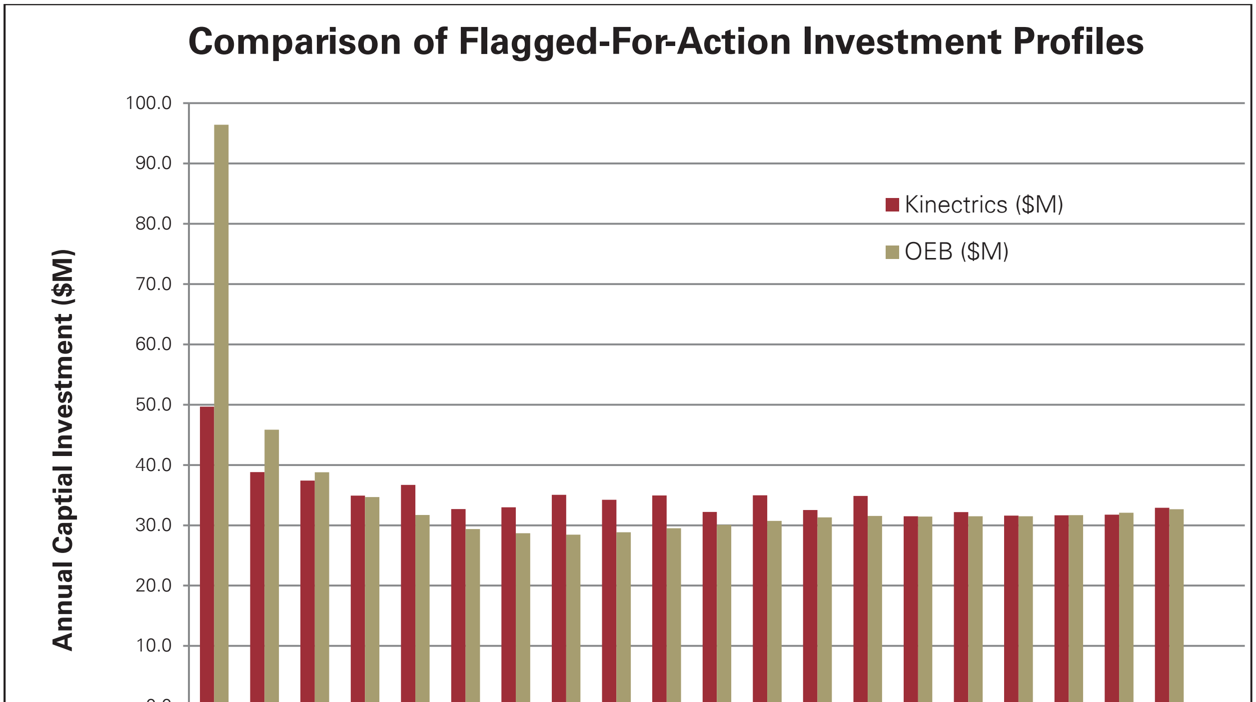
Figure 10: Comparison of Average Effective Ages against Average Chronological Ages



5.3.2 Comparison of Kinectrics' Flagged-for-Action Plan against Accepted Asset Life Standards

The final test to determine reasonability of the Kinectrics Flagged-for-Action plan was to compare the total plan against published and accepted industry standards for asset life expectancies. The standard life expectancies chosen for comparison were those published in the Asset Depreciation Study for the Ontario Energy Board (see Appendix 2). The published Typical Useful Life (TUL) and the Maximum Useful Life (MUL) were used to estimate the failure curve (f_t) and the cumulative probability of failure (P_f) for use in projecting asset replacements. Based on interpretation of the OEB report, the TUL was assigned 20% P_f, and the MUL was assigned 85% P_f. Failure curves were subsequently developed using the published TUL and MUL figures; the only exception was for the Submersible LBD Switches for which figures were not available in the OEB report. For this asset class, the UG Vault switch values for TUL and MUL were used as a proxy. Flagged-for-Action plans for each asset class were then calculated using the chronological age as the OEB useful lives data was developed for use with chronological asset age. The comparison of the normalized monetary results for the two different Flagged-for-Action plans is shown in Figure 11 below.

Figure 11: Comparison of Kinectrics Flagged-for-Action Plan versus Plan Generated from OEB Data



	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	Total ($M)
Kinectrics ($M)	49.7	38.8	37.4	34.9	36.7	32.7	33.0	35.1	34.2	35.0	32.2	35.0	32.5	34.9	31.5	32.2	31.6	31.7	31.8	32.9	693.7
OEB ($M)	96.4	45.9	38.8	34.7	31.7	29.4	28.7	28.4	28.9	29.5	30.1	30.7	31.3	31.6	31.4	31.5	31.5	31.7	32.1	32.7	706.9

The total estimated investment for the two different plans over twenty years is within 2% of each other. The results calculated from the OEB life expectancies are heavily front-end loaded suggesting that model assesses Horizon's asset base as being closer to end of life than Kinectrics effective age model. This comparison substantiates the life curves used by Kinectrics in their models are reasonably close to industry accepted useful life data. The Kinectrics' life curves have longer average expected life-spans for some of the asset classes leading to fewer asset investments identified for the immediate short term. When compared to the OEB results, the Kinectrics Flagged-for-Action plan is not overstated and is reasonably within the industry accepted asset replacement or refurbishment practices for distribution utilities in Ontario.

6 Conclusions

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.

Appendix 1 Comparison of Twenty Year Flagged-for-Action Plans

Assets Class	Source	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	Total
Substation Transformers	Kinectrics	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	1	0	1	0	2	5
Substation Transformers	KPMG	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	1	0	0	1	2	5
Substation Circuit Breakers	Kinectrics	16	0	10	0	11	0	9	0	17	0	7	0	0	0	0	9	1	0	0	9	89
Substation Circuit Breakers	KPMG	16	0	10	0	11	0	9	11	6	7	0	0	0	0	0	9	1	0	0	9	89
Substation Switchgear	Kinectrics	1	0	1	1	4	0	0	4	2	4	0	4	1	4	0	0	0	0	0	0	26
Substation Switchgear	KPMG	0	1	1	0	2	1	3	0	1	5	4	0	2	3	4	0	0	0	0	0	27
PoleMounted Transformers	Kinectrics	593	277	232	218	215	217	220	223	226	228	229	229	230	230	231	234	238	244	252	262	5028
PoleMounted Transformers	KPMG	594	277	232	218	215	217	220	223	226	228	229	229	230	230	232	234	238	244	252	262	5029
Overhead Conductors (in km) Primary	Kinectrics	53	45	40	37	34	32	31	30	29	30	30	31	32	32	32	33	33	33	33	34	684
Overhead Conductors (in km) Primary	KPMG	53	46	41	37	34	32	31	30	29	30	30	31	32	32	33	33	33	33	33	34	685
Overhead Conductors (in km) Secondary	Kinectrics	86	63	52	44	40	38	38	38	39	39	39	39	39	39	38	37	36	34	33	32	843
Overhead Conductors (in km) Secondary	KPMG	87	63	52	44	40	38	38	38	39	39	39	39	39	39	38	37	36	34	33	32	846
Overhead Conductors (in km) Service	Kinectrics	97	69	54	44	39	36	35	36	36	36	36	36	36	35	34	33	32	30	28	27	809
Overhead Conductors (in km) Service	KPMG	99	69	54	44	39	36	35	36	36	36	36	36	36	35	34	33	31	30	28	27	810
Overhead Line Switches	Kinectrics	31	26	23	22	20	20	19	18	19	18	18	18	17	17	17	17	16	17	17	17	387
Overhead Line Switches	KPMG	31	26	23	22	21	20	19	19	18	18	18	17	17	17	17	17	17	17	17	17	386
Wood Poles	Kinectrics	1509	1103	1011	967	935	905	876	845	814	782	752	724	699	678	662	648	637	627	619	611	16404
Wood Poles	KPMG	1509	1103	1011	968	935	906	876	845	814	782	752	724	699	678	661	648	637	627	619	611	16405
Concrete Poles	Kinectrics	97	98	100	101	103	104	105	107	108	109	110	111	112	114	115	118	119	121	123	126	2201
Concrete Poles	KPMG	97	98	100	101	103	104	105	106	108	109	110	111	112	114	116	117	119	121	124	126	2202
Underground Cables (in km) Prim. XLPE	Kinectrics	126	103	96	91	88	85	83	80	78	76	74	72	71	70	69	68	67	66	66	66	1595
Underground Cables (in km) Prim. XLPE	KPMG	127	103	95	91	88	85	83	80	78	76	74	73	71	70	69	68	67	67	66	66	1597
Underground Cables (in km) Prim. PILC	Kinectrics	11	11	12	12	12	13	14	14	15	16	17	18	19	20	20	21	22	23	24	25	339
Underground Cables (in km) Prim. PILC	KPMG	12	12	12	12	12	13	14	14	15	16	17	18	19	20	20	21	22	23	24	25	340
Underground Cables (in km) Sec. DB	Kinectrics	28	28	28	27	27	27	27	27	26	26	26	26	25	25	25	25	24	24	24	24	519
Underground Cables (in km) Sec. DB	KPMG	28	28	28	27	27	27	27	27	26	26	26	26	25	25	25	25	24	24	24	24	518
Underground Cables (in km) Sec. ID	Kinectrics	21	21	21	20	20	19	19	19	18	18	18	18	17	17	17	17	17	16	16	16	365
Underground Cables (in km) Sec. ID	KPMG	21	21	20	20	20	19	19	19	18	18	18	18	17	17	17	17	16	16	16	16	364
Underground Cables (in km) Serv. DB	Kinectrics	20	20	20	19	19	19	19	18	18	18	18	17	17	17	16	16	16	15	15	15	352
Underground Cables (in km) Serv. DB	KPMG	20	20	20	19	19	19	19	18	18	18	18	17	17	17	16	16	16	15	15	15	350
Underground Cables (in km) Serv. ID	Kinectrics	10	11	11	11	11	12	12	12	13	13	13	13	14	14	14	14	14	15	15	15	257
Underground Cables (in km) Serv. ID	KPMG	10	11	11	11	11	12	12	12	12	13	13	13	13	14	14	14	14	15	15	15	256
Pad Mounted Transformers	Kinectrics	17	17	20	23	27	31	36	41	47	53	59	65	70	75	79	83	87	92	98	105	1125
Pad Mounted Transformers	KPMG	17	17	20	23	27	31	36	41	47	53	59	65	70	75	79	83	87	92	98	105	1125
Pad Mounted Switchgear	Kinectrics	3	3	3	3	3	3	3	3	3	3	3	4	4	4	4	4	4	4	4	5	70
Pad Mounted Switchgear	KPMG	3	3	3	3	3	3	3	3	3	4	4	4	4	4	4	4	4	4	5	5	73
Vault Transformers	Kinectrics	309	294	282	270	260	250	240	230	221	212	203	194	186	178	170	162	156	150	144	139	4250
Vault Transformers	KPMG	309	294	282	270	260	250	240	230	221	212	203	194	186	178	170	163	156	150	144	139	4251
Utility Chambers	Kinectrics	12	13	13	14	15	15	16	17	17	18	19	20	20	21	22	23	23	24	25	26	373
Utility Chambers	KPMG	13	13	13	14	15	15	16	17	17	18	19	20	20	21	22	23	24	24	25	26	375
Vaults	Kinectrics	6	7	7	7	8	8	9	10	10	11	12	12	13	14	15	16	17	18	19	20	239
Vaults	KPMG	6	7	7	7	8	8	9	10	10	11	12	12	13	14	15	16	17	18	19	20	239
Submersible LBD Switches	Kinectrics	14	8	7	6	5	5	5	4	4	4	3	3	3	3	2	2	2	2	2	3	87
Submersible LBD Switches	KPMG	14	8	7	6	5	5	5	4	4	4	4	3	3	3	3	3	2	2	2	2	89

F SUMMARY OF RESULTS

Table F - 1 summarizes useful lives, and factors impacting those lives as developed by this report.

Table F - 1 Summary of Componentized Assets, Service Life and Factors

PARENT*	#	ASSET DETAILS Category | Component | Type			USEFUL LIFE MIN UL	TUL	MAX UL	FACTORS ** MC	EL	EN	OP	MP	NPF
OH	1	Fully Dressed Wood Poles	Overall		35	45	75	H	L	M	NI	L	L
			Cross Arm	Wood	20	40	55						
				Steel	30	70	95						
	2	Fully Dressed Concrete Poles	Overall		50	60	80	H	L	M	NI	L	NI
			Cross Arm	Wood	20	40	55						
				Steel	30	70	95						
	3	Fully Dressed Steel Poles	Overall		60	60	80	H	M	L	NI	L	NI
			Cross Arm	Wood	20	40	55						
				Steel	30	70	95						
	4	OH Line Switch			30	45	55	L	L	L	L	M	L
	5	OH Line Switch Motor			15	25	25	L	NI	L	L	M	L
	6	OH Line Switch RTU			15	20	20	NI	NI	L	L	L	M
	7	OH Integral Switches			35	45	60	L	M	M	M	L	H
	8	OH Conductors			50	60	75	M	L	M	NI	NI	L
	9	OH Transformers & Voltage Regulators			30	40	60	L	M	M	NI	NI	M
	10	OH Shunt Capacitor Banks			25	30	40	-	-	-	-	-	-
	11	Reclosers			25	40	55	L	L	L	M	L	M
TS & MS	12	Power Transformers	Overall		30	45	60	NI	M	M	L	L	NI
			Bushing		10	20	30						
			Tap Changer		20	30	60						
	13	Station Service Transformer			30	45	55	NI	L	M	L	NI	L
	14	Station Grounding Transformer			30	40	40	-	-	-	-	-	-
	15	Station DC System	Overall		10	20	30	NI	M	L	L	M	M
			Battery bank		10	15	15						
			Charger		20	20	30						
	16	Station Metal Clad Switchgear	Overall		30	40	60	L	L	M	M	M	M
			Removable Breaker		25	40	60						
	17	Station Independent Breakers			35	45	65	M	M	M	M	M	M
	18	Station Switch			30	50	60	M	L	M	M	M	L

* OH = Overhead Lines System TS & MS = Transformer and Municipal Stations
** MC = Mechanical Stress EL = Electrical Loading OP = Operating Practices EN = Environmental Conditions
MP = Maintenance Practices NPF=Non-Physical Factors
H=High M=Medium L=Low NI=No Impact

PARENT*	#	ASSET DETAILS Category| Component | Type		USEFUL LIFE MIN UL	TUL	MAX UL	FACTORS ** MC	EL	EN	OP	MP	NPF
TS & MS	19	Electromechanical Relays		25	35	50	NI	NI	NI	NI	NI	H
TS & MS	20	Solid State Relays		10	30	45	NI	NI	NI	NI	NI	H
TS & MS	21	Digital & Numeric Relays		15	20	20	NI	NI	NI	NI	NI	H
TS & MS	22	Rigid Busbars		30	55	60	L	L	L	NI	NI	L
TS & MS	23	Steel Structure		35	50	90	L	NI	M	NI	NI	L
UG	24	Primary Paper Insulated Lead Covered (PILC) Cables		60	65	75	L	L	M	L	NI	M
UG	25	Primary Ethylene-Propylene Rubber (EPR) Cables		20	25	25	NI	M	L	NI	NI	NI
UG	26	Primary Non-Tree Retardant (TR) Cross Linked Polyethylene (XLPE) Cables Direct Buried		20	25	30	M	M	M	L	L	L
UG	27	Primary Non-TR XLPE Cables In Duct		20	25	30	M	M	M	L	L	M
UG	28	Primary TR XLPE Cables Direct Buried		25	30	35	M	M	M	L	L	L
UG	29	Primary TR XLPE Cables In Duct		35	40	55	M	M	M	L	L	L
UG	30	Secondary PILC Cables		70	75	80	NI	L	L	NI	NI	H
UG	31	Secondary Cables Direct Buried		25	35	40	M	M	M	L	NI	NI
UG	32	Secondary Cables In Duct		35	40	60	M	M	M	L	NI	NI
UG	33	Network Transformers	Overall	20	35	50	NI	L	H	NI	NI	NI
UG	33	Network Transformers	Protector	20	35	40						
UG	34	Pad-Mounted Transformers		25	40	45	L	M	M	NI	L	L
UG	35	Submersible/Vault Transformers		25	35	45	L	M	M	NI	L	L
UG	36	UG Foundations		35	55	70	M	NI	M	L	L	M
UG	37	UG Vaults	Overall	40	60	80	M	NI	M	L	L	L
UG	37	UG Vaults	Roof	20	30	45						
UG	38	UG Vault Switches		20	35	50	L	L	L	L	L	NI
UG	39	Pad-Mounted Switchgear		20	30	45	L	L	H	L	L	L
UG	40	Ducts		30	50	85	H	NI	M	NI	NI	L
UG	41	Concrete Encased Duct Banks		35	55	80	M	NI	M	NI	NI	L
UG	42	Cable Chambers		50	60	80	M	NI	H	NI	L	NI
S	43	Remote SCADA		15	20	30	NI	NI	L	NI	L	H

* TS & MS = Transformer and Municipal Stations UG = Underground Systems S = Monitoring and Control Systems
** MC = Mechanical Stress EL = Electrical Loading OP = Operating Practices EN = Environmental Conditions
MP = Maintenance Practices NPF=Non-Physical Factors
H=High M=Medium L=Low NI=No Impact

References

Kinectrics Inc. (2013). *Horizon Utilities 2013 Asset Condition Assessment.* Toronto: Kinectrics Inc.

Kinectrics Inc. Report No: K-418033-RA-001-R000. (2010). *Asset Depreciation Study for the Ontario Energy Board.* Toronto: Kinectrics Inc.

Author Biography

Julius Pataky, P.Eng. MBA

Julius Pataky is a KPMG Partner with 35 years progressive industry and consulting experience in the energy industry, with demonstrated leadership skills in asset management, building effective teams, leading transformation and bringing innovation to the business. Julius joined KPMG after having led innovative asset management solutions at BC Transmission and BC Hydro. In his roles as VP, Asset Investment, he brought the PAS 55 framework into organization's operating model, led the development of innovative asset analytic and planning solutions and gained regulatory approval for increased capital investment. He not only had accountability for developing the Capital Plans for transmission and distribution but also developing the regulatory justification for these capital investments. During this period, investments in the grid for the utility had grown from under $200M/yr to $1.3B/yr. He acted as company lead in communication of the need for increase in grid investment with stakeholders and the public. He also led numerous consultation efforts to gain acceptance of contentious projects with municipal leaders and landowners.

David Cheng, P.Eng.

David Cheng is a Senior Manager in KPMG LLP's Advisory Services Practice and is a member of the firm's Asset Management practice. Over his career, David has successfully transformed numerous businesses through his knowledge of asset management, operations management, business process improvement, information management and project and program management. He has led a diverse portfolio of projects as a consultant for private and public sector organizations plus he has years of executive and managerial experience leading teams in the utilities, aerospace, high-technology, healthcare and consumer products industries. As a former Manager of Asset Data and Information at BC Hydro and BC Transmission Corporation (BCTC), David was responsible for the development of asset analytic algorithms used to support capital investment justifications contained within the rate application submissions to BC Utilities Commission (BCUC). The asset analytics deployed probabilistic asset health based analysis to determine projected asset replacement requirements based on asset condition and asset demographics.

David Cheng

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Function and Specialization

- Asset Management
- Data and Information Management
- Business Process Improvement
- Utilities

Education, Licenses & Certifications

- Bachelor of Applied Science
  The University of British Columbia
- P.Eng.
  The Professional and Geoscientist Association of BC

Background

David Cheng is a Senior Manager in KPMG LLP's Advisory Services Practice in Vancouver Canada and is a member of the firm's Asset Management practice. Over his career, David has successfully transformed numerous businesses through his knowledge of asset management, operations and engineering management, business process improvement, information management and project and program management. He has led a diverse portfolio of projects as a consultant for private and public sector organizations plus he has years of executive and managerial experience leading teams in the utilities, aerospace, high-technology, healthcare and consumer products industries.

Relevant Experience

- **Integrated Asset Management Capital Planning Process, Major Utility –** David was a key member of a team responsible for developing the integrating planning process for a major electric utility in Western Canada. The integrated planning process included the identification of needs, integrated solution options assessment, consolidated project planning, project prioritization and project approval. As part of this project, David was responsible for leading the development of the functional specifications for a Needs Registry built on a geospatial web mapping engine.
- **Asset Management Data and Information Management, Major Utility –** David led a team that delivered the Data and Information Management function for Asset Management within a major integrated electric utility. In his role, he directed the development of a five-year strategic roadmap for the major utility's asset management related data and information needs. The roadmap took into consideration the business requirements for asset condition and investment analytics, geospatial visualization and analysis, emerging data standards and available commercial off-the-shelf products to replace custom developed applications.
- **Retail Electricity Billing and Meter Data Management Policy: Government of Alberta –** On behalf of the government of Alberta, managed the development of the billing and meter data management policies during the deregulation of the electric industry in Alberta. The work included the facilitated negotiations between stakeholders in the wholesale and retail environments on their roles and responsibilities for billing and meter data management and the subsequent development of approved policies and standards for billing and meter data management.
- **Capital Asset Acquire to Retire Business Case, Major Utility –** David successfully led a project that delivered a business case and an information technology investment roadmap for a large western Canadian utility. The project involved the assessment of business requirements within the capital management process, evaluation of existing technologies in use and potential solutions that are currently available in the market. Final recommendations were presented to company executives for review and budget approval.

# David Cheng

Senior Manager, Advisory Services, Management Consulting

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Instructions to Expert

KPMG was retained by Horizon 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 expresses no opinion on financial results, internal control, data quality or other information.

Specific Information upon which Expert's Evidence is Based

The following sources of information were consulted:

- Kinectrics Inc. (2013). *Horizon Utilities 2013 Asset Condition Assessment.* Toronto: Kinectrics Inc.
- Kinectrics Inc. Report No: K-418033-RA-001-R000. (2010). *Asset Depreciation Study for the Ontario Energy Board.* Toronto: Kinectrics Inc.
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- Ishak, J. (n.d.). *Parametric Survival Analysis Overview.* Retrieved from www.ispor.org/congresses/Spain1111/.../W29_Ishak-Jack.pdf
- Jones, J. H. (n.d.). *Mathematical Hazards Models and Model Life Tables.* Retrieved from Stanford Summer Short Course: www.stanford.edu/~jhj1/teachingdocs/Jones-mortmodel2005.pdf

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Appendix D – Innovative Customer Consultation Report

horizon UTILITIES Looking beyond...

Distribution System Plan Review WORKBOOK

Table of Contents

This review is focused on the near-term plan for Horizon Utilities Corporation's distribution system over the next five years.

If you are interested in broader medium- and long-term electricity issues such as Ontario's energy supply mix, conservation planning and general energy policy in the province, there are other opportunities for you to be heard.

Ontario's Long-Term Energy Plan: The Ontario Government's Plan details how electricity will be generated and the longer-term conservation strategy for the province. It can be found at this website: www.energy.gov.on.ca/en/ltep/

Regional Planning: The Ontario Power Authority (OPA) looks ahead to the future electricity needs of your region and how those needs can be addressed through conservation, local generation and electricity from outside the region. You can follow the OPA's regional planning process at this website:
www.powerauthority.on.ca/power-planning/regional-planning

What is this about?

Thank you for your participation in Horizon Utilities Corporation's distribution system plan review

The purpose of this workbook is to get your feedback on Horizon Utilities' plan to distribute electricity in the Hamilton and St. Catharines service areas over the next five years. We want to make sure that we get this right and we need your feedback. This is an opportunity for you to tell us what you think about our plans. This is about helping us to serve you better. This is also an opportunity for us to communicate to you about the challenges our electric system will be facing and, more importantly, how we intend to meet those challenges over time.

We've engaged an independent, third-party research firm (Innovative Research Group Inc.) to collect customer feedback to ensure the integrity of our process.

While this plan requires an increase in rates, costs have been maintained to be as affordable as possible

What might this mean to your bill?

Residential Customers: As you can see in the sample bill on the following page, distribution charges are part of the Delivery charge and are about $27 of an average residential electricity bill. We estimate that an additional **$1.12 per month** each year (or about 4.2% per year) will be required over the next 5 years to address the needs of the local electricity system.

General Service Customers: For small businesses and organizations in the General Service (GS) **under 50 kW** rate class, distribution charges are about $50 of an average electricity bill and the increase will be about **$2.12 per month** each year (or about 4.2% per year) over the next 5 years for this group.

For larger businesses and organizations in the General Service **over 50 kW** rate class, distribution charges are about $820 of an average electricity bill (based on monthly demand of 250 kW) and the increase will be about **$77.64 per month** each year (or about 9.5% per year) over the next 5 years for this group.

You don't have to be an electricity expert to participate in this review

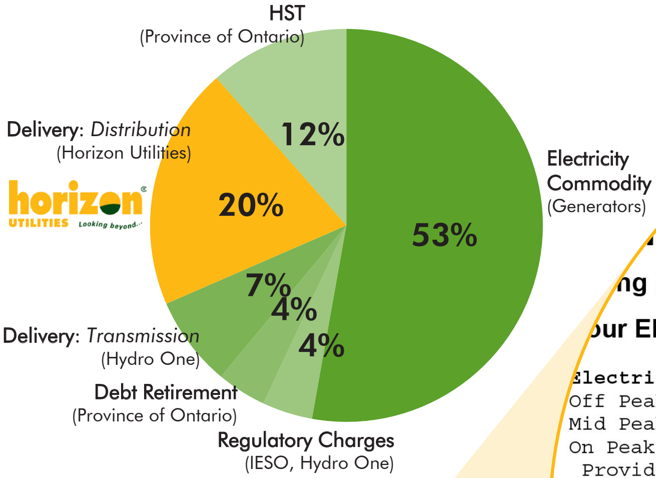
The following sections of the workbook explain the key elements of our system, the challenges facing the system, our recent work to maintain the system, and our plan for the next five years.

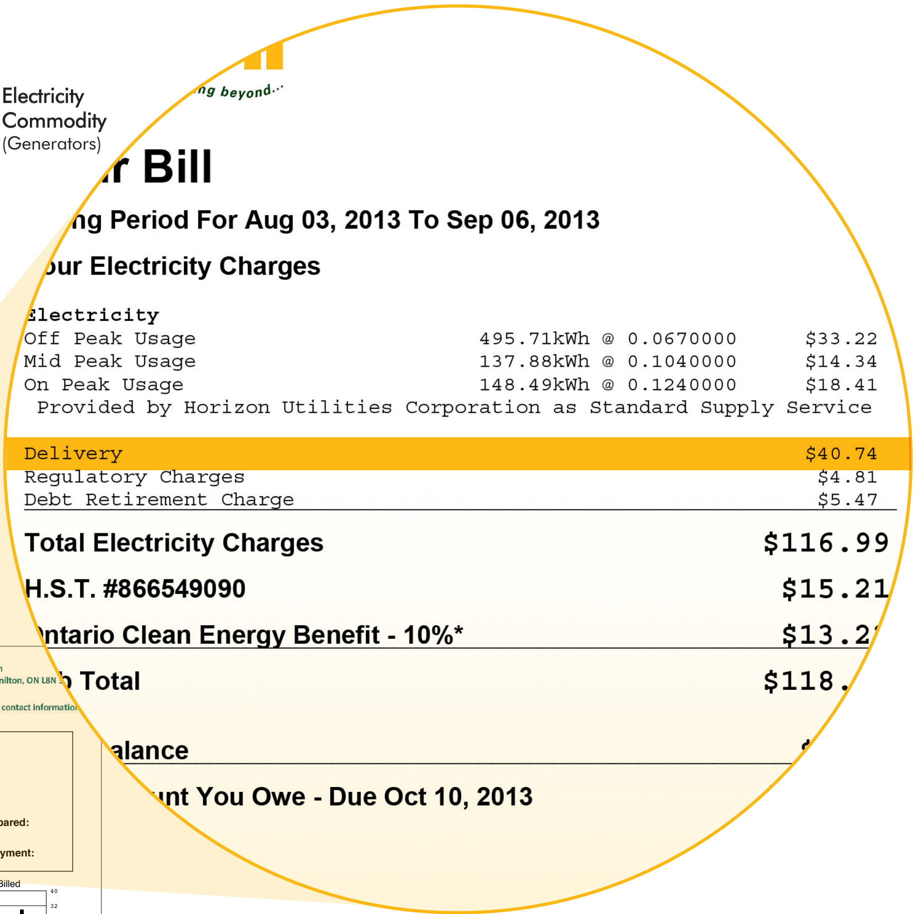
Our engineers are reviewing the technical requirements and feasibility of various options to ensure service at the lowest possible costs.

Understanding the needs and priorities of our customers and the communities we serve allows us to consider your views as we finalize our plan for submission to the Ontario Energy Board (OEB), the regulatory agency that sets electricity rates for all utilities in Ontario.

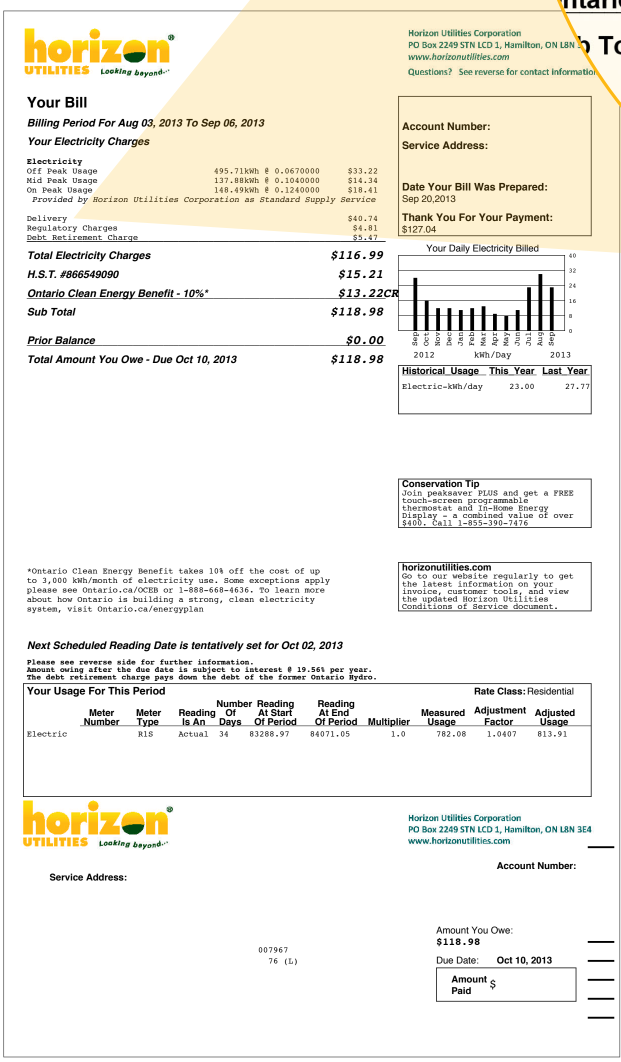
For a brief overview of Horizon Utilities' background and history, please see Appendix A: About Horizon Utilities Corporation (page 23).

20% of your total electricity bill goes to Horizon Utilities





Sample Residential Electricity Bill



horizon UTILITIES Looking beyond...

Horizon Utilities Corporation
PO Box 2249 STN LCD 1, Hamilton, ON L8N 3E4
www.horizonutilities.com
Questions? See reverse for contact information

Your Bill

Billing Period For Aug 03, 2013 To Sep 06, 2013

Your Electricity Charges

Electricity		
Off Peak Usage	495.71kWh @ 0.0670000	$33.22
Mid Peak Usage	137.88kWh @ 0.1040000	$14.34
On Peak Usage	148.49kWh @ 0.1240000	$18.41
Provided by Horizon Utilities Corporation as Standard Supply Service		
Delivery		$40.74
Regulatory Charges		$4.81
Debt Retirement Charge		$5.47
Total Electricity Charges		*$116.99*
H.S.T. #866549090		*$15.21*
*Ontario Clean Energy Benefit - 10%**		*$13.22CR*
Sub Total		*$118.98*
Prior Balance		*$0.00*
Total Amount You Owe - Due Oct 10, 2013		*$118.98*

Account Number:
Service Address:
Date Your Bill Was Prepared:
Sep 20,2013
Thank You For Your Payment:
$127.04

Your Daily Electricity Billed
Sep Oct Nov Dec Jan Feb Mar Apr May Jun Jul Aug Sep
2012 kWh/Day 2013

Historical Usage	This Year	Last Year
Electric-kWh/day	23.00	27.77

Conservation Tip
Join peaksaver PLUS and get a FREE touch-screen programmable thermostat and In-Home Energy Display - a combined value of over $400. Call 1-855-390-7476

horizonutilities.com
Go to our website regularly to get the latest information on your invoice, customer tools, and view the updated Horizon Utilities Conditions of Service document.

*Ontario Clean Energy Benefit takes 10% off the cost of up to 3,000 kWh/month of electricity use. Some exceptions apply please see Ontario.ca/OCEB or 1-888-668-4636. To learn more about how Ontario is building a strong, clean electricity system, visit Ontario.ca/energyplan

Next Scheduled Reading Date is tentatively set for Oct 02, 2013

Please see reverse side for further information.
Amount owing after the due date is subject to interest @ 19.56% per year.
The debt retirement charge pays down the debt of the former Ontario Hydro.

Your Usage For This Period — Rate Class: Residential

Meter Number	Meter Type	Reading Is An	Number Of Days	Reading At Start Of Period	Reading At End Of Period	Multiplier	Measured Usage	Adjustment Factor	Adjusted Usage
Electric	R1S	Actual	34	83288.97	84071.05	1.0	782.08	1.0407	813.91

horizon UTILITIES Looking beyond...

Horizon Utilities Corporation
PO Box 2249 STN LCD 1, Hamilton, ON L8N 3E4
www.horizonutilities.com

Account Number:

Service Address:

007967
76 (L)

Amount You Owe:
$118.98
Due Date: Oct 10, 2013
Amount Paid $

The Delivery charge on your bill has two main cost drivers: distribution and transmission. While Horizon Utilities collects both, it remits the transmission charge to Hydro One. The distribution charges are what Horizon Utilities uses to fund its utility needs.

On average, distribution costs make up about 20% of the average residential customer's (800 kWh per month) total electricity bill.

Every item on your bill is either mandated by the provincial government or regulated by the OEB. Horizon Utilities' costs of distributing electricity are bundled together with Hydro One's transmission costs in the Delivery charge line item of your bill.

The OEB reviews Horizon Utilities' rates and regulates the rates that can be charged to customers. Incorporated in our rates is also a fair return on our capital investments.

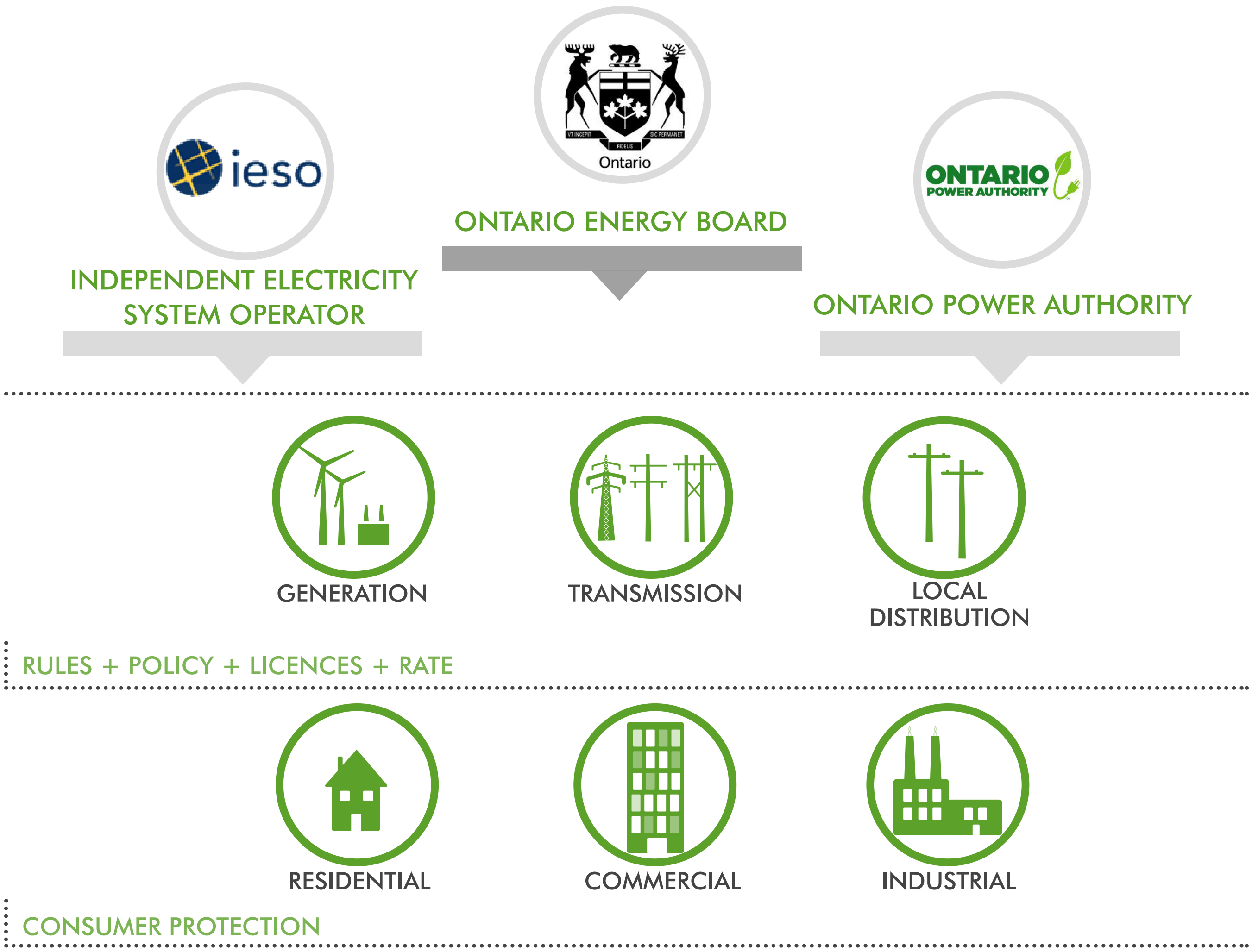
Electricity Grid 101

Who Does What in Ontario's Power System?

Ontario's electricity system is owned and operated by public, private and municipal corporations across the province. Electricity systems – whether in Ontario or other jurisdictions – have three key components: **generation, transmission** and **distribution**.

GENERATION Generating facilities convert various forms of energy into electric power.	EXAMPLE Ontario Power Generation TransCanada Energy Ltd Bruce Power Samsung Renewable
TRANSMISSION Transmission lines connect the power produced at generating facilities to substations.	EXAMPLE Hydro One Great Lakes Power Canadian Niagara Power
DISTRIBUTION Distribution lines carry electricity to homes and businesses.	EXAMPLE horizon UTILITIES Looking beyond... Burlington Hydro Niagara-On-The-Lake Hydro
CONSUMERS Electricity is delivered to homes and businesses.	EXAMPLE Residential Commercial Industrial

How is Ontario's Power System Regulated?



Ontario Ministry of Energy:

The Ontario Ministry of Energy creates energy policy. It sets the rules and establishes key planning and regulatory agencies through legislation.

Ontario Power Authority:

The Ontario Power Authority (OPA) is responsible for medium and long-term electricity planning to ensure an adequate supply of electricity is available for Ontario residents and businesses. The OPA receives directives from the Ministry of Energy (i.e. energy supply mix, Green Energy Act), but otherwise works at arm's-length from the government.

Independent Electricity System Operator:

The Independent Electricity System Operator (IESO) is responsible for electricity supply over the short-term. It operates the grid in real-time to ensure that Ontario has the electricity it needs, where and when it needs it.

Ontario Energy Board:

The mission of the Ontario Energy Board (OEB) is to promote a viable, sustainable and efficient energy sector that serves the public interest. It is an independent body established by legislation that sets the rules and regulations for the provincial electricity sector. Of particular importance to this discussion is the fact that the OEB reviews the distribution plans of all electricity distributors and sets their rates.

Horizon Utilities' Distribution System Today

Horizon Utilities has some of the oldest distribution assets in the province. Some of the equipment serving Hamilton and St. Catharines has been in service for nearly 100 years.

Electricity investment comes in cycles of growth. A significant portion of our existing system was installed during expansions in the 1950s to the 1970s, when Hamilton and St. Catharines grew. Since then, the way we use electricity has changed significantly. Through careful management, we have been able to make full use of and, where possible, extend the life of this equipment. But now, we have reached the point where 50% of our equipment is operating beyond, or close to, end-of-life expectancy. While much of that equipment is still in good shape and will continue to operate for several more years, we need to prepare to replace that equipment sooner rather than later.

System Reliability

For most customers, the key test of the system is "do the lights stay on". We track both the number of power service interruptions per customer and how long those outages last.

Since 2006, the average number of times customers have experienced a power service interruption has increased by 35% (to about two times a year), while the average length of the power service interruption has risen by 54% (to about 1.5 hours).

This trend is largely due to a higher occurrence of adverse weather and an increase in equipment failure. Replacing our aging equipment is a key part of the plan that we will be laying out for your review and input.

Paying for the Distribution System

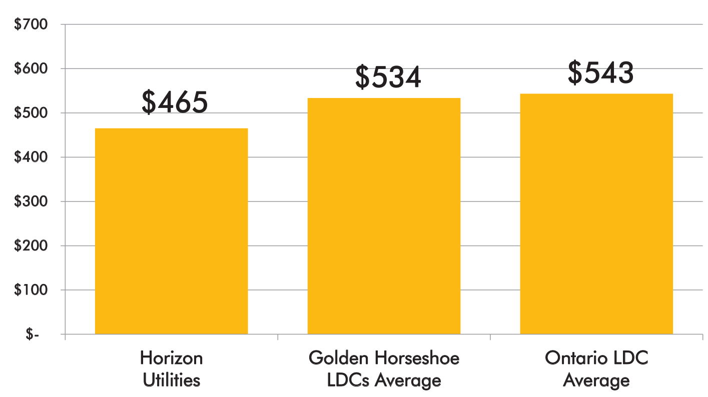
As anyone who runs their own business would expect, we manage our spending in two budgets – an operating budget and a capital budget.

Our **operating budget** covers regularly recurring expenses such as the costs of running our vehicles, the payroll for our employees, and the maintenance of our distribution equipment and buildings.

Our **capital budget** covers items that, when purchased, do not need to be repurchased for some time and that have lasting benefits over many years. This can include much of the equipment that is part of the distribution system, such as poles, wires and transformers, major computer systems, and vehicles.

Over the last five years, our average annual operating costs per customer has been $179, compared to the industry average of $270 per year. This means that across the province, Horizon Utilities' costs are nearly 34% lower than other local distribution companies. By managing costs and organizational efficiencies, we have kept our operating costs among the lowest in the sector.

Distribution Revenue Per Customer (2012)



Your distribution system has three main equipment categories: **distribution stations**, **overhead system**, and **underground system**.

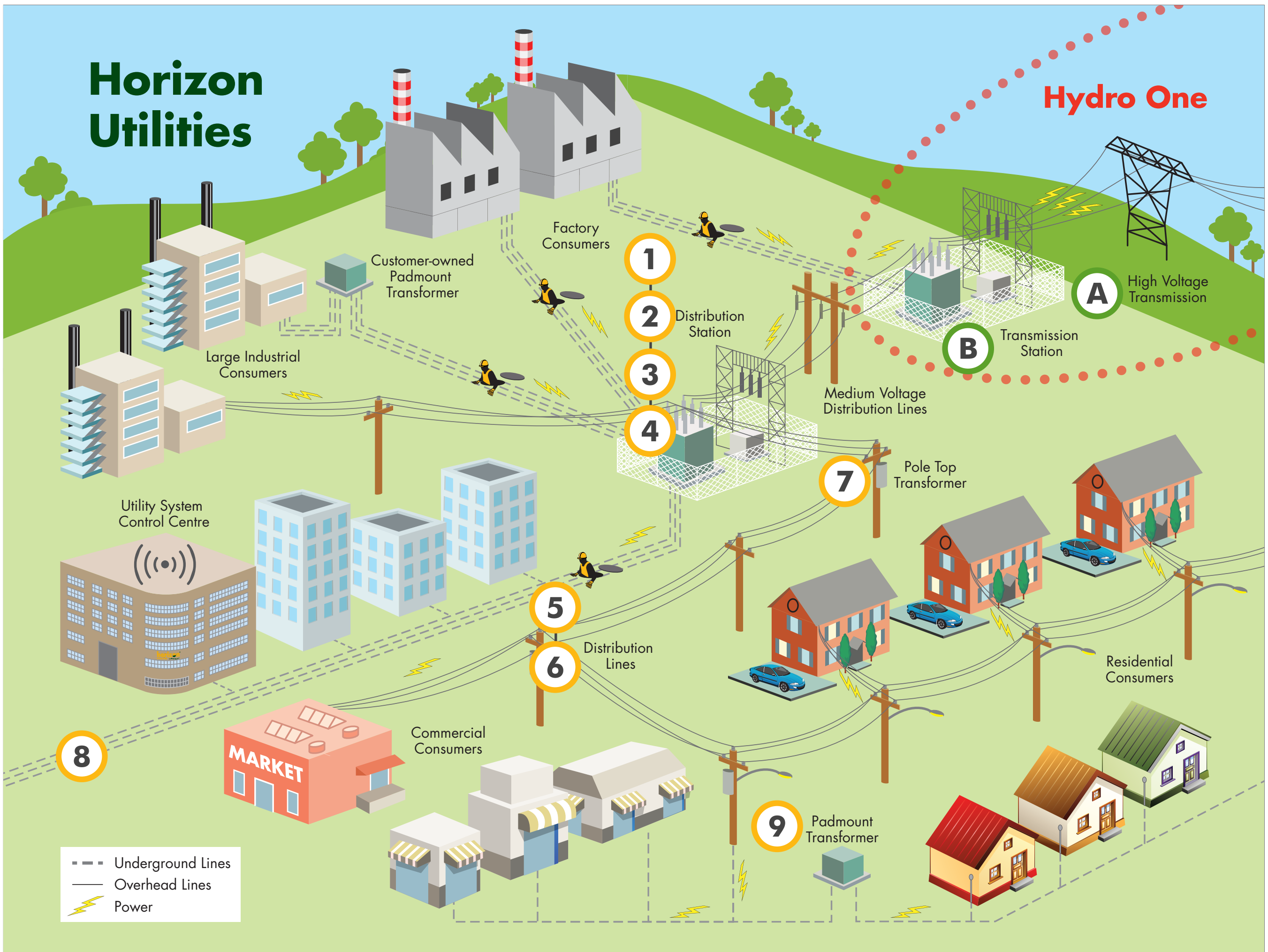
Hydro One's high voltage transmission lines connect the power produced at generating stations across the province (nuclear power plants, gas power plants, hydroelectric dams, wind farms, etc.) to transmission stations in Hamilton and St. Catharines. From Hydro One's transmission stations electricity flows to our distribution stations; this in turn, energizes our entire distribution system.

Hydro One's Transmission System

(A) **High Voltage Transmission** – connects our distribution system to electricity generating stations across the province.

(B) **Transmission Station** – reduces high voltage electricity from transmission lines to medium voltage which is fed into our distribution stations.

Your Distribution System



Horizon Utilities' Distribution System

Distribution Stations

Distribution stations are a critical element of the electricity grid—they are the local hubs from where electricity is distributed to an area. Distribution stations contain:

1. **Transformers** – devices that reduce the voltage of electricity to a lower level for use in the local distribution system.

2. **Breakers** – safety devices that interrupt a circuit if an unsafe amount of electricity passes through it (similar to a breaker panel in your home, except much larger).

3. **Switches** – devices that control the flow of electricity. They direct which supply of electricity is used and which circuits are energized.

4. **Feeder Circuits** – are the wires that exit the distribution station and deliver electricity to customers.

Overhead System

The overhead system includes the wires that are commonly seen across Horizon Utilities' service area. The voltage of the overhead system can be from 4 kV (1000 volts) to 28 kV.

5. **Wires** – there are 1,500 km of wire that carry electricity across our overhead distribution system.

6. **Poles** – wires are suspended from these usually wooden (sometimes concrete) poles.

7. **Pole Top Transformers** – these transformers are mounted near the top of utility poles and are needed to further step-down the voltage from the lines to the final connection to customers.

Underground System

The underground system includes 1,900 km of cable, some of which are direct buried (exactly as it sounds), and much of it is installed in ducts. At certain intervals underground service chambers (with manholes) are required to permit cables to be spliced together and to allow underground equipment such as switches to be housed.

A big advantage of underground systems is that they are less affected by weather. The disadvantage is that they are more expensive to install and maintain, and when there is a power outage it often takes longer to locate and repair a problem compared to overhead wires. Currently, about half of the outages caused by equipment occur in our underground system.

8. **Underground Cable** - convey the electricity in the underground system. Cables that connect the distribution stations and major industrial users to the distribution station are significantly larger than cables used to connect residential neighbourhoods, as one would suspect.

9. **Padmount Transformers** – similar to transformers in the overhead system, these reduce the voltage to a lower level before final connection to customers. In the underground system there are concrete padmounted transformers, which are above ground transformers that are supplied by underground cable, and vault transformers, which are housed in underground chambers.

Feedback

For the following questions, please select the answer that best represents your point of view.

1 Did you experience a power service interruption in the last year?

- Yes
- No
- Don't Know

2 If so, how long did your most recent power service interruption last?

3 If you did experience a power service interruption, how satisfied were you with the way that Horizon Utilities responded to that power service interruption?

- Very Satisfied
- Somewhat Satisfied
- Not Very Satisfied
- Not Satisfied At All
- Don't Know

4 Is Horizon Utilities response to power service interruptions getting better or worse?

- Much Better
- Somewhat Better
- Somewhat Worse
- Much Worse
- Don't Know

No system delivers perfectly reliable electricity. Generally, the more reliable the system, the more expensive the system is to build and maintain. Right now, the average customer served by Horizon Utilities experiences two power service interruptions a year, averaging one and a half hours per power service interruption. Please note - these are average durations and frequencies - some customers may have experienced significantly longer power service interruptions while others may have experienced shorter interruptions or no interruptions.

Please answer the following three questions, from your point of view:

5 How many power service interruptions are reasonable in a year?

- None
- One
- Two
- Three
- Four
- More than four
- Don't Know

6 What is a reasonable duration for a service interruption?

- 0 minutes
- 30 minutes
- 1 hour
- 2 hours
- 3 hours
- 4 hours or more
- Don't Know

7 From your perspective, if Horizon Utilities is able to improve the reliability of its distribution system, should they put more focus on reducing the number of power service interruptions or reducing the duration of the power service interruption?

- Focus on reducing the NUMBER of power service interruptions
- Focus on reducing the DURATION of the power service interruption
- Both
- Don't Know

Challenges Facing Our Distribution System

As we look ahead to our plan for the next five years, what are the major issues we need to address?

The expansion of the local distribution system in Hamilton and St. Catharines was among the first in Canada. Over the years, our employees have worked hard to keep our equipment working well beyond its originally expected life, to get maximum value for money. However, now there are many parts of the system for which we will not be able to continue to extend the operating life. While we do have some specific areas that will need additional capacity, our key challenges come from the need to replace aging equipment while supporting growth in certain areas of our communities.

To assist us in prioritizing what needs to be replaced and by when, we utilize an asset management model to drive replacement decisions.

Using the information provided by the asset management model, we plan for four types of capital replacement costs:

System Access

Definition: Projects that respond to customer requests for new connections or new infrastructure development. These are usually a high priority, "must do" type of requests.

Programs (e.g.): Customer Connections, Street Lighting

System Renewal

Definition: Projects focused on replacing aging equipment in poor condition.

Programs (e.g.): Distribution Station Refurbishment, Voltage Conversion, Underground Cable Replacement, Overhead Wire Replacement

System Service

Definition: Primarily consisting of projects that improve system reliability.

Programs (e.g.): Automated Switches, better distribution system monitoring equipment

General Plant

Definition: Investments in supporting assets, such as tools, vehicles, buildings and information technology (IT) equipment that are needed so that we may perform our task to operate and maintain the distribution system.

Programs (e.g.): IT, Facilities, Fleet

Investment Drivers

	System Service	General Plant
Challenges	System Service projects are initiated to deal with reliability and security issues rather than equipment failure. There are several projects being proposed to provide support to areas that are growing or to allow better use of existing equipment. Spend in this area is stable and not expected to be more than what has been required in the past on a go forward basis.	Just as with our distribution system, the buildings and equipment we need to support our business – facilities, IT and vehicles – are in need of refurbishment and replacement. We have made good progress on protecting and refurbishing our buildings to halt further degradation and make them more productive work environments over the last few years. The pace of investment will slow going forward as this is near completion.
Examples	• Automated switches to minimize the duration of a power service interruption.	• Building renewal plan to bring existing facilities into compliance with current building codes and increase space utilization • Ongoing fleet management to maintain and replace service vehicles • IT renewal program
Our Five Year Plan	System Service projects are initiated to expand capacity for future growth or to deal with reliability and security issues that are driven by grid design rather than equipment failure. Our distribution system is well-developed and there are relatively few of these projects within the plan. One project involves replacing older switches with automated switches which will reduce the restoration time for a power service interruption. Today, one has to wait for a service crew to arrive on the scene and to manually operate switches and move to the next location and repeat this task to restore the network. An automated switch will be able to operate remotely from a central control room. Another example will be to add a third feeder line in Waterdown to facilitate new development in the area. These projects will help to limit outages, reduce the length of outages, and reduce bottlenecks that will allow us to make better use of existing lines.	Operating the business effectively requires that Horizon Utilities' employees have offices and service centres to work in, vehicles to drive and IT systems to manage business functions. With a significant amount of our renovation program completed, capital expenditure on buildings will drop from just under \$4 million in 2015 to just under \$2 million in 2019. Vehicle financing is projected at just under \$800,000 for all five years. This is down \$300,000 from previous years to mitigate our need for and increased expenditure in building renovations. It is important that we have the technology and systems available to serve our customers. IT expenditure will be higher in 2015 at \$4 million as we complete a major and necessary overhaul of our core business management software.

System Access

Our communities developed in large part in the 50s, 60s, and 70s. Meeting the demand of new growth is currently limited to a few areas in the community. We expect the costs in this area to remain relatively stable.

Investments for new customer connections are spread over 40 years which keeps overall costs lower for everyone.

- Connecting businesses to the distribution system based on growth of the Hamilton Port and downtown commercial property redevelopment
- The village of Waterdown in Flamborough is experiencing one of the highest rates of residential growth in our service area, requiring new connections to the distribution system.

System Access projects include the type of action needed to enable new connections to the grid or to make changes to equipment to keep pace with customer requirements. This type of capital expenditure is mandated by legislation and scheduled by customer request.

In addition to the regular demand from customers using electricity, we are now enabling projects under the FIT and microFIT programs that supply renewable electricity to the grid.

Other projects will include moving the poles for the widening of Rymal Road in Hamilton within the next few months.

Based on past experience, we are projecting expenditures to be fairly stable over the next five years at approximately $6 million.

System Renewal

Although our equipment is in reasonably good shape for its age, it is getting old and much of it will need to be replaced soon.

The time lost to power service interruptions caused by aging equipment has been growing steadily over the past decade. We started to replace critical equipment in our distribution stations as well as the grid in downtown St. Catharines. We need now to manage the balancing act of replacing equipment proactively before it fails. Proactive replacement is less costly than replacing equipment on a reactive basis.

- Low voltage renewal plan
- Distribution station decomissioning
- Coordination of renewal of Gage Transmission Station with Hydro One
- Proactive underground cable replacement in St. Catharines, Hamilton Mountain and Stoney Creek

System renewal is by far the biggest financial and operational challenge facing the grid. Projects to replace aging elements of the grid that are in poor condition or at high risk of failure will be a key driver of rate increases in this application and for the foreseeable future.

An independent engineering firm that analyzed the health of the Horizon Utilities' system assets has identified a 20-year investment requirement of approximately $700 million. The analysis indicates that Horizon Utilities' reliability of the distribution system is worsening and investments are required to maintain the reliable service we all expect.

We propose increasing annual renewal investment from the current rate to an annual value of $35 million by 2019 and approximately $37 million by 2025.

Based on our engineering studies this is the minimum investment level required to maintain the current health of our major asset categories through 2019.

Feedback

For the following questions, please select the answer that best represents your point of view.

1 How satisfied are you with the job Horizon Utilities is doing running your local distribution system?

- Very Satisfied
- Somewhat Satisfied
- Don't Know
- Somewhat Dissatisfied
- Very Dissatisfied

2 Is there anything in particular Horizon Utilities can do to improve their service to you?

3 In order to secure the full value for its investment, Horizon Utilities allows some equipment to "run-to-failure". The equipment that is allowed to run-to-failure (such as pole top transformers) only creates power service interruptions for a very limited number of customers and can quickly be restored. While many utilities follow this practice, others do not. Which of the following best represents your view?

- "Running-to-failure" is a good way to get full value from equipment so long as the resulting power service interruption is contained and quickly restored.
- Horizon Utilities should ensure reliable power and not wait until equipment fails, even if that means it needs to spend more money replacing equipment that is still working.
- Don't Know

Controlling Costs

In our last OEB rate application three years ago, we set out a plan to control costs and to begin addressing aging infrastructure in key parts of our distribution system.

Before we ask our rate payers for more money, we have an obligation to ensure we are getting the best value we can from the revenue we already receive from customers.

We have been able to deliver among the lowest operating costs and the lowest residential and commercial rates in Ontario.

We have kept our costs down with a productivity strategy that focuses on delivering more or better service for the same costs or less. We have been lowering training costs, and increasing tool time (the amount of onsite work vs. travel time and administration) across the organization. We are a company of 400 employees and we expect productivity to improve by approximately $3 million between 2012 and 2014.

Conservation and Demand Management (CDM)

Conservation programs are a key part of Ontario's Long-Term Energy Plan to meet the needs of electricity customers while contributing to improvements in air quality and reducing greenhouse gases. Investing in conservation is a cost effective means by which to reduce the amount of electricity used rather than build new generation resources.

We have been actively working with customers to implement conservation initiatives for many years. In 2011, the OEB mandated aggressive Conservation and Demand Management targets for all local distribution companies in Ontario to be met by the end of 2014.

With the help of our customers, our conservation programs have delivered energy savings of over 110 million kilowatt-hours (kWh) and 31 thousand kW of peak demand between 2008 and 2012. These savings represent the equivalent of taking close to 12,000 homes off the grid for one year. Additional savings of 64 million kWh and 15,000 kW of peak demand are expected to be realized by the end of 2014; this represents a further reduction in electricity that is equivalent to taking 6,600 homes off the grid for one year. Local businesses in Hamilton and St. Catharines have received over $17 million in incentives, funded by the Ontario Power Authority, for their energy conservation efforts.

Getting the Most From Our Assets

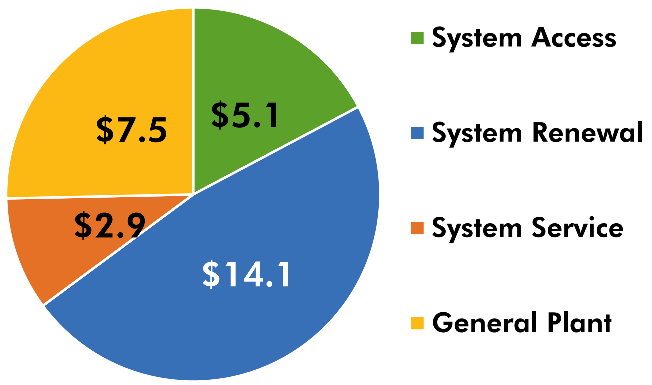
Another important way we keep costs down is by carefully managing and maintaining our equipment to extend its life. The people who built our system built it well, and we avoided replacing useful equipment for as long as was reasonably possible. We work hard to extend the service life of all of our equipment, but we have now reached a point where much of our system will need to be replaced within the foreseeable future.

As mentioned earlier, we use an asset management model to identify key replacement priorities. There are a large number of challenges that must be dealt with, but we don't have to fix it all at once. The key to having an asset management plan is that it guides our decisions about when the timing is right to replace assets.

We have already started to renew

Our 2008 asset management plan identified several immediate priorities for replacement. Since then, our investment in annual renewal has grown from just under $10 million to $17 million.

2012 Capital Expenditures ($ millions)



Distribution stations play a critical role connecting the distribution grid so they have been the top priority for new investment. Some of the work we have already completed includes:

Distribution station transformers: Six distribution transformers in very poor condition were replaced. In four of the installations, we used refurbished transformers, which are half of the cost of a new transformer.

Distribution station switchgear: A full switchgear replacement was done at one station due to a significant number of equipment health issues. That distribution station will be in service for at least another 35 years. As a result, a full replacement ensures we are utilizing this asset to its full potential.

Distribution station assets (breakers and relays): These assets were prioritized based on the condition of the assets and how long the station would continue to be in service for the surrounding community. New breakers have been standardized and take full advantage of technological innovation. All of our distribution station equipment that is removed from service is refurbished and used for spare parts, if it qualifies. The station breaker program was initiated and completed in 2012 and 2013. No further investments in distribution station circuit breakers are forecast from 2015 through 2019.

In addition to the distribution station work, we also have given priority to a program that is replacing aging equipment with new technology:

Voltage conversion program: A key element of our overhead plan is the conversion of our 4 kV and 8 kV distribution systems. These systems serve approximately 82,000 customers representing 34% of the total customer base scattered across all of our operating areas. These lines worked well when they were first installed in the 1950s, but new lines use higher voltage for better efficiency. We have organized this work to give priority to lines that are supported by distribution station equipment that is in poor condition so we can optimize our renewal plans for both distribution station and overhead lines.

What Our Plan Means For You

We have worked hard to deliver among the lowest operating costs and the lowest residential and commercial rates in Ontario.

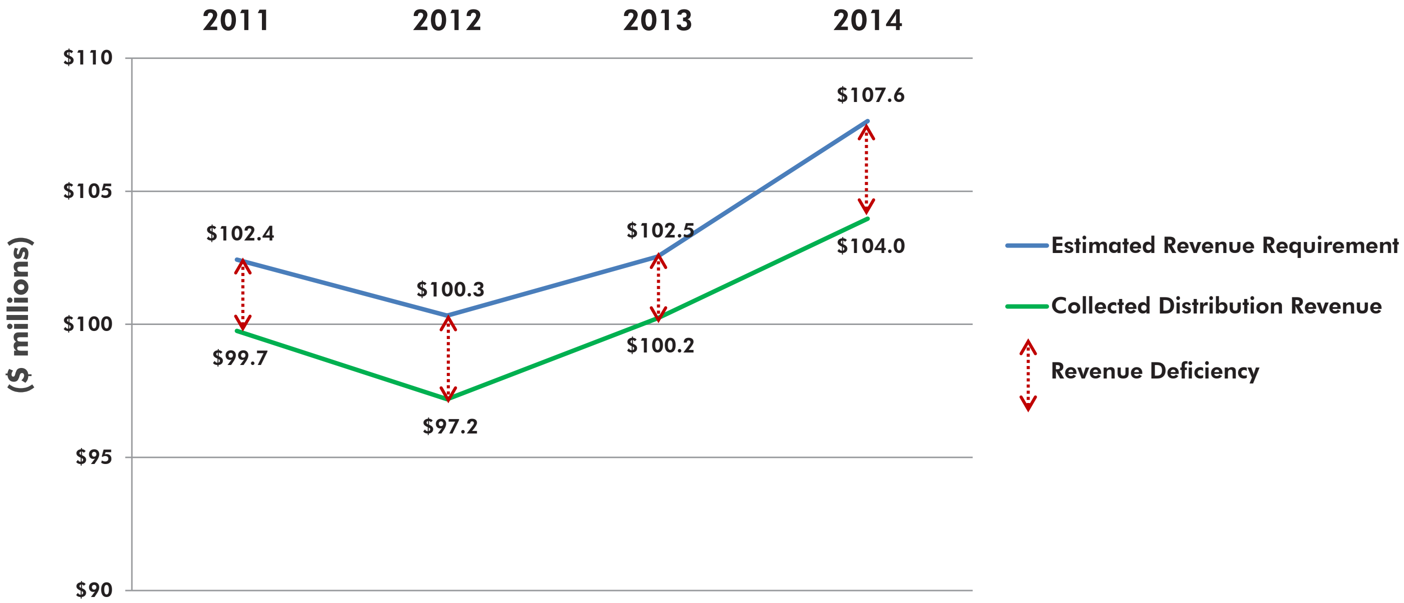
While we do our best to keep our rates low, over the past three years our rate increases have actually been lower than they should have been to maintain the system adequately.

In our last rate application, only one approach was available for all utilities to follow. Rates in 2011 were set using a cost of service method, which looked at the actual costs of providing electricity distribution in our service area. Then once those cost of service rates were set, a mechanistic formula was applied each year to account for inflation less an adjustment for efficiency. This method resulted in a revenue shortfall for us since investments made over time were not recognized and thus did not allow for any adjustment to our growing rate base.

The result can be seen in the chart below. We have built up a revenue shortfall of $12 million since 2011. This has reduced our ability to reinvest in our system. Given that so many of our assets have reached their end-of-life or are approaching, we need to correct this problem and make the required replacements.

The OEB has recognized this problem and has now given utilities in Ontario a number of options to calculate their rates. At Horizon Utilities, we will be using the Custom Incentive Rate cost of service approach where our rates will be based on actual costs each year of our five year plan.

Revenue Shortfall



		2011		2012		2013		2014
Estimated Revenue Requirement	$	102.4	$	100.3	$	102.5	$	107.6
Collected Distribution Revenue	$	99.7	$	97.2	$	100.2	$	104.0
Revenue Deficiency	$	(2.7)	$	(3.1)	$	(2.3)	$	(3.7)

Addressing the Revenue Shortfall

Despite our relatively old equipment, we run our operation on less money per customer than the average electricity distributor in Ontario. However, under the previous rate approval process, our actual costs were not fully covered. This has left us with a gap, which we need to address in this rate application.

Our current rate application will avoid the revenue shortfall that occured over the past several years.

Looking across the full five year period, while the bulk of our spending is for the renewal of our aging equipment, we will also be applying for an increase to our operating budget. Most of our operating budget increase comes from rising labour costs and inflation (rising fuel, materials such as wire, and equipment costs.) Those increases will be offset by ongoing efforts to improve productivity. After expected productivity savings, the average increase in operating costs is 2.1% a year for a total of approximately $7 million over the five years.

Rate Changes

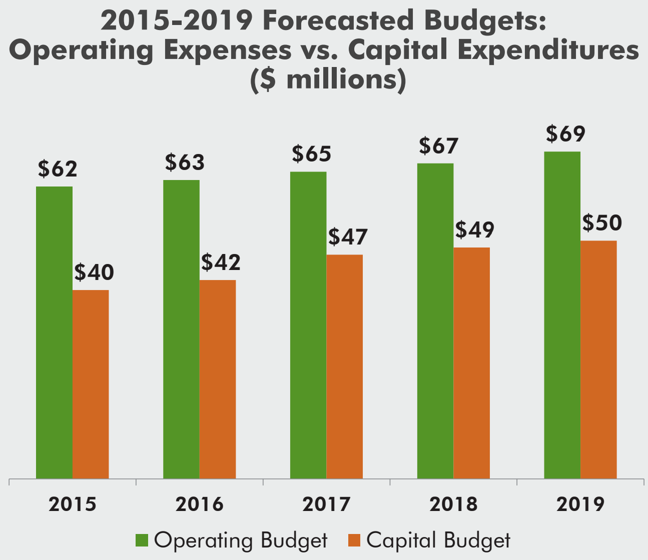
Different classes of customers will have their rates affected in different ways.

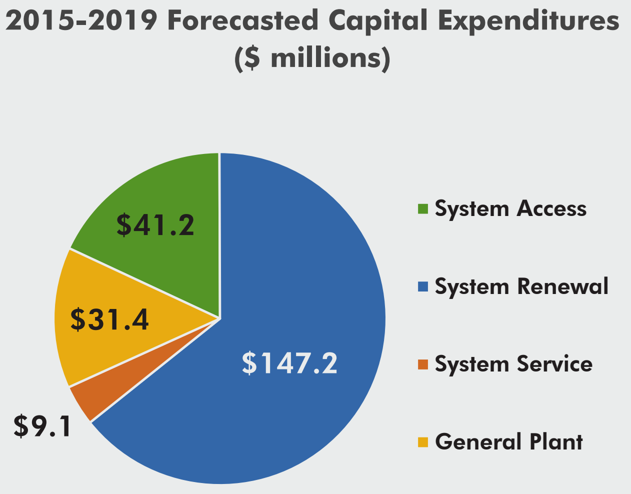
The OEB has established that each rate class should pay for the cost of serving that class; this is a core OEB rate-making principle. Applying this principle will result in different rate increases for different users.

Following the last rate application, we discovered that large use rate class customers were being charged an inequitable share of costs. As part of this rate application, we are proposing to revise our rate structure in the following manner:

- By creating a new rate class for the largest users who were paying much more than their fair share; and,
- By assessing the rates of all rate classes to appropriately reflect the cost of service.

While no one wants to see a price increase, the OEB's direction to ensure each rate class pays its own share of the costs is central to its core principle of ratepayer equity. All utilities in Ontario are required to comply with this mandate.

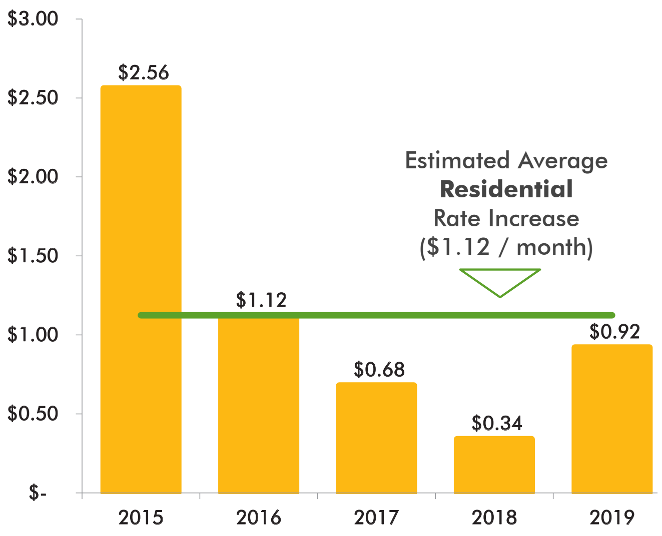




What Does this Mean for Residential Customers?

Those customers with an average monthly consumption of 800 kWh may see an average rate increase of 4.2% on the distribution portion of their bill for the next five years. That works out to an average annual increase of approximately $1.12 a month, each year. As such, by 2019, the average residential household will be paying an estimated $5.60 more per month on their distribution portion of their electricity bill.

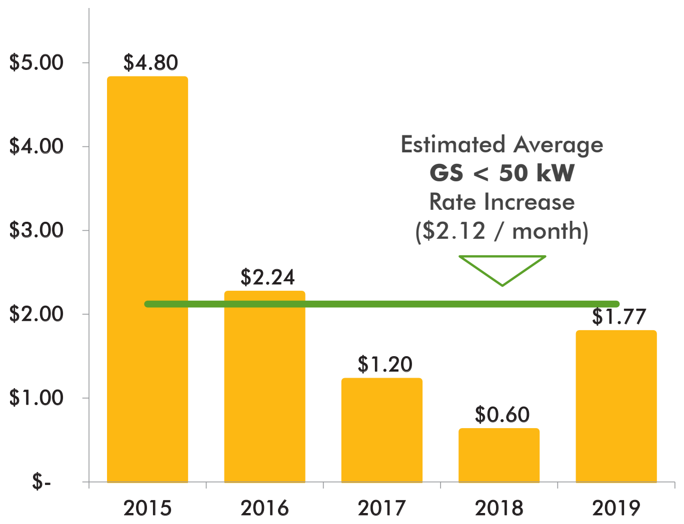
Estimated Average Residential Rate Increase



What Does this Mean for Commercial Customers?

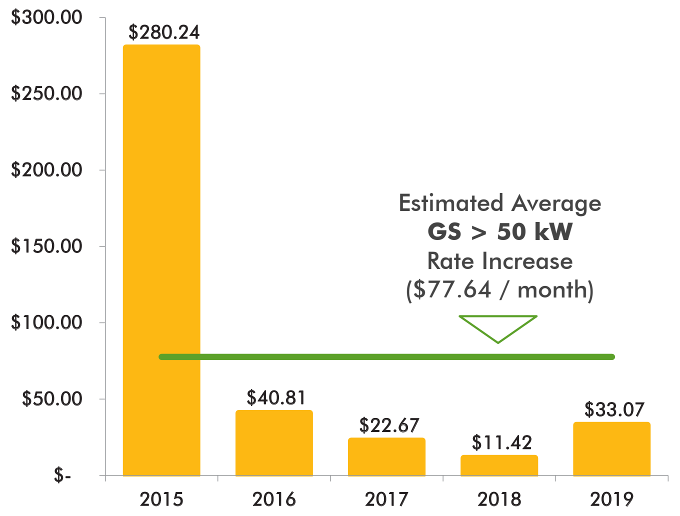
GS < 50 kW: Those customers with an average monthly consumption of 2000 kWh may see an average rate increase of 4.2% on the distribution portion of their bill for the next five years. That works out to an average annual increase of approximately $2.12 a month, each year. By 2019, the average small business will be paying an estimated $10.60 more per month on their distribution portion of their electricity bill.

Estimated Average GS < 50 kW Rate Increase



GS > 50 kW: Those customers with an average monthly demand of 250 kW may see an average rate increase of 9.5% on the distribution portion of their bill for the next five years. That works out to an average annual increase of approximately $77.64 a month, each year. Therefore, by 2019, the average GS > 50 kW customer will be paying an estimated $388.20 more per month on their distribution portion of their electricity bill.

Estimated Average GS > 50 kW Rate Increase



Based on the current plan, we expect that the increases for all customer classes in the earlier years may be higher followed by lower increases in the later years.

Feedback

For the following questions, please select the answer that best represents your point of view.

1 Did Horizon Utilities' Distribution System Plan cover the topics you expected?

- Yes
- No
- Don't Know

If No: What was it missing?

2 Based on what you already knew and what you have read in this workbook, do you feel you have a good general sense of how the Horizon Utilities' distribution system works?

- Yes
- No
- Don't Know

3 Based on what you already knew and what you have read in this workbook, do you feel you have a good general understanding of the challenges regarding Horizon Utilities' distribution system?

- Yes
- No
- Don't Know

4 Considering what you know and have learned about the local distribution system, do you feel the proposed rate of system renewal is …

- Too Slow
- Too Fast
- About Right
- Don't Know

Why do you say that?

5 Considering what you know about the local distribution system, which of the following best represents your point of view:

- The rate increase is reasonable and I support it
- I don't like it, but I think the rate increase is necessary
- The rate increase is unreasonable and I oppose it
- Don't Know

Why do you say that?

About Horizon Utilities Corporation

APPENDIX A

Horizon Utilities serves the cities of Hamilton and St. Catharines.

We are locally owned by the City of Hamilton and the City of St. Catharines, with a long and proud history of industry leadership.

Today, we are one of the largest municipally owned electricity distribution companies in Ontario. The company provides electricity and related utility services to 239,000 residential, commercial and industrial customers in Hamilton and St. Catharines.

Our History Helps Define Us

1883	Hamilton installs Canada's first incandescent streetlights
1884	Incorporation of St. Catharines Electric Light and Power
1898	DeCew Falls station in St. Catharines is the oldest continually running hydroelectric plant in Canada and is connected to Hamilton by the world's first long-distance transmission line, at 56 kilometres
1911	Hamilton voters support creating Hamilton Hydro in a municipal referendum
1914	St. Catharines Hydro is established
1960s – 1990s	Ongoing infrastructure and technological investments ensure robust and reliable electricity distribution networks in St. Catharines and Hamilton
2005	Hamilton Hydro and St. Catharines Hydro merge to form Horizon Utilities – becoming the then third largest municipality-owned electricity distributor in Ontario
2008	Horizon Utilities is the first electricity distribution company in Canada to make a full sustainability report under the Global Reporting Initiative (GRI) framework
2011	Horizon Utilities is awarded Canadian Electricity Association's Sustainability Company of the Year and named to Hamilton-Niagara's Top Employers list

Horizon Utilities serves a diverse group of customers. We have over 200,000 residential customers, more than 18,000 general service customers who take less than 50 thousand watts (kW) of energy, about 500 general service customers that require more than 50 kW, and 11 large users who use more than 5,000 kW of electricity, monthly.

Under OEB direction, we are required to do our best to ensure the rates from each class of customers covers the cost of serving those customers.

Questions and Comments

If you have any questions or comments about Horizon Utilities' Distribution System Plan Review please email:

DSPreview@horizonutilites.com

or send your questions or comments to:

Horizon Utilities Corporation
Attn: DSP Review
55 John Street North
Hamilton, ON
L8R 3M8

Appendix E – Renewable Energy Generation

Horizon Utilities

Distribution System Plan

Appendix E – REG Investment Plan

Introduction

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 "DS Plan Filing Requirements") which reflects the Board's policy direction on an integrated approach to distribution network planning. Horizon Utilities has prepared its DS Plan in accordance with these DS Plan Filing Requirements.

The Board issued a letter dated March 28, 2013 accompanying the DS Plan Filing Requirements. In that letter, the Board stated that "*under the renewed regulatory framework for electricity, a distributor's investments to accommodate and connect renewable energy generation and to develop and implement a smart grid are integral to its overall capital expenditure plan."*

Section 5.1.4.2 of the DS Plan Filing Requirements requires that distributors submit information to the Ontario Power Authority (the "OPA") in relation to the renewable energy generation ("REG") investments identified in its DS Plan. The OPA is expected to provide a letter of comment with regard to these plans. Horizon Utilities' REG Plan forms part of its overall Distribution System Plan. Horizon Utilities has separated its REG Plan for the purpose of the obtaining OPA's review and letter of comment. The Board's expectations for the OPA's comment letter are summarized in Attachment A. A copy of the OPA's comment letter will, once complete, be attached as Attachment B.

1. Summary of Renewable Energy Generation Investments (5.4.1(g))

Horizon Utilities is one of the largest municipally-owned electricity distribution companies in Ontario, providing electricity and related utility services to more than 240,000 residential and commercial customers in Hamilton and St. Catharines. The company is owned by Horizon Holdings Inc., a company jointly owned by Hamilton Utilities Corporation and St. Catharines Hydro Inc. The latter two companies are respectively owned by the City of Hamilton and the City of St. Catharines.

Horizon Utilities is supplied through the Hydro One Networks Inc. transmission system at voltages of 13.8 kV and 27.6 kV. Electricity is then distributed through Horizon Utilities' service area of 426 square kilometres over 1,904 kilometres of underground cable and 1,524 kilometres of overhead cable and 52,000 poles. Horizon Utilities not only delivers electricity at its supply voltage of 13.8 kV and 27.6 kV but also owns 28 distribution stations stepping voltage down to 4.16 kV and 8.3 kV. Voltage is further stepped down in order to supply individual customers through approximately 24,000 transformers.

Horizon Utilities supports and promotes the installation of renewable generation per the Distribution System Code ("DSC") requirements. Horizon Utilities has received 54 applications since 2010, of which 24 have been successfully connected.

Horizon Utilities' distribution system has sufficient capacity to accommodate the amount of forecasted renewable generation identified in section 4(b) below.

Historically, connection costs are covered by the customer through capital contributions. Horizon Utilities accounts for all up-stream enhancement costs only after a project has been connected. Only one of the 54 projects to date involved upstream enhancement work. The amount spent for this enhancement work on this one project was not material (less than $10,000).

Based on the foregoing, Horizon Utilities does not forecast any REG investments will be required over the 5 year period.

2. <u>REG and the Regional Planning Process (5.1.4.1)</u>

Horizon Utilities uses an integrated approach to planning which includes all categories of investments: system renewal, system access, system service, general plant, renewable generation connection and regional planning requirements. This integrated approach optimizes investments that support the outcomes identified by the Board.

The DS Plan Filing Requirements are intended to ensure that, among other things, the Board's expectations for the optimization of investments reflect regional considerations. The Board also made amendments to the DSC such that distributors would be required to request one of three documents from the lead transmitter: a regional infrastructure plan; a letter regarding the status of the regional infrastructure plan; or a Needs Assessment Report (where participation in a regional planning process is not required).

Horizon Utilities service area falls into two Regional Planning areas: Burlington to Nanticoke and Niagara. Horizon Utilities requested a letter from Hydro One Networks Inc. (“Hydro One”) confirming the status of regional planning for the two Regional Planning areas of which Horizon Utilities is a part.

Horizon Utilities has been working with the OPA and Hydro One with respect to Regional Planning for the Burlington to Nanticoke region. Horizon Utilities has completed Hydro One’s requests for information on system loading and generation to complete the ‘Needs Screening’ assessment for the Burlington to Nanticoke region. Most recently, Horizon Utilities’ hosted a Hydro One Regional Planning meeting at the Horizon Utility facilities on January 31, 2014.

Hydro One has not initiated the Needs Screening phase for the Niagara region; this is anticipated for 2016-2017. Horizon Utilities will support the Regional Planning process for the Niagara region once these meetings commence.

Horizon Utilities actively participates with regional distributors, the IESO and Hydro One at an operational level and looks forward to participating at the regional planning level as well. The following distributors are located adjacent to Horizon Utilities’ service areas:

City Of Hamilton service area:

- Burlington Hydro
- Grimsby Power Incorporated
- Hydro One Networks Incorporated (“Hydro One”)
- Niagara Peninsula Energy Incorporated

City of St. Catharines service area:

- Hydro One Networks Incorporated (“Hydro One”)
- Niagara-On-The-Lake Hydro Inc.
- Niagara Peninsula Energy Incorporated

Horizon Utilities has multiple connection points with Hydro One and meets with them regularly to discuss regional issues. In comparison among the remaining adjacent distributors, Horizon Utilities only has 1 connection point. Any project that arises along the borders are discussed and planned with the neighbouring distributor as it arises. Consequently, regular meetings are not required, particularly due to the small number of interconnections.

3. REG and the capital expenditure planning process (5.4.2)

Horizon Utilities plans its distribution system investments to accommodate the connection of potential future renewable generation during the design phase of any project. Capital investments related to the accommodation of REG investments are project specific and are recovered through capital contributions.

Horizon Utilities' capital planning objectives, including its objective for accommodating the connection of renewable generation facilities, are to connect 100% of renewable generation where possible.

These objectives relate to Horizon Utilities' asset management objectives as described in Section 2.1.1 of the DSP. Both REG investments and Conservation and Demand Management projects are potential options for solutions to system capacity constraints during system planning.

Horizon Utilities' planning criteria and assumptions used in connection with its outlook for accommodating the connection of renewable generation facilities are as follows. Horizon Utilities considers the average number of renewable connections per year and size of the connection installed on a historical basis in order to prepare a forecast of future renewable connections.

Horizon Utilities' method and criteria used to prioritize REG investments in accordance with the planned development of the system are similar to its approach to the treatment of load customers. All necessary investments are seen as non-discretionary and are planned and designed in accordance with Horizon Utilities' standard process

Horizon Utilities does not plan to connect any distributor-owned renewable generation project(s) during the forecast period. Horizon Utilities does not own distributor-owned generation directly. Horizon Utilities owns a 99.9% interest in Solar Sunbelt General Partnership (SSGP), a general partnership that undertakes solar photovoltaic ("PV") projects. The methodology used for the prioritization of REG investments related to SSGP is the same as that which is used for all other REG investments.

4. System capability assessment for REG (5.4.3)

The estimated capability of Horizon Utilities' distribution system to accommodate renewable energy generation connections at each transformer station is shown in Table 5 below.

Horizon Utilities is not aware of specific network locations where constraints are expected to emerge due to forecast changes in load and/or connected renewable generation capacity.

(a) Applications for REG (5.4.3 (a))

A list of all of the submitted Customer Impact Assessment ("CIA") applications for renewable generation projects over 10kW is provided in Table 1. Horizon Utilities has 24 connected rooftop solar FIT applications, 16 are currently in construction and 2 had been denied as of January 28, 2014. The two projects were denied from different reasons. The first project was denied due to minimal loading on the feeder; specifically it did not comply with Institute of Electricians and Electronics Engineers (IEEE) 1547 requirements (generation must not exceed 33% of the minimum feeder load). The second project was denied due to a lack of available capacity at the Hydro One Nebo Transformer Station. The remaining applications are in process; a detailed status of each application is provided in Table 1: List of CIA Applications, below.

Table 1: List of CIA Applications

CIA #	CIA Agreement (Execution date)	Generation Type	Status	Station	Bus	Feeder	Project Size (kW)
1	Monday, November 15, 2010	Rooftop Solar PV	Connected	Newton	B	232X	100
2	Monday, November 15, 2010	Rooftop Solar PV	Connected	Newton	B	232X	175
3	Tuesday, March 15, 2011	Rooftop Solar PV	Connected	Nebo	QJ	3631X	70
4	Tuesday, March 15, 2011	Rooftop Solar PV	Connected	Nebo	QJ	3631X	70
5	Thursday, May 23, 2013	Rooftop Solar PV	Construction	Lake	J1J2	1412X	250
6	Thursday, August 04, 2011	Rooftop Solar PV	Connected	Dundas	JQ	2D12X	95
7	Wednesday, August 10, 2011	Rooftop Solar PV	Construction	Dundas	JQ	2D14X	14
8	Thursday, August 04, 2011	Rooftop Solar PV	Connected	Elgin	QJ	5231X	40
9	Monday, October 24, 2011	Rooftop Solar PV	Connected	Nebo	QJ	3541X	200
10	Monday, October 24, 2011	Rooftop Solar PV	Connected	Winona	JQ	W15X	100
11	Thursday, May 23, 2013	Rooftop Solar PV	CIA Issued	Lake	Q1Q2	1831X	250
12	Thursday, May 23, 2013	Rooftop Solar PV	Construction	Dundas	JQ	2D13X	250
13	Monday, October 24, 2011	Rooftop Solar PV	Connected	Winona	JQ	W14X	200
14	Monday, October 24, 2011	Rooftop Solar PV	Connected	Winona	JQ	W14X	200

CIA #	CIA Agreement (Execution date)	Generation Type	Status	Station	Bus	Feeder	Project Size (kW)
15	Wednesday, November 30, 2011	Rooftop Solar PV	Connected	Winona	JQ	W14X	125
16	Wednesday, November 30, 2011	Rooftop Solar PV	Connected	Winona	JQ	W14X	125
17	Wednesday, November 16, 2011	Rooftop Solar PV	Construction	Lake	J1J2	1411X	100
18	Wednesday, November 16, 2011	Rooftop Solar PV	Construction	Lake	J1J2	1411X	50
19	Monday, October 24, 2011	Rooftop Solar PV	Connected	Birmingham	JQ	50x81	250
20	Wednesday, December 07, 2011	Rooftop Solar PV	Connected	Vansickle	JQ	VSM72	250
21	Monday, January 30, 2012	Rooftop Solar PV	Connected	Carlton	BY	CTM21	125
22	Monday, October 24, 2011	Rooftop Solar PV	Connected	Newton	B	282X	250
23	Thursday, May 23, 2013	Rooftop Solar PV	Construction	Carlton	HK	CMT18	250
24	Monday, January 30, 2012	Rooftop Solar PV	Connected	Glendale	DQ	GLM5	250
25	Monday, January 30, 2012	Rooftop Solar PV	Connected	Bunting	Q1Q2	BUM82	108
26	Tuesday, November 20, 2012	Rooftop Solar PV	Connected	Vansickle	BY	VSM52	65
30	Tuesday, April 17, 2012	Rooftop Solar PV	Connected	Lake	J1J2	1411X	70
29	Tuesday, April 17, 2012	Rooftop Solar PV	Connected	Vansickle	JQ	VSM72	100

CIA #	CIA Agreement (Execution date)	Generation Type	Status	Station	Bus	Feeder	Project Size (kW)
30	Tuesday, April 17, 2012	Rooftop Solar PV	Construction	Nebo	QJ	3521X	250
31	Tuesday, April 17, 2012	Rooftop Solar PV	Construction	Dundas	JQ	2D12X	250
32	Tuesday, April 17, 2012	Rooftop Solar PV	Connected	Dundas	JQ	2D12X	250
33	Friday, August 03, 2012	Rooftop Solar PV	Connection Denied	Stirton	QJ	8511X	250
34	Tuesday, May 15, 2012	Rooftop Solar PV	Connected	Lake	J1J2	1411X	100
35	Tuesday, June 19, 2012	Load Displacement	Waiting for OPA	Beach		M42	8120
36	Tuesday, May 29, 2012	Rooftop Solar PV	Connected	Winona	JQ	W14X	250
37	Tuesday, November 13, 2012	Rooftop Solar PV	Construction	Vansickle	JQ	VSM72	250
38	Wednesday, May 08, 2013	Rooftop Solar PV	Offer to connect	Lake	Q1Q2	1811X	100
39	Wednesday, May 08, 2013	Rooftop Solar PV	Construction	Beach	Q2Q1	7321X	100
40	Wednesday, May 08, 2013	Rooftop Solar PV	Construction	Lake	Q1Q2	1811X	70
41	Friday, May 03, 2013	Rooftop Solar PV	Construction	Carlton	HK	CTM18	250
42	Friday, May 03, 2013	Rooftop Solar PV	Construction	Vansickle	JQ	VSM72	250
43	Friday, May 03, 2013	Rooftop Solar PV	Construction	Beach	Q2Q1	7321X	250

CIA #	CIA Agreement (Execution date)	Generation Type	Status	Station	Bus	Feeder	Project Size (kW)
44	Thursday, May 23, 2013	Rooftop Solar PV	Offer to connect	Lake	Q1Q2	1731X	40
45	Thursday, May 23, 2013	Rooftop Solar PV	Offer to connect	Lake	Q1Q2	1731X	70
46	Thursday, May 23, 2013	Rooftop Solar PV	Offer to connect	Lake	Q1Q2	1731X	70
47	Thursday, May 23, 2013	Rooftop Solar PV	Offer to connect	Lake	Q1Q2	1731X	70
48	Friday, June 14, 2013	Rooftop Solar PV	Construction	Glendale	DQ	GLM8	250
49	Friday, June 14, 2013	Rooftop Solar PV	CIA	Bunting	Q1Q2	BUM82	250
50	Friday, June 14, 2013	Rooftop Solar PV	Offer to connect	Lake	Q1Q2	1731X	70
51	Friday, June 14, 2013	Rooftop Solar PV	Offer to connect	Lake	Q1Q2	1811X	70
52	Friday, July 19, 2013	Rooftop Solar PV	Connection Denied	Nebo	BY	341X	150
53	Thursday, July 25, 2013	Rooftop Solar PV	Construction	Dundas	BY	2D12X	250
54	Friday, November 15, 2013	Rooftop Solar PV	Conducting CIA	Lake	Q1Q2	1722X	500

(b) Anticipated REG over Forecast Period (5.4.3(b))

Horizon Utilities understands that the OPA has received a total of 66 FIT Applications for Horizon Utilities' service area since the launch of the FIT Program in 2009, of which 58 have received FIT Contracts.

As described in subsection (a) above, Horizon Utilities has received 54 CIA applications. Horizon Utilities expects the balance of the 58 contracts awarded to be received in 2014.Horizon Utilities' expectations for the number of connected projects per year for each year of the forecast period is an average of 3 applications in Hamilton and 1 application in St. Catharines; more generally, the values may range between 2-4 applications in Hamilton and 0-2 applications in St. Catharines. These forecasts are based on existing applications, information available from the OPA and trending over the period seen in Tables 2 and 3, below. Horizon Utilities forecasts that such projects may add an average of 0.5MW of capacity in Hamilton (ranging between 0.50-0.75MW) and an average of 0.25MW of capacity in St. Catharines (ranging between 0.25-0.5MW).

Table 2: Number of Connected Applications

Number of Connected Applications Per Year						
	2010	2011	2012	2013	Total	Average
St. Catharines	0	1	5	0	6	1.50
Hamilton	2	12	4	0	18	4.50
				Total	24	6

Table 3: MW Capacity of Connected Projects

MW Capacity of Connected Projects Per Year						
	2010	2011	2012	2013	Total	Average
St. Catharines	0	0.25	0.648	0	0.89	0.22
Hamilton	0.275	1.725	0.67	0	2.67	0.66
				Total	3.568	0.892

(c) Capacity of the Distribution System for REG (5.4.3(c))

In general, Horizon Utilities has sufficient of capacity to support REG connections in both Hamilton and St. Catharines. However, Horizon Utilities identifies that some feeders are constrained, as shown in Table 4. A list of available generation capacity for each individual station is identified in Table 5, below.

Table 4: 4.16kV and 8.32kV Generation Availability

Station	Feeder	Generation Capacity (kVA)	Existing Generation (A)	Existing Generation (kVA)	Available Generation Capacity (A)	Available Generation Capacity (kW)
Aberdeen	AB-1	1369.01	0.00	0.00	190.00	1232.11
Aberdeen	AB-2	1369.01	0.00	0.00	190.00	1232.11
Aberdeen	AB-3	0.00	0.00	0.00	0.00	0.00
Aberdeen	AB-4	1369.01	0.00	0.00	190.00	1232.11
Aberdeen	AB-5	1369.01	0.00	0.00	190.00	1232.11
Aberdeen	AB-6	0.00	0.00	0.00	0.00	0.00
Baldwin	BD-1	2418.59	0.00	0.00	336.00	2176.73
Baldwin	BD-2	2418.59	0.00	0.00	336.00	2176.73
Bartonville	BA-1	1369.01	0.00	0.00	190.00	1232.11
Bartonville	BA-2	1369.01	0.00	0.00	190.00	1232.11
Bartonville	BA-3	1369.01	0.00	0.00	190.00	1232.11
Bartonville	BA-4	1369.01	0.00	0.00	190.00	1232.11
Bartonville	BA-5	0.00	0.00	0.00	0.00	0.00
Bartonville	BA-6	0.00	0.00	0.00	0.00	0.00
Bartonville	BA-7	1369.01	0.00	0.00	190.00	1232.11
Caroline	CA-2	0.00	0.00	0.00	0.00	0.00
Caroline	CA-3	1369.01	0.00	0.00	190.00	1232.11
Caroline	CA-4	1369.01	0.00	0.00	190.00	1232.11
Caroline	CA-5	0.00	0.00	0.00	0.00	0.00
Caroline	CA-6	0.00	0.00	0.00	0.00	0.00
Caroline	CA-7	0.00	0.00	0.00	0.00	0.00
Caroline	CA-8	0.00	0.00	0.00	0.00	0.00
Central	CE-1	1369.01	0.00	0.00	190.00	1232.11
Central	CE-2	1369.01	0.00	0.00	190.00	1232.11
Central	CE-3	1369.01	0.00	0.00	190.00	1232.11
Central	CE-4	1369.01	0.00	0.00	190.00	1232.11
Central	CE-5	1369.01	0.00	0.00	190.00	1232.11
Central	CE-6	1369.01	0.00	0.00	190.00	1232.11
Central	CE-8	1369.01	0.00	0.00	190.00	1232.11
Central	CE-9	0.00	0.00	0.00	0.00	0.00
Central	CE-10	1369.01	0.00	0.00	190.00	1232.11
Central	CE-11	1369.01	0.00	0.00	190.00	1232.11
Cope	CP-1	1369.01	0.00	0.00	190.00	1232.11
Cope	CP-2	1369.01	0.00	0.00	190.00	1232.11
Cope	CP-3	1369.01	0.00	0.00	190.00	1232.11
Cope	CP-4	1369.01	0.00	0.00	190.00	1232.11
Cope	CP-5	1369.01	0.00	0.00	190.00	1232.11
Cope	CP-6	1369.01	0.00	0.00	190.00	1232.11
Cope	CP-7	1369.01	0.00	0.00	190.00	1232.11
Cope	CP-8	1369.01	0.00	0.00	190.00	1232.11
Cope	CP-9	1369.01	0.00	0.00	190.00	1232.11
Deerhurst	DH-1	2738.03	0.00	0.00	190.00	2464.22
Deerhurst	DH-2	2738.03	0.00	0.00	190.00	2464.22

Station	Feeder	Generation Capacity (kVA)	Existing Generation (A)	Existing Generation (kVA)	Available Generation Capacity (A)	Available Generation Capacity (kW)
Deerhurst	DH-3	2738.03	0.00	0.00	190.00	2464.22
Dewitt	DW-1	4837.18	0.00	0.00	336.00	4353.46
Dewitt	DW-2	4837.18	0.00	0.00	336.00	4353.46
Dewitt	DW-3	4837.18	0.00	0.00	336.00	4353.46
Eastmount	EA-1	1369.01	0.00	0.00	190.00	1232.11
Eastmount	EA-2	1369.01	0.00	0.00	190.00	1232.11
Eastmount	EA-3	1369.01	0.00	0.00	190.00	1232.11
Eastmount	EA-4	1369.01	0.00	0.00	190.00	1232.11
Eastmount	EA-6	1369.01	0.00	0.00	190.00	1232.11
Eastmount	EA-7	1369.01	0.00	0.00	190.00	1232.11
Eastmount	EA-8	1369.01	0.00	0.00	190.00	1232.11
Eastmount	EA-9	1369.01	0.00	0.00	190.00	1232.11
Eastmount	EA-10	1369.01	0.00	0.00	190.00	1232.11
Eastmount	EA-11	1369.01	0.00	0.00	190.00	1232.11
Elmwood	EL-2	1369.01	0.00	0.00	190.00	1232.11
Elmwood	EL-3	1369.01	0.00	0.00	190.00	1232.11
Elmwood	EL-4	1369.01	0.00	0.00	190.00	1232.11
Elmwood	EL-5	0.00	0.00	0.00	0.00	0.00
Elmwood	EL-7	1369.01	0.00	0.00	190.00	1232.11
Elmwood	EL-8	1369.01	0.00	0.00	190.00	1232.11
Elmwood	EL-9	1369.01	0.00	0.00	190.00	1232.11
Elmwood	EL-10	1369.01	0.00	0.00	190.00	1232.11
Galbraith	GA-1	1916.62	0.00	0.00	133.00	1724.96
Galbraith	GA-2	1916.62	0.00	0.00	133.00	1724.96
Galbraith	GA-3	1916.62	0.00	0.00	133.00	1724.96
Highland	HI-1	1369.01	0.00	0.00	190.00	1232.11
Highland	HI-2	1369.01	0.00	0.00	190.00	1232.11
Highland	HI-3	1369.01	0.00	0.00	190.00	1232.11
Hughson	HU-2	0.00	0.00	0.00	0.00	0.00
Hughson	HU-4	0.00	0.00	0.00	0.00	0.00
Hughson	HU-5	0.00	0.00	0.00	0.00	0.00
Hughson	HU-6	0.00	0.00	0.00	0.00	0.00
Hughson	HU-7	0.00	0.00	0.00	0.00	0.00
Hughson	HU-8	0.00	0.00	0.00	0.00	0.00
Hughson	HU-9	0.00	0.00	0.00	0.00	0.00
Hughson	HU-10	0.00	0.00	0.00	0.00	0.00
Hughson	HU-11	0.00	0.00	0.00	0.00	0.00
Hughson	HU-12	0.00	0.00	0.00	0.00	0.00
John	JN-1	2418.59	0.00	0.00	336.00	2176.73
John	JN-2	2418.59	0.00	0.00	336.00	2176.73
Kenilworth	KE-1	1369.01	0.00	0.00	190.00	1232.11
Kenilworth	KE-2	1369.01	0.00	0.00	190.00	1232.11
Kenilworth	KE-3	1369.01	0.00	0.00	190.00	1232.11

Station	Feeder	Generation Capacity (kVA)	Existing Generation (A)	Existing Generation (kVA)	Available Generation Capacity (A)	Available Generation Capacity (kW)
Kenilworth	KE-4	1369.01	0.00	0.00	190.00	1232.11
Kenilworth	KE-5	1369.01	0.00	0.00	190.00	1232.11
Kenilworth	KE-6	1369.01	0.00	0.00	190.00	1232.11
Mohawk	MK-1	1369.01	0.00	0.00	190.00	1232.11
Mohawk	MK-2	1369.01	0.00	0.00	190.00	1232.11
Mohawk	MK-3	1369.01	0.00	0.00	190.00	1232.11
Mohawk	MK-5	1369.01	0.00	0.00	190.00	1232.11
Mohawk	MK-6	1369.01	0.00	0.00	190.00	1232.11
Mohawk	MK-9	1369.01	0.00	0.00	190.00	1232.11
Mohawk	MK-10	1369.01	0.00	0.00	190.00	1232.11
Mohawk	MK-11	1369.01	0.00	0.00	190.00	1232.11
Mountain	MT-2	1369.01	0.00	0.00	190.00	1232.11
Mountain	MT-3	1369.01	0.00	0.00	190.00	1232.11
Mountain	MT-4	1369.01	0.00	0.00	190.00	1232.11
Mountain	MT-5	1369.01	0.00	0.00	190.00	1232.11
Mountain	MT-6	1369.01	0.00	0.00	190.00	1232.11
Mountain	MT-9	1369.01	0.00	0.00	190.00	1232.11
Mountain	MT-10	1369.01	0.00	0.00	190.00	1232.11
Mountain	MT-11	0.00	0.00	0.00	0.00	0.00
Ottawa	OT-1	1369.01	0.00	0.00	190.00	1232.11
Ottawa	OT-2	1369.01	0.00	0.00	190.00	1232.11
Ottawa	OT-3	1369.01	0.00	0.00	190.00	1232.11
Ottawa	OT-4	1369.01	0.00	0.00	190.00	1232.11
Ottawa	OT-5	1369.01	0.00	0.00	190.00	1232.11
Ottawa	OT-6	0.00	0.00	0.00	0.00	0.00
Ottawa	OT-7	1369.01	0.00	0.00	190.00	1232.11
Ottawa	OT-8	1369.01	0.00	0.00	190.00	1232.11
Parkdale	PA-F1	1369.01	0.00	0.00	190.00	1232.11
Parkdale	PA-F2	1369.01	0.00	0.00	190.00	1232.11
Parkdale	PA-F3	1369.01	0.00	0.00	190.00	1232.11
Parkdale	PA-F4	1369.01	0.00	0.00	190.00	1232.11
Parkdale	PA-F5	1369.01	0.00	0.00	190.00	1232.11
Parkdale	PA-F6	1369.01	0.00	0.00	190.00	1232.11
Parkdale	PA-F7	1369.01	0.00	0.00	190.00	1232.11
Parkdale	PA-F8	0.00	0.00	0.00	0.00	0.00
Spadina	SP-1	1369.01	0.00	0.00	190.00	1232.11
Spadina	SP-2	1369.01	0.00	0.00	190.00	1232.11
Spadina	SP-3	1369.01	0.00	0.00	190.00	1232.11
Spadina	SP-4	1369.01	0.00	0.00	190.00	1232.11
Spadina	SP-5	1369.01	0.00	0.00	190.00	1232.11
Spadina	SP-6	1369.01	0.00	0.00	190.00	1232.11
Spadina	SP-7	0.00	0.00	0.00	0.00	0.00
Strouds	ST-2	1369.01	0.00	0.00	190.00	1232.11

Station	Feeder	Generation Capacity (kVA)	Existing Generation (A)	Existing Generation (kVA)	Available Generation Capacity (A)	Available Generation Capacity (kW)
Strouds	ST-3	1369.01	0.00	0.00	190.00	1232.11
Strouds	ST-4	1369.01	0.00	0.00	190.00	1232.11
Strouds	ST-6	1369.01	0.00	0.00	190.00	1232.11
Strouds	ST-7	1369.01	0.00	0.00	190.00	1232.11
Webster						0.00
Wellington	WL-1	1369.01	0.00	0.00	190.00	1232.11
Wellington	WL-2	1369.01	0.00	0.00	190.00	1232.11
Wellington	WL-3	1369.01	0.00	0.00	190.00	1232.11
Wellington	WL-4	1369.01	0.00	0.00	190.00	1232.11
Wellington	WL-5	1369.01	0.00	0.00	190.00	1232.11
Wellington	WL-6	1369.01	0.00	0.00	190.00	1232.11
Wellington	WL-8	1369.01	0.00	0.00	190.00	1232.11
Wellington	WL-9	1369.01	0.00	0.00	190.00	1232.11
Wellington	WL-10	1369.01	0.00	0.00	190.00	1232.11
Wellington	WL-11	1369.01	0.00	0.00	190.00	1232.11
Wentworth	WT-1	1369.01	0.00	0.00	190.00	1232.11
Wentworth	WT-2	1369.01	0.00	0.00	190.00	1232.11
Wentworth	WT-3	1369.01	0.00	0.00	190.00	1232.11
Wentworth	WT-4	1369.01	0.00	0.00	190.00	1232.11
Wentworth	WT-5	1369.01	0.00	0.00	190.00	1232.11
Wentworth	WT-6	1369.01	0.00	0.00	190.00	1232.11
Wentworth	WT-8	1369.01	0.00	0.00	190.00	1232.11
Wentworth	WT-9	1369.01	0.00	0.00	190.00	1232.11
Wentworth	WT-10	1369.01	0.00	0.00	190.00	1232.11
Wentworth	WT-11	1369.01	0.00	0.00	190.00	1232.11
Wentworth	WT-12	1369.01	0.00	0.00	190.00	1232.11
Whitney	WH-1	1369.01	0.00	0.00	190.00	1232.11
Whitney	WH-2	1369.01	0.00	0.00	190.00	1232.11
Whitney	WH-3	1369.01	0.00	0.00	190.00	1232.11
Whitney	WH-4	1369.01	0.00	0.00	190.00	1232.11
Whitney	WH-5	1369.01	0.00	0.00	190.00	1232.11
Whitney	WH-6	1369.01	0.00	0.00	190.00	1232.11
York	YK-1	2418.59	0.00	0.00	336.00	2176.73
York	YK-2	1232.11	0.00	0.00	171.00	1108.90

Table 5: 13.8kV and 27.6kV Generation Availability

Station	Bus	Breaker	Feeder	Voltage	Generation Capacity (MVA)	Existing Generation (MVA)	Available Generation Capacity (MW)
Beach	B1B2	M11	7111SC	13.86	4.56	0.00	4.11
Beach	B1B2	M12	7121SC	13.86	4.56	0.00	4.11
Beach	B1B2	M13	7131CW	13.86	4.56	0.00	4.11
Beach	B1B2	M14	7141F	13.86	4.56	0.00	4.11
Beach	B1B2	M14	7142F	13.86	4.56	0.00	4.11
Beach	B1B2	M21	7211F	13.86	4.56	0.00	4.11
Beach	B1B2	M21	7212F	13.86	4.56	0.00	4.11
Beach	B1B2	M22	7222CW	13.86	4.56	0.00	4.11
Beach	B1B2	M23	7231SC	13.86	4.56	0.00	4.11
Beach	B1B2	M24	7241SC	13.86	4.56	0.00	4.11
Beach	Y1Y2	M51	7511P	13.86	4.56	0.00	4.11
Beach	Y1Y2	M52	7521X	13.86	4.56	0.00	4.11
Beach	Y1Y2	M53	7531X	13.86	4.56	0.00	4.11
Beach	Y1Y2	M53	7532OL	13.86	4.56	0.00	4.11
Beach	Y1Y2	M54	7541SC	13.86	4.56	0.00	4.11
Beach	Y1Y2	M54	7542PE	13.86	4.56	0.00	4.11
Beach	Y1Y2	M61	7611X	13.86	4.56	0.00	4.11
Beach	Y1Y2	M62	7621X	13.86	4.56	0.00	4.11
Beach	Y1Y2	M62	7622IM	13.86	4.56	0.00	4.11
Beach	Y1Y2	M63	7631X	13.86	4.56	0.00	4.11
Beach	Y1Y2	M64	7641P	13.86	4.56	0.00	4.11
Beach	J1J2	M71	7711DF	13.86	0.00	0.00	0.00
Beach	J1J2	M71	7712DF	13.86	0.00	0.00	0.00
Beach	J1J2	M72	7722X	13.86	4.56	1.25	2.98
Beach	J1J2	M73	7731X	13.86	4.56	0.00	4.11
Beach	J1J2	M74	7741S	13.86	4.56	2.00	2.31
Beach	J1J2	M74	7742X	13.86	4.56	0.00	4.11
Beach	J1J2	M81	7811DF	13.86	4.56	0.00	4.11
Beach	J1J2	M81	7812X	13.86	4.56	0.00	4.11
Beach	J1J2	M82	7821X	13.86	4.56	1.25	2.98
Beach	J1J2	M82	7822X	13.86	4.56	0.00	4.11
Beach	J1J2	M83	7831BP	13.86	4.56	0.00	4.11
Beach	J1J2	M83	7832X	13.86	4.56	0.00	4.11
Beach	J1J2	M84	7841S	13.86	4.56	2.00	2.31
Beach	J1J2	M84	7842X	13.86	4.56	0.00	4.11
Beach	Q1Q2	M31	7311B	13.86	4.56	0.00	4.11
Beach	Q1Q2	M32	7321X	13.86	4.56	0.35	3.79
Beach	Q1Q2	M33	7331CP	13.86	4.56	0.00	4.11
Beach	Q1Q2	M34	7341X	13.86	4.56	0.00	4.11
Beach	Q1Q2	M34	7342X	13.86	4.56	0.00	4.11
Beach	Q1Q2	M41	7411X	13.86	4.56	0.00	4.11
Beach	Q1Q2	M42	7421X	13.86	4.56	0.00	4.11

Station	Bus	Breaker	Feeder	Voltage	Generation Capacity (MVA)	Existing Generation (MVA)	Available Generation Capacity (MW)
Beach	Q1Q2	M43	7431CP	13.86	4.56	0.00	4.11
Beach	Q1Q2	M43	7432X	13.86	4.56	0.00	4.11
Beach	Q1Q2	M44	7441X	13.86	4.56	0.00	4.11
Birmingham	BY	M21	50L21	13.86	19.77	0.00	17.79
Birmingham	BY	M22	50L22	13.86	19.77	0.00	17.79
Birmingham	QJ	M3	50X32	13.86	3.80	0.00	3.42
Birmingham	QJ	M1	50B12	13.86	4.56	0.00	4.11
Birmingham	QJ	M1	50PG11	13.86	4.56	0.00	4.11
Birmingham	QJ	M2	50PG21	13.86	4.56	0.00	4.11
Birmingham	QJ	M2	50X22	13.86	4.56	0.00	4.11
Birmingham	QJ	M4	50X41	13.86	4.56	0.00	4.11
Birmingham	QJ	M4	50X42	13.86	4.56	0.00	4.11
Birmingham	QJ	M5	50X51	13.86	4.56	0.00	4.11
Birmingham	QJ	M5	50X52	13.86	4.56	0.00	4.11
Birmingham	QJ	M6	50X61	13.86	4.56	0.00	4.11
Birmingham	QJ	M7	50X71	13.86	4.56	0.00	4.11
Birmingham	QJ	M8	50X81	13.86	4.56	0.25	3.88
Birmingham	DK	M71	50L71	13.86	19.77	0.00	17.79
Birmingham	DK	M81	50L81	13.86	19.77	0.00	17.79
Birmingham	EZ	M10	50DC101	13.86	19.77	0.00	17.79
Birmingham	EZ	M11	50L11	13.86	19.77	0.00	17.79
Birmingham	EZ	M14	50L14	13.86	19.77	0.00	17.79
Dundas	BY	M6	2D6X	27.60	16.05	0.00	14.44
Dundas	BY	M7	2D7X	27.60	16.05	0.00	14.44
Dundas	BY	M1	2D1X	27.60	22.10	0.00	19.89
Dundas	BY	M2	2D2X	27.60	22.10	0.00	19.89
Dundas	QJ	M11	2D11X	27.60	17.14	0.00	15.42
Dundas	QJ	M12	2D12X	27.60	17.14	0.85	14.66
Dundas	QJ	M13	2D13X	27.60	17.14	0.25	15.20
Dundas	QJ	M14	2D14X	27.60	17.14	0.01	15.41
Elgin	DK	M41	5411X	13.86	4.56	0.00	4.11
Elgin	DK	M41	5412X	13.86	4.56	1.00	3.21
Elgin	DK	M42	5421X	13.86	4.56	0.00	4.11
Elgin	DK	M42	5422X	13.86	4.56	0.00	4.11
Elgin	DK	M43	5431X	13.86	4.56	0.00	4.11
Elgin	DK	M44	5441X	13.86	4.56	0.00	4.11
Elgin	DK	M44	5442X	13.86	4.56	0.00	4.11
Elgin	DK	M45	5451X	13.86	4.56	0.00	4.11
Elgin	DK	M45	5452X	13.86	4.56	0.00	4.11
Elgin	DK	M46	5461X	13.86	4.56	0.00	4.11
Elgin	DK	M46	5462BC	13.86	4.56	1.00	3.21
Elgin	DK	M47	5471C	13.86	4.56	0.00	4.11
Elgin	DK	M47	5472X	13.86	4.56	0.00	4.11
Elgin	DK	M48	5481X	13.86	4.56	0.00	4.11

Station	Bus	Breaker	Feeder	Voltage	Generation Capacity (MVA)	Existing Generation (MVA)	Available Generation Capacity (MW)
Elgin	QJ	M22	5221C	13.86	4.56	0.00	4.11
Elgin	QJ	M23	5231X	13.86	3.80	0.04	3.39
Elgin	QJ	M24	5241CU	13.86	4.56	4.38	0.17
Elgin	QJ	M25	5251X	13.86	4.56	0.00	4.11
Elgin	QJ	M26	5261X	13.86	4.56	4.38	0.17
Elgin	QJ	M27	5271X	13.86	4.56	0.00	4.11
Elgin	QJ	M28	5281X	13.86	4.56	0.00	4.11
Elgin	QJ	M30	5301X	13.86	4.56	0.00	4.11
Elgin	QJ	M31	5311CU	13.86	4.56	4.38	0.17
Elgin	QJ	M32	5321X	13.86	4.56	0.00	4.11
Elgin	QJ	M33	5331X	13.86	4.56	0.00	4.11
Elgin	QJ	M34	5341X	13.86	4.56	0.00	4.11
Elgin	EZ	M51	5511X	13.86	4.56	0.00	4.11
Elgin	EZ	M51	5512HG	13.86	4.56	0.00	4.11
Elgin	EZ	M52	5521X	13.86	4.56	0.00	4.11
Elgin	EZ	M52	5522X	13.86	4.56	0.00	4.11
Elgin	EZ	M53	5531SJ	13.86	4.56	0.00	4.11
Elgin	EZ	M53	5532SJ	13.86	4.56	0.00	4.11
Elgin	EZ	M61	5611X	13.86	4.56	0.00	4.11
Elgin	EZ	M61	5612X	13.86	4.56	0.00	4.11
Elgin	EZ	M62	5612X	13.86	4.56	6.56	-1.80
Elgin	EZ	M62	5622X	13.86	4.56	6.56	-1.80
Elgin	EZ	M63	5631X	13.86	4.56	0.00	4.11
Elgin	EZ	M63	5632X	13.86	4.56	0.00	4.11
Gage	ZY	M13	M13	13.86	8.36	0.00	7.53
Gage	ZY	M15	M15	13.86	11.40	0.00	10.26
Gage	ZY	M16	M16	13.86	11.40	0.00	10.26
Gage	ZY	M17	M17	13.86	15.20	0.00	13.68
Gage	ZY	M19	M19	13.86	15.20	0.00	13.68
Gage	ZY	M20	M20	13.86	15.20	0.00	13.68
Gage	DJ	M23	M23	13.86	15.20	0.00	13.68
Gage	DJ	M24	M24	13.86	15.20	0.00	13.68
Gage	DJ	M26	M26	13.86	15.20	0.00	13.68
Gage	DJ	M27	M27	13.86	22.81	0.00	20.53
Gage	KE	M37	M37	13.86	7.60	0.00	6.84
Gage	KE	M38	M38	13.86	7.60	0.00	6.84
Gage	KE	M32	M32	13.86	11.40	0.00	10.26
Gage	KE	M33	M33	13.86	11.40	0.00	10.26
Gage	KE	M35	M35	13.86	12.16	0.00	10.95
Gage	KE	M36	M36	13.86	12.16	0.00	10.95
Gage	KE	M34	M34	13.86	13.68	0.00	12.32
Gage	KE	M39	M39	13.86	13.68	0.00	12.32
Gage	KE	M40	M40	13.86	13.68	0.00	12.32
Gage	KE	M31	M31	13.86	18.25	0.00	16.42

Station	Bus	Breaker	Feeder	Voltage	Generation Capacity (MVA)	Existing Generation (MVA)	Available Generation Capacity (MW)
Horning	B1B2	M2	421X	13.86	4.56	0.00	4.11
Horning	B1B2	M3	431X	13.86	4.56	0.00	4.11
Horning	B1B2	M4	441X	13.86	4.56	0.00	4.11
Horning	B1B2	M5	451X	13.86	4.56	0.00	4.11
Horning	B1B2	M6	461EL	13.86	4.56	0.00	4.11
Horning	B1B2	M6	462X	13.86	4.56	0.00	4.11
Horning	B1B2	M7	471X	13.86	4.56	0.00	4.11
Horning	B1B2	M8	481X	13.86	4.56	0.00	4.11
Horning	B1B2	M9	491X	13.86	4.56	0.00	4.11
Horning	B1B2	M9	492X	13.86	4.56	0.00	4.11
Horning	B1B2	M10	4101X	13.86	4.56	0.00	4.11
Horning	B1B2	M10	4102X	13.86	4.56	0.00	4.11
Horning	B1B2	M11	4111X	13.86	4.56	0.00	4.11
Horning	Q1Q2	M45	4451X	13.86	4.56	0.00	4.11
Horning	Q1Q2	M46	4461X	13.86	4.56	0.00	4.11
Horning	Q1Q2	M46	4462SJ	13.86	4.56	0.00	4.11
Horning	Q1Q2	M47	4471X	13.86	4.56	0.00	4.11
Horning	Q1Q2	M48	4481X	13.86	4.56	0.00	4.11
Horning	Q1Q2	M49	4491X	13.86	4.56	0.00	4.11
Horning	Q1Q2	M50	4501X	13.86	4.56	0.00	4.11
Kenilworth	DK	Decommissioned		13.86	13.86	0.00	0.00
Kenilworth	EJ	M20	9201O	13.86	4.56	0.00	4.11
Kenilworth	EJ	M21	9211O	13.86	4.56	0.00	4.11
Kenilworth	EJ	M22	9221K	13.86	4.56	0.00	4.11
Kenilworth	EJ	M23	9231K	13.86	4.56	0.00	4.11
Kenilworth	EJ	M25	9251N	13.86	4.56	0.00	4.11
Kenilworth	EJ	M26	9261N	13.86	4.56	0.00	4.11
Kenilworth	EJ	M27	9271X	13.86	4.56	0.00	4.11
Kenilworth	EJ	M27	9281X	13.86	4.56	0.00	4.11
Kenilworth	EJ	M29	9291X	13.86	4.56	0.00	4.11
Kenilworth	EJ	M30	9301N	13.86	4.56	0.00	4.11
Kenilworth	BY	M54	M54	13.86	9.12	0.00	8.21
Kenilworth	BY	M64	M64	13.86	9.12	0.00	8.21
Kenilworth	BY	M51	M51	13.86	18.25	0.00	16.42
Kenilworth	BY	M52	M52	13.86	18.25	0.00	16.42
Kenilworth	BY	M53	M53	13.86	18.25	0.00	16.42
Kenilworth	BY	M61	M61	13.86	18.25	0.00	16.42
Kenilworth	BY	M62	M62	13.86	18.25	0.00	16.42
Kenilworth	BY	M63	M63	13.86	18.25	0.00	16.42
Lake	BY	M1	111X	27.60	19.07	0.00	17.17
Lake	BY	M2	121X	27.60	19.07	0.00	17.17
Lake	BY	M3	131X	27.60	19.07	0.00	17.17
Lake	BY	M4	141X	27.60	19.07	0.00	17.17

Station	Bus	Breaker	Feeder	Voltage	Generation Capacity (MVA)	Existing Generation (MVA)	Available Generation Capacity (MW)
Lake	BY	M5	151X	27.60	19.07	0.00	17.17
Lake	BY	M6	161X	27.60	19.07	0.00	17.17
Lake	J1J2	M31	1311X	13.86	4.56	0.00	4.11
Lake	J1J2	M32	1321X	13.86	4.56	0.00	4.11
Lake	J1J2	M33	1331X	13.86	4.56	0.00	4.11
Lake	J1J2	M41	1411X	13.86	4.56	0.32	3.82
Lake	J1J2	M41	1412X	13.86	4.56	0.25	3.88
Lake	J1J2	M42	1421X	13.86	4.56	0.00	4.11
Lake	J1J2	M42	1422X	13.86	4.56	0.00	4.11
Lake	J1J2	M43	1431X	13.86	4.56	0.00	4.11
Lake	Q1Q2	M71	1711X	13.86	4.56	0.00	4.11
Lake	Q1Q2	M71	1712X	13.86	4.56	0.00	4.11
Lake	Q1Q2	M72	1721X	13.86	4.56	0.00	4.11
Lake	Q1Q2	M72	1722X	13.86	4.56	0.00	4.11
Lake	Q1Q2	M73	1731X	13.86	4.56	0.00	4.11
Lake	Q1Q2	M81	1811X	13.86	4.56	0.07	4.04
Lake	Q1Q2	M81	1812X	13.86	4.56	0.00	4.11
Lake	Q1Q2	M82	1821X	13.86	4.56	0.00	4.11
Lake	Q1Q2	M82	1822X	13.86	4.56	0.00	4.11
Lake	Q1Q2	M83	1831X	13.86	4.56	0.00	4.11
Lake	Q1Q2	M83	1832X	13.86	4.56	0.00	4.11
Mohawk	B1B2	M51	0511X	13.86	4.56	0.00	4.11
Mohawk	B1B2	M51	0512X	13.86	4.56	0.00	4.11
Mohawk	B1B2	M52	0521EA	13.86	4.56	0.00	4.11
Mohawk	B1B2	M52	0522WL	13.86	4.56	0.00	4.11
Mohawk	B1B2	M53	0531X	13.86	4.56	0.00	4.11
Mohawk	B1B2	M53	0532X	13.86	4.56	1.01	3.19
Mohawk	B1B2	M61	0611X	13.86	4.56	0.00	4.11
Mohawk	B1B2	M61	0612X	13.86	4.56	0.00	4.11
Mohawk	B1B2	M62	0621LM	13.86	4.56	0.00	4.11
Mohawk	B1B2	M62	0622X	13.86	4.56	1.01	3.19
Mohawk	B1B2	M63	0631WL	13.86	4.56	0.00	4.11
Mohawk	B1B2	M63	0632MK	13.86	4.56	0.00	4.11
Mohawk	B1B2	M64	0641X	13.86	4.56	0.00	4.11
Mohawk	B1B2	M64	0642X	13.86	4.56	0.00	4.11
Mohawk	Y1Y2	M71	0711X	13.86	4.56	0.00	4.11
Mohawk	Y1Y2	M71	0712WL	13.86	4.56	0.00	4.11
Mohawk	Y1Y2	M72	0721X	13.86	4.56	0.00	4.11
Mohawk	Y1Y2	M72	0722X	13.86	4.56	1.01	3.19
Mohawk	Y1Y2	M73	0731X	13.86	4.56	0.00	4.11
Mohawk	Y1Y2	M73	0732EA	13.86	4.56	0.00	4.11
Mohawk	Y1Y2	M81	0811MK	13.86	4.56	0.00	4.11
Mohawk	Y1Y2	M81	0812X	13.86	4.56	0.00	4.11
Mohawk	Y1Y2	M82	0821X	13.86	4.56	0.00	4.11

Station	Bus	Breaker	Feeder	Voltage	Generation Capacity (MVA)	Existing Generation (MVA)	Available Generation Capacity (MW)
Mohawk	Y1Y2	M82	0822WL	13.86	4.56	0.00	4.11
Mohawk	Y1Y2	M83	0831M	13.86	4.56	0.00	4.11
Mohawk	Y1Y2	M83	0832X	13.86	4.56	0.00	4.11
Nebo	BY	M3	331X	27.60	19.07	0.00	17.17
Nebo	BY	M4	341X	27.60	19.07	0.00	17.17
Nebo	QJ	M51	3511X	13.86	4.56	0.00	4.11
Nebo	QJ	M51	3512X	13.86	4.56	0.00	4.11
Nebo	QJ	M52	3521X	13.86	4.56	0.25	3.88
Nebo	QJ	M53	3531X	13.86	4.56	0.00	4.11
Nebo	QJ	M53	3532X	13.86	4.56	0.00	4.11
Nebo	QJ	M54	3541X	13.86	4.56	0.20	3.93
Nebo	QJ	M61	3611X	13.86	4.56	0.00	4.11
Nebo	QJ	M61	3612X	13.86	4.56	0.00	4.11
Nebo	QJ	M62	3621X	13.86	4.56	0.00	4.11
Nebo	QJ	M63	3631X	13.86	4.56	0.14	3.98
Nebo	QJ	M63	3632X	13.86	4.56	0.00	4.11
Nebo	QJ	M64	3641X	13.86	4.56	0.00	4.11
Nebo	QJ	M64	3642X	13.86	4.56	0.00	4.11
Newton	B	M1	211SL	13.86	4.56	0.00	4.11
Newton	B	M1	212X	13.86	4.56	0.00	4.11
Newton	B	M3	231X	13.86	4.56	0.00	4.11
Newton	B	M3	232X	13.86	4.56	0.28	3.86
Newton	B	M6	261SL	13.86	4.56	0.00	4.11
Newton	B	M6	262X	13.86	4.56	0.00	4.11
Newton	B	M8	281X	13.86	4.56	0.00	4.11
Newton	B	M8	282X	13.86	4.56	0.25	3.88
Newton	B	M10	2101C	13.86	4.56	0.00	4.11
Newton	Y	M2	221CA	13.86	4.56	0.00	4.11
Newton	Y	M2	222X	13.86	4.56	0.00	4.11
Newton	Y	M4	241X	13.86	4.56	0.00	4.11
Newton	Y	M4	242X	13.86	4.56	0.00	4.11
Newton	Y	M5	251A	13.86	4.56	0.00	4.11
Newton	Y	M5	252X	13.86	4.56	0.00	4.11
Newton	Y	M7	271X	13.86	4.56	0.00	4.11
Newton	Y	M9	291X	13.86	4.56	0.00	4.11
Newton	Y	M9	292X	13.86	4.56	0.00	4.11
Stirton	BY	M71	8711X	13.86	3.80	0.00	3.42
Stirton	BY	M72	8721X	13.86	3.80	0.00	3.42
Stirton	BY	M76	8762G	13.86	3.80	0.00	3.42
Stirton	BY	M83	8832X	13.86	3.80	0.00	3.42
Stirton	BY	M85	8852X	13.86	3.80	0.00	3.42
Stirton	BY	M71	8712W	13.86	4.56	0.00	4.11
Stirton	BY	M72	8722W	13.86	4.56	0.00	4.11
Stirton	BY	M75	8751WC	13.86	4.56	0.00	4.11

Station	Bus	Breaker	Feeder	Voltage	Generation Capacity (MVA)	Existing Generation (MVA)	Available Generation Capacity (MW)
Stirton	BY	M81	8811X	13.86	4.56	0.00	4.11
Stirton	BY	M82	8821DG	13.86	4.56	0.00	4.11
Stirton	BY	M83	8831W	13.86	4.56	0.00	4.11
Stirton	BY	M84	8841W	13.86	4.56	0.00	4.11
Stirton	BY	M84	8842X	13.86	4.56	0.00	4.11
Stirton	BY	M86	8862X	13.86	4.56	0.00	4.11
Stirton	QZ	M51	8511X	13.86	4.56	0.00	4.11
Stirton	QZ	M62	8621X	13.86	3.80	8.75	-4.45
Stirton	QZ	M52	8521S	13.86	4.56	0.00	4.11
Stirton	QZ	M53	8531S	13.86	4.56	0.00	4.11
Stirton	QZ	M54	8541X	13.86	4.56	0.00	4.11
Stirton	QZ	M54	8542X	13.86	4.56	0.00	4.11
Stirton	QZ	M61	8611S	13.86	4.56	0.00	4.11
Stirton	QZ	M63	8631X	13.86	4.56	0.00	4.11
Stirton	QZ	M64	8641S	13.86	4.56	0.00	4.11
Stirton	QZ	M64	8642WC	13.86	4.56	0.00	4.11
Winona	QJ	M11	W11X	27.60	17.14	0.00	15.42
Winona	QJ	M12	W12X	27.60	17.14	2.36	13.30
Winona	QJ	M13	W13X	27.60	17.14	0.00	15.42
Winona	QJ	M14	W14X	27.60	17.14	0.90	14.61
Winona	QJ	M15	W15X	27.60	17.14	0.10	15.33
Winona	QJ	M16	W16X	27.60	17.14	0.00	15.42

(d) System Constraints (5.4.3(d))

Horizon Utilities has three feeders which 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 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.

(e) Constraints for Embedded Distributor (5.4.3(e))

Horizon Utilities receives electricity from the Hydro One distribution system at certain delivery points, rather than from the IESO-controlled grid. Horizon Utilities' Hamilton service area is partially embedded in the Hydro One distribution system in the vicinities of Ancaster, Dundas, Flamborough, and Stoney Creek. These are former municipalities that now form part of the City of Hamilton following a municipal amalgamation in 2001; they are within the Horizon Utilities Hamilton service area. Horizon Utilities has no embedded distributors.

5. Conclusions

At this time, neither a Regional Infrastructure Plan, nor an Integrated Regional Resource Plan ("IRRP") has been initiated for the Horizon Utilities' service territory in the Niagara region.

However, within the Burlington to Nanticoke region, an IRRP is currently being developed for the Brant sub-region called the Brant IRRP. Horizon Utilities receives information and updates on regional planning for the Brant sub-region, although it has not been directly impacted by the supply issues associated with the Brant area.

As part of the regional planning process, a "Needs Screening" assessment for the Burlington to Nanticoke region has also been initiated. The OPA confirms that Horizon Utilities is actively participating in planning meetings, consultations and regional planning initiatives with the OPA, LDCs and Hydro One Networks Inc.

With respect to the OPA commenting on the consistency of planned REG Investments to regional plans, Horizon Utilities' Plan indicates that it has sufficient capacity to accommodate the amount of forecasted renewable energy generation identified in its 5-year Distribution System Plan, and that no REG investments will be required over this time period.

Attachment A: The Board's expectations for the OPA's comment letter

On March 28, 2013, 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 "DS Plan Filing Requirements"). The Board's expectations for a letter of comment from the OPA are set out in Section 5.1.4.2 of the DS Plan Filing Requirements.

The OPA letter of comment will include:

- The applications it has received from renewable generators through the FIT program for connection in the distributor's service area;
- Whether the distributor has consulted with the OPA, or participated in planning meetings with the OPA;
- The potential need for co-ordination with other distributors and/or transmitters or others on implementing elements of the Renewable Energy Generation investments; and
- Whether the Renewable Energy Generation investments proposed in the DS Plan are consistent with any Regional Infrastructure Plan.

The Board identified in its DS Plan Filing Requirements that it may postpone processing an application where a comment letter from the OPA has not been filed in accordance with this requirement.

Attachment B: OPA Letter

OPA Letter of Comment

Horizon Utilities Corporation

Renewable Energy Generation Investments Plan





March 14, 2014

ONTARIO POWER AUTHORITY

Introduction

On March 28, 2013, the Ontario Energy Board ("the OEB" or "Board") issued its Filing Requirements for Electricity Transmission and Distribution Applications; Chapter 5 – Consolidated Distribution System Plan Filing Requirements (EB-2010-0377). Chapter 5 implements the Board's policy direction on 'an integrated approach to distribution network planning', outlined in the Board's October 18, 2012 Report of the Board - A Renewed Regulatory Framework for Electricity Distributors: A Performance Based Approach.

As outlined in the Chapter 5 filing requirements, the Board expects that the Ontario Power Authority ("OPA") comment letter will include:

- the applications it has received from renewable generators through the FIT program for connection in the distributor's service area;
- whether the distributor has consulted with the OPA, or participated in planning meetings with the OPA;
- the potential need for co-ordination with other distributors and/or transmitters or others on implementing elements of the REG investments; and
- whether the REG investments proposed in the DS Plan are consistent with any Regional Infrastructure Plan.

Horizon Utilities Corporation. – Distribution System Plan

On February 12, 2014 Horizon Utilities Corporation ("Horizon Utilities") provided the OPA with Appendix E – Renewable Energy Generation Investment Plan ("Plan"), which is part of its overall 5-year Distribution System Plan . The OPA has reviewed Horizon Utilities' Plan and has provided its comments below.

OPA FIT/microFIT Applications Received

In its Plan, Horizon Utilities indicates that since 2010 it has received 54 applications totalling 8,542 kW of capacity. Of these, 24 FIT projects totalling 3,568 kW of capacity have been connected to its distribution system. Horizon Utilities' Plan does not breakout the microFIT from FIT projects.

According to OPA's information, as of February 2014, the OPA has offered contracts to 58 FIT projects totalling 8,893 kW of capacity. The OPA has also offered contracts to 259 microFIT projects totalling approximately 3,096 kW of capacity in Horizon Utilities' distribution system, all of which remain active as of February 2014.

The OPA finds that Horizon Utilities' Plan is reasonably consistent with the OPA's information regarding renewable energy generation ("REG") applications to date. The slight difference in the number of applications is likely the result of different dates for data collection.

Ontario Power Authority
120 Adelaide Street West, Ste. 1600, Toronto, Ontario M5H 1T1 Tel 416 967-7474 Fax 416 967-1947 1-800-797-9604 Toll Free
info@powerauthority.on.ca www.powerauthority.on.ca

Consultation / Participation in Planning Meetings; Coordination with Distributors / Transmitters / Others; Consistency with Regional Plans

The OPA notes that Horizon Utilities is part of the "Group 1" - Burlington to Nanticoke region, and the "Group 3" - Niagara region, for regional planning purposes.

At this time, neither a Regional Infrastructure Plan, nor an Integrated Regional Resource Plan ("IRRP") has been initiated for the Horizon Utilities' service territory in the Niagara region.

However, within the Burlington to Nanticoke region, an IRRP is currently being developed for the Brant sub-region called the Brant IRRP. Horizon Utilities receives information and updates on regional planning for the Brant sub-region, although it has not been directly impacted by the supply issues associated with the Brant area.

As part of the regional planning process, a "Needs Screening" assessment for the Burlington to Nanticoke region has also been initiated. The OPA confirms that Horizon Utilities is actively participating in planning meetings, consultations and regional planning initiatives with the OPA, LDCs and Hydro One Networks Inc.

With respect to the OPA commenting on the consistency of planned REG Investments to regional plans, Horizon Utilities' Plan indicates that it has sufficient capacity to accommodate the amount of forecasted renewable energy generation identified in its 5-year Distribution System Plan, and that no REG investments will be required over this time period.

The OPA looks forward to working further with Horizon Utilities Corporation throughout the regional planning process for these areas, and appreciates the opportunity to comment on the information provided as part of its Distribution System Plan.

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Appendix F – 4kV and 8kV Renewal Program

Executive Summary

Horizon Utilities Corporation ("Horizon Utilities") distributes electricity to approximately 240,000 customers in the Hamilton and St. Catharines area. Of the entire customer base, 75,000 customers are served from the 4.16 kV and 8.32 kV voltage levels. The service area where these distribution assets are located was mainly constructed in the 1950s and these assets generally have a poor or very poor health index exposing Horizon to higher risk from failures. The aging infrastructure and changing distribution system standards makes it imperative to replace these assets. Prolonging to sustain this infrastructure will result in reliability levels continuing to degrade and unnecessarily increase capital and operating costs.

The 4.16 kV and 8.32 kV systems are comprised of two main asset categories: substation class assets and distribution class assets. These assets are among the oldest assets in Horizon's service area. They are also, not surprisingly, in poor or very poor condition generally. The priority of a 4.16 kV or 8.32 kV service areas for renewal is derived by the health index rating of each of the distribution assets and the substation assets. Each of these assets has its own probability of failure, consequence for failure, and required investment to replace or renew. In some cases the substation must be renewed but the distribution assets can continue to operate for some time yet. In other cases all the assets in the area need to be addressed; distribution and substation assets alike. The eventuality however is that the 4.16 kV and 8.32 kV systems will be eliminated since these are based on older technologies, are less efficient having higher line losses, and by utilizing the higher voltages at the 13.8 kV and 27.6 kV levels one can completely avoid the need for costly municipal substations.

The 4.16 kV and 8.32 kV voltage level renewal plan outlined in Section 4 contains a specific order of suggested areas to be renewed. This area-wide renewal approach is based on asset condition of substations and the distribution system, and operating and backup capabilities within the substations that reside in these areas. The 4.16 kV and 8.32 kV areas are derived of operating "Neighborhood Clusters" wherein the substations within each area back each other up and going down a level of detail the feeders within this area also back each other up. Thus it makes inherent sense to initiate the renewal with an area-wide focus in most cases. The renewal plan has been designed in such a way so as to maintain adequate backup capability with the area at all times.

Table of Contents

1. Introduction

Horizon Utilities Corporation (Horizon Utilities) is one of the largest municipally owned electricity distribution company in Ontario. It provides electricity and related utility services to over 240,000 residential, commercial, and industrial customers in Hamilton and St. Catharines. The electricity distribution system is comprised of several voltage levels ranging from 4.16 kilovolts (kV) to a maximum of 27.6 kV.

Although the majority of the customer base in Hamilton and St. Catharines is served from the 13.8 kV and the 27.6 kV distribution voltage levels, approximately 75,000 customers are served from the 4.16 kV and 8.32 kV levels. These areas include 28 substations among which 25 are in Hamilton and 3 are in St. Catharines. In these service areas, the assets are at or nearing their end of life. This poses the threat of incurring unanticipated outages due to equipment failure and high capital expenditure levels. Renewing assets by converting these parts of the system to a higher voltage will result in lower maintenance costs, higher reliability indices, increased customer satisfaction and avoid capital and maintenance costs associated with maintaining aged substation assets. The 4.16 kV and 13.8 kV Renewal Program entails the eventual upgrade of all the distribution system assets to the higher voltage standard and the corresponding removal of load from the substations allowing them to be decommissioned.

The plan provides Horizon Utilities with a decision model to justify and prioritize capital investments in various parts of the 4.16 kV and 8.32 kV voltage service areas allowing Horizon Utilities to organize capital investments over the long term while maintaining or improving system reliability levels throughout the programs duration.

Based on the most current information available, a list of priority areas and a schedule of these investments has been outlined. Annually a detailed analysis is performed on individual feeders prior to project issuance to ensure that accelerated degradation or unexpected results have not occurred in other areas. The updated information, based on experience and heath of assets, is fed into the decision model and, if required, priorities are rearranged.

Similarly, as the Asset Management Implementation Program undergoes continuous improvements, better asset information and performance will be incorporated into the data analysis as it becomes available. This would enable better condition assessment of the assets and enable more timely investment decisions on the 4.16 kV and 8.32 kV system renewals.

2. Background

This 4kV and 8kV Renewal Program is a system-wide study on the 4.16 kV and 8.32 kV voltage level service areas that prioritizes capital investments required and sets out a plan regarding the decommissioning of substations in the Horizon Utilities service area.

The plan has evolved over the years as Horizon Utilities asset management plan has been revised. The original plan was initiated in 2008 using the distribution assets as the primary driver for renewal and conversion. In 2009 the plan was revised to include substation assets as part of the evaluation criteria. The following year in 2010, Horizon Utilities retained the services of AESI to perform a Substation Asset Condition Assessment (SACA) against a defined scoring methodology to benchmark the substations against. The SACA results led to the first major shift in the Renewal Plan, brought upon by the more extensive investigation of assets in the substations and observation of operational issues impacting the performance of the assets.

In 2013, Horizon Utilities retained the services of Kinectrics to perform an Asset Condition Assessment (ACA) on all major asset categories, both substation and distribution assets. The updated asset condition information has been used to update the plan, but this new information has just re-enforced the decisions made in previous years, and has had no material impact to the findings and necessity of the overall plan.

Year	4kV & 8kV Plan Modifications
2008	Distribution Assets included
2009	Substation Assets included
2010	AESI SACA performed, plan refined
2013	Kinectrics ACA performed

The Renewal Plan takes many factors into consideration to formulate the order of substation renewal. The key parameters of the plan are:

- Distribution Asset Age
- Substation Asset Condition
- Distribution System Arrangement
- Feeder Dependency
- Customer Impact
- Source Availability
- Cost of renewal
- Safety and environmental risks

The assumptions used in the process of developing the Renewal Program are as follows:

- The design group will assess every feeder in detail to develop a conversion design at the time of renewal.

- The Renewal Program is developed based on a ‘best utility practice’ for replacement of distribution assets.
- The asset condition data is used to assist in the prioritization of substation and distribution renewal.
- If any major assets in the substations fail or load capacity increase is required, the plan is re-evaluated to justify the conversion of the whole feeder or parts of the feeder and the plan is adjusted to capture the effects of the change.
- GIS data used in the Renewal Program is reliable and where new information is available, it will be incorporated into the plan.

3. History and Progress

Although Horizon Utilities' created the 4kV and 8kV Renewal Program in 2009 as a result of formalizing Asset Management practices, the renewal of distribution assets to a higher voltage level and subsequent decommissioning of municipal substations has been ongoing for many years. These activities pre-date the amalgamation and formation of Horizon Utilities.

The area serviced by the following substations were renewed and converted to a higher voltage level prior to 2009:

- Gibson Substation
- Ferrie Substation
- Sherman Substation
- Vineland Substation
- Waterdown Substation
- Watkins Substation
- Burgoyne Substation
- Ferndale Substation
- Willow Substation

From 2009 - 2013, the areas served by the following substations were renewed and converted to a higher voltage:

- Halson Substation – Complete
- Webster Substation – Complete
- Taylor Substation – Complete
- Welland Substation – 2 of 3 phases complete
- Caroline Substation – 6 of 7 phases complete
- Hughson Substation – 6 of 7 phases complete
- Aberdeen Substation – 1 of 6 phases complete

When comparing the above list of stations to the scores found in the 2010 4kV and 8kV Renewal Program it is apparent that Horizon Utilities has been able to eliminate most of the worst scoring substation assets based on the 2009 ACA performed by AESI, which also aligned to the Kinectrics ACA completed in 2013.

The appendix contains a copy of the revised schedule for the 40 year Renewal Program. An additional phase was required for the Hughson Substation voltage conversion project due to increased complexities working in urban downtown settings. As a result of this, the Caroline Substation conversion was also delayed due to the requirement of feeder back-ups between the two stations. From the experience gained from these projects, the original estimated schedule for Central Substation has been increased from 6 years to 7 years as it features many of the same challenges observed during the Hughson project. In St. Catharines, a similar situation occurred with the Taylor Substation, where the project required an extra phase to fully complete the work.

4. Renewal Plan Methodology

The 4.16 kV and 8.32 kV Renewal Program outlines a recommended order of conversions to the 13.8 kV or 27.6 kV voltage level. The replacement of the 4.16 kV and 8.32 kV assets is in accordance to a logical plan – one that reduces risk by replacing assets in an order that minimizes the risk of failures due to assets with a poor health rating and minimizes investments in future capital costs of substation assets. The recommended replacement strategy uses design criteria establishes the most logical justification for undertaking conversion projects. The design criteria are utilized in the different stages of plan development to derive a detailed scoring methodology that analyzes each of the feeders. Based on this scoring methodology, the feeders are evaluated in comparison to each other leading to a final area ranking. The methodology of the renewal Program is broken down into the feeder ranking, substation condition scoring, cost analysis and feasibility analysis procedures. The criteria below are used as inputs to each of these design procedures to ultimately derive the final plan.

Following are each of the criteria and their contributions in the different stages of the design methodology procedures:

Distribution Asset Condition

Upgrading the aging distribution assets is one of the main drivers behind the conversion projects in Horizon Utilities. The majority of distribution assets in the 4.16 kV and 8.32 kV voltage level service areas are past their end of life expectancies. The Security Planning process ensures that we reduce the impact of unplanned outages due to failure. Based on the demographics of the distribution assets found in the GIS, not adopting a proactive replacement strategy would result in high levels of capital expenditures and higher operating and maintenance costs as reactive replacements are more expensive than planned replacement. It is also inefficient to replace individual assets as required as large scale renewal projects optimize resources. The assets considered are transformers, poles, conductors and cables. Using the Kinectrics ACA Horizon Utilities is able to create an overall health snapshot of the feeder assets and extrapolate that information into an overall substation area ranking.

Substation Asset Condition

The major assets in a distribution substation are power transformer(s), switchgear, circuit breakers, protection and control system, the station services, reclosers, and the physical facility. The substation assets are managed through extensive maintenance programs. The analyses of the maintenance results are used to assess asset condition and probability of failure. To establish the recommended year of decommissioning a substation both the Kinectrics ACA and SACA were used to derive a score for each station based on the following components: Station Services, Switchgear, Protection and Control (P&C),

Reclosers, Circuit Breakers, and Transformers. A summary of the results for each station is documented in Section 6 of this report.

Feeder dependency

Horizon Utilities 4.16 kV and 8.32 kV distribution feeders are operated with a detailed contingency plan ensuring redundancy and load transfer capability in case of failure. The Horizon Utilities distribution area, when studied for backup contingencies, shows that there is an area based structure whereby a group of substations back each other up through tie points between feeders. This structure mimics a cluster-like zone that is primarily self-contained with minimal backup between adjacent areas. This prompted the development of an area-based ranking that ensures that the operability is maintained while the feeders are renewed at the higher voltage.

An analysis of feeders which have ties to adjacent substations identifies that the 28 substations remaining in the system can be organized into the following operating areas:

Dundas (4 stations – Baldwin, Highland, John and York)
West Hamilton (2 stations – Stroud's Lane, Whitney)
Downtown Hamilton (4 stations – Aberdeen, Hughson, Central, Caroline)
East Hamilton (7 stations – Bartonville, Cope, Kenilworth, Ottawa, Parkdale, Spadina, Wentworth)
Hamilton Mountain (5 stations – Eastmount, Elmwood, Mountain, Mohawk, Wellington)
Stoney Creek (3 stations – Deerhurst, Dewitt, Galbraith)
St. Catharines (3 stations – Grantham, Welland, Vine)

Each of these areas can be considered islanded from other operating areas as few ties exist between clusters, but contain multiple ties to other feeders within the same cluster. Accordingly, assessment of total health indices by area is useful to ensure that support from other feeders within the same operating area will be available and consequently, security of supply to all customers is retained.

Customer Impact

The number of customers connected onto each feeder has been considered in the Renewal Program. The customer score has been derived by the weighted average of each customer class (i.e. commercial, industrial, and residential) per feeder. The weights used for each customer class vary based on the impact of a failure on that class of customers. The commercial customers have a higher weighting than the residential customers, and industrial customers have a higher weighting then both commercial or residential. The rationale for adopting this weighting system is that the impact of a failure to a customer is directly correlated to the value that the customer attaches to the service. Horizon Utilities refers to this impact as Value of Service (VOS), based on the metrics developed by Roy Billinton of the University of Saskatchewan. The VOS is used to quantify the effect of lost sales, lost production, lost opportunity costs, etc., and is expressed in terms of $/kwh.

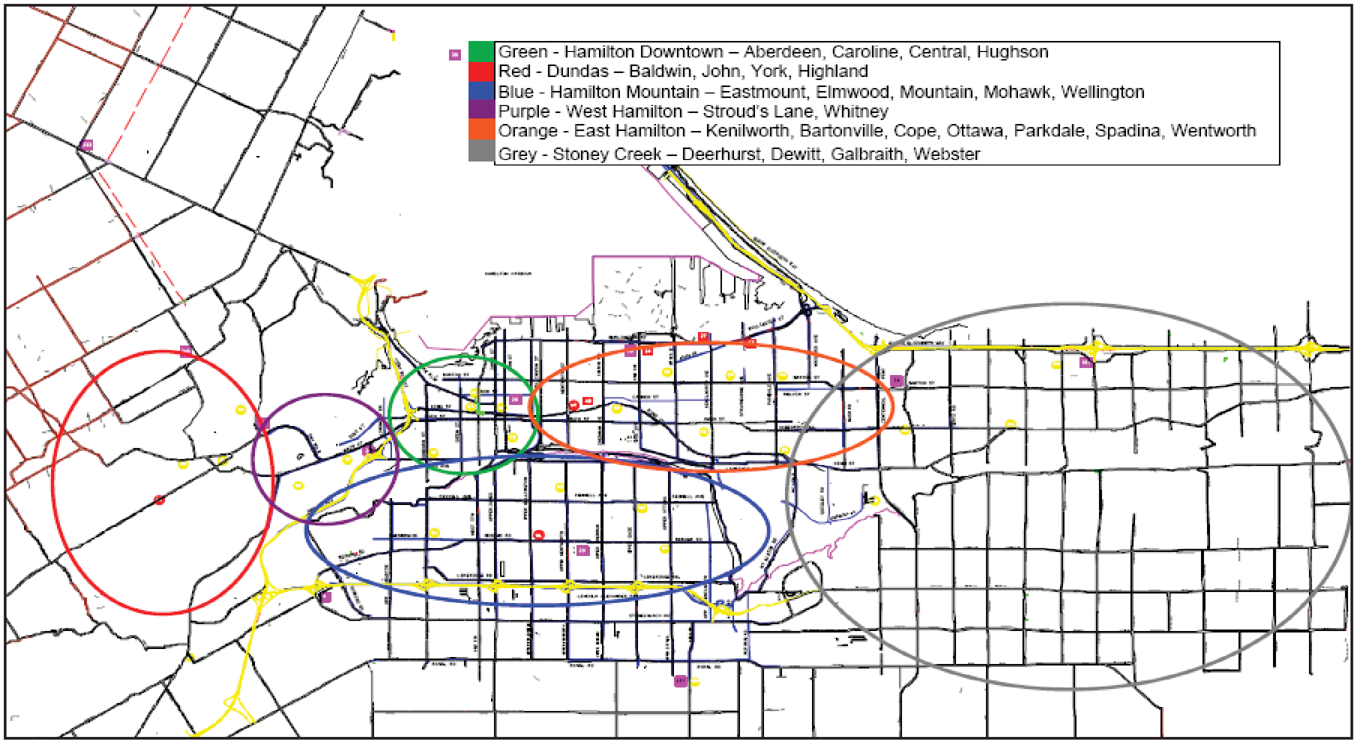
The application of the weighted customer score has been incorporated in the final Renewal Program in the distribution failure scores.

Since a renewal project would entail replacing all assets in an area, it is expected that outages caused by defective equipment will be reduced in the process. With the progress of the Smart Grid Strategy Implementation, other solutions such as installing mid-line reclosers, remote operable switches etc. will allow for quicker response and restoration times resulting in improved reliability levels.

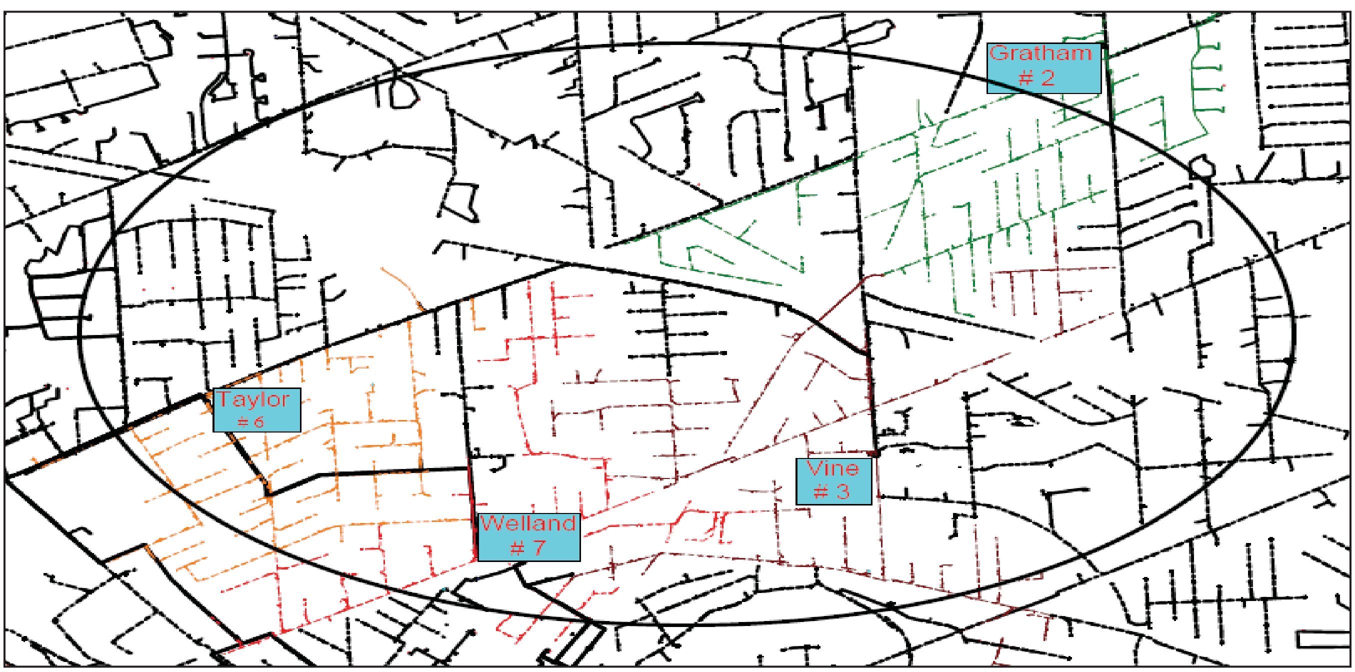
5. Conversion Maps – Horizon Service Area

The following pages contain the 2009 and year-end 2013 GIS Maps showing the areas served by the 4.16 kV and 8.32 kV voltage levels in the Horizon Utilities Corporation service area.

Hamilton Area Operating Clusters



St. Catharines Area Operating Cluster



6. Substation Assessments:

Aberdeen

Address: 416 ABERDEEN AVENUE, HAMILTON
Facility: INDOOR S/S
Year Built: 1969

Assessment

	Equipment Type	Health Index	Weighting - Indoor
1)	Transformer	90%	25%
2)	Breaker	39%	20%
3)	Reclosers	0	0%
4)	Switch Gear	46%	20%
5)	P&C	35%	20%
6)	Station Service	45%	5%
7)	Site & Civil	44%	10%
8)	Bus, Switches & Structures	0%	0%
	Station Health Index	**53%**	**100%**

Dependency / Loading

Station	Circuit	Forecasted Peak Current (Amps)	Connected to
Aberdeen	AB-1	197	AB-2
Aberdeen	AB-2	272	AB-1
Aberdeen	AB-3	0	
Aberdeen	AB-4	203	CE-2, CE-3
Aberdeen	AB-5	176	ST-6
Aberdeen	AB-6	B.E.	

Baldwin

Address: 38 BALDWIN STREET, DUNDAS.
Facility: OUTDOOR S/S
Year Built: UNKNOWN

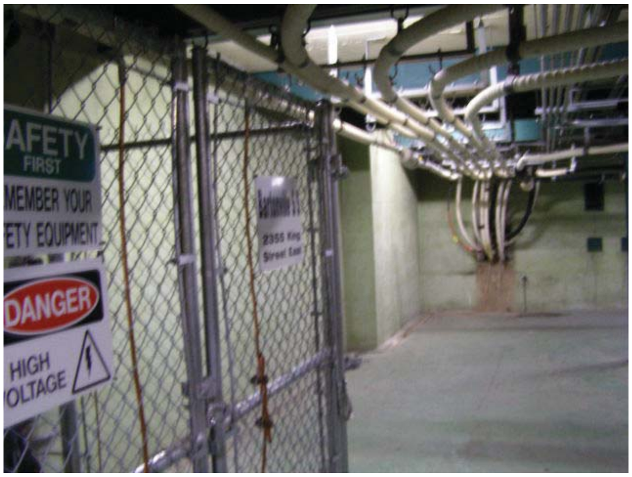
Assessment

	Equipment Type	Health Index	Weighting - Outdoor
1)	Transformer	93%	30%
2)	Breaker	0%	0%
3)	Reclosers	96%	15%
4)	Switch Gear	0%	0%
5)	P&C	67%	15%
6)	Station Service	40%	5%
7)	Site & Civil	83%	10%
8)	Bus, Switches & Structures	83%	25%
	Station Health Index	**84%**	**100%**

Dependency / Loading

Station	Circuit	Forecasted Peak Current (Amps)	Connected to
Baldwin	BD-1	195	BD-2, JN-1, JN-2
Baldwin	BD-2	130	BD-1, HI-2

Bartonville



Address: 2355 KING STREET EAST, HAMILTON
Year Built: 1952
Facility: INDOOR S/S

Assessment

	Equipment Type	Health Index	Weighting - Indoor
1)	Transformer	86%	25%
2)	Breaker	100%	20%
3)	Reclosers	0%	0%
4)	Switch Gear	52%	20%
5)	P&C	90%	20%
6)	Station Service	10%	5%
7)	Site & Civil	66%	10%
8)	Bus, Switches & Structures	0%	0%
	Station Health Index	**77%**	**100%**

Dependency / Loading

Station	Circuit	Forecasted Peak Current (Amps)	Connected to
Bartonville	BA-1	181	BA-2,BA-4,PA-F3
Bartonville	BA-2	126	BA-1,KE-5
Bartonville	BA-3	64	BA-4,BA-7
Bartonville	BA-4	218	BA-1,BA-3,KE-6
Bartonville	BA-5	B.E.	
Bartonville	BA-6	B.E.	
Bartonville	BA-7	131	BA-3

Caroline

Address: 117 MARKET STREET, HAMILTON
Year Built: 1955
Facility: INDOOR S/S

Assessment

	Equipment Type	Health Index	Weighting - Indoor
1)	Transformer	86%	25%
2)	Breaker	51%	20%
3)	Reclosers	0%	0%
4)	Switch Gear	51%	20%
5)	P&C	55%	20%
6)	Station Service	25%	5%
7)	Site & Civil	64%	10%
8)	Bus, Switches & Structures	0%	0%
	Station Health Index	**61%**	**100%**

Dependency / Loading

Station	Circuit	Forecasted Peak Current (Amps)	Connected to
Caroline	CA-2	0	
Caroline	CA-3	122	AB-2
Caroline	CA-4	266	
Caroline	CA-5	0	
Caroline	CA-6	0	
Caroline	CA-7	53	HU-12
Caroline	CA-8	B.E.	

Central

Address: 193 JOHN ST. SOUTH, HAMILTON
Year Built: 1950
Facility: INDOOR S/S

Assessment

	Equipment Type	Health Index	Weighting - Indoor
1)	Transformer	90%	25%
2)	Breaker	46%	20%
3)	Reclosers	0	0%
4)	Switch Gear	58%	20%
5)	P&C	30%	20%
6)	Station Service	20%	5%
7)	Site & Civil	62%	10%
8)	Bus, Switches & Structures	0%	0%
	Station Health Index	**56%**	**100%**

Dependency / Loading

Station	Circuit	Forecasted Peak Current (Amps)	Connected to
Central	CE-1	82	
Central	CE-2	140	CE-8
Central	CE-3	146	CE-10.CE-8
Central	CE-4	193	CE-5,CE-11
Central	CE-5	50	CE-4
Central	CE-6	17	
Central	CE-8	90	CE-2,CE-3
Central	CE-9	11	
Central	CE-10	197	CE-3,MT-10
Central	CE-11	141	CE-4

Cope

Address: 1430 BARTON ST. EAST, HAMILTON
Year Built: 1965
Facility: INDOOR S/S

Assessment

	Equipment Type	Health Index	Weighting - Indoor
1)	Transformer	88%	25%
2)	Breaker	100%	20%
3)	Reclosers	0%	0%
4)	Switch Gear	71%	20%
5)	P&C	90%	20%
6)	Station Service	40%	5%
7)	Site & Civil	82%	10%
8)	Bus, Switches & Structures	0%	0%
	Station Health Index	**84%**	**100%**

Dependency / Loading

Station	Circuit	Forecasted Peak Current (Amps)	Connected to
Cope	CP-1	141	CP-9,PA-F3,KE-2
Cope	CP-2	214	CP-8, OT-3
Cope	CP-3	131	PA-F1, CP-4
Cope	CP-4	103	PA-F1, CP-3,CP-7
Cope	CP-5	131	CP-6,OT-2,OT-5
Cope	CP-6	86	CP-5
Cope	CP-7	217	CP-4,OT-4
Cope	CP-8	96	CP-2
Cope	CP-9	216	CP-1, KE-5

Deerhurst

Address: 357 HIGHWAY #8, STONEY CREEK
Year Built: UNKNOWN
Facility: OUTDOOR S/S

Assessment

	Equipment Type	Health Index	Weighting - Outdoor
1)	Transformer	97%	30%
2)	Breaker	0%	0%
3)	Reclosers	100%	15%
4)	Switch Gear	0%	0%
5)	P&C	0%	15%
6)	Station Service	60%	5%
7)	Site & Civil	69%	10%
8)	Bus, Switches & Structures	100%	25%
	Station Health Index	**79%**	**100%**

Dependency / Loading

Station	Circuit	Forecasted Peak Current (Amps)	Connected to
Deerhurst	DH-1	60	DH-2,DW-2,DW-3
Deerhurst	DH-2	26	DH-1,DW-1,GA-2
Deerhurst	DH-3	41	DH-1,GA-2

Dewitt

Address: DEWITT ROAD, STONEY CREEK
Year Built: UNKNOWN
Facility: OUTDOOR S/S

Assessment

	Equipment Type	Health Index	Weighting - Outdoor
1)	Transformer	82%	30%
2)	Breaker	0%	0%
3)	Reclosers	100%	15%
4)	Switch Gear	0%	0%
5)	P&C	0%	15%
6)	Station Service	55%	5%
7)	Site & Civil	65%	10%
8)	Bus, Switches & Structures	100%	25%
	Station Health Index	**74%**	**100%**

Dependency / Loading

Station	Circuit	Forecasted Peak Current (Amps)	Connected to
Dewitt	DW-1	88	DH-2,DW-2,DW-3
Dewitt	DW-2	9	DH-1,DW-1,DW-3
Dewitt	DW-3	19	DH-1,DW-1,DW-2

Eastmount

Address: 856 MOHAWK RD. EAST, HAMILTON
Year Built: 1959
Facility: INDOOR S/S

Assessment

	Equipment Type	Health Index	Weighting - Indoor
1)	Transformer	90%	25%
2)	Breaker	45%	20%
3)	Reclosers	0%	0%
4)	Switch Gear	69%	20%
5)	P&C	45%	20%
6)	Station Service	10%	5%
7)	Site & Civil	78%	10%
8)	Bus, Switches & Structures	0	0%
	Station Health Index	**63%**	**100%**

Dependency / Loading

Station	Circuit	Forecasted Peak Current (Amps)	Connected to
Eastmount	EA-1	162	MK-1,MK-11
Eastmount	EA-2	206	EA-10,MK-2,WL-3
Eastmount	EA-3	239	EA-8,MK-10
Eastmount	EA-4	113	EA-6,EA-11
Eastmount	EA-6	156	EA-4
Eastmount	EA-7	128	EA-9
Eastmount	EA-8	186	EA-3
Eastmount	EA-9	165	EA-7,MK-6
Eastmount	EA-10	132	EA-2
Eastmount	EA-11	145	EA-4

Elmwood

Address: 218 WEST 19TH ST., HAMILTON
Year Built: 1958
Facility: INDOOR S/S

Assessment

	Equipment Type	Health Index	Weighting - Indoor
1)	Transformer	93%	25%
2)	Breaker	73%	20%
3)	Reclosers	0%	0%
4)	Switch Gear	55%	20%
5)	P&C	35%	20%
6)	Station Service	15%	5%
7)	Site & Civil	82%	10%
8)	Bus, Switches & Structures	0%	0%
	Station Health Index	**65%**	**100%**

Dependency / Loading

Station	Circuit	Forecasted Peak Current (Amps)	Connected to
Elmwood	EL-2	114	EL-8,EL-10
Elmwood	EL-3	109	EL-7,EL-10
Elmwood	EL-4	159	WL-6,EL-7
Elmwood	EL-5	0	
Elmwood	EL-7	124	EL-3,EL-4
Elmwood	EL-8	139	EL-2,EL-9
Elmwood	EL-9	96	EL-8,WL-10
Elmwood	EL-10	198	EL-2, EL-3

Galbraith

Address: 16 GALBRAITH DR., STONEY CREEK
Year Built: 1959
Facility: OUTDOOR S/S

Assessment

	Equipment Type	Health Index	Weighting - Outdoor
1)	Transformer	95%	30%
2)	Breaker	0%	0%
3)	Reclosers	100%	15%
4)	Switch Gear	93%	10%
5)	P&C	100%	15%
6)	Station Service	45%	5%
7)	Site & Civil	56%	10%
8)	Bus, Switches & Structures	100%	15%
	Station Health Index	**91%**	**100%**

Dependency / Loading

Station	Circuit	Forecasted Peak Current (Amps)	Connected to
Galbraith	GA-1	29	GA-2
Galbraith	GA-2	92	GA-1,DH-2,DH-3,GA-3
Galbraith	GA-3	0	GA-2

Highland

Address: 259 GOVERNORS RD., DUNDAS
Year Built: 1977
Facility: INDOOR S/S

Assessment

	Equipment Type	Health Index	Weighting - Indoor
1)	Transformer	95%	25%
2)	Breaker	33%	20%
3)	Reclosers	0%	0%
4)	Switch Gear	36%	20%
5)	P&C	25%	20%
6)	Station Service	50%	5%
7)	Site & Civil	72%	10%
8)	Bus, Switches & Structures	0%	0%
	Station Health Index	**52%**	**100%**

Dependency / Loading

Station	Circuit	Forecasted Peak Current (Amps)	Connected to
Highland	HI-1	94	HI-2
Highland	HI-2	119	HI-1,HI-3,JN-1, BD-2
Highland	HI-3	126	HI-2

Hughson

Address: 48 HUGHSON ST. NORTH, HAMILTON
Year Built: 1926
Facility: INDOOR S/S

Assessment

	Equipment Type	Health Index	Weighting - Indoor
1)	Transformer	95%	25%
2)	Breaker	79%	20%
3)	Reclosers	0%	0%
4)	Switch Gear	81%	20%
5)	P&C	60%	20%
6)	Station Service	40%	5%
7)	Site & Civil	55%	10%
8)	Bus, Switches & Structures	0%	0%
	Station Health Index	**75%**	**100%**

Dependency / Loading

Station	Circuit	Forecasted Peak Current (Amps)	Connected to
Hughson	HU-2	13	
Hughson	HU-4	0	
Hughson	HU-5	0	
Hughson	HU-6	277	HU-11,CA-4
Hughson	HU-7	0	
Hughson	HU-8	0	
Hughson	HU-9	0	
Hughson	HU-10	0	
Hughson	HU-11	211	HU-6,WT-10,WT-4
Hughson	HU-12	0	CA-7

John

Address: 150 HATT ST., DUNDAS
Year Built: 1985
Facility: OUTDOOR S/S

Assessment

	Equipment Type	Health Index	Weighting - Outdoor
1)	Transformer	80%	30%
2)	Breaker	0%	0%
3)	Reclosers	100%	15%
4)	Switch Gear	0%	0%
5)	P&C	67%	15%
6)	Station Service	50%	5%
7)	Site & Civil	95%	10%
8)	Bus, Switches & Structures	86%	25%
	Station Health Index	**83%**	**100%**

Dependency / Loading

Station	Circuit	Forecasted Peak Current (Amps)	Connected to
John	JN-1	270	HI-2,JN-2,BD-1
John	JN-2	82	JN-1,BD-1

Kenilworth

Address: 96 KENILWORTH AVE. SOUTH, HAMILTON
Year Built: 1960
Facility: INDOOR S/S

Assessment

	Equipment Type	Health Index	Weighting - Indoor
1)	Transformer	91%	25%
2)	Breaker	100%	20%
3)	Reclosers	0%	0%
4)	Switch Gear	50%	20%
5)	P&C	90%	20%
6)	Station Service	25%	5%
7)	Site & Civil	61%	10%
8)	Bus, Switches & Structures	0%	0%
	Station Health Index	**78%**	**100%**

Dependency / Loading

Station	Circuit	Forecasted Peak Current (Amps)	Connected to
Kenilworth	KE-1	195	KE-3,KE-4,KE-6,OT-3,SP-6
Kenilworth	KE-2	128	CP-1
Kenilworth	KE-3	176	KE-1,KE-5
Kenilworth	KE-4	160	KE-1,KE-5,KE-6
Kenilworth	KE-5	71	KE-3,KE-4,BA-2,CP-9
Kenilworth	KE-6	142	KE-1,KE-4,BA-4

Mohawk

Address: 709 UPPER GAGE, HAMILTON
Year Built: 1953
Facility: INDOOR S/S

Assessment

	Equipment Type	Health Index	Weighting - Indoor
1)	Transformer	85%	25%
2)	Breaker	100%	20%
3)	Reclosers	0	0%
4)	Switch Gear	59%	20%
5)	P&C	90%	20%
6)	Station Service	25%	5%
7)	Site & Civil	68%	10%
8)	Bus, Switches & Structures	0%	0%
	Station Health Index	**79%**	**100%**

Dependency / Loading

Station	Circuit	Forecasted Peak Current (Amps)	Connected to
Mohawk	MK-1	192	MK-9,EA-1
Mohawk	MK-2	155	EA-2,MK-5,MK-6,MT-6
Mohawk	MK-3	204	MT-2,MT-3
Mohawk	MK-5	42	MK-2
Mohawk	MK-6	131	MK-2,EA-9
Mohawk	MK-9	180	MK-1,MT-3
Mohawk	MK-10	195	EA-3
Mohawk	MK-11	162	EA-1

Mountain

Address: 510 UPPER WENTWORTH, HAMILTON
Year Built: 1965
Facility: INDOOR S/S

Assessment

	Equipment Type	Health Index	Weighting - Indoor
1)	Transformer	91%	25%
2)	Breaker	100%	20%
3)	Reclosers	0	0%
4)	Switch Gear	57%	20%
5)	P&C	90%	20%
6)	Station Service	25%	5%
7)	Site & Civil	53%	10%
8)	Bus, Switches & Structures	0%	0%
	Station Health Index	**79%**	**100%**

Dependency / Loading

Station	Circuit	Forecasted Peak Current (Amps)	Connected to
Mountain	MT-2	141	MT-3,MK-3
Mountain	MT-3	169	MT-2,MK-3,MK-9
Mountain	MT-4	222	MT-5,MT-9,MT-10,MT-11
Mountain	MT-5	174	MT-4,MT-6,MT-10,WL-9
Mountain	MT-6	195	MK-2,MT-5,MT-9,WL-2,WL4
Mountain	MT-9	205	MT-4,MT-6
Mountain	MT-10	195	CE-10,MT-5,MT-11
Mountain	MT-11	0	MT-4,MT-10

Ottawa

Address: 64 DALKEITH ST., HAMILTON
Year Built: 1967
Facility: INDOOR S/S

Assessment

	Equipment Type	Health Index	Weighting - Indoor
1)	Transformer	89%	25%
2)	Breaker	100%	20%
3)	Reclosers	0%	0%
4)	Switch Gear	76%	20%
5)	P&C	90%	20%
6)	Station Service	25%	5%
7)	Site & Civil	86%	10%
8)	Bus, Switches & Structures	0%	0%
	Station Health Index	**85%**	**100%**

Dependency / Loading

Station	Circuit	Forecasted Peak Current (Amps)	Connected to
Ottawa	OT-1	83	OT-2,OT-8
Ottawa	OT-2	157	OT-1,CP-5
Ottawa	OT-3	183	OT-4,KE-1,SP-1,CP-5
Ottawa	OT-4	222	OT-3,CP-7
Ottawa	OT-5	167	CP-5
Ottawa	OT-6	0	
Ottawa	OT-7	150	SP-7,SP-5
Ottawa	OT-8	113	OT-1

Parkdale

Address: 300 PARKDALE AVE. NORTH, HAMILTON
Year Built: 1924
Facility: INDOOR S/S

Assessment

	Equipment Type	Health Index	Weighting - Indoor
1)	Transformer	100%	25%
2)	Breaker	100%	20%
3)	Reclosers	0%	0%
4)	Switch Gear	100%	20%
5)	P&C	90%	20%
6)	Station Service	25%	5%
7)	Site & Civil	66%	10%
8)	Bus, Switches & Structures	0%	0%
	Station Health Index	**91%**	**100%**

Dependency / Loading

Station	Circuit	Forecasted Peak Current (Amps)	Connected to
Parkdale	PA-F1	178	PA-F5,CP-3,CP-4
Parkdale	PA-F2	192	PA-F5
Parkdale	PA-F3	171	PA-F6,CP-1,BA-1
Parkdale	PA-F4	159	PA-F5, PA-F7
Parkdale	PA-F5	159	PA-F1,PA-F2, PA-F4
Parkdale	PA-F6	159	PA-F3
Parkdale	PA-F7	64	PA-F4
Parkdale	PA-F8	0	

Spadina

Address: 994 KING ST. EAST, HAMILTON
Year Built: 1930
Facility: INDOOR S/S

Assessment

	Equipment Type	Health Index	Weighting - Indoor
1)	Transformer	88%	25%
2)	Breaker	68%	20%
3)	Reclosers	0%	0%
4)	Switch Gear	79%	20%
5)	P&C	90%	20%
6)	Station Service	20%	5%
7)	Site & Civil	68%	10%
8)	Bus, Switches & Structures	0%	0%
	Station Health Index	**77%**	**100%**

Dependency / Loading

Station	Circuit	Forecasted Peak Current (Amps)	Connected to
Spadina	SP-1	154	SP-5,OT-3
Spadina	SP-2	204	SP-5,WT-9
Spadina	SP-3	194	SP-4,WT-5
Spadina	SP-4	132	SP-3,SP-6
Spadina	SP-5	222	SP-1,SP-2,OT-7
Spadina	SP-6	217	KE-1,SP-4
Spadina	SP-7	0	OT-7

Stroud's Lane

Address: 1225 MAIN ST. EAST, HAMILTON
Year Built: 1938
Facility: INDOOR S/S

Assessment

	Equipment Type	Health Index	Weighting - Indoor
1)	Transformer	85%	25%
2)	Breaker	70%	20%
3)	Reclosers	0%	0%
4)	Switch Gear	37%	20%
5)	P&C	55%	20%
6)	Station Service	25%	5%
7)	Site & Civil	71%	10%
8)	Bus, Switches & Structures	0%	0%
	Station Health Index	**62%**	**100%**

Dependency / Loading

Station	Circuit	Forecasted Peak Current (Amps)	Connected to
Strouds	ST-2	146	ST-7
Strouds	ST-3	267	ST-4
Strouds	ST-4	21	ST-3,WH-1,WH-2
Strouds	ST-6	171	ST-7,AB-5
Strouds	ST-7	182	ST-2,ST-6

Wellington

Address: 227 MOHAWK RD. EAST, HAMILTON
Year Built: 1960
Facility: INDOOR S/S

Assessment

	Equipment Type	Health Index	Weighting - Indoor
1)	Transformer	85%	25%
2)	Breaker	100%	20%
3)	Reclosers	0%	0%
4)	Switch Gear	59%	20%
5)	P&C	90%	20%
6)	Station Service	25%	5%
7)	Site & Civil	83%	10%
8)	Bus, Switches & Structures	0%	0%
	Station Health Index	**81%**	**100%**

Dependency / Loading

Station	Circuit	Forecasted Peak Current (Amps)	Connected to
Wellington	WL-1	116	WL-8
Wellington	WL-2	193	WL-9, MT-6
Wellington	WL-3	116	WL-4
Wellington	WL-4	137	WL-3,MT-6
Wellington	WL-5	120	WL-11,WL-8
Wellington	WL-6	69	WL-8,WL-9,EL-4
Wellington	WL-8	143	WL-1,WL-5,WL-6,WL-10
Wellington	WL-9	169	WL-2,WL-6,MT-5
Wellington	WL-10	92	WL-8,EL-9
Wellington	WL-11	137	WL-5

Wentworth

Address: 681 KING ST. EAST, HAMILTON
Year Built: 1930
Facility: INDOOR S/S

Assessment

	Equipment Type	Health Index	Weighting - Indoor
1)	Transformer	90%	25%
2)	Breaker	82%	20%
3)	Reclosers	0%	0%
4)	Switch Gear	73%	20%
5)	P&C	90%	20%
6)	Station Service	25%	5%
7)	Site & Civil	64%	10%
8)	Bus, Switches & Structures	0%	0%
	Station Health Index	**79%**	**100%**

Dependency / Loading

Station	Circuit	Forecasted Peak Current (Amps)	Connected to
Wentworth	WT-1	171	WT-6,WT-11
Wentworth	WT-2	266	WT-11,WT-5
Wentworth	WT-3	234	WT-4,WT-9
Wentworth	WT-4	210	WT-3
Wentworth	WT-5	256	WT-2,SP-3
Wentworth	WT-6	152	WT-1
Wentworth	WT-8	66	
Wentworth	WT-9	99	SP-2,WT-3
Wentworth	WT-10	153	WT-12
Wentworth	WT-11	71	WT-1,WT-2
Wentworth	WT-12	73	WT-10

Whitney

Address: 252 WHITNEY AVE., HAMILTON
Year Built: 1963
Facility: INDOOR S/S

Assessment

	Equipment Type	Health Index	Weighting - Indoor
1)	Transformer	92%	25%
2)	Breaker	65%	20%
3)	Reclosers	0%	0%
4)	Switch Gear	43%	20%
5)	P&C	45%	20%
6)	Station Service	30%	5%
7)	Site & Civil	83%	10%
8)	Bus, Switches & Structures	0%	0%
	Station Health Index	**63%**	**100%**

Dependency / Loading

Station	Circuit	Forecasted Peak Current (Amps)	Connected to
Whitney	WH-1	193	ST-4, WH-4
Whitney	WH-2	116	WH-6,ST-4
Whitney	WH-3	196	WH-5,WH-6
Whitney	WH-4	32	WH-1
Whitney	WH-5	149	WH-3
Whitney	WH-6	91	WH-2,WH-3

York

Address: 230 YORK RD, DUNDAS
Year Built: UNKNOWN
Facility: OUTDOOR S/S

Assessment

	Equipment Type	Health Index	Weighting - Outdoor
1)	Transformer	88%	30%
2)	Breaker	0%	0%
3)	Reclosers	100%	15%
4)	Switch Gear	0%	0%
5)	P&C	90%	15%
6)	Station Service	40%	5%
7)	Site & Civil	73%	10%
8)	Bus, Switches & Structures	83%	25%
	Station Health Index	**85%**	**100%**

Dependency / Loading

Station	Circuit	Forecasted Peak Current (Amps)	Connected to
York	YK-1	75	YK-2
York	YK-2	39	YK-1

Grantham

Address: 319 ½ GRANTHAM AVE.,
ST.CATHARINES
Year Built: 1965
Facility: INDOOR S/S

Assessment

	Equipment Type	Health Index	Weighting - Indoor
1)	Transformer	82%	25%
2)	Breaker	52%	20%
3)	Reclosers	0%	0%
4)	Switch Gear	57%	20%
5)	P&C	35%	20%
6)	Station Service	63%	5%
7)	Site & Civil	59%	10%
8)	Bus, Switches & Structures	0%	0%
	Station Health Index	**58%**	**100%**

Dependency / Loading

Station	Circuit	Forecasted Peak Current (Amps)	Connected to
Grantham	GRF1	216	VIF3,GRF2
Grantham	GRF2	169	GRF1,GRF4
Grantham	GRF3	B.E.	
Grantham	GRF4	105	GRF2

Vine

Address: 95 VINE ST.,
ST.CATHARINES
Year Built: 1959
Facility: INDOOR S/S

Assessment

	Equipment Type	Health Index	Weighting - Indoor
1)	Transformer	70%	25%
2)	Breaker	52%	20%
3)	Reclosers	0%	0%
4)	Switch Gear	61%	20%
5)	P&C	50%	20%
6)	Station Service	38%	5%
7)	Site & Civil	53%	10%
8)	Bus, Switches & Structures	0%	0%
	Station Health Index	**57%**	**100%**

Dependency / Loading

Station	Circuit	Forecasted Peak Current (Amps)	Connected to
Vine	VIF1	137	VIF5
Vine	VIF3	147	GRF1
Vine	VIF4	176	VIF5,WEF1
Vine	VIF5	201	VIF1,VIF4, WEF4

Welland

Address: 136 WELLAND AVE.,
ST.CATHARINES
Year Built:
Facility: INDOOR S/S

Assessment

	Equipment Type	Health Index	Weighting - Indoor
1)	Transformer	85%	25%
2)	Breaker	60%	20%
3)	Reclosers	0%	0%
4)	Switch Gear	55%	20%
5)	P&C	40%	20%
6)	Station Service	38%	5%
7)	Site & Civil	45%	10%
8)	Bus, Switches & Structures	0%	0%
	Station Health Index	**59%**	**100%**

Dependency / Loading

Station	Circuit	Forecasted Peak Current (Amps)	Connected to
Welland	WEF1	101	WEF2,VIF4
Welland	WEF2	0	WEF1
Welland	WEF4	70	VIF5

7. Recommendations:

1. Horizon Utilities should continue to follow the voltage conversion outline provided in this document for 4.16 kV and 8.32 kV Asset Renewal.

2. The organization should maintain a 40 year project plan for 4.16 kV and 8.32 kV asset renewal and determine an appropriate level of investment and rate of progress for the Renewal Program.

3. The organization should continue to include in its capital plans a program of investment in substation assets that will ensure the reliable performance of the stations until their anticipated decommissioning dates.

4. Adequate maintenance programs should continue in these areas throughout the life of the Renewal Program.

5. The organization should complete a regular review of the assessments to determine if the plan or priorities require to be altered.

6. The organization should integrate smart grid strategies with the Renewal Program when rebuilding distribution system to capture synergies.

7. Included in the appendix is the revised 40 year renewal schedule for all 4.16 kV and 8.32 kV assets.

Appendix

Horizon Renewal Schedule 2009-2049

2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
			1/6						2/6	3/6	4/6	5/6	6/6					
													1/4					
										1/2	2/2							
1/6	2/6	3/6	4/6	5/6	6/6	7/6												
								1/7	2/7	3/7	4/7	5/7	6/7	7/7				
												1/3	2/3	3/3				
												1/4	2/4	3/4	4/4			
																1/6	2/6	3/6
																1/6	2/6	3/6
													1/4	2/4	3/4	4/4		
							1/3	2/3	3/3									
3/4	4/4																	
						1/3	2/3	3/3										
1/6	2/6	3/6	4/6	5/6	6/6	7/6												
										1/2	2/2							
						1/5	2/5	3/5	4/5	5/5								
	1/3	2/3	3/3	4/3														
							1/3	2/3	3/3									
1/3	2/3	3/3																
			1/3		2/3	3/3												
						1/5	2/5	3/5	4/5	5/5								
										1/2	2/2							

Substation Renewal Plan Schedule 2006 - 2028

2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047
					2/4	3/4	4/4									
													1/6	2/6	3/6	4/6
													1/6	2/6	3/6	4/6
2/6	3/6	4/6	5/6	6/6												
2/6	3/6	4/6	5/6	6/6												
											1/6	2/6	3/6	4/6	5/6	6/6
											1/6	2/6	3/6	4/6	5/6	6/6
					1/6	2/6	3/6	4/6	5/6	6/6						
2/6	3/6	4/6	5/6	6/6												
					1/6	2/6	3/6	4/6	5/6	6/6						

Substation Renewal Plan Schedule 2029 - 2049

Appendix G – Material Capital Project Templates

Table of Contents

Capital Project Summary

General Information on Project (5.4.5.2.A)

Project Name	2015 Meters
Budget Year	2015
Investment Category	System Access
Project Summary	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; • 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.

Capital Investment (5.4.5.2.A.i)	Capital Investment	$ 2,471,000
	Total	$ 2,471,000
	O&M Expenditure	$ 0
Customer Attachments / Load (kVA) (5.4.5.2.A.ii)	n/a	

Project Dates (5.4.5.2.A.iii)

Start Date 2015/01/01

In Service Date 2015/12/31

Expenditure Timing			
Q1	Q2	Q3	Q4
25%	25%	25%	25%

Schedule Risk and Risk Mitigation (5.4.5.2.A.iv**)**

Schedule risk for the installation of meters at new service locations is due to customer delays or restricted access to work sites. Horizon Utilities co-ordinates the connection of new services with customers to mitigate this risk.

Comparative Information from Equivalent Projects (5.4.5.2.A.v)

Metering investments for the 2010 to 2013 Historical Years and the 2014 Bridge Year are:

2010 (CGAAP) - $1,715,716
2011 (CGAAP)- $3,467,413
2012 (MIFRS) - $25,168,043
2013 (MIFRS) - $1,658,707
2014 (MIFRS) - $2,499,104

The increased investment in 2012 was due to the implementation of Smart Meters at a cumulative capital cost of $23,277,588. 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.

Total Capital OM&A Costs Associated with REG Investments (5.4.5.2.A.vi)

This project is not associated with an REG investment and as such no associated OM&A costs related to REG will be incurred.

Leave to Construct Approval (5.4.5.2.A.vii)

This project does not require "Leave to Construct" under Section 92 of the *Ontario Energy Board Act 1998.*

Evaluation Criteria and Information (5.4.5.2.B)

Project Name 2015 Meters Table 2

Efficiency, Customer Value, Reliability (5.4.5.2.B.1)

Investment Driver (5.4.5.2.B.1.a)
System Access (80%)

Secondary Driver (5.4.5.2.B.1.a)
System Renewal (20%)

Replacement of commercial meters with smart meters.

Investment Priority (5.4.5.2.B.1.b)
5 – Mandatory Project

Analysis of Project and Project Alternatives (5.4.5.2.B.1.c) (where applicable)

Metering asset management is governed by Measurement Canada regulation and customer requirements for new and upgraded services.

Safety (5.4.5.2.B.2)

This project is not intended to address safety concerns with the distribution system.

	Cyber-Security and Privacy (5.4.5.2.B.3) (where applicable) Horizon Utilities' Smart Meter and related AMI network have been procured through Elster. Elster's system supports a multi-layered security approach including: access control, authorization, authentication and data integrity protocols. As part of its continuous improvement model, Horizon Utilities performs periodic security assessments to identify opportunities for enhanced system hardening.
	Co-ordination and Interoperability (5.4.5.2.B.4) **(where applicable)** **Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.5.2.B.4.a) (where applicable)** Co-ordination with utilities and regional planning is not required. Horizon Utilities coordinates with customers as required by the scope of work involved.
	Enabling of Future Technology and/or Future Operational Requirements (5.4.5.2.B.4.b) A component of this investment supports the capital investment required for the ongoing operation, maintenance, and installation of the Smart Metering infrastructure.
	Economic Development (5.4.5.2.B.5) **(where applicable)** Horizon Utilities ensures that policies and practices do not unnecessarily create barriers to economic development which are primarily focused within its communities.
	Environmental Benefits (5.4.5.2.B.6) **(where applicable)** The Smart Meter infrastructure supports the province's conservation culture. Smart metering also provides environmental benefits through reduction of in field visits associated with manual meter reading.

System Access Specific Requirements (5.4.5.2.C.a)	**Project Name** 2015 Metering Table 3
	System Access Specific Requirements (5.4.5.2.C.a) **Factors Affecting Implementing Project Timing/Priority (5.4.5.2.C.a.i)** Compliance sampling work completed to comply with Measurement Canada regulations. The schedule is created to smooth the annual sampling requirements from the original Smart Meter mass deployments. New and replacement metering is provided on demand to address new load growth and meter failures.
	Factors Related to Customer Preference or 3rd Party Input (5.4.5.2.C.a.ii) Metering for new and upgraded connection projects are customer initiated and are designed to meet customer identified requirements.
	Factors Affecting Final Project Cost (5.4.5.2.C.a.iii) Please refer to Note I for an explanation on the factors affecting the final project cost.

Controllable Cost Minimization (5.4.5.2.C.a.iv)

Please refer to Note I for an explanation regarding controllable cost minimization.

Other Planning Objectives (5.4.5.2.C.a.v)

Horizon Utilities combines work from multiple work groups to reduce costs and increase efficiency. The line work and meter work is combined when connecting new customers to allow the work to be completed by a single work group.

Assessment of Technical or Implementation Options (5.4.5.2.C.a.vi)

Metering work is Measurement Canada and customer driven and the technology is primarily based on the metering products available from a sole source supplier.

Summary of Options Analysis (5.4.5.2.C.a.vii) (where applicable)

Metering supplier selected as part of the smart meter implementation program.

Final Economic Evaluation Results (5.4.5.2.C.a.viii) (where applicable)

Horizon Utilities completes the economic evaluation for any customer system access project which requires the construction of new facilities to the main distribution system or an increase in the existing capacity of distribution facilities. For further details please see Appendix E of Horizon Utilities' Conditions of Service. The economic evaluation is completed in accordance with section 3.2 of the Distribution System Code ("DSC"). For the 2015-2019 Test Years, Horizon Utilities has no known projects for which to provide the final economic evaluation. When a road authority requests a relocation of Horizon Utilities' plant located on the public road allowance, the costs shall be shared, as outlined in the Ontario *Public Service Works on Highways Act*. Other projects within this category will have an economic evaluation completed where applicable in accordance with both the DSC and Appendix E of Horizon Utilities' Conditions of Service.

Identification of System Impacts (5.4.5.2.C.a.ix) (where applicable)

System expansion, if required, to connect customers within this category is governed by Horizon Utilities' Conditions of Service, Section 2.1.2.1.

Capital Project Summary

General Information on Project (5.4.5.2.A)

Project Name	2015 Road Relocations
Budget Year	2015
Investment Category	System Access
Project Description	Projects in this category involve 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, the Ministry of Transportation, and the Region of Niagara.

Capital Investment (5.4.5.2.A.i)		
	Capital Investment (gross)	$ 2,990,011
	Customer Contribution	$ 904,360
	Capital Investment (net)	$ 2,085,561
	O&M Expenditure	$ 0

Customer Attachments / Load (kVA) (5.4.5.2.A.ii): n/a

Project Dates (5.4.5.2.A.iii)

Start Date	Various – driven by road authority schedules
In Service Date	Various – driven by road authority schedules

Expenditure Timing

Q1	Q2	Q3	Q4
25%	25%	25%	25%

Schedule Risk and Risk Mitigation (5.4.5.2.A.iv**)**

The initiation and timing of these projects are dictated by the City of Hamilton, City of St. Catharines, the Ministry of Transportation, or the Region of Niagara. Consequently, the timing and value of investment required by Horizon Utilities is subject to change.
Please refer to Note I for an explanation on general risk and cost mitigation.

Comparative Information from Equivalent Projects (5.4.5.2.A.v)

Road relocations for the 2010 to 2013 Historical Years and the 2014 Bridge Year are:

2010 (CGAAP) - $ 2,889,575
2011 (CGAAP)- $ 895,524
2012 (MIFRS) - $ 3,151,887
2013 (MIFRS) - $ 340,491
2014 (MIFRS) - $ 977,024

Total Capital OM&A Costs Associated with REG Investments (5.4.5.2.A.vi)

This project is not associated with an REG investment and therefore OM&A costs related to REG will not be incurred.

Leave to Construct Approval (5.4.5.2.A.vii)

This project does not require "Leave to Construct" under Section 92 of the *Ontario Energy Board Act* 1998.

Evaluation Criteria and Information (5.4.5.2.B)

Project Name 2015 Road Relocations Table 2

Efficiency, Customer Value, Reliability (5.4.5.2.B.1)

Investment Driver (5.4.5.2.B.1.a)

System Access (90%)

Secondary Driver (5.4.5.2.B.1.a)

System Renewal (5%)
System Service (5%)

Investment Priority (5.4.5.2.B.1.b)
5 – Mandatory Project

Analysis of Project and Project Alternatives (5.4.5.2.B.1.c) (where applicable)

Horizon Utilities co-ordinates project design and discusses design alternatives for each project with the organization (City, Region, Ministry of Transportation) from which the request originates to relocate distribution assets.

Safety (5.4.5.2.B.2)

These projects are not intended to address safety concerns with the distribution system.

Cyber-Security and Privacy (5.4.5.2.B.3) (where applicable)

Cyber-Security and Privacy are not applicable to this project.

Co-ordination and Interoperability (5.4.5.2.B.4)

Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.5.2.B.4.a) (where applicable)

Timelines for the execution of these projects are dictated by the City of Hamilton, City of 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.

Enabling of Future Technology and/or Future Operational Requirements (5.4.5.2.B.4.b)

Please refer to Note IV for an explanation enabling of future technology and future operational requirements.

	Economic Development (5.4.5.2.B.5) **(where applicable)** Horizon Utilities ensures that policies and practices do not unnecessarily create barriers to economic development which are primarily focused within its communities.
	Environmental Benefits (5.4.5.2.B.6) **(where applicable)** n/a

System Access Specific Requirements (5.4.5.2.C.a)

Project Name 2015 Road Relocations Table 3

System Access Specific Requirements (5.4.5.2.C.a)

Factors Affecting Implementing Project Timing/Priority (5.4.5.2.C.a.i)

The road authority's schedule and timing of the road project will affect the Horizon Utilities' project implementation and timing.

Factors Related to Customer Preference or 3rd Party Input (5.4.5.2.C.a.ii)

Road relocation projects involve a co-ordinated design process and the initiating organization (City, Municipality, or Ministry of Transportation) has input into the design of the project.
The designs for all projects within the public right-of-way are reviewed with the City (whether Hamilton or St. Catharines) as Municipal Consents are required prior to construction. Consideration is given by the road authority to coordinate all utilities within the right-of-way in the least disruptive manner.

Factors Affecting Final Project Cost (5.4.5.2.C.a.iii)

Please refer to Note I for an explanation on the factors that can affect the final project cost.

Controllable Cost Minimization (5.4.5.2.C.a.iv)

50% of Labour, Labour saving devices and Equipment rentals are recovered from the road authority. Please refer to Note I for an explanation on controllable cost minimization.

Other Planning Objectives (5.4.5.2.C.a.v)

Horizon Utilities combines work to reduce overall costs and increase efficiency. The most common opportunity is during city road relocation projects where a new water main is being installed. Horizon Utilities may be able to take advantage of the fact that installing duct structure is less costly since the road is already excavated. Horizon Utilities may also be able to change the schedule of a renewal project to align with the road authority's work to maximize these benefits. The costs of these additional works are allocated to either system service or system renewal where applicable. Horizon Utilities can maximize the amount of work that can be completed at the lowest cost to benefit ratepayers in these cases.

Assessment of Technical or Implementation Options (5.4.5.2.C.a.vi)

Horizon Utilities co-ordinates project design and discusses design alternatives for each project with the road authority (City, Municipality, Ministry of Transportation) originating the request to relocate distribution assets.

Summary of Options Analysis (5.4.5.2.C.a.vii) (where applicable)

Horizon Utilities reviews proposed design with municipalities and the Ministry of Transportation, as applicable, in an effort to determine the most cost effective solution.

Final Economic Evaluation Results (5.4.5.2.C.a.viii) (where applicable)

n/a

Identification of System Impacts (5.4.5.2.C.a.ix) (where applicable)

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.

Capital Project Summary

General Information on Project (5.4.5.2.A)

Project Name	2015 Customer Connections			
Budget Year	2015			
Investment Category	System Access			
Project Summary	Projects in this category include multiple projects required to connect, upgrade, or disconnect customers to the distribution system. Horizon Utilities' obligation to connect new customers is governed by the *Electricity Act, 1998, Schedule 28.*			
Capital Investment (5.4.5.2.A.i)	Capital Investment (gross)	$ 4,414,998		
	Customer Contribution	$ 728,725		
	Capital Investment (net)	$ 3,686,273		
	O&M Expenditure	n/a		
Customer Attachments / Load (kVA) (5.4.5.2.A.ii)	Horizon Utilities completes approximately 1800 connections annually; 1500 through subdivisions and 300 customer projects, contributing approximately 25MVA in system load growth.			
Project Dates (5.4.5.2.A.iii)	Start Date	Various – as driven by the customer		
	In Service Date	Various – as driven by the customer		
	Expenditure Timing			
	Q1	Q2	Q3	Q4
	25%	25%	25%	25%

Schedule Risk and Risk Mitigation (5.4.5.2.A.iv**)**

Please refer to Note I for risk and risk mitigation.

Comparative Information from Equivalent Projects (5.4.5.2.A.v)

Comparable investments, net of capital contributions, for the 2010 to 2013 Historical Years and the 2014 Bridge Year are:

2010 (CGAAP)- $ 1,023,336
2011 (CGAAP)- $ 2,030,541
2012 (MIFRS) - $ 1,652,000
2013 (MIFRS) - $ 3,541,455
2014 (MIFRS) - $ 4,063,471

Total Capital OM&A Costs Associated with REG Investments (5.4.5.2.A.vi)

This project is not associated with an REG investment and therefore OM&A costs related to REG will not be incurred.

Leave to Construct Approval (5.4.5.2.A.vii)

This project does not require "Leave to Construct" under Section 92 of the *Ontario Energy Board Act* 1998.

Evaluation Criteria and Information (5.4.5.2.B)

Project Name	2015 Customer Connections	Table 2

Efficiency, Customer Value, Reliability (5.4.5.2.B.1)

Investment Driver (5.4.5.2.B.1.a)
System Access (100%)

Secondary Driver (5.4.5.2.B.1.a)
N/A

Investment Priority (5.4.5.2.B.1.b)
5 – Mandatory Project

Analysis of Project and Project Alternatives (5.4.5.2.B.1.c)
Customer connection projects are driven by customer requests and the customer's specific technical requirements. To build efficiencies into the process, Horizon Utilities utilizes a set of design standards that have been engineered and approved. Customer connections requests are fulfilled consistent with Horizon Utilities' Conditions of Service, designed to meet the customer requirements and maintain system reliability.

Safety (5.4.5.2.B.2)

These projects are not intended to address safety concerns with the distribution system.

Cyber-Security and Privacy (5.4.5.2.B.3) (where applicable) (where applicable)

n/a

Co-ordination and Interoperability (5.4.5.2.B.4) **(where applicable)**

Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.5.2.B.4.a) (where applicable)
Please refer to Note II for an explanation on co-ordination with utilities, regional planning and/or links with 3rd parties.

Enabling of Future Technology and/or Future Operational Requirements (5.4.5.2.B.4.b)

This is not applicable for these projects.

Economic Development (5.4.5.2.B.5) **(where applicable)**

Horizon Utilities ensures that policies and practices do not unnecessarily create barriers to economic development which are primarily focused within its communities.

	Environmental Benefits (5.4.5.2.B.6) **(where applicable)** n/a

System Access Specific Requirements (5.4.5.2.C.a)	**Project Name** 2015 Customer Connections Table 3
	System Access Specific Requirements (5.4.5.2.C.a) **Factors Affecting Implementing Project Timing/Priority (5.4.5.2.C.a.i)** Schedule of work is based on customer expectations; customer request may not be standard design. **Factors Related to Customer Preference or 3rd Party Input (5.4.5.2.C.a.ii)** These projects are customer initiated and are designed to meet customer identified requirements. **Factors Affecting Final Project Cost (5.4.5.2.C.a.iii)** Please refer to Note I for an explanation on the factors affecting final project cost. **Controllable Cost Minimization (5.4.5.2.C.a.iv)** Please refer to Note I for an explanation on the factors affecting controllable cost. **Other Planning Objectives (5.4.5.2.C.a.v)** n/a **Assessment of Technical or Implementation Options (5.4.5.2.C.a.vi)** Please refer to Note III for information on the technical and implementation options. **Summary of Options Analysis (5.4.5.2.C.a.vii)** Please refer to Note III for information on the technical and implementation options. **Final Economic Evaluation Results (5.4.5.2.C.a.viii)** Horizon Utilities completes the economic evaluation for any customer system access project which requires the construction of new facilities to the main distribution system or an increase in the existing capacity of distribution facilities. For further details please see Appendix E of Horizon Utilities' Conditions of Service. The economic evaluation is completed in accordance with section 3.2 of the Distribution System Code ("DSC"). For the 2015-2019 forecast period Horizon Utilities has no known projects for which to provide the final economic evaluation. When a road authority requests a relocation of Horizon Utilities' plant located on the public road allowance, the costs shall be shared, as outlined in the Ontario *Public Service Works on Highways Act*. Other projects within this category will have an economic evaluation completed where applicable in accordance with both

	the DSC and Appendix E of Horizon Utilities' Conditions of Service. **Identification of System Impacts (5.4.5.2.C.a.ix) (where applicable)** System expansion, if required, to connect customers within this category are governed by Horizon Utilities' Conditions of Service Section 2.1.2.1.

Capital Project Summary

General Information on Project (5.4.5.2.A)

Project Name	2015 Reactive Renewal
Budget Year	2015
Investment Category	System Renewal
Project Summary	This category includes all projects required for the reactive renewal or repairs driven by emergency equipment failures and associated corrective action. Projects arise from trouble calls or inspection programs identifying an urgent need to replace system assets and the scope of the equipment replacement requires engineering. Also included in this category are projects to address customer power quality issues and Electrical Safety Authority ("ESA") due diligence inspection outcomes.

Capital Investment (5.4.5.2.A.i)	Capital Investment (gross)	$4,780,000
	Customer Contribution	n/a
	Capital Investment (net)	n/a
	O&M Expenditure	n/a
Customer Attachments / Load (kVA) (5.4.5.2.A.ii)	n/a	

Project Dates (5.4.5.2.A.iii)

Start Date	January 1, 2015
In Service Date	December 31, 2015

Expenditure Timing

Q1	Q2	Q3	Q4
25%	25%	25%	25%

Schedule Risk and Risk Mitigation (5.4.5.2.A.iv**)**

Please refer to Note I for risk and risk mitigation.

Comparative Information from Equivalent Projects (5.4.5.2.A.v)

Comparable investments for the 2010 to 2013 Historical Year and the 2014 Bridge Year are:
2010 (CGAAP)- $ 8,745,125
2011 (CGAAP)- $ 8,230,970
2012 (MIFRS) - $ 4,032,000
2013 (MIFRS) - $ 6.069,566
2014 (MIFRS) - $ 4,840,000

Total Capital OM&A Costs Associated with REG Investments (5.4.5.2.A.vi)

This project is not associated with an REG investment and therefore OM&A costs related to REG will not be incurred.

Leave to Construct Approval (5.4.5.2.A.vii)

This project does not require "Leave to Construct" under Section 92 of the *Ontario Energy Board Act 1998.*

Evaluation Criteria and Information (5.4.5.2.B)

Project Name 2015 Reactive Renewal Table 2

Efficiency, Customer Value, Reliability (5.4.5.2.B.1)

Investment Driver (5.4.5.2.B.1.a)
System Renewal (80%)

Secondary Driver (5.4.5.2.B.1.a)
System Service (20%)

Investment Priority (5.4.5.2.B.1.b)
5 – Mandatory project

Analysis of Project and Project Alternatives (5.4.5.2.B.1.c) (where applicable)

No alternatives are considered for these projects as they involve the emergency replacement of failed equipment required to restore service.

Safety (5.4.5.2.B.2)

These projects are intended to primarily address failed assets however investments required to address immediate safety issues, including issues presenting a potential risk to public safety identified by the ESA, and are included in this project.

Cyber-Security and Privacy (5.4.5.2.B.3) (where applicable) (where applicable)

n/a

Co-ordination and Interoperability (5.4.5.2.B.4) **(where applicable)**

Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.5.2.B.4.a) (where applicable)
Please refer to Note II for an explanation on co-ordination with utilities, regional planning and/or links with 3rd parties.

Enabling of Future Technology and/or Future Operational Requirements (5.4.5.2.B.4.b)

This is not applicable to these projects.

Economic Development (5.4.5.2.B.5) **(where applicable)**

Horizon Utilities ensures that policies and practices do not unnecessarily create barriers to economic development which are primarily focused within its communities.

Environmental Benefits (5.4.5.2.B.6) **(where applicable)**

n/a

System Renewal Specific Requirements (5.4.5.2.C.b)

Project Name	2015 Reactive Renewal	Table 3

System Renewal Specific Requirements (5.4.5.2.C.b)

Asset Performance Target and Asset Lifecycle Optimization (5.4.5.2.C.b.i.1)

These projects are reactive in nature and are initiated from equipment that has failed or that has a high risk of failure that would result in a service interruption. These projects have a very high probability of impacting Horizon Utilities' reliability targets.

Asset Condition Relative to Typical Life Cycle (5.4.5.2.C.b.i.2)

These projects address failed assets or assets with a high risk of imminent failure and as such, these assets are at the end of their useful life. The asset condition relative to their typical life cycle varies in each incident or outage.

Number of Customers Impacted (5.4.5.2.C.b.i.3)

The number of customers impacted varies in each incident or outage.

Quantitative Customer Impact and Risk (5.4.5.2.C.b.i.4)

The quantitative customer impact varies in each incident or outage.

Qualitative Customer Impact and Risk (5.4.5.2.C.b.i.5)

These projects address customer satisfaction as they are required to address failed assets that have either caused a system interruption, or have a high probability of causing a service interruption.

Value of Customer Impact (5.4.5.2.C.b.i.6)

The value of the customer impact varies in each incident or outage.

Other Factors Affecting Project Timing (5.4.5.2.C.b.ii)

These projects are reactive in nature and address failed assets, or assets at risk of imminent failure. Investments must be performed when identified.

Impact on System O&M Costs (5.4.5.2.C.b.iii)

These projects do not materially impact system O&M costs.

Reliability and Safety Factors (5.4.5.2.C.b.iv)

Improvements to reliability and security are expected as secondary benefits to this project.

Analysis of Project Benefits and Timing (5.4.5.2.C.b.v) (where applicable)

Investment for this project addresses failed assets, or assets at risk of imminent failure. Investments are not subject to project prioritization as they are reactive and non-discretionary.

	Like-for-Like Renewal Analysis (5.4.5.2.C.b.vi) Assets are replaced reactively to replace failed assets, or assets at risk of imminent failure are performed on a like-for-like basis. No extra costs to address other distributor planning objectives are incurred with these projects.

horizon UTILITIES Looking beyond...

Capital Project Summary

General Information on Project (5.4.5.2.A)

Project Name	HI-F3 Renewal –Governor's Road West of Pirie Drive				
Budget Year	2015				
Investment Category	System Renewal				
Project Summary	This project involves the renewal of 4kV distribution assets on the Highland F3 feeder as part of the 4kV and 8kV Renewal Program. The assets are located along Governor's Road West of Pirie Drive.				
Capital Investment (5.4.5.2.A.i)	Capital Investment (gross)	$973,728			
	Customer Contribution	$0			
	Capital Investment (net)	$973,728			
	O&M Expenditure	$ 0			
Customer Attachments / Load (kVA) (5.4.5.2.A.ii)	The project affects 48 customers and 1,025kVA of transformation.				
Project Dates (5.4.5.2.A.iii)	Start Date	2015/03/01			
	In Service Date	2015/09/30			
	Expenditure Timing				
	Q1	Q2	Q3	Q4	
	14%	43%	43%	O%	

Schedule Risk and Risk Mitigation (5.4.5.2.A.iv**)**

Please refer to Note I for risk and risk mitigation.

Comparative Information from Equivalent Projects (5.4.5.2.A.v)

There is no direct comparator in scope, size and design characteristics for this project. This project is one phase of a multi-year investment to renew the area served by Highland substation as part of the 4kV and 8kV Renewal Program. The 2015 investment for the renewal of Highland substation is $1,128,000. The 2015 investment in the 4kV and 8kV Renewal Program is $8,160,000. Comparable gross investments for the 4kv and 8kV Renewal Program for the 2010 to 2013 Historical Years and the 2014 Bridge Year are:

2010 (CGAAP)- $ 2,556,076
2011 (CGAAP)- $ 8,820,000
2012 (MIFRS) - $ 5,268,441
2013 (MIFRS) - $ 5,072,233
2014 (MIFRS) - $ 6,434,000

Total Capital OM&A Costs Associated with REG Investments (5.4.5.2.A.vi)

This project is not associated with an REG investment and therefore OM&A costs related to REG will not be incurred.

Leave to Construct Approval (5.4.5.2.A.vii)

This project does not require “Leave to Construct” under Section 92 of the *Ontario Energy Board Act* 1998.

Evaluation Criteria and Information (5.4.5.2.B)

Project Name HI-F3 Renewal –Governor’s Road West of Pirie Drive Table 2

Efficiency, Customer Value, Reliability (5.4.5.2.B.1)

Investment Driver (5.4.5.2.B.1.a)
System Renewal (80%)

Secondary Driver (5.4.5.2.B.1.a)
System Service (20%)

Investment Priority (5.4.5.2.B.1.b)

3 – Required project

Analysis of Project and Project Alternatives (5.4.5.2.B.1.c)

This project is part of the multi-year 4kV and 8kV Renewal Program. Both the 4kV and 8kV distribution system and the Horizon Utilities owned substations are at the end of their useful life. Horizon Utilities has chosen to renew the 4kV and 8kV distribution systems to a higher voltage to avoid the cost of the investment in the renewal of the substations. The total avoided substation renewal investment over the remaining 35 years of the program is $70,000,000 for all 28 substations. Therefore the renewal of the distribution assets at the current 4kV level was not a feasible alternative.

This project is the first project of multiple projects required to renew the service territory serviced by Highland substation.

Safety (5.4.5.2.B.2)

This project is not intended to address safety concerns with the distribution system

Cyber-Security and Privacy (5.4.5.2.B.3) (where applicable)

n/a

Co-ordination and Interoperability (5.4.5.2.B.4) **(where applicable)**

Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.5.2.B.4.a) (where applicable)
Please refer to Note II for an explanation on co-ordination with utilities, regional planning and/or links with 3rd parties.

Enabling of Future Technology and/or Future Operational Requirements (5.4.5.2.B.4.b)

Please refer to Note IV for an explanation enabling of future technology and future operational requirements.

	Economic Development (5.4.5.2.B.5) **(where applicable)** Horizon Utilities ensures that policies and practices do not unnecessarily create barriers to economic development which are primarily focused within its communities.
	Environmental Benefits (5.4.5.2.B.6) **(where applicable)** n/a

System Renewal Specific Requirements (5.4.5.2.C.b)	**Project Name**	HI-F3 Renewal –Governor's Road West of Pirie Drive Table 3
	System Renewal Specific Requirements (5.4.5.2.C.b) **Asset Performance Target and Asset Lifecycle Optimization (5.4.5.2.C.b.i.1)** The distribution assets in the Dundas operating area are in poor health and have significant operating constraints. 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'. **Asset Condition Relative to Typical Life Cycle (5.4.5.2.C.b.i.2)** Generally the 4kV assets are the oldest vintage in the system. 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. **Number of Customers Impacted (5.4.5.2.C.b.i.3)** This project impacts 48 customers. **Quantitative Customer Impact and Risk (5.4.5.2.C.b.i.4)** SAIDI of 0.002 **Qualitative Customer Impact and Risk (5.4.5.2.C.b.i.5)** This project will address aging assets with inadequate backup. Aging assets represent an increased risk of service interruption to customers and inadequate backup would result in long duration service interruptions upon occurrence. These factors would lead to customer dissatisfaction in this area. **Value of Customer Impact (5.4.5.2.C.b.i.6)** High **Other Factors Affecting Project Timing (5.4.5.2.C.b.ii)** The renewal of the area serviced by Highland substation is scheduled for renewal in 2015, 2016 and 2017. This project is required to be completed in 2015 to allow for the renewal of the remaining area to completed on schedule.	

Impact on System O&M Costs (5.4.5.2.C.b.iii)

This project will have no material impact on planned O&M costs. The renewal of the 4kV and 8kV distribution systems, as a whole, will provide a reduction in reactive O&M costs to address service interruptions caused by failed equipment. These reductions will not be material in the 2015 to 2019 Test Years.

Reliability and Safety Factors (5.4.5.2.C.b.iv)

The renewal of the 4kV and 8kV distribution system will provide reliability improvements through reduced service interruptions caused by failed equipment.

Analysis of Project Benefits and Timing (5.4.5.2.C.b.v)

The timing of this project, as part of the 4kV and 8kV Renewal Program, is determined through the assessment of the distribution system health and the health of the substation assets servicing the area. Renewal of this area will allow for the decommissioning of the substation assets by 2017 thereby avoiding the need for capital investment into these substations.

Like-for-Like Renewal Analysis (5.4.5.2.C.b.vi)

The like-for-like renewal of these assets (i.e. same system configuration and same distribution voltage) will perpetuate the existing operating constraints and require capital investment to renew substation assets. Renewal of the distribution assets at a higher voltage does not involve any material incremental costs over renewal at the existing voltage. Operating constraints (e.g. undersized conductor, radial feeds) are addressed on a case by case basis where appropriate.

Capital Project Summary

General Information on Project (5.4.5.2.A)

Project Name	HI-F3 Renewal U/G Bridlewood subdivision
Budget Year	2015
Investment Category	System Renewal
Project Summary	This project involves the renewal of XLPE in the Bridlewood subdivision within the Dundas operating area.

Capital Investment (5.4.5.2.A.i)	Capital Investment (gross)	$2,105,630
	Customer Contribution	$0
	Capital Investment (net)	$2,105,630
	O&M Expenditure	$0

Customer Attachments / Load (kVA) (5.4.5.2.A.ii)	This project affects 178 customers and 600kVA of transformation
Project Dates (5.4.5.2.A.iii)	Start Date 2015/06/01
	In Service Date 2015/12/31

Expenditure Timing

Q1	Q2	Q3	Q4
0%	14%	43%	43%

Schedule Risk and Risk Mitigation (5.4.5.2.A.iv**)**

Please refer to Note I for risk and risk mitigation.

Comparative Information from Equivalent Projects (5.4.5.2.A.v)

There is no direct comparator in scope, size and design characteristics for this project. This project supports both the 4kV and 8kV Renewal Program and the XLPE Renewal Program.

Total Capital OM&A Costs Associated with REG Investments (5.4.5.2.A.vi)

This project is not associated with an REG investment and therefore OM&A costs related to REG will not be incurred.

Leave to Construct Approval (5.4.5.2.A.vii)

This project does not require “Leave to Construct” under Section 92 of the *Ontario Energy Board Act* 1998.

Evaluation Criteria and Information (5.4.5.2.B)	**Project Name** HI-F3 Renewal U/G Bridlewood subdivision Table 2
	Efficiency, Customer Value, Reliability (5.4.5.2.B.1) **Investment Driver (5.4.5.2.B.1.a)** System Renewal (80%) **Secondary Driver (5.4.5.2.B.1.a)** System Service (20%) **Investment Priority (5.4.5.2.B.1.b)** 3 – Required project
	Analysis of Project and Project Alternatives (5.4.5.2.B.1.c) This is currently a 4kV underground distribution and Horizon Utilities has chosen to renew the 4kV and 8kV distribution systems to a higher voltage to avoid the cost of the investment in the renewal of the substations. The total avoided substation renewal investment over the remaining 35 years of the plan is $70,000,000 for all 28 substations. Therefore, the renewal of this project at the current 4kV level was not a feasible alternative.
	Safety (5.4.5.2.B.2) This project is not intended to address safety concerns with the distribution system.
	Cyber-Security and Privacy (5.4.5.2.B.3) (where applicable) n/a
	Co-ordination and Interoperability (5.4.5.2.B.4) **(where applicable)** **Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.5.2.B.4.a) (where applicable)** Please refer to Note II for an explanation on co-ordination with utilities, regional planning and/or links with 3rd parties. **Enabling of Future Technology and/or Future Operational Requirements (5.4.5.2.B.4.b)** Please refer to Note IV for an explanation enabling of future technology and future operational requirements.
	Economic Development (5.4.5.2.B.5) **(where applicable)** Horizon Utilities ensures that policies and practices do not unnecessarily create barriers to economic development which are primarily focused within its communities.
	Environmental Benefits (5.4.5.2.B.6) **(where applicable)** n/a

System Renewal Specific Requirements (5.4.5.2.C.b)

Project Name	HI-F3 Renewal U/G Bridlewood subdivision	Table 3

System Renewal Specific Requirements (5.4.5.2.C.b)

Asset Performance Target and Asset Lifecycle Optimization (5.4.5.2.C.b.i.1)

XLPE primary cable is the asset group with the largest investment requirement as identified by the Kinectrics ACA. 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

The Dundas operating area has 13.5km of XLPE cable with a Health Index of either "very poor" or "poor".

Asset Condition Relative to Typical Life Cycle (5.4.5.2.C.b.i.2)

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.

Number of Customers Impacted (5.4.5.2.C.b.i.3)

This project impacts 178 customers.

Quantitative Customer Impact and Risk (5.4.5.2.C.b.i.4)

SAIDI of 0.006

Qualitative Customer Impact and Risk (5.4.5.2.C.b.i.5)

This project will address aging assets with inadequate backup. Aging assets represent an increased risk of service interruption to customers and inadequate backup would result in long duration service interruptions upon occurrence. These factors would lead to customer dissatisfaction in this area.

Value of Customer Impact (5.4.5.2.C.b.i.6)

High

Other Factors Affecting Project Timing (5.4.5.2.C.b.ii)

The timing of this project is required to co-ordinate with the 4kV and 8kV Renewal Program as it involves both the renewal of XLPE primary cable and the renewal of the underground section of the Highland substation F3 feeder. Renewal of this area will allow for the decommissioning of the substation assets by 2017 thereby avoiding the need for capital investment into these substations.

Impact on System O&M Costs (5.4.5.2.C.b.iii)

This project will have no material impact on planned O&M costs. The renewal of the 4kV and 8kV distribution systems, as a whole, will provide a reduction in reactive O&M costs to address service interruptions caused by failed equipment. These reductions will not be material in the 2015 to 2019 Test Years.

Reliability and Safety Factors (5.4.5.2.C.b.iv)

The renewal of XLPE primary cable will provide reliability improvements through reduced service interruptions caused by failed equipment. The cable renewed by this project is direct buried and therefore subject to extended outages, requiring multiple hours to repair, upon failure.

Analysis of Project Benefits and Timing (5.4.5.2.C.b.v)

The timing of this project is required to co-ordinate with the 4kV and 8kV Renewal Program as it involves both the renewal of XLPE primary cable and the renewal of the underground section of the Highland substation F3 feeder. Renewal of this area will allow for the decommissioning of the substation assets by 2017 thereby avoiding the need for capital investment into these substations.

Like-for-Like Renewal Analysis (5.4.5.2.C.b.vi)

The like-for-like renewal of these assets (i.e. same system configuration and same distribution voltage) will perpetuate the existing operating constraints and require capital investment to renew substation assets. Renewal of the distribution assets at a higher voltage does not involve any material incremental costs over renewal at the existing voltage. Operating constraints (e.g. undersized conductor, radial feeds) are addressed on a case by case basis where appropriate.

Capital Project Summary

General Information on Project (5.4.5.2.A)

Project Name	2015 Pole Residual Replacements
Budget Year	2015
Investment Category	System Renewal
Project Summary	This project involves the replacement of wood poles identified by pole residual testing as having a high risk of failure.

Capital Investment (5.4.5.2.A.i)

Capital Investment (gross)	$1,225,920
Customer Contribution	$0
Capital Investment (net)	$1,225,920
O&M Expenditure	$0

Customer Attachments / Load (kVA) (5.4.5.2.A.ii): n/a

Project Dates (5.4.5.2.A.iii)

Start Date 2015/01/01

In Service Date 2015/06/30

Expenditure Timing

Q1	Q2	Q3	Q4
50%	50%	0%	0%

Schedule Risk and Risk Mitigation (5.4.5.2.A.iv**)**

Please refer to Note I for risk and risk mitigation.

Comparative Information from Equivalent Projects (5.4.5.2.A.v)

Comparable gross investments for the 2010 to 2013 Historical Year and the 2014 Bridge Year are:
2010 (CGAAP)- $ 1,326,407
2011 (CGAAP)- $ 895,000
2012 (MIFRS) - $ 930,000
2013 (MIFRS) - $ 718,074
2014 (MIFRS) - $ 1,190,000

Total Capital OM&A Costs Associated with REG Investments (5.4.5.2.A.vi)

This project is not associated with an REG investment and therefore OM&A costs related to REG will not be incurred.

Leave to Construct Approval (5.4.5.2.A.vii)

This project does not require “Leave to Construct” under Section 92 of the *Ontario Energy Board Act* 1998.

Evaluation Criteria and Information (5.4.5.2.B)

Project Name	2015 Pole Residual Replacements	Table 2

Efficiency, Customer Value, Reliability (5.4.5.2.B.1)

Investment Driver (5.4.5.2.B.1.a)
System Renewal (100%)

Secondary Driver (5.4.5.2.B.1.a)
n/a

Investment Priority (5.4.5.2.B.1.b)
3 – Required project

Analysis of Project and Project Alternatives (5.4.5.2.B.1.c)

The replacement of wood poles in this project is identified through Horizon Utilities' pole testing maintenance program. The pole testing categorized the poles requiring replacement into two categories: 1) requiring immediate replacement; and 2) requiring replacement within five years.

Horizon Utilities replaces poles requiring immediate replacement as soon as possible to mitigate the risk of service interruptions and the risk to public safety resulting from a failure of the pole.

Horizon Utilities replaces poles requiring replacement within five years in the following year. Failure to replace in the following year compounds the volume of work in subsequent years resulting in cascading delays and compounded volumes in subsequent years.

Poles replaced in this project are replaced on a like-for-like basis where possible.

Safety (5.4.5.2.B.2)

This project will address wood poles requiring replacement as identified through testing. Renewal of these assets prior to failure avoids the potential risk to public safety that would result from a failure of a wood pole.

Cyber-Security and Privacy (5.4.5.2.B.3) (where applicable)

Cyber-Security and Privacy are not applicable to this project.

Co-ordination and Interoperability (5.4.5.2.B.4) **(where applicable)**

Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.5.2.B.4.a) (where applicable)
Please refer to Note II for an explanation on co-ordination with utilities, regional planning and/or links with 3rd parties.

Enabling of Future Technology and/or Future Operational Requirements (5.4.5.2.B.4.b) (where applicable)
n/a

Economic Development (5.4.5.2.B.5) **(where applicable)**

Horizon Utilities ensures that policies and practices do not unnecessarily create barriers to economic development which are primarily focused within its communities.

Environmental Benefits (5.4.5.2.B.6) **(where applicable)**

n/a

System Renewal Specific Requirements (5.4.5.2.C.b)

Project Name 2015 Pole Residual Replacements Table 3

System Renewal Specific Requirements (5.4.5.2.C.b)

Asset Performance Target and Asset Lifecycle Optimization (5.4.5.2.C.b.i.1)

This project is reactive in nature the work required is initiated through Horizon Utilities' maintenance and inspection programs. This project has a very high probability of impacting Horizon Utilities' reliability targets if the poles are not replaced.

Asset Condition Relative to Typical Life Cycle (5.4.5.2.C.b.i.2)

This project address wood poles that have been identified as having a high risk of failure and as such, these assets are at the end of their useful life. The asset condition relative to their typical life cycle varies in case.

Number of Customers Impacted (5.4.5.2.C.b.i.3)

The number of customers impacted varies in each incident or outage.

Quantitative Customer Impact and Risk (5.4.5.2.C.b.i.4)

The quantitative customer impact varies in each incident or outage.

Qualitative Customer Impact and Risk (5.4.5.2.C.b.i.5)

These projects address customer satisfaction as they are required to address assets at risk of failure which would result in a service interruption.

Value of Customer Impact (5.4.5.2.C.b.i.6)

The value of the customer impact varies in each incident or outage.

Other Factors Affecting Project Timing (5.4.5.2.C.b.ii)

These projects are reactive in nature and address assets at risk of failure. Horizon Utilities replaces poles requiring immediate replacement as soon as possible to mitigate the risk of service interruptions and the risk to public safety resulting from a failure of the pole.

Horizon Utilities replaces poles requiring replacement within five years in the following year. Failure to replace in the following year compounds the volume of work in subsequent years resulting in cascading delays and compounded volumes in subsequent years.

Impact on System O&M Costs (5.4.5.2.C.b.iii)

These projects do not materially impact system O&M costs.

Reliability and Safety Factors (5.4.5.2.C.b.iv)

This project will provide reliability and safety benefits as the project involves the replacement of wood poles that are at risk of failure. Failure of the asset would result in a service interruption and a potential risk to public safety.

Analysis of Project Benefits and Timing (5.4.5.2.C.b.v)

These poles present a risk to public safety and are scheduled in the near term.

Like-for-Like Renewal Analysis (5.4.5.2.C.b.vi)

Poles replaced in this project are replaced on a like-for-like basis where possible as this presents the lowest cost option. No additional costs are incurred to address other distributor planning objectives.

Capital Project Summary

General Information on Project (5.4.5.2.A)

Project Name	2015 Load Break Disconnect Switch ("LBDS") Replacement
Budget Year	2015
Investment Category	System Renewal
Project Summary	This project involves the replacement of LBDS found to be either inoperable or beyond economic repair (where the cost of maintenance is not warranted) as found through Horizon Utilities' maintenance and inspection programs. Such switches will be replaced with automated switches where an operational benefit can be realized. This is a multi-year program based on 16 replacements per year

Capital Investment (5.4.5.2.A.i)	Capital Investment (gross)	$323,000
	Customer Contribution	$0
	Capital Investment (net)	$323,000
	O&M Expenditure	$0

Customer Attachments / Load (kVA) (5.4.5.2.A.ii)	n/a

Project Dates (5.4.5.2.A.iii)

Start Date	2015/01/01
In Service Date	2015/06/30

Expenditure Timing

Q1	Q2	Q3	Q4
0%	0%	50%	50%

Schedule Risk and Risk Mitigation (5.4.5.2.A.iv**)**

Please refer to Note I for risk and risk mitigation.

Comparative Information from Equivalent Projects (5.4.5.2.A.v)

Comparable gross investments for the 2010 to 2013 Historical Years and the 2014 Bridge Year are:

2010 (CGAAP)- $ 0
2011 (CGAAP)- $ 0
2012 (MIFRS) - $ 0
2013 (MIFRS) - $ 212,000
2014 (MIFRS) - $ 312,000

Total Capital OM&A Costs Associated with REG Investments (5.4.5.2.A.vi)

This project is not associated with an REG investment and therefore OM&A costs related to REG will not be incurred.

Leave to Construct Approval (5.4.5.2.A.vii)

This project does not require "Leave to Construct" under Section 92 of the *Ontario Energy Board Act* 1998.

Evaluation Criteria and Information (5.4.5.2.B)

Project Name 2015 LBDS Replacement Table 2

Efficiency, Customer Value, Reliability (5.4.5.2.B.1)

Investment Driver (5.4.5.2.B.1.a)
System Renewal (80%)

Secondary Driver (5.4.5.2.B.1.a)
System Service (20%)

Investment Priority (5.4.5.2.B.1.b)
3 – Required project

Analysis of Project and Project Alternatives (5.4.5.2.B.1.c)

This project involves the replacement of LBDS switches identified as requiring replacement through Horizon Utilities' maintenance and inspection programs. When feasible, the switches are refurbished rather than replaced. Where refurbishment is not possible the switches will be replaced with an automated switch where an operational benefit can be realized.

Safety (5.4.5.2.B.2)

This project is not intended to address safety concerns with the distribution system.

Cyber-Security and Privacy (5.4.5.2.B.3) (where applicable)

Horizon Utilities utilizes the Smart Meter communication infrastructure when communicating with automated switches. Horizon Utilities' Smart Meter and related AMI network have been procured through Elster. Elster's system supports a multi-layered security approach including: access control, authorization, authentication and data integrity protocols. As part of its continuous improvement model, Horizon Utilities performs periodic security assessments to identify opportunities for enhanced system hardening.

Co-ordination and Interoperability (5.4.5.2.B.4)

Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.5.2.B.4.a) (where applicable)

Please refer to Note II for an explanation on co-ordination with utilities, regional planning and/or links with 3rd parties.

Enabling of Future Technology and/or Future Operational Requirements (5.4.5.2.B.4.b) (where applicable)
n/a

Economic Development (5.4.5.2.B.5) **(where applicable)**

Horizon Utilities ensures that policies and practices do not unnecessarily create barriers to economic development which are primarily focused within its communities.

Environmental Benefits (5.4.5.2.B.6) **(where applicable)**

n/a

System Renewal Specific Requirements (5.4.5.2.C.b)

Project Name	2015 LBDS Replacement	Table 3

System Renewal Specific Requirements (5.4.5.2.C.b)

Asset Performance Target and Asset Lifecycle Optimization (5.4.5.2.C.b.i.1)

LBDS are critical devices for the operation of the distribution system and are installed at key operating points (e.g. feeder tie points, feeder sectionalizing). Unplanned failures of these devices would impact Horizon Utilities' ability to restore power, resulting in extended outages.

Asset Condition Relative to Typical Life Cycle (5.4.5.2.C.b.i.2)

The asset condition of LBDS relative to their typical lifecycle varies from switch to switch depending upon the operational stresses experienced by the switch. LBDS that are identified for replacement are replaced because they would not operate properly when required and are beyond economical repair.

Number of Customers Impacted (5.4.5.2.C.b.i.3)

No customers impacted if the work is planned.

Quantitative Customer Impact and Risk (5.4.5.2.C.b.i.4)

n/a

Qualitative Customer Impact and Risk (5.4.5.2.C.b.i.5)

Failure of an LBDS to operate when required can impact Horizon Utilities' operational ability which can adversely affect the service experienced by customers.

Value of Customer Impact (5.4.5.2.C.b.i.6)

The value of the customer impact varies in each instance.

Other Factors Affecting Project Timing (5.4.5.2.C.b.ii)

The timing of this project is dependent upon the timing of Horizon Utilities' LBDS maintenance program.

Impact on System O&M Costs (5.4.5.2.C.b.iii)

These projects do not materially impact system O&M costs.

Reliability and Safety Factors (5.4.5.2.C.b.iv)

Reliability can be adversely affected when a LBDS fails to operate when required as part of switching to restore service.

Analysis of Project Benefits and Timing (5.4.5.2.C.b.v)

n/a

Like-for-Like Renewal Analysis (5.4.5.2.C.b.vi)

LDBS are replaced with an automated switch where an operational benefit can be realized. Otherwise they are replaced on a like-for-like basis.

Capital Project Summary

General Information on Project (5.4.5.2.A)

Project Name	2015 Proactive Transformer Replacement		
Budget Year	2015		
Investment Category	System Renewal		
Project Summary	This project was established to proactively replace distribution transformers as required. Renewal of distribution transformers in the past has either been reactive upon failure or proactive when included in the 4kV & 8kV Renewal or XLPE Primary Cable renewal programs. There are instances where proactive replacement of transformers is required even when the replacement is outside of the scope of the programs mentioned above. This is a multi-year project, based on 25 replacements per year.		
Capital Investment (5.4.5.2.A.i)	Capital Investment (gross)	$350,000	
	Customer Contribution	$0	
	Capital Investment (net)	$350,000	
	O&M Expenditure	$0	
Customer Attachments / Load (kVA) (5.4.5.2.A.ii)	n/a		
Project Dates (5.4.5.2.A.iii)	Start Date	2015/06/01	
	In Service Date	2015/12/31	

Expenditure Timing

Q1	Q2	Q3	Q4
0%	0%	50%	50%

Schedule Risk and Risk Mitigation (5.4.5.2.A.iv**)**

Please refer to Note I for risk and risk mitigation.

Comparative Information from Equivalent Projects (5.4.5.2.A.v)

Comparable gross investments for the 2010 to 2013 Historical Years and the 2014 Bridge Year are:

2010 (CGAAP)- $ 0
2011 (CGAAP)- $ 104,447
2012 (MIFRS) - $ 185,523
2013 (MIFRS) - $ 276,978
2014 (MIFRS) - $ 339,000

Total Capital OM&A Costs Associated with REG Investments (5.4.5.2.A.vi)

This project is not associated with an REG investment and therefore OM&A costs related to REG will not be incurred.

Leave to Construct Approval (5.4.5.2.A.vii)

This project does not require "Leave to Construct" under Section 92 of the *Ontario Energy Board Act* 1998.

Evaluation Criteria and Information (5.4.5.2.B)

Project Name	2015 Proactive Transformer Replacement	Table 2

Efficiency, Customer Value, Reliability (5.4.5.2.B.1)

Investment Driver (5.4.5.2.B.1.a)
System Renewal (100%)

Secondary Driver (5.4.5.2.B.1.a)
N/A

Investment Priority (5.4.5.2.B.1.b)
3 – Required project

Analysis of Project and Project Alternatives (5.4.5.2.B.1.c)

Proactive transformer replacements are identified through Horizon Utilities' visual inspection programs and 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, in a reactive replacement scenario, the customer(s) may be subject to an extended outage duration;
- Transformers that have visible oil leaks; and
- Transformers that have been identified through testing as containing PCBs.

These criteria were selected due to the level of associated risk. Transformers with visible oil leaks or containing PCBs represent a significant environmental risk. All oil spills must be tracked, reported, and the oil reclaimed where possible. Obsolete transformers, where a replacement is not available in inventory, represent a risk of prolonged service interruption upon failure and are replaced to reduce the risk of outage to the customer.

Safety (5.4.5.2.B.2)

This project is not intended to address safety concerns with the distribution system.

Cyber-Security and Privacy (5.4.5.2.B.3) (where applicable)

Cyber-Security and Privacy are not applicable to this project.

Co-ordination and Interoperability (5.4.5.2.B.4) **(where applicable)**

Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.5.2.B.4.a) (where applicable)
Please refer to Note II for an explanation on co-ordination with utilities, regional planning and/or links with 3rd parties.

Enabling of Future Technology and/or Future Operational Requirements (5.4.5.2.B.4.b) (where applicable)
This is not applicable to this project.

	Economic Development (5.4.5.2.B.5) **(where applicable)** Horizon Utilities ensures that policies and practices do not unnecessarily create barriers to economic development which are primarily focused within its communities.
	Environmental Benefits (5.4.5.2.B.6) **(where applicable)** n/a
System Renewal Specific Requirements (5.4.5.2.C.b)	**Project Name** 2015 Proactive Transformer Replacement Table 3
	System Renewal Specific Requirements (5.4.5.2.C.b) **Asset Performance Target and Asset Lifecycle Optimization (5.4.5.2.C.b.i.1)** The transformers selected for proactive replacement represent a level of risk to Horizon Utilities and this project provides risk mitigation consistent with Horizon Utilities' asset management objectives. **Asset Condition Relative to Typical Life Cycle (5.4.5.2.C.b.i.2)** The asset condition of these transformers relative to their typical lifecycle varies from transformer to transformer. Transformers selected for replacement present a level of risk to Horizon Utilities either through imminent failure of the transformer or through the need to address environmental risk associated with PCBs; or through the risks associated with transformers that have visible oil leaks. **Number of Customers Impacted (5.4.5.2.C.b.i.3)** Varies per project. **Quantitative Customer Impact and Risk (5.4.5.2.C.b.i.4)** Varies per project. **Qualitative Customer Impact and Risk (5.4.5.2.C.b.i.5)** These criteria were selected due to the level of associated risk. Transformers with visible oil leaks or containing PCBs represent a significant environmental risk. All oil spills must be tracked, reported, and the oil reclaimed where possible. Obsolete transformers, where a replacement is not available in inventory, represent a risk of prolonged service interruption upon failure and are replaced to reduce the risk of outage to the customer. **Value of Customer Impact (5.4.5.2.C.b.i.6)** The value of the customer impact varies in each instance. **Other Factors Affecting Project Timing (5.4.5.2.C.b.ii)** n/a **Impact on System O&M Costs (5.4.5.2.C.b.iii)** These projects do not materially impact system O&M costs. **Reliability and Safety Factors (5.4.5.2.C.b.iv)** n/a.

Analysis of Project Benefits and Timing (5.4.5.2.C.b.v)
n/a.

Like-for-Like Renewal Analysis (5.4.5.2.C.b.vi)
n/a.

Capital Project Summary

General Information on Project (5.4.5.2.A)

Project Name	ST-F7 Renewal – Part 1		
Budget Year	2015		
Investment Category	System Renewal		
Project Summary	The project involves the renewal of the Strouds Substation F7 feeder in the Hamilton West operating area. This project is part of the 4kV and 8kV Renewal Program.		
Capital Investment (5.4.5.2.A.i)	Capital Investment (gross)	$1,020,180	
	Customer Contribution	$0	
	Capital Investment (net)	$1,020,180	
	O&M Expenditure	$0	
Customer Attachments / Load (kVA) (5.4.5.2.A.ii)	This project affects 474 customers and 1,818kVA transformation		
Project Dates (5.4.5.2.A.iii)	Start Date	2015/03/01	
	In Service Date	2015/10/31	

Expenditure Timing

Q1	Q2	Q3	Q4
28%	28%	28%	16%

Schedule Risk and Risk Mitigation (5.4.5.2.A.iv**)**

Please refer to Note I for risk and risk mitigation.

Comparative Information from Equivalent Projects (5.4.5.2.A.v)

There is no direct comparator in scope, size and design characteristics for this project. This project is one phase of a multi-year investment to renew the area served by Strouds substation as part of the 4kV and 8kV Renewal Program. The 2015 investment for the renewal of Strouds substation is $1,406,000. The 2015 investment in the 4kV and 8kV Renewal Program is $8,160,000.

Comparable gross investments for the 4kV and 8kV Renewal Program for the 2010 to 2013 Historical Years and the 2014 Bridge Year are:

2010 (CGAAP)- $ 2,556,076
2011 (CGAAP)- $ 8,820,000
2012 (MIFRS) - $ 5,268,441
2013 (MIFRS) - $ 5,072,233
2014 (MIFRS) - $ 6,434,000

Total Capital OM&A Costs Associated with REG Investments (5.4.5.2.A.vi) **(where applicable)**

This project is not associated with an REG investment and therefore OM&A costs related to REG will not be incurred.

Leave to Construct Approval (5.4.5.2.A.vii)

This project does not require "Leave to Construct" under Section 92 of the *Ontario Energy Board Act* 1998.

Evaluation Criteria and Information (5.4.5.2.B)

Project Name	ST-F7 Renewal – Part 1	Table 2

Efficiency, Customer Value, Reliability (5.4.5.2.B.1)

Investment Driver (5.4.5.2.B.1.a)
System Renewal (80%)

Secondary Driver (5.4.5.2.B.1.a)
System Service (20%)

Investment Priority (5.4.5.2.B.1.b)
4 – Required project

Analysis of Project and Project Alternatives (5.4.5.2.B.1.c)

This project is part of the multi-year 4kV and 8kV Renewal Program. Both the 4kV and 8kV distribution system and the Horizon Utilities-owned substations are at the end of their useful life. Horizon Utilities has chosen to renew the 4kV and 8kV distribution systems to a higher voltage to avoid the cost of the investment in the renewal of the substations. The total avoided substation renewal investment over the remaining 35 years of the plan is $70,000,000 for all 28 substations. Therefore, the renewal of the distribution assets at the current 4kV level was not a feasible alternative.

The renewal of the area serviced by the Strouds substation started in 2014 and is scheduled to be completed in 2018. Strouds substation was constructed in 1938. The switchgear at this substation is 44 years old and has a Health Index of 'very poor' as identified in the Substation Asset Condition Assessment ("SACA") and confirmed by the Kinectrics ACA.

Safety (5.4.5.2.B.2)

This project is not intended to address safety concerns with the distribution system.

Cyber-Security and Privacy (5.4.5.2.B.3) (where applicable)

Cyber-Security and Privacy are not applicable to this project.

Co-ordination and Interoperability (5.4.5.2.B.4)

Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.5.2.B.4.a) (where applicable)
Please refer to Note II for an explanation on co-ordination with utilities, regional planning and/or links with 3rd parties.

Enabling of Future Technology and/or Future Operational Requirements (5.4.5.2.B.4.b) (where applicable)
Please refer to Note IV for an explanation enabling of future technology and future operational requirements.

Economic Development (5.4.5.2.B.5) **(where applicable)**

Horizon Utilities ensures that policies and practices do not unnecessarily create barriers to economic development which are primarily focused within its communities.

Environmental Benefits (5.4.5.2.B.6) **(where applicable)**

n/a

System Renewal Specific Requirements (5.4.5.2.C.b)

Project Name	ST-F7 Renewal – Part 1	Table 3

System Renewal Specific Requirements (5.4.5.2.C.b)

Asset Performance Target and Asset Lifecycle Optimization (5.4.5.2.C.b.i.1)

The distribution assets in the Hamilton West operating area are in poor health and the switchgear in both substations servicing this area has switchgear with a 'very poor' Health Index.

Asset Condition Relative to Typical Life Cycle (5.4.5.2.C.b.i.2)

Generally the 4kV assets are the oldest vintage in the system. 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.

Number of Customers Impacted (5.4.5.2.C.b.i.3)
This project impacts 474 customers.

Quantitative Customer Impact and Risk (5.4.5.2.C.b.i.4)

SAIDI of 0.016

Qualitative Customer Impact and Risk (5.4.5.2.C.b.i.5)

This project will address aging assets with inadequate backup. Aging assets represent an increased risk of service interruption to customers and inadequate backup would result in long duration service interruptions upon occurrence. These factors would lead to customer dissatisfaction in this area.

Value of Customer Impact (5.4.5.2.C.b.i.6)

High

Other Factors Affecting Project Timing (5.4.5.2.C.b.ii)

The renewal of the area serviced by the Strouds substation is scheduled for 2014 to 2018. This project is required to be completed in 2015 to allow for the renewal of the remaining area to be completed on schedule.

Impact on System O&M Costs (5.4.5.2.C.b.iii)

This project will have no material impact on planned O&M costs. The renewal of the 4kV and 8kV distribution systems, as a whole, will provide a reduction in reactive O&M costs to address service interruptions caused by failed equipment. These reductions will not be material in the 2015 to 2019 Test Years.

Reliability and Safety Factors (5.4.5.2.C.b.iv)

The renewal of the 4kV and 8kV distribution system will provide reliability improvements through reduced service interruptions caused by failed equipment.

Analysis of Project Benefits and Timing (5.4.5.2.C.b.v)

The timing of this project, as part of the 4kV and 8kV Renewal Program, is determined through the assessment of the distribution system health and the health of the substation assets servicing the area. Kinectrics identified that both substations' switchgear had a high probability of failure within one to three years. Failure of both substations would leave the 5400 customers serviced by these substations without power until the substation assets were repaired. Renewal of this area will allow for the decommissioning of the substation assets by 2018, thereby avoiding the need for capital investment into these substations.

Like-for-Like Renewal Analysis (5.4.5.2.C.b.vi)

The like-for-like renewal of these assets (i.e., same system configuration and same distribution voltage) will perpetuate the existing operating constraints and require capital investment to renew substation assets. Renewal of the distribution assets at a higher voltage does not involve any material incremental costs over renewal at the existing voltage. Operating constraints (e.g., undersized conductor, radial feeds) are addressed on a case by case basis where appropriate.

Capital Project Summary

General Information on Project (5.4.5.2.A)

Project Name	WH-F3 Renewal
Budget Year	2015
Investment Category	System Renewal
Project Summary	This project involves the renewal of Whitney substation F3 feeder in the Hamilton West operating area. This project is part of the 4kV and 8kV Renewal Program.

Capital Investment (5.4.5.2.A.i)	Capital Investment (gross)	$2,871,286
	Customer Contribution	$0
	Capital Investment (net)	$2,871,286
	O&M Expenditure	$0

Customer Attachments / Load (kVA) (5.4.5.2.A.ii)

This project affects 802 customers and 1,678kVA of transformation.

Project Dates (5.4.5.2.A.iii)

Start Date 2015/02/01

In Service Date 2015/12/31

Expenditure Timing

Q1	Q2	Q3	Q4
16%	28%	28%	28%

Schedule Risk and Risk Mitigation (5.4.5.2.A.iv**)**

Please refer to Note I for risk and risk mitigation.

Comparative Information from Equivalent Projects (5.4.5.2.A.v)

There is no direct comparator in scope, size and design characteristics for this project. This project is one phase of a multi-year investment to renew the area served by Whitney substation as part of the 4kV and 8kV Renewal Program. The 2015 investment for the renewal of Whitney substation is $4,384,000. The 2015 investment in the 4kV and 8kV Renewal Program is $8,160,000.

Comparable gross investments for the 4kv and 8kV Renewal Program for the 2010 to 2013 Historical Years and the 2014 Bridge Year are:

2010 (CGAAP)- $ 2,556,076
2011 (CGAAP)- $ 8,820,000
2012 (MIFRS) - $ 5,268,441
2013 (MIFRS) - $ 5,072,233
2014 (MIFRS) - $ 6,434,000

Total Capital OM&A Costs Associated with REG Investments (5.4.5.2.A.vi)

This project is not associated with an REG investment and therefore OM&A costs related to REG will not be incurred.

Leave to Construct Approval (5.4.5.2.A.vii)

This project does not require “Leave to Construct” under Section 92 of the *Ontario Energy Board Act* 1998.

Evaluation Criteria and Information (5.4.5.2.B)

Project Name	WH-F3 Renewal	Table 2

Efficiency, Customer Value, Reliability (5.4.5.2.B.1)

Investment Driver (5.4.5.2.B.1.a)
System Renewal (80%)

Secondary Driver (5.4.5.2.B.1.a)
System Service (20%)

Investment Priority (5.4.5.2.B.1.b)
3 – Required project

Analysis of Project and Project Alternatives (5.4.5.2.B.1.c)

This project is part of the multi-year 4kV and 8kV Renewal Program. Both the 4kV and 8kV distribution system and the Horizon Utilities-owned substations are at the end of their useful life. Horizon Utilities has chosen to renew the 4kV and 8kV distribution systems to a higher voltage to avoid the cost of the investment in the renewal of the substations. The total avoided substation renewal investment over the remaining 35 years of the plan is $70,000,000 for all 28 substations. Therefore, the renewal of the distribution assets at the current 4kV level was not a feasible alternative.

The renewal of the area serviced by the Whitney substation started in 2014 and is scheduled to be completed in 2018. Whitney substation was constructed in 1962. The switchgear at this substation is 46 years old and has a Health Index of ‘very poor’ as identified in the Substation Asset Condition Assessment (“SACA”) and confirmed by the Kinectrics ACA.

Safety (5.4.5.2.B.2)

This project is not intended to address safety concerns with the distribution system.

Cyber-Security and Privacy (5.4.5.2.B.3) (where applicable)

Cyber-Security and Privacy are not applicable to this project.

Co-ordination and Interoperability (5.4.5.2.B.4)

Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.5.2.B.4.a) (where applicable)
Please refer to Note II for an explanation on co-ordination with utilities, regional planning and/or links with 3rd parties.

Enabling of Future Technology and/or Future Operational Requirements (5.4.5.2.B.4.b) (where applicable)

Please refer to Note IV for an explanation enabling of future technology and future operational requirements.

Economic Development (5.4.5.2.B.5) **(where applicable)**

Horizon Utilities ensures that policies and practices do not unnecessarily create barriers to economic development which are primarily focused within its communities.

Environmental Benefits (5.4.5.2.B.6) **(where applicable)**

n/a

System Renewal Specific Requirements (5.4.5.2.C.b)

Project Name	WH-F3 Renewal	Table 3

System Renewal Specific Requirements (5.4.5.2.C.b)

Asset Performance Target and Asset Lifecycle Optimization (5.4.5.2.C.b.i.1)

The distribution assets in the Hamilton West operating area are in poor health and the switchgear in both substations servicing this area have a ‘very poor’ Health Index.

Asset Condition Relative to Typical Life Cycle (5.4.5.2.C.b.i.2)

Generally the 4kV assets are the oldest vintage in the system. 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.

Number of Customers Impacted (5.4.5.2.C.b.i.3)

This project impacts 802 customers.

Quantitative Customer Impact and Risk (5.4.5.2.C.b.i.4)

SAIDI of 0.027

Qualitative Customer Impact and Risk (5.4.5.2.C.b.i.5)

This project will address aging assets with inadequate backup. Aging assets represent an increased risk of service interruption to customers and inadequate backup would result in long duration service interruptions upon occurrence. These factors would lead to customer dissatisfaction in this area.

Value of Customer Impact (5.4.5.2.C.b.i.6)

High

Other Factors Affecting Project Timing (5.4.5.2.C.b.ii)

The renewal of the area serviced by the Whitney substation is scheduled for 2014 to 2018. This project is required to be completed in 2015 to allow for the renewal of the remaining area to be completed on schedule.

Impact on System O&M Costs (5.4.5.2.C.b.iii)

This project will have no material impact on planned O&M costs. The renewal of the 4kV and 8kV distribution systems, as a whole, will provide a reduction in reactive O&M costs to address service interruptions caused by failed equipment. These reductions will not be material in the 2015 to 2019 Test Years.

Reliability and Safety Factors (5.4.5.2.C.b.iv)

The renewal of the 4kV and 8kV distribution system will provide reliability improvements through reduced service interruptions caused by failed equipment.

Analysis of Project Benefits and Timing (5.4.5.2.C.b.v)

The timing of this project, as part of the 4kV and 8kV Renewal Program, is determined through the assessment of the distribution system health and the health of the substation assets servicing the area. Kinectrics identified that both substations' switchgear had a high probability of failure within one to three years. Failure of both substations would leave the 5400 customers serviced by these substations without power until the substation assets were repaired. Renewal of this area will allow for the decommissioning of the substation assets by 2018, thereby avoiding the need for capital investment into these substations.

Like-for-Like Renewal Analysis (5.4.5.2.C.b.vi)

The like-for-like renewal of these assets (i.e. same system configuration and same distribution voltage) will perpetuate the existing operating constraints and will require capital investment to renew substation assets. Renewal of the distribution assets at a higher voltage does not involve any material incremental costs over renewal at the existing voltage. Operating constraints (e.g. undersized conductor, radial feeds) are addressed on a case by case basis, where appropriate.

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Capital Project Summary

General Information on Project (5.4.5.2.A)

Project Name	WH-F3 Renewal – Rear Lot
Budget Year	2015
Investment Category	System Renewal
Project Summary	This project involves the renewal of Whitney Substation F3 feeder in the Hamilton West operating area. This project is part of the 4kV and 8kV Renewal Program. This project addresses a section of the feeder that serves customers via rear lot construction

Capital Investment (5.4.5.2.A.i)	Capital Investment (gross)	$1,512,165
	Customer Contribution	$0
	Capital Investment (net)	$1,512,165
	O&M Expenditure	$0

Customer Attachments / Load (kVA) (5.4.5.2.A.ii)	This project impacts 102 customers.
Project Dates (5.4.5.2.A.iii)	Start Date 2015/04/01 In Service Date 2015/08/31

Expenditure Timing

Q1	Q2	Q3	Q4
0%	40%	60%	0%

Schedule Risk and Risk Mitigation (5.4.5.2.A.iv**)**

Please refer to Note I for risk and risk mitigation.

Comparative Information from Equivalent Projects (5.4.5.2.A.v)

There is no directly comparator in scope, size and design characteristics for this project. This project is one phase of a multi-year investment to renew the area served by Whitney substation as part of the 4kV and 8kV Renewal Program. The 2015 investment for the renewal of Whitney substation is $4,384,000. The 2015 investment in the 4kV and 8kV Renewal Program is $8,160,000.

Comparable gross investments for the 4kv and 8kV Renewal Program for the 2010 to 2013 Historical Years and the 2014 Bridge Year are:

2010 (CGAAP)- $ 2,556,076
2011 (CGAAP)- $ 8,820,000
2012 (MIFRS) - $ 5,268,441
2013 (MIFRS) - $ 5,072,233
2014 (MIFRS) - $ 6,434,000

Total Capital OM&A Costs Associated with REG Investments (5.4.5.2.A.vi)

This project is not associated with an REG investment and therefore OM&A costs related to REG will not be incurred.

Leave to Construct Approval (5.4.5.2.A.vii)

This project does not require "Leave to Construct" under Section 92 of the *Ontario Energy Board Act* 1998.

Evaluation Criteria and Information (5.4.5.2.B)

Project Name WH-F3 Renewal – Rear Lot Table 2

Efficiency, Customer Value, Reliability (5.4.5.2.B.1)

Investment Driver (5.4.5.2.B.1.a)
System Renewal (80%)

Secondary Driver (5.4.5.2.B.1.a)
System Service (20%)

Investment Priority (5.4.5.2.B.1.b)
3 – Required project

Analysis of Project and Project Alternatives (5.4.5.2.B.1.c)

This project is part of the multi-year 4kV and 8kV Renewal Program. Both the 4kV and 8kV distribution system and the Horizon Utilities owned substations are at the end of their useful life. Horizon Utilities has chosen to renew the 4kV and 8kV distribution systems to a higher voltage to avoid the cost of the investment in the renewal of the substations. The total avoided substation renewal investment over the remaining 35 years of the plan is $70,000,000 for all 28 substations. Therefor the renewal of this project at the current 4kV level was not a feasible alternative

The renewal of the area serviced by the Whitney substation started in 2014 and is scheduled to be completed in 2018. Whitney substation was constructed in 1962. The switchgear at this attain is 46 years old and has a Health Index of 'very poor' as identified in the Substation Asset Condition Assessment ("SACA") and confirmed by the Kinectrics ACA.

Safety (5.4.5.2.B.2)

This project is not intended to address safety concerns with the distribution system.

Cyber-Security and Privacy (5.4.5.2.B.3) (where applicable)

Cyber-Security and Privacy are not applicable to this project.

Co-ordination and Interoperability (5.4.5.2.B.4)

Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.5.2.B.4.a) (where applicable)
Please refer to Note II for an explanation on co-ordination with utilities, regional planning and/or links with 3rd parties.

Enabling of Future Technology and/or Future Operational Requirements (5.4.5.2.B.4.b) (where applicable)
Please refer to Note IV for an explanation enabling of future technology and future operational requirements.

Economic Development (5.4.5.2.B.5) **(where applicable)**

Horizon Utilities ensures that policies and practices do not unnecessarily create barriers to economic development which are primarily focused within its communities.

Environmental Benefits (5.4.5.2.B.6) **(where applicable)**

n/a

Project Name	WH-F3 Renewal – Rear Lot	Table 3

System Renewal Specific Requirements

System Renewal Specific Requirements (5.4.5.2.C.b)

Asset Performance Target and Asset Lifecycle Optimization (5.4.5.2.C.b.i.1)

The distribution assets in the Hamilton West operating area are in poor health and the switchgear in both substations servicing this area has switchgear with a ‘very poor’ Health Index.

Asset Condition Relative to Typical Life Cycle (5.4.5.2.C.b.i.2)

Generally the 4kV assets are the oldest vintage in the system. 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.

Number of Customers Impacted (5.4.5.2.C.b.i.3)

This project impacts 102 customers.

Quantitative Customer Impact and Risk (5.4.5.2.C.b.i.4)

SAIDI of 0.007

Qualitative Customer Impact and Risk (5.4.5.2.C.b.i.5)

This project will address aging assets with inadequate backup. Aging assets represent an increased risk of service interruption to customers and inadequate backup would result in long duration service interruptions upon occurrence. These factors would lead to customer dissatisfaction in this area.

Value of Customer Impact (5.4.5.2.C.b.i.6)

High

Other Factors Affecting Project Timing (5.4.5.2.C.b.ii)

The renewal of the area serviced by the Whitney substation is scheduled for 2014 to 2018. This project is required to be completed in 2015 to allow for the renewal of the remaining area to be completed on schedule.

Impact on System O&M Costs (5.4.5.2.C.b.iii)

This project will have no material impact on planned O&M costs. The renewal of the 4kV and 8kV distribution systems, as a whole, will provide a reduction in reactive O&M costs to address service interruptions caused by failed equipment. These reductions will not be material in the 2015 to 2019 Test Years.

Reliability and Safety Factors (5.4.5.2.C.b.iv)

The renewal of the 4kV and 8kV distribution system will provide reliability improvements through reduced service interruptions caused by failed equipment.

Analysis of Project Benefits and Timing (5.4.5.2.C.b.v)

The timing of this project, as part of the 4kV and 8kV Renewal Program, is determined through the assessment of the distribution system health and the health of the substation assets servicing the area. Kinectrics identified that both substations' switchgear had a high probability of failure within one to three years. Failure of both substations would leave the 5400 customers serviced by these substations without power until the substation assets were repaired. Renewal of this area will allow for the decommissioning of the substation assets by 2018 thereby avoiding the need for capital investment into these substations.

Like-for-Like Renewal Analysis (5.4.5.2.C.b.vi)

The like-for-like renewal of these assets (i.e. same system configuration and same distribution voltage) will perpetuate the existing operating constraints and require capital investment to renew substation assets. Renewal of the distribution assets at a higher voltage does not involve any material incremental costs over renewal at the existing voltage. Operating constraints (e.g. undersized conductor, radial feeds) are addressed on a case by case basis where appropriate.

Capital Project Summary

General Information on Project (5.4.5.2.A)

Project Name	GR-F4 Renewal			
Budget Year	2015			
Investment Category	System Renewal			
Project Summary	This project involves the renewal of Grantham Substation F4 feeder in St Catharines. This project is part of the 4kV and 8kV Renewal Program.			
Capital Investment (5.4.5.2.A.i)	Capital Investment (gross)	$650,256		
	Customer Contribution	$0		
	Capital Investment (net)	$650,256		
	O&M Expenditure	$0		
Customer Attachments / Load (kVA) (5.4.5.2.A.ii)	This project impacts 156 customers and 2,000kVA of transformation.			
Project Dates (5.4.5.2.A.iii)	Start Date	2015/04/01		
	In Service Date	2015/08/31		
	Expenditure Timing			
	Q1	Q2	Q3	Q4
	0%	50%	50%	0%

Schedule Risk and Risk Mitigation (5.4.5.2.A.iv**)**

Please refer to Note I for risk and risk mitigation.

Comparative Information from Equivalent Projects (5.4.5.2.A.v)

There is no direct comparator in scope, size and design characteristics for this project. This project is one phase of a multi-year investment to renew the area served by Grantham substation as part of the 4kV and 8kV Renewal Program. The 2015 investment for the renewal of Grantham substation is $650,000. The 2015 investment in the 4kV and 8kV Renewal Program is $8,160,000.

Comparable gross investments for the 4kv and 8kV Renewal Program for the 2010 to 2013 Historical Years and the 2014 Bridge Year are:

2010 (CGAAP)- $ 2,556,076
2011 (CGAAP)- $ 8,820,000
2012 (MIFRS) - $ 5,268,441
2013 (MIFRS) - $ 5,072,233
2014 (MIFRS) - $ 6,434,000

Total Capital OM&A Costs Associated with REG Investments (5.4.5.2.A.vi)

This project is not associated with an REG investment and therefore OM&A costs related to REG will not be incurred.

	Leave to Construct Approval (5.4.5.2.A.vii) This project does not require "Leave to Construct" under Section 92 of the *Ontario Energy Board Act* 1998.

<table>
<tr><td rowspan="6">Evaluation Criteria and Information (5.4.5.2.B)</td><td>Project Name GR-F4 Renewal Table 2</td></tr>
<tr><td>Efficiency, Customer Value, Reliability (5.4.5.2.B.1)

Investment Driver (5.4.5.2.B.1.a)
System Renewal (80%)

Secondary Driver (5.4.5.2.B.1.a)
System Service (20%)

Investment Priority (5.4.5.2.B.1.b)
3 – Required project</td></tr>
<tr><td>Analysis of Project and Project Alternatives (5.4.5.2.B.1.c)
This project is part of the multi-year 4kV and 8kV Renewal Program. Both the 4kV and 8kV distribution system and the Horizon Utilities-owned substations are at the end of their useful life. Horizon Utilities has chosen to renew the 4kV and 8kV distribution systems to a higher voltage to avoid the cost of the investment in the renewal of the substations. The total avoided substation renewal investment over the remaining 35 years of the plan is $70,000,000 for all 28 substations. Therefore, the renewal of the distribution assets at the current 4kV level was not a feasible alternative.

This is the initial year of the multi-year project to renew the area serviced by Grantham substation. Renewal of this area is scheduled to be completed in 2017.</td></tr>
<tr><td>Safety (5.4.5.2.B.2)

This project is not intended to address safety concerns with the distribution system.</td></tr>
<tr><td>Cyber-Security and Privacy (5.4.5.2.B.3) (where applicable)

Cyber-Security and Privacy are not applicable to this project.</td></tr>
<tr><td>Co-ordination and Interoperability (5.4.5.2.B.4)

Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.5.2.B.4.a) (where applicable)

Please refer to Note II for an explanation on co-ordination with utilities, regional planning and/or links with 3rd parties.

Enabling of Future Technology and/or Future Operational Requirements (5.4.5.2.B.4.b) (where applicable)

Please refer to Note IV for an explanation enabling of future technology and future operational requirements.</td></tr>
</table>

	Economic Development (5.4.5.2.B.5) **(where applicable)** Horizon Utilities ensures that policies and practices do not unnecessarily create barriers to economic development which are primarily focused within its communities.
	Environmental Benefits (5.4.5.2.B.6) **(where applicable)** n/a

System Renewal Specific Requirements (5.4.5.2.C.b)	**Project Name** GR-F4 Renewal	Table 3
	System Renewal Specific Requirements (5.4.5.2.C.b) **Asset Performance Target and Asset Lifecycle Optimization (5.4.5.2.C.b.i.1)** The 4kV distribution assets and substations assets in the St. Catharines operating area are in poor health and require renewal. The overall substation Health Indices for Vine, Welland and Grantham substations are 57%, 59%, 58% respectively. 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. 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. **Asset Condition Relative to Typical Life Cycle (5.4.5.2.C.b.i.2)** Generally the 4kV assets are the oldest vintage in the system. 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. **Number of Customers Impacted (5.4.5.2.C.b.i.3)** This project affects 156 customers. **Quantitative Customer Impact and Risk (5.4.5.2.C.b.i.4)** SAIDI of 0.005 **Qualitative Customer Impact and Risk (5.4.5.2.C.b.i.5)** This project will address aging assets with inadequate backup. Aging assets represent an increased risk of service interruption to customers and inadequate backup would result in long duration service interruptions upon occurrence. These factors would lead to customer dissatisfaction in this area. **Value of Customer Impact (5.4.5.2.C.b.i.6)** High	

Other Factors Affecting Project Timing (5.4.5.2.C.b.ii)

The renewal of the area serviced by Grantham substation is scheduled for 2015 to 2017. This project is required to be completed in 2015 to allow for the renewal of the remaining area to be completed on schedule.

Impact on System O&M Costs (5.4.5.2.C.b.iii)

This project will have no material impact on planned O&M costs. The renewal of the 4kV and 8kV distribution systems, as a whole, will provide a reduction in reactive O&M costs to address service interruptions caused by failed equipment. These reductions will not be material in the 2015 to 2019 Test Years.

Reliability and Safety Factors (5.4.5.2.C.b.iv)

The renewal of the 4kV and 8kV distribution system will provide reliability improvements through reduced service interruptions caused by failed equipment.

Analysis of Project Benefits and Timing (5.4.5.2.C.b.v)

The timing of this project, as part of the 4kV and 8kV Renewal Program, is determined through the assessment of the distribution system health and the health of the substation assets servicing the area. Kinectrics' evaluation found that the switchgear assets were at a high risk of failure within five years. Failure of this substation would leave the 900 customers serviced by it substations without power until the substation assets were repaired. Renewal of this area will allow for the decommissioning of the substation assets by 2018 thereby avoiding the need for capital investment into these substations.

Like-for-Like Renewal Analysis (5.4.5.2.C.b.vi)

The like-for-like renewal of these assets (i.e. same system configuration and same distribution voltage) will perpetuate the existing operating constraints and require capital investment to renew substation assets. Renewal of the distribution assets at a higher voltage does not involve any material incremental costs over renewal at the existing voltage. Operating constraints (e.g. undersized conductor, radial feeds) are addressed on a case by case basis where appropriate.

Capital Project Summary

General Information on Project (5.4.5.2.A)

Project Name	GR-F4 Renewal Charleen Circle U/G				
Budget Year	2015				
Investment Category	System Renewal				
Project Summary	This project involves the renewal of the Grantham Substation F4 feeder in St. Catharines and the renewal of XLPE cable serving customers on Charleen Circle.				
Capital Investment (5.4.5.2.A.i)	Capital Investment (gross)	$309,695			
	Customer Contribution	$0			
	Capital Investment (net)	$309,695			
	O&M Expenditure	$0			
Customer Attachments / Load (kVA) (5.4.5.2.A.ii)	This project affects 300 customers and 612 kVA of transformation.				
Project Dates (5.4.5.2.A.iii)	Start Date	2015/06/01			
	In Service Date	2015/09/30			
	Expenditure Timing				
	Q1	Q2	Q3	Q4	
	0%	75%	25%	0%	

Schedule Risk and Risk Mitigation (5.4.5.2.A.iv**)**

Please refer to Note I for risk and risk mitigation.

Comparative Information from Equivalent Projects (5.4.5.2.A.v)

There is no direct comparator in scope, size and design characteristics for this project. This project supports both the 4kV and 8kV Renewal Program and the XLPE Renewal Program.

Total Capital OM&A Costs Associated with REG Investments (5.4.5.2.A.vi)

This project is not associated with an REG investment and therefore OM&A costs related to REG will not be incurred.

Leave to Construct Approval (5.4.5.2.A.vii)

This project does not require “Leave to Construct” under Section 92 of the *Ontario Energy Board Act* 1998.

Evaluation Criteria and Information (5.4.5.2.B)

Project Name GR-F4 Renewal Charleen Circle U/G Table 2

Efficiency, Customer Value, Reliability (5.4.5.2.B.1)

Investment Driver (5.4.5.2.B.1.a)
System Renewal (80%)

Secondary Driver (5.4.5.2.B.1.a)
System Service (20%)

Investment Priority (5.4.5.2.B.1.b)
3 – Required project

Analysis of Project and Project Alternatives (5.4.5.2.B.1.c)

This is currently a 4kV underground distribution and Horizon Utilities has chosen to renew the 4kV and 8kV distribution systems to a higher voltage to avoid the cost of the investment in the renewal of the substations. The total avoided substation renewal investment over the remaining 35 years of the plan is $70,000,000 for all 28 substations. Therefore, the renewal of the distribution assets at the current 4kV level was not a feasible alternative.

In addition, this is a mature area currently serviced via an underground distribution system; it would not be feasible to renew the assets with an overhead solution.

Safety (5.4.5.2.B.2)

These projects are not intended to address safety concerns with the distribution system.

Cyber-Security and Privacy (5.4.5.2.B.3) (where applicable)

n/a

Co-ordination and Interoperability (5.4.5.2.B.4)

Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.5.2.B.4.a) (where applicable)
Please refer to Note II for an explanation on co-ordination with utilities, regional planning and/or links with 3rd parties.

Enabling of Future Technology and/or Future Operational Requirements (5.4.5.2.B.4.b) (where applicable)
Please refer to Note IV for an explanation enabling of future technology and future operational requirements.

Economic Development (5.4.5.2.B.5) **(where applicable)**

Horizon Utilities ensures that policies and practices do not unnecessarily create barriers to economic development which are primarily focused within its communities.

Environmental Benefits (5.4.5.2.B.6) **(where applicable)**

n/a

Project Name	GR-F4 Renewal Charleen Circle U/G	Table 3

System Renewal Specific Requirements (5.4.5.2.C.b)

System Renewal Specific Requirements (5.4.5.2.C.b)

Asset Performance Target and Asset Lifecycle Optimization (5.4.5.2.C.b.i.1)

The 4kV distribution assets and substations assets in the St. Catharines operating area are in poor health and require renewal. The overall substation Health Indices for Vine, Welland and Grantham substations is 57%, 59%, 58% respectively. 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. 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.

Asset Condition Relative to Typical Life Cycle (5.4.5.2.C.b.i.2)

Generally the 4kV assets are the oldest vintage in the system. 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.

Number of Customers Impacted (5.4.5.2.C.b.i.3)

300

Quantitative Customer Impact and Risk (5.4.5.2.C.b.i.4)

SAIDI of 0.015

Qualitative Customer Impact and Risk (5.4.5.2.C.b.i.5)

This project will address aging assets with inadequate backup. Aging assets pose an increased risk of service interruption to customers and inadequate backup would result in long duration service interruptions upon occurrence. These factors would lead to customer dissatisfaction in this area.

Value of Customer Impact (5.4.5.2.C.b.i.6)

High

Other Factors Affecting Project Timing (5.4.5.2.C.b.ii)

The renewal of the area serviced by Grantham substation is scheduled for 2015 to 2017. This project is required to be completed in 2015 to allow for the renewal of the remaining area to be completed on schedule.

Impact on System O&M Costs (5.4.5.2.C.b.iii)

This project will have no material impact on planned O&M costs. The renewal of the 4kV and 8kV distribution systems, as a whole, will provide a reduction in reactive O&M costs to address service interruptions caused by failed equipment. These reductions will not be material in the 2015 to 2019 Test Years.

Reliability and Safety Factors (5.4.5.2.C.b.iv)

The renewal of the 4kV and 8kV distribution system will provide reliability improvements through reduced service interruptions caused by failed equipment.

Analysis of Project Benefits and Timing (5.4.5.2.C.b.v)

The timing of this project, as part of the 4kV and 8kV Renewal Program, is determined through the assessment of the distribution system health and the health of the substation assets servicing the area. Kinectrics' evaluation of the switchgear assets were at a high risk of failure within five years. Failure of the substation would leave the 900 customers serviced by it without power until the substation assets were repaired. Renewal of this area will allow for the decommissioning of the substation assets by 2018 thereby avoiding the need for capital investment into these substations.

Like-for-Like Renewal Analysis (5.4.5.2.C.b.vi)

The like-for-like renewal of these assets (i.e. same system configuration and same distribution voltage) will perpetuate the existing operating constraints and require capital investment to renew substation assets. Renewal of the distribution assets at a higher voltage does not involve any material incremental costs over renewal at the existing voltage. Operating constraints (e.g. undersized conductor, radial feeds) are addressed on a case by case basis where appropriate.

Capital Project Summary

General Information on Project (5.4.5.2.A)

Project Name	VE-F5 Renewal
Budget Year	2015
Investment Category	System Renewal
Project Summary	This project involves the renewal of the Vine Substation F5 feeder in St. Catharines.

Capital Investment (5.4.5.2.A.i)		
	Capital Investment (gross)	$978,064
	Customer Contribution	$0
	Capital Investment (net)	$978,064
	O&M Expenditure	$0

Customer Attachments / Load (kVA) (5.4.5.2.A.ii): This project affects 592 customers and 2,220kVA of transformation.

Project Dates (5.4.5.2.A.iii)

Start Date	2015/01/01
In Service Date	2015/06/30

Expenditure Timing

Q1	Q2	Q3	Q4
50%	50%	0%	0%

Schedule Risk and Risk Mitigation (5.4.5.2.A.iv**)**

Please refer to Note I for risk and risk mitigation.

Comparative Information from Equivalent Projects (5.4.5.2.A.v)

There is no direct comparator in scope, size and design characteristics for this project. This project is one phase of a multi-year investment to renew the area served by Vine substation as part of the 4kV and 8kV Renewal Program. The 2015 investment for the renewal of Vine substation is $978,000. The 2015 investment in the 4kV and 8kV Renewal Program is $8,160,000.

Comparable gross investments for the 4kv and 8kV Renewal Program for the 2010 to 2013 Historical Years and the 2014 Bridge Year are:

2010 (CGAAP)- $ 2,556,076
2011 (CGAAP)- $ 8,820,000
2012 (MIFRS) - $ 5,268,441
2013 (MIFRS) - $ 5,072,233
2014 (MIFRS) - $ 6,434,000

Total Capital OM&A Costs Associated with REG Investments (5.4.5.2.A.vi)

This project is not associated with an REG investment and therefore OM&A costs related to REG will not be incurred.

Leave to Construct Approval (5.4.5.2.A.vii)

This project does not require "Leave to Construct" under Section 92 of the *Ontario Energy Board Act* 1998.

Evaluation Criteria and Information (5.4.5.2.B)

Project Name	VE-F5 Renewal	Table 2

Efficiency, Customer Value, Reliability (5.4.5.2.B.1)

Investment Driver (5.4.5.2.B.1.a)
System Renewal (80%)

Secondary Driver (5.4.5.2.B.1.a)
System Service (20%)

Investment Priority (5.4.5.2.B.1.b)
3 – Required project

Analysis of Project and Project Alternatives (5.4.5.2.B.1.c)

This project is part of the multi-year 4kV and 8kV Renewal Program. Both the 4kV and 8kV distribution system and the Horizon Utilities-owned substations are at the end of their useful life. Horizon Utilities has chosen to renew the 4kV and 8kV distribution systems to a higher voltage to avoid the cost of the investment in the renewal of the substations. The total avoided substation renewal investment over the remaining 35 years of the program is $70,000,000 for all 28 substations. Therefore, the renewal of the distribution assets at the current 4kV level was not a feasible alternative.

Safety (5.4.5.2.B.2)

These projects are not intended to address safety concerns with the distribution system.

Cyber-Security and Privacy (5.4.5.2.B.3) (where applicable) (where applicable)

n/a

Co-ordination and Interoperability (5.4.5.2.B.4)

Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.5.2.B.4.a) (where applicable)
Please refer to Note II for an explanation on co-ordination with utilities, regional planning and/or links with 3rd parties.

Enabling of Future Technology and/or Future Operational Requirements (5.4.5.2.B.4.b) (where applicable)
Please refer to Note IV for an explanation enabling of future technology and future operational requirements.

Economic Development (5.4.5.2.B.5) **(where applicable)**

Horizon Utilities ensures that policies and practices do not unnecessarily create barriers to economic development which are primarily focused within its communities.

	Environmental Benefits (5.4.5.2.B.6) **(where applicable)** n/a.

System Renewal Specific Requirements (5.4.5.2.C.b)	**Project Name** VE-F5 Renewal Table 3
	System Renewal Specific Requirements (5.4.5.2.C.b)
	Asset Performance Target and Asset Lifecycle Optimization (5.4.5.2.C.b.i.1) The 4kV distribution assets and substations assets in the St. Catharines operating area are in poor health and require renewal. The overall substation Health Indices for Vine, Welland and Grantham substations is 57%, 59%, 58% respectively. 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. 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.
	Asset Condition Relative to Typical Life Cycle (5.4.5.2.C.b.i.2) Generally the 4kV assets are the oldest vintage in the system. 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.
	Number of Customers Impacted (5.4.5.2.C.b.i.3) This project affects 592 customers.
	Quantitative Customer Impact and Risk (5.4.5.2.C.b.i.4) SAIDI of 0.02
	Qualitative Customer Impact and Risk (5.4.5.2.C.b.i.5) This project will address aging assets with inadequate backup. Aging assets pose an increased risk of service interruption to customers and inadequate backup would result in long duration service interruptions upon occurrence. These factors would lead to customer dissatisfaction in this area.
	Value of Customer Impact (5.4.5.2.C.b.i.6) High
	Other Factors Affecting Project Timing (5.4.5.2.C.b.ii) The renewal of the area serviced by Vine substation is scheduled for 2015 to 2017. This project is required to be completed in 2015 to allow for the renewal of the remaining area to be completed on schedule.

Impact on System O&M Costs (5.4.5.2.C.b.iii)

This project will have no material impact on planned O&M costs. The renewal of the 4kV and 8kV distribution systems, as a whole, will provide a reduction in reactive O&M costs to address service interruptions caused by failed equipment. These reductions will not be material in the 2015 to 2019 Test Years.

Reliability and Safety Factors (5.4.5.2.C.b.iv)

The renewal of the 4kV and 8kV distribution system will provide reliability improvements through reduced service interruptions caused by failed equipment.

Analysis of Project Benefits and Timing (5.4.5.2.C.b.v)

The timing of this project, as part of the 4kV and 8kV Renewal Program, is determined through the assessment of the distribution system health and the health of the substation assets servicing the area.

Like-for-Like Renewal Analysis (5.4.5.2.C.b.vi)

The like-for-like renewal of these assets (i.e. same system configuration and same distribution voltage) will perpetuate the existing operating constraints and require capital investment to renew substation assets. Renewal of the distribution assets at a higher voltage does not involve any material incremental costs over renewal at the existing voltage. Operating constraints (e.g. undersized conductor, radial feeds) are addressed on a case by case basis, where appropriate.

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Capital Project Summary

General Information on Project (5.4.5.2.A)

Project Name	2015 St. Catharines XLPE Renewal
Budget Year	2015
Investment Category	System Renewal
Project Summary	This project involves the renewal of direct buried XLPE primary cable in the St. Catharines service territory.

Capital Investment (5.4.5.2.A.i)	Capital Investment (gross)	$310,000
	Customer Contribution	$0
	Capital Investment (net)	$310,000
	O&M Expenditure	$0

Customer Attachments / Load (kVA) (5.4.5.2.A.ii)	The customer and load impacted by this project will vary depending upon the final scope of the project.

Project Dates (5.4.5.2.A.iii)

Start Date	2015/01/01
In Service Date	2015/06/30

Expenditure Timing			
Q1	Q2	Q3	Q4
50%	50%	0%	0%

Schedule Risk and Risk Mitigation (5.4.5.2.A.iv)

Please refer to Note I for risk and risk mitigation.

Comparative Information from Equivalent Projects (5.4.5.2.A.v)

There is no direct comparator in scope, size and design characteristics for this project. This project is part of a multi-year investment to renew XLPE primary cable. The 2015 investment in the XLPE Renewal Program is $2,567,000.

Comparable gross investments for the XLPE Renewal Program for the 2010 to 2013 Historical Years and the 2014 Bridge Year are:

2010 (CGAAP)- $ 0
2011 (CGAAP)- $ 0
2012 (MIFRS) - $ 0
2013 (MIFRS) - $ 1,572,090
2014 (MIFRS) - $ 893,000

Total Capital OM&A Costs Associated with REG Investments (5.4.5.2.A.vi)

This project is not associated with an REG investment and therefore OM&A costs related to REG will not be incurred.

Leave to Construct Approval (5.4.5.2.A.vii)

This project does not require "Leave to Construct" under Section 92 of the *Ontario Energy Board Act* 1998.

Evaluation Criteria and Information (5.4.5.2.B)

Project Name 2015 St. Catharines XLPE Renewal Table 2

Efficiency, Customer Value, Reliability (5.4.5.2.B.1)

Investment Driver (5.4.5.2.B.1.a)
System Renewal (80%)

Secondary Driver (5.4.5.2.B.1.a)
System Service (20%)

Investment Priority (5.4.5.2.B.1.b)
3 – Required project

Analysis of Project and Project Alternatives (5.4.5.2.B.1.c)

This project is part of the multi-year XLPE Renewal Program. Horizon Utilities considered the four replacement philosophies for addressing risk inherent in the XLPE asset group: Area; Reactive; Selected; and Refurbishment. The area replacement philosophy will be utilized 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 continue to be used for the remaining areas of the service territory. The St. Catharines operating area contains many small pockets of direct buried XLPE primary cable. The XLPE renewal projects in the St. Catharines operating area will involve the full renewal of each pocket of XLPE cable. Project selection will be guided by: asset health; operating history; and reliability of each of the underground pockets of XLPE.

Safety (5.4.5.2.B.2)

These projects are not intended to address safety concerns with the distribution system.

Cyber-Security and Privacy (5.4.5.2.B.3) (where applicable)

n/a

Co-ordination and Interoperability (5.4.5.2.B.4)

Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.5.2.B.4.a) (where applicable)

Please refer to Note II for an explanation on co-ordination with utilities, regional planning and/or links with 3rd parties.

Enabling of Future Technology and/or Future Operational Requirements (5.4.5.2.B.4.b) (where applicable)

Please refer to Note IV for an explanation enabling of future technology and future operational requirements.

Economic Development (5.4.5.2.B.5) **(where applicable)**

Horizon Utilities ensures that policies and practices do not unnecessarily create barriers to economic development which are primarily focused within its communities.

Environmental Benefits (5.4.5.2.B.6) **(where applicable)**

n/a.

System Renewal Specific Requirements (5.4.5.2.C.b)

Project Name	2015 St. Catharines XLPE Renewal	Table 3

System Renewal Specific Requirements (5.4.5.2.C.b)

Asset Performance Target and Asset Lifecycle Optimization (5.4.5.2.C.b.i.1)

XLPE primary cable is the asset group with the largest investment requirement as identified by the Kinectrics ACA. 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 those years. This represents a managed, gradual increase in investment in order to balance rate payer concerns and practical operational limitations.

Asset Condition Relative to Typical Life Cycle (5.4.5.2.C.b.i.2)

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.

Number of Customers Impacted (5.4.5.2.C.b.i.3)

The number of customers impacted will vary depending upon the area.

Quantitative Customer Impact and Risk (5.4.5.2.C.b.i.4)

Varies; dependent on the final scope of the project.

Qualitative Customer Impact and Risk (5.4.5.2.C.b.i.5)

This project will address aging assets at risk of failure. Failures of XLPE primary cable result in extended service interruptions; 30% of these outages exceeded four hours in duration, while 5% of these outages exceeded twelve hours in duration.

Value of Customer Impact (5.4.5.2.C.b.i.6)

High

Other Factors Affecting Project Timing (5.4.5.2.C.b.ii)

Proactive replacements are required because, as assets continue to age and degrade, the cable will fail at an exponential rate. In the worst case scenario, rate of failure will exceed Horizon Utilities' ability to keep pace with repairs. Reliability will also deteriorate to unacceptable levels. Reactive replacements will be considerably more costly than proactive renewal.

Impact on System O&M Costs (5.4.5.2.C.b.iii)

This project will have no material impact on planned O&M costs. The renewal of the XLPE primary cable, as a whole, will provide a reduction in reactive O&M costs to address service interruptions caused by failed equipment. These reductions will not be material in the 2015 to 2019 Test Years.

Reliability and Safety Factors (5.4.5.2.C.b.iv)

The renewal of the XLPE primary cable system will provide reliability improvements through reduced service interruptions caused by failed equipment.

Analysis of Project Benefits and Timing (5.4.5.2.C.b.v)

Failure to invest in the proactive renewal of XLPE primary cable and associated underground assets would result in unacceptable levels of system failures and outages beyond the ability of Horizon Utilities to resolve within a reasonable timeframe as these assets continue to age and degrade. Reactive replacements will also be considerably more costly than the forecast expenditure required to execute the proposed proactive replacement.

Like-for-Like Renewal Analysis (5.4.5.2.C.b.vi)

XLPE renewal projects will include the elimination of radial underground feeds; replacement of below grade transformers with padmount transformers; and the introduction of fusing on the underground distribution systems where applicable.

Capital Project Summary

General Information on Project (5.4.5.2.A)

Project Name	2015 Substation Infrastructure Renewal
Budget Year	2015
Investment Category	System Renewal
Project Summary	This program involves the renewal of substation infrastructure throughout Horizon Utilities' service territory. Substation maintenance and inspection programs annually identify a number of required investments for the continued safe and reliable operation of Horizon Utilities' substations. Investments under this program include: battery replacements; SCADA and communication upgrades; and grounding improvements.

Capital Investment (5.4.5.2.A.i)		
	Capital Investment (gross)	$464,000
	Customer Contribution	$0
	Capital Investment (net)	$464,000
	O&M Expenditure	$0

Customer Attachments / Load (kVA) (5.4.5.2.A.ii)	n/a

Project Dates (5.4.5.2.A.iii)

Start Date 2015/01/01

In Service Date 2015/12/31

Expenditure Timing			
Q1	Q2	Q3	Q4
25%	25%	25%	25%

Schedule Risk and Risk Mitigation (5.4.5.2.A.iv**)**

Please refer to Note I for risk and risk mitigation.

Comparative Information from Equivalent Projects (5.4.5.2.A.v)

Comparable gross investments for the 2010 to 2013 Historical Years and the 2014 Bridge Year are:

2010 (CGAAP)- $ 146,477
2011 (CGAAP)- $ 326,000
2012 (MIFRS) - $ 305,000
2013 (MIFRS) - $ 168,507
2014 (MIFRS) - $ 455,503

Total Capital OM&A Costs Associated with REG Investments (5.4.5.2.A.vi)

This project is not associated with an REG investment and therefore OM&A costs related to REG will not be incurred.

Leave to Construct Approval (5.4.5.2.A.vii)

This project does not require "Leave to Construct" under Section 92 of the *Ontario Energy Board Act* 1998.

Evaluation Criteria and Information (5.4.5.2.B)

Project Name Substation Infrastructure Renewal Table 2

Efficiency, Customer Value, Reliability (5.4.5.2.B.1)

Investment Driver (5.4.5.2.B.1.a)
System Renewal (80%)

Secondary Driver (5.4.5.2.B.1.a)
System Service (20%)

Investment Priority (5.4.5.2.B.1.b)
3 – Required project

Analysis of Project and Project Alternatives (5.4.5.2.B.1.c)

This program is required for the ongoing safe and reliable operation of Horizon Utilities' municipal substations. The 4kV and 8kV Renewal Program is structured to decommission Horizon Utilities' 28 substations over the next 34 years. There is no investment in the renewal of the major electrical assets (power transformers, switchgear and breakers) forecasted for the 2015 to 2019 Test Years. The investments provided above are required to maintain the ancillary substation assets in safe working order. Substation investment requirements are identified though preventative maintenance programs performed on both routine maintenance cycles and monthly inspections. 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. Investments are required to address both electrical assets within the substation (e.g. replacement of switchgear components and instrument transformers), and ancillary equipment (e.g. SCADA, communication equipment, or backup batteries). All of these components are critical to the continued safe and reliable operation of the substation. A failure to undertake these required investments could lead to premature failure of substation components that would result in a service interruption and increased operating or reactive capital expenditure.

Safety (5.4.5.2.B.2)

This project is not intended to address safety concerns with the distribution system.

Cyber-Security and Privacy (5.4.5.2.B.3) (where applicable)

n/a

Co-ordination and Interoperability (5.4.5.2.B.4)

Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.5.2.B.4.a) (where applicable)

Please refer to Note II for an explanation on co-ordination with utilities, regional planning and/or links with 3rd parties.

Enabling of Future Technology and/or Future Operational Requirements (5.4.5.2.B.4.b) (where applicable)

Please refer to Note IV for an explanation enabling of future technology and future operational requirements.

Economic Development (5.4.5.2.B.5) **(where applicable)**

Horizon Utilities ensures that policies and practices do not unnecessarily create barriers to economic development which are primarily focused within its communities.

Environmental Benefits (5.4.5.2.B.6) **(where applicable)**

n/a.

System Renewal Specific Requirements (5.4.5.2.C.b)

Project Name	Substation Infrastructure Renewal	Table 3

System Renewal Specific Requirements (5.4.5.2.C.b)

Asset Performance Target and Asset Lifecycle Optimization (5.4.5.2.C.b.i.1)

This project involves investment to replace substation infrastructure required for the continued safe and reliable operation of Horizon Utilities' substations.

Asset Condition Relative to Typical Life Cycle (5.4.5.2.C.b.i.2)

n/a

Number of Customers Impacted (5.4.5.2.C.b.i.3)

n/a.

Quantitative Customer Impact and Risk (5.4.5.2.C.b.i.4)

n/a

Qualitative Customer Impact and Risk (5.4.5.2.C.b.i.5)

n/a

Value of Customer Impact (5.4.5.2.C.b.i.6)

Medium

Other Factors Affecting Project Timing (5.4.5.2.C.b.ii)

The timing of investments in this project is dependent upon the timing of substation maintenance programs and the infrastructure requiring renewal identified while performing maintenance.

Impact on System O&M Costs (5.4.5.2.C.b.iii)

This project will have no material impact on O&M expenditures.

Reliability and Safety Factors (5.4.5.2.C.b.iv)

n/a

Analysis of Project Benefits and Timing (5.4.5.2.C.b.v)

n/a

Like-for-Like Renewal Analysis (5.4.5.2.C.b.vi)

The assets renewed in this program are replaced on a like-for-like basis.

Capital Project Summary

General Information on Project (5.4.5.2.A)

Project Name	Distribution Automation				
Budget Year	2015				
Investment Category	System Service				
Project Summary	This project involves the deployment of automated switches, reclosers and fault indicators through Horizon Utilities' service territory.				
Capital Investment (5.4.5.2.A.i)	Capital Investment (gross)	$1,250,000			
	Customer Contribution	$0			
	Capital Investment (net)	$1,250,000			
	O&M Expenditure	$0			
Customer Attachments / Load (kVA) (5.4.5.2.A.ii)	n/a				
Project Dates (5.4.5.2.A.iii)	Start Date	2015/04/01			
	In Service Date	2015/12/31			
	Expenditure Timing				
	Q1	Q2	Q3	Q4	
	0%	25%	50%	25%	

Schedule Risk and Risk Mitigation (5.4.5.2.A.iv**)**

Please refer to Note I for risk and risk mitigation.

Comparative Information from Equivalent Projects (5.4.5.2.A.v)

Comparable gross investments for the distribution automation for the 2010 to 2013 Historical Years and the 2014 Bridge Year are:

2010 (CGAAP)- $ 0
2011 (CGAAP)- $ 0
2012 (MIFRS) - $ 0
2013 (MIFRS) - $ 0
2014 (MIFRS) - $ 1,250,000

Total Capital OM&A Costs Associated with REG Investments (5.4.5.2.A.vi)

This project is not associated with an REG investment and therefore OM&A costs related to REG will not be incurred.

Leave to Construct Approval (5.4.5.2.A.vii)

This project does not require "Leave to Construct" under Section 92 of the *Ontario Energy Board Act* 1998.

Evaluation Criteria and Information (5.4.5.2.B)

Project Name Distribution Automation Table 2

Efficiency, Customer Value, Reliability (5.4.5.2.B.1)

Investment Driver (5.4.5.2.B.1.a)
System Service (100%)

Secondary Driver (5.4.5.2.B.1.a)
n/a

Investment Priority (5.4.5.2.B.1.b)
3 – Required project

Analysis of Project and Project Alternatives (5.4.5.2.B.1.c)

Automation provides 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 (e.g., the high volume of outages resulting from wind and ice storms). Horizon Utilities' worst performing feeders with the largest number of customer minutes of outage are the highest priority for automation.

Safety (5.4.5.2.B.2)

These projects are not intended to address safety concerns with the distribution system.

Cyber-Security and Privacy (5.4.5.2.B.3) (where applicable)

Horizon Utilities utilizes the Smart Meter communication infrastructure when communicating with automated switches. Horizon Utilities' Smart Meter and related AMI network have been procured through Elster. Elster's system supports a multi-layered security approach including: access control; authorization; authentication; and data integrity protocols. As part of its continuous improvement model, Horizon Utilities performs periodic security assessments to identify opportunities for enhanced system hardening.

Co-ordination and Interoperability (5.4.5.2.B.4)

Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.5.2.B.4.a) (where applicable)
Please refer to Note II for an explanation on co-ordination with utilities, regional planning and/or links with 3rd parties.

Enabling of Future Technology and/or Future Operational Requirements (5.4.5.2.B.4.b)

Please refer to Note IV for an explanation enabling of future technology and future operational requirements.

Economic Development (5.4.5.2.B.5) **(where applicable)**

Horizon Utilities ensures that its policies and practices do not unnecessarily create barriers to economic development which are primarily focused within its communities.

Environmental Benefits (5.4.5.2.B.6) **(where applicable)**

n/a

System Service Specific Requirements (5.4.5.2.C.c)

Project Name	Distribution Automation	Table 3

System Service Specific Requirements (5.4.5.2.C.c)

Benefit to Customers (5.4.5.2.C.c.i)

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). Horizon Utilities worst performing feeders with the largest number of customer minutes of outage are the highest priority for automation.

Regional Planning Requirements (5.4.5.2.C.c.i)

This project is not related or impacted by regional planning requirements.

Integration of Advance Technology (5.4.5.2.C.c.iii)

Please refer to Note IV for an explanation enabling of future technology and future operational requirements.

System Benefits to Reliability, Efficiency and Safety (5.4.5.2.C.c.iv)

Automation, once fully deployed throughout the distribution system, is expected to improve reliability by 10%. Horizon Utilities' reliability is driven by a small number of large outages (1% of outages constitute 40% of the total customer of minutes annually). Analysis of the 2013 largest impact outages (excluding the July 2013 windstorm and December 2013 ice storm) indicated that automation would have reduced the impact of these outages by 25%. These results, when extrapolated across all outages, would result in a reduction of 10% annually.

Factors Affecting Implementing Timing/Priority (5.4.5.2.C.c.v)

n/a

Summary of Options Analysis (5.4.5.2.C.c.vi)

n/a.

horizon UTILITIES Looking beyond...

Capital Project Summary

General Information on Project (5.4.5.2.A)

Project Name	#6 Wire Removal - Eastmount			
Budget Year	2015			
Investment Category	System Service			
Project Summary	This project involves the replacement of #6 solid copper wire in the east Hamilton Mountain area around Lawfield Dr.			
Capital Investment (5.4.5.2.A.i)	Capital Investment (gross)	$570,484		
	Customer Contribution	$0		
	Capital Investment (net)	$570,484		
	O&M Expenditure	$0		
Customer Attachments / Load (kVA) (5.4.5.2.A.ii)				
Project Dates (5.4.5.2.A.iii)	Start Date	2015/09/01		
	In Service Date	2015/12/31		
	Expenditure Timing			
	Q1	Q2	Q3	Q4
	0%	0%	25%	75%

Schedule Risk and Risk Mitigation (5.4.5.2.A.iv**)**

Please refer to Note I for risk and risk mitigation.

Comparative Information from Equivalent Projects (5.4.5.2.A.v)

The size and volume of #6 wire replacement projects varies from year to year. The 2015 investment in the #6 Wire Replacement program is $570,000.

Comparable gross investments for the # 6 Wire Removal Program for the 2010 to 2013 Historical Years and the 2014 Bridge Year are:

2010 (CGAAP)- $ 208,622
2011 (CGAAP)- $ 626,000
2012 (MIFRS) - $ 349,000
2013 (MIFRS) - $ 69,121
2014 (MIFRS) - $ 418,000

Total Capital OM&A Costs Associated with REG Investments (5.4.5.2.A.vi)

This project is not associated with an REG investment and therefore OM&A costs related to REG will not be incurred.

Leave to Construct Approval (5.4.5.2.A.vii)

This project does not require "Leave to Construct" under Section 92 of the *Ontario Energy Board Act* 1998.

Evaluation Criteria and Information (5.4.5.2.B)

Project Name #6 Wire Removal - Eastmount Table 2

Efficiency, Customer Value, Reliability (5.4.5.2.B.1)

Investment Driver (5.4.5.2.B.1.a)
System Service (60%)

Secondary Driver (5.4.5.2.B.1.a)
System Renewal (40%)

Investment Priority (5.4.5.2.B.1.b)
3 – Required project

Analysis of Project and Project Alternatives (5.4.5.2.B.1.c)

The #6 Wire Replacement projects are primarily initiated to reduce risk to public safety due to the higher failure rates associated with #6 wire. Where possible, these projects are co-ordinated with 4kV and 8kV renewal projects.

Safety (5.4.5.2.B.2)

These projects are not intended to address safety concerns with the distribution system.

Cyber-Security and Privacy (5.4.5.2.B.3) (where applicable)

n/a

Co-ordination and Interoperability (5.4.5.2.B.4)

Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.5.2.B.4.a) (where applicable)

Please refer to Note II for an explanation on co-ordination with utilities, regional planning and/or links with 3rd parties.

Enabling of Future Technology and/or Future Operational Requirements (5.4.5.2.B.4.b) (where applicable)

Please refer to Note IV for an explanation enabling of future technology and future operational requirements.

	Economic Development (5.4.5.2.B.5) **(where applicable)** Horizon Utilities ensures that policies and practices do not unnecessarily create barriers to economic development which are primarily focused within its communities.
	Environmental Benefits (5.4.5.2.B.6) **(where applicable)** n/a

System Service Specific Requirements (5.4.5.2.C.c)	**Project Name** #6 Wire Removal - Eastmount Table 3
	System Service Specific Requirements (5.4.5.2.C.c) **Benefit to Customers (5.4.5.2.C.c.i)** The #6 Wire Replacement projects provide a benefit to customers through the elimination of outages due to failure of #6 solid copper wire. Failure of #6 copper wire results in service interruptions to customers and presents a high risk to public safety. **Regional Planning Requirements (5.4.5.2.C.c.i)** This project is not related or impacted by regional planning requirements. **Integration of Advance Technology (5.4.5.2.C.c.iii)** Please refer to Note IV for an explanation enabling of future technology and future operational requirements. **System Benefits to Reliability, Efficiency and Safety (5.4.5.2.C.c.iv)** Safer working conditions for personnel, renewed assets and improved system reliability are benefits of these projects. Where possible, #6 Wire replacement projects are co-ordinated with 4kV and 8KV renewal projects. **Factors Affecting Implementing Timing/Priority (5.4.5.2.C.c.v)** N/A **Summary of Options Analysis (5.4.5.2.C.c.vi)** Failure to renew #6 copper wire allows the operational and safety risk presented by #6 copper wire to persist. Where possible, replacement of #6 copper wire is co-ordinated with 4kV and 8kV renewal projects.

horizon UTILITIES Looking beyond...

Capital Project Summary

General Information on Project (5.4.5.2.A)

Project Name	Caroline and George Backup
Budget Year	2015
Investment Category	System Service
Project Summary	This project involves the construction of a full capacity backup to the redeveloped Caroline and George Street area of downtown Hamilton. The system currently does not have the ability to back up the full forecasted load for the area should a failure of the primary feed occur.

Capital Investment (5.4.5.2.A.i)

Capital Investment (gross)	$951,557
Customer Contribution	$0
Capital Investment (net)	$951,557
O&M Expenditure	$0

Customer Attachments / Load (kVA) (5.4.5.2.A.ii)

This project will provide a full capacity backup to an area servicing over 7MVA of load.

Project Dates (5.4.5.2.A.iii)

Start Date	2015/09/01
In Service Date	2015/12/31

Expenditure Timing

Q1	Q2	Q3	Q4
0%	0%	25%	75%

Schedule Risk and Risk Mitigation (5.4.5.2.A.iv**)**

This project must proceed in 2015 as failure to construct would leave this area of the Hamilton core with insufficient back up capacity.

Comparative Information from Equivalent Projects (5.4.5.2.A.v)

There are no comparable projects in scope and nature for comparison.

Total Capital OM&A Costs Associated with REG Investments (5.4.5.2.A.vi)

This project is not associated with an REG investment and therefore OM&A costs related to REG will not be incurred.

Leave to Construct Approval (5.4.5.2.A.vii)

This project does not require “Leave to Construct” under Section 92 of the *Ontario Energy Board Act* 1998.

Evaluation Criteria and Information (5.4.5.2.B)	**Project Name** Caroline and George Backup Table 2
	Efficiency, Customer Value, Reliability (5.4.5.2.B.1) **Investment Driver (5.4.5.2.B.1.a)** System Service (100%) **Secondary Driver (5.4.5.2.B.1.a)** n/a **Investment Priority (5.4.5.2.B.1.b)** 3 – Required project
	Analysis of Project and Project Alternatives (5.4.5.2.B.1.c) The primary feed to this area involved the construction of a new dedicated feeder to the area. Construction of an additional dedicated feeder was considered but discounted. The proposed project to increase the inter-tie capacity with existing feeders in the area proved to be the lower cost option.
	Safety (5.4.5.2.B.2) This project is not intended to address safety concerns with the distribution system.
	Cyber-Security and Privacy (5.4.5.2.B.3) (where applicable) n/a
	Co-ordination and Interoperability (5.4.5.2.B.4) **Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.5.2.B.4.a) (where applicable)** Please refer to Note II for an explanation on co-ordination with utilities, regional planning and/or links with 3rd parties. **Enabling of Future Technology and/or Future Operational Requirements (5.4.5.2.B.4.b) (where applicable)** Please refer to Note IV for an explanation enabling of future technology and future operational requirements.
	Economic Development (5.4.5.2.B.5) **(where applicable)** Horizon Utilities ensures that policies and practices do not unnecessarily create barriers to economic development which are primarily focused within its communities.
	Environmental Benefits (5.4.5.2.B.6) **(where applicable)** n/a

System Service Specific Requirements (5.4.5.2.C.c)	**Project Name** Caroline and George Backup Table 3

System Service Specific Requirements (5.4.5.2.C.c)

Benefit to Customers (5.4.5.2.C.c.i)

Improved feeder security is a benefit of this project as the existing feeder designated to back-up the area does not have sufficient capacity under peak loading conditions.

Regional Planning Requirements (5.4.5.2.C.c.i)

This project is not related or impacted by regional planning requirements.

Integration of Advance Technology (5.4.5.2.C.c.iii)

Please refer to Note IV for an explanation enabling of future technology and future operational requirements.

System Benefits to Reliability, Efficiency and Safety (5.4.5.2.C.c.iv)

System benefits include improved operability and redundancy within the Hamilton downtown core area.

Factors Affecting Implementing Timing/Priority (5.4.5.2.C.c.v)

This project must proceed in 2015 as failure to construct would leave this area of the Hamilton core with insufficient back up capacity.

Summary of Options Analysis (5.4.5.2.C.c.vi)

The primary feed to this area involved the construction of a new dedicated feeder to the area. Construction of an additional dedicated feeder was considered but discounted. The proposed project to increase the inter-tie capacity with existing feeders in the area proved to be the lower cost option.

horizon UTILITIES Looking beyond...

Capital Project Summary

General Information on Project (5.4.5.2.A)

Project Name	Waterdown 3rd Feeder – Upgrade York Road
Budget Year	2015
Investment Category	System Service
Project Summary	This project involves the construction of a 3rd feeder to improve the security for the Waterdown express feeders 2D12X and 2D13X.

Capital Investment (5.4.5.2.A.i)	Capital Investment (gross)	$984,189
	Customer Contribution	$0
	Capital Investment (net)	$984,189
	O&M Expenditure	$0
Customer Attachments / Load (kVA) (5.4.5.2.A.ii)	n/a	

Project Dates (5.4.5.2.A.iii)

Start Date	2015/06/01
In Service Date	2015/10/31

Expenditure Timing

Q1	Q2	Q3	Q4
0%	20%	60%	20%

Schedule Risk and Risk Mitigation (5.4.5.2.A.iv**)**

Please refer to Note I for risk and risk mitigation.

Comparative Information from Equivalent Projects (5.4.5.2.A.v)

There are no comparable projects in scope and nature for comparison

Total Capital OM&A Costs Associated with REG Investments (5.4.5.2.A.vi)

This project is not associated with an REG investment and therefore OM&A costs related to REG will not be incurred.

Leave to Construct Approval (5.4.5.2.A.vii)

This project does not require “Leave to Construct” under Section 92 of the *Ontario Energy Board Act* 1998.

Evaluation Criteria and Information (5.4.5.2.B)	**Project Name** Waterdown 3rd Feeder – Upgrade York Road Table 2
	Efficiency, Customer Value, Reliability (5.4.5.2.B.1) **Investment Driver (5.4.5.2.B.1.a)** System Service (100%) **Secondary Driver (5.4.5.2.B.1.a)** n/a **Investment Priority (5.4.5.2.B.1.b)** 3 – Required project
	Analysis of Project and Project Alternatives (5.4.5.2.B.1.c) No feasible project alternatives exist for providing a 3rd feed to the Waterdown area. An alternative feed is required to address load growth in the area and to address the lack of redundancy.
	Safety (5.4.5.2.B.2) This project is not intended to address safety concerns with the distribution system.
	Cyber-Security and Privacy (5.4.5.2.B.3) (where applicable) Cyber-Security and Privacy are not applicable to this project.
	Co-ordination and Interoperability (5.4.5.2.B.4) **Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.5.2.B.4.a) (where applicable)** This project is a prerequisite for the Highway 5 and Highway 6 grade separation. The project will require significant co-ordination with the Ministry of Transportation and the City of Hamilton. **Enabling of Future Technology and/or Future Operational Requirements (5.4.5.2.B.4.b) (where applicable)** Please refer to Note IV for an explanation enabling of future technology and future operational requirements.
	Economic Development (5.4.5.2.B.5) **(where applicable)** Horizon Utilities ensures that policies and practices do not unnecessarily create barriers to economic development which are primarily focused within its communities.
	Environmental Benefits (5.4.5.2.B.6) **(where applicable)** n/a

System Service Specific Requirements (5.4.5.2.C.c)	**Project Name** Waterdown 3rd Feeder – Upgrade York Road Table 3

System Service Specific Requirements (5.4.5.2.C.c)

Benefit to Customers (5.4.5.2.C.c.i)

This project provides benefits to customers by providing improved security to the village of Waterdown. Waterdown has over 6,600 customers who are serviced by two feeders sharing a single pole line through a heavily treed section of the Niagara Escarpment. This project provides an alternate feed to this area, thereby eliminating the risk of outage to the entire village through a single point of failure.

Regional Planning Requirements (5.4.5.2.C.c.i)

This project is not related or impacted by regional planning requirements.

Integration of Advance Technology (5.4.5.2.C.c.iii)

Please refer to Note IV for an explanation enabling of future technology and future operational requirements.

System Benefits to Reliability, Efficiency and Safety (5.4.5.2.C.c.iv)

System benefits include improved security and operability within the Waterdown area.

Factors Affecting Implementing Timing/Priority (5.4.5.2.C.c.v)

This project is a prerequisite for the Highway 5 and Highway 6 grade separation and must be completed in 2015. The project will require significant co-ordination with the Ministry of Transportation and the City of Hamilton.

Summary of Options Analysis (5.4.5.2.C.c.vi)

There are limited alternatives available to provide an alternative feed to service the village of Waterdown.

2015 General Plant Investments

Capital Project Summary

Project Name	Annual Corporate Computer Replacement
Budget Year	2015
Investment Category	General Plant
Project Summary	This project is part of an ongoing business requirement to refresh end user computers. Horizon Utilities utilizes a three-year lifecycle for replacement of end user computers. On an annual basis, approximately one third of all of Horizon Utilities' computers (~150 personal computers ("PCs")/year) are replaced.

Capital Investment (5.4.5.2.A.i)	Capital Investment (gross)	$318,000
	Customer Contribution	n/a
	Capital Investment (net)	n/a
	O&M Expenditure	n/a
Customer Attachments / Load (5.4.5.2.A.ii)	n/a	

Project Dates (5.4.5.2.A.iii)

Start Date Jan. 2015

In Service Date Dec. 2015

Expenditure Timing			
Q1	Q2	Q3	Q4
25%	25%	25%	25%

Schedule Risk and Risk Mitigation (5.4.5.2.A.iv**)**

Schedule - Implementation is phased throughout the year starting in January and ending in December, based on the age of the PCs being replaced.

Risk – The primary risk to this project is product availability from suppliers.
Risk Mitigation – Work closely with suppliers to schedule orders based on required delivery times.

Comparative Information from Equivalent Projects (5.4.5.2.A.v)

Comparable gross investments for the annual corporate computer replacement for the 2010 to 2013 Historical Years and the 2014 Bridge Year are:

2010 (CGAAP)- $ 336,000
2011 (CGAAP)- $ 227,000
2012 (MIFRS) - $ 312,000
2013 (MIFRS) - $ 364,947
2014 (MIFRS) - $ 366,200

Total Capital and OM&A Costs Associated with REG Investments (5.4.5.2.A.vi)
n/a

Leave to Construct Approval (5.4.5.2.A.vii)
n/a

Evaluation Criteria and Information

Project Name	Annual Corporate Computer Replacement	Table 2

Efficiency, Customer Value, Reliability (5.4.5.2.B.1)

Investment Driver (5.4.5.2.B.1.a)
General Plant (100%)

Secondary Driver (5.4.5.2.B.1.a)
n/a

Investment Priority (5.4.5.2.B.1.b)
High Priority – Personal computers are treated as a strategic asset. They are Horizon Utilities' primary staff productivity tool. They are used to: maintain and deliver services to customers; improve staff productivity; cost-effectively manage total cost of PC ownership; and support investments in new applications, infrastructure and business capabilities.

Analysis of Project and Project Alternatives (5.4.5.2.B.1.c)
n/a

Safety (5.4.5.2.B.2)
n/a

Cyber-Security and Privacy (5.4.5.2.B.3) (where applicable)
n/a

Co-ordination and Interoperability (5.4.5.2.B.4)

Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.5.2.B.4.a) (where applicable)
n/a

Enabling of Future Technology and/or Future Operational Requirements (5.4.5.2.B.4.b)

Suppliers of enterprise systems such as: GIS; OMS; SCADA; AMI; and IFS ERP, are constantly upgrading their products to deliver new processes and functionality. As new versions are released, up-to-date hardware is required in order to perform necessary upgrades to maintain vendor support for the systems.

Economic Development (5.4.5.2.B.5) **(where applicable)**

N/A

Environmental Benefits (5.4.5.2.B.6) **(where applicable)**

N/A

General Plant Specific Requirements

Project Name	Annual Corporate Computer Replacement	Table 3

General Plant Specific Requirements (5.4.5.2.C.d)

Summary of Qualitative and Quantitative Analysis (5.4.5.2.C.d.i)

n/a

Business Case Justification Documentation (5.4.5.2.C.d.i)

Horizon Utilities' PCs are treated as a strategic asset, because they are the primary staff productivity tool. Horizon Utilities has streamlined its PC lifecycle management processes utilizing a PC refresh cycle of three years, in order to: deliver, maintain and improve services to customers; to improve staff productivity; to cost-effectively manage total cost of PC ownership; and to support investments in new applications, infrastructure and business capabilities.

A three-year PC refresh cycle reduces the total cost of ownership by reducing the number of models of PCs supported, which results in the reduction of the IST service desk effort required to deploy, secure, and manage new systems and applications. The reduction in the number of supported models has allowed Horizon Utilities to introduce mobile computing for remote field workers and to increase the number of supported PCs by over 100 devices since 2011, without an increase in IST service desk support staff.

A refresh lifecycle of three years reduces the likelihood of device failures that lead to a loss of staff productivity and increased IT support effort. Over 50% of Horizon Utilities' staff utilizes a mobile PC (laptop or tablet) in the performance of their daily activities, many in harsh operating environments outside the office, which increases the likelihood of failure due to operating environment and the age of the device.

Horizon Utilities has introduced several new enterprise business and engineering systems to: mitigate business risks related to aging systems (e.g. GIS); improve electricity system operation (i.e. GIS, OMS); and to address end of vendor support for systems (i.e. IFS ERP, Microsoft Windows XP). Maintaining a three-year PC lifecycle refresh program allows Horizon Utilities' to migrate to these applications without a need to make large one-time investments in PCs to meet the minimum operating requirements of new applications.

PCs are the primary productivity tool used by Horizon Utilities' staff. Unreliable and slow PCs impact productivity and customer service.

Minimizing the number of supported models reduces the IST support effort required to manage, order, configure, and deploy PCs and it reduces the total cost of ownership for PCs.

Capital Project Summary

Project Name	2015 IFS ERP Upgrade
Budget Year	2015
Investment Category	General Plant
Project Summary	This project is the third and final phase of an enterprise-wide project commencing in 2013 through to 2015 to upgrade Horizon Utilities' ERP system. This phase involves the redesign and optimization of existing business processes, and the implementation of new business processes using new features and functions available in the IFS version 8.1 to deliver operational efficiencies and staff productivity improvements. The estimated annual cost benefit for this phase is approximately $703,500.

Capital Investment (5.4.5.2.A.i)	Capital Investment (gross)	$1,382,607
	Customer Contribution	n/a
	Capital Investment (net)	n/a
	O&M Expenditure	n/a
Customer Attachments / Load (5.4.5.2.A.ii)	n/a	

Project Dates (5.4.5.2.A.iii)	Start Date	Jan. 2015		
	In Service Date	Dec. 2015		
	Expenditure Timing			
	Q1	Q2	Q3	Q4
	20%	30%	25%	25%

Schedule Risk and Risk Mitigation (5.4.5.2.A.iv**)**

Schedule - Implementation is being phased throughout the year, starting in January and ending in December. The project is being phased based on a combination of the potential benefit value of the process improvement and the business unit resource availability to define, configure, and test the process change.

Risk – The primary risk to this project is internal resource availability.
Risk Mitigation – Utilization of Horizon Utilities' Project Management Framework to effectively manage project to budget and schedule.

Comparative Information from Equivalent Projects (5.4.5.2.A.v)

Horizon Utilities has no recently completed project which is comparable in scope and scale which can be used as a reasonable comparator.

Total Capital and OM&A Costs Associated with REG Investments (5.4.5.2.A.vi)
n/a

Leave to Construct Approval (5.4.5.2.A.vii)

n/a

Evaluation Criteria and Information

Project Name 2015 IFS ERP Upgrade Table 2

Efficiency, Customer Value, Reliability (5.4.5.2.B.1)

Investment Driver (5.4.5.2.B.1.a)

General Plant (100%)

Secondary Driver (5.4.5.2.B.1.a)
n/a

Investment Priority (5.4.5.2.B.1.b)

High Priority – The IFS ERP System is an enterprise-wide system used to manage business processes in Finance, Human Resources, Supply Chain, and Engineering Project Management. Optimization of business processes in IFS will delivery annual staff productivity/capacity improvements estimated at $603,500 and annual cost reductions/future cost avoidance estimated at $100,000.

Analysis of Project and Project Alternatives (5.4.5.2.B.1.c)
n/a

Safety (5.4.5.2.B.2)

n/a

Cyber-Security and Privacy (5.4.5.2.B.3) (where applicable)

n/a

Co-ordination and Interoperability (5.4.5.2.B.4)

Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.5.2.B.4.a) (where applicable)
n/a

Enabling of Future Technology and/or Future Operational Requirements (5.4.5.2.B.4.b)

n/a

Economic Development (5.4.5.2.B.5) **(where applicable)**

n/a

	Environmental Benefits (5.4.5.2.B.6) **(where applicable)** n/a

General Plant Specific Requirements	**Project Name**	2015 IFS ERP Upgrade	Table 3

General Plant Specific Requirements (5.4.5.2.C.d)

Summary of Qualitative and Quantitative Analysis (5.4.5.2.C.d.i)

n/a

Business Case Justification Documentation (5.4.5.2.C.d.i)

The 2015 capital investment $1,382,600 consisting of $750,000 of capitalized internal labour and $632,600 in software add-ons and third-party consulting support.

The estimated annual cost benefit for this phase is approximately $703,500. These benefits will be realized in the following areas:

- Staff productivity improvements – This phase of the project is estimated to deliver approximately 6,965 hours of staff productivity improvements annually for an annual productivity improvement of $603,500. These improvements will be realized through reductions in transaction processing times and automation of manual tasks.

- Cost Reductions and Cost Avoidance - For some processes it is estimated that process changes will deliver reduction in costs related to transaction completion and elimination of fees currently being incurred. The automation of some of processes will allow existing staff to process more transactions, avoiding future cost increases related to incremental headcount to support transaction volumes. The estimated annual total of these cost reduction and cost avoidance improvements is $100,000.

Capital Project Summary

Project Name	Enterprise Phone System Upgrade
Budget Year	2015
Investment Category	General Plant
Project Summary	This project is a required planned lifecycle upgrade to mitigate risk related to end of vendor support for Horizon Utilities' phone system and phone system management software installed in 2010. The phone system is a key communications vehicle used by customers to contact Horizon Utilities. This involves replacement of the phone system and call centre software in Hamilton and the redundant backup phone system in St. Catharines. The two phone systems are configured to provide disaster recovery capabilities for automatic failover in the event of loss of service at either site.

Capital Investment (5.4.5.2.A.i)	Capital Investment (gross)	$400,000
	Customer Contribution	n/a
	Capital Investment (net)	n/a
	O&M Expenditure	n/a
Customer Attachments / Load (5.4.5.2.A.ii)	n/a	

Project Dates (5.4.5.2.A.iii)

Start Date	Aug. 2015
In Service Date	Nov. 2015

Expenditure Timing

Q1	Q2	Q3	Q4
0%	0%	0%	100%

Schedule Risk and Risk Mitigation (5.4.5.2.A.iv**)**

Schedule - Planning Aug. 2015, Configuration Sep. 2015, Testing Oct. 2015, Go Live Nov. 2015

Risk – The primary risk to this project is internal resource availability.

Risk Mitigation – Utilization of Horizon Utilities' Project Management Framework to effectively manage project to budget and schedule.

Comparative Information from Equivalent Projects (5.4.5.2.A.v)

Horizon Utilities has no recently completed project which is comparable in scope and scale that can be used as a reasonable comparator.

Total Capital and OM&A Costs Associated with REG Investments (5.4.5.2.A.vi)

n/a

Leave to Construct Approval (5.4.5.2.A.vii)

n/a

Evaluation Criteria and Information

Project Name	Enterprise Phone System Upgrade	Table 2

Efficiency, Customer Value, Reliability (5.4.5.2.B.1)

Investment Driver (5.4.5.2.B.1.a)

General Plant 100%

Secondary Driver (5.4.5.2.B.1.a)
n/a

Investment Priority (5.4.5.2.B.1.b)

High Priority – This is a risk mitigation project to ensure continued vendor support for the primary method of communications with Horizon Utilities' customers.

Analysis of Project and Project Alternatives (5.4.5.2.B.1.c)
n/a

Safety (5.4.5.2.B.2)

n/a

Cyber-Security and Privacy (5.4.5.2.B.3) (where applicable)

n/a

Co-ordination and Interoperability (5.4.5.2.B.4) **(where applicable)**

Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.5.2.B.4.a) (where applicable)
n/a

Enabling of Future Technology and/or Future Operational Requirements (5.4.5.2.B.4.b)

n/a

Economic Development (5.4.5.2.B.5) **(where applicable)**

n/a

Environmental Benefits (5.4.5.2.B.6) **(where applicable)**

n/a

General Plant Specific Requirements	**Project Name** Enterprise Phone System Upgrade Table 3
	General Plant Specific Requirements (5.4.5.2.C.d) **Summary of Qualitative and Quantitative Analysis (5.4.5.2.C.d.i)** n/a **Business Case Justification Documentation (5.4.5.2.C.d.i)** The Horizon Utilities' phone system is a critical IT infrastructure component that is the primary method of communication with customers and as such needs to be at vendor supported levels to maintain optimum customer service levels.

Capital Project Summary

Project Name	[redacted]
Budget Year	2015
Investment Category	General Plant

Project Summary

The objective of this 3 year project starting in 2014 [redacted]

Capital Investment (5.4.5.2.A.i)	Capital Investment (gross)	$300,000	
	Customer Contribution	n/a	
	Capital Investment (net)	n/a	
	O&M Expenditure	n/a	
Customer Attachments / Load (5.4.5.2.A.ii)	n/a		

Project Dates (5.4.5.2.A.iii)

Start Date	March 2015
In Service Date	December 2015

Expenditure Timing

Q1	Q2	Q3	Q4
0%	33%	33%	34%

Schedule Risk and Risk Mitigation (5.4.5.2.A.iv**)**

Project timelines and costs exceeding the budget are risks. The project manager will report regularly on project timelines and adherence to budget and escalates issues for resolution.

Comparative Information from Equivalent Projects (5.4.5.2.A.v)

n/a

Total Capital OM&A Costs Associated with REG Investments (5.4.5.2.A.vi)

n/a

Leave to Construct Approval (5.4.5.2.A.vii)

n/a

Evaluation Criteria and Information	
	Project Name: [redacted] Table 2
	Efficiency, Customer Value, Reliability (5.4.5.2.B.1) **Investment Driver (5.4.5.2.B.1.a)** General Plant (100%) **Secondary Driver (5.4.5.2.B.1.a)** n/a
	Investment Priority (5.4.5.2.B.1.b) High
	Analysis of Project and Project Alternatives (5.4.5.2.B.1.c) Horizon Utilities engaged CAPSYS Integrated Technology Consulting in 2013 to [redacted]
	Safety (5.4.5.2.B.2) [redacted]
	Cyber-Security and Privacy (5.4.5.2.B.3) (where applicable) n/a
	Co-ordination and Interoperability (5.4.5.2.B.4) **Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.5.2.B.4.a) (where applicable)** n/a **Enabling of Future Technology and/or Future Operational Requirements (5.4.5.2.B.4.b)** n/a
	Economic Development (5.4.5.2.B.5) **(where applicable)** n/a
	Environmental Benefits (5.4.5.2.B.6) **(where applicable)** n/a

General Plant Specific Requirements

Project Name	Building Security Replacement	Table 3

General Plant Specific Requirements (5.4.5.2.C.d)

Summary of Qualitative and Quantitative Analysis (5.4.5.2.C.d.i)

Horizon Utilities engaged CAPSYS Integrated Technology Consulting in [redacted]

Business Case Justification Documentation (5.4.5.2.C.d.i)

[redacted]

[redacted]

[redacted]

Capital Project Summary

Project Name	2015 John St. Building Roof Replacement
Budget Year	2015
Investment Category	General Plant

Project Summary

This project involves the replacement of John Street and Hughson Street rooves. This project will:

- Reduce the risk of water damage to assets and sustain daily operations;
- Improve the structural integrity of the buildings;
- Improved energy performance of buildings including systems and infrastructure; and
- Decreased maintenance and operating costs.

Capital Investment (5.4.5.2.A.i)	Capital Investment (gross)	$900,000
	Customer Contribution	n/a
	Capital Investment (net)	n/a
	OM&A Expenditure	n/a
Customer Attachments / Load (5.4.5.2.A.ii)	n/a	

Project Dates (5.4.5.2.A.iii)

Start Date	March 2015
In Service Date	November 2015

Expenditure Timing

Q1	Q2	Q3	Q4
0%	40%	60%	0%

Schedule Risk and Risk Mitigation (5.4.5.2.A.iv**)**

Project timelines and costs exceeding the budget are risks. The project manager will report regularly on project timelines and adherence to budget and escalates issues for resolution.

Comparative Information from Equivalent Projects (5.4.5.2.A.v)

n/a

Total Capital OM&A Costs Associated with REG Investments (5.4.5.2.A.vi)

n/a

Leave to Construct Approval (5.4.5.2.A.vii)

n/a

Evaluation Criteria and Information	**Project Name:** 2015 John St. Building Roof Replacement — Table 2
	Efficiency, Customer Value, Reliability (5.4.5.2.B.1) **Investment Driver (5.4.5.2.B.1.a)** General Plant 100% **Secondary Driver (5.4.5.2.B.1.a)** n/a
	Investment Priority (5.4.5.2.B.1.b) High
	Analysis of Project and Project Alternatives (5.4.5.2.B.1.c) An asset condition roof assessment conducted by Garland Canada Inc. in 2013 provided Horizon Utilities with the findings and recommendations for improvement and forecasted costs.
	Safety (5.4.5.2.B.2) n/a
	Cyber-Security and Privacy (5.4.5.2.B.3) n/a
	Co-ordination and Interoperability (5.4.5.2.B.4) **(where applicable)** **Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.5.2.B.4.a)** n/a **Enabling of Future Technology and/or Future Operational Requirements (5.4.5.2.B.4.b)** n/a
	Economic Development (5.4.5.2.B.5) **(where applicable)** n/a.
	Environmental Benefits (5.4.5.2.B.6) **(where applicable)** Horizon Utilities will explore sustainable roof options such as a green roof and solar panels to improve energy efficiencies.

General Plant Specific Requirements

Project Name 2015 John St. Building Roof Replacement Table 3

General Plant Specific Requirements (5.4.5.2.C.d)

Summary of Qualitative and Quantitative Analysis (5.4.5.2.C.d.i)

In 2013 Horizon Utilities engaged Garland Canada Inc. to conduct an asset condition roof assessment to determine the condition of the roof and provide recommendations for improvement as well as the related costs.

Business Case Justification Documentation (5.4.5.2.C.d.i)

The rooves at the John St. building, Hughson Street building, Hughson Substation building and parking garage, have reached end-of-life and were identified to be in poor condition. The rooves were originally installed in 1999.

There are visible signs of deterioration. The roof membrane is starting to de-granulate, reducing the strength and UV resistance of the roof. Some walls are in very poor condition and require new cladding, stucco or coating. There are some blisters on the roof area that are caused when air and/or air vapour is trapped. Previous repairs to the roof have degraded and water leaks have damaged the windows and floor walls below.

Capital Project Summary

Project Name	2015 John Street Windows Replacement
Budget Year	2015
Investment Category	General Plant

Project Summary;

This project is scheduled to take place between 2015 to 2017 to replace the existing windows of the John Street building as they have reached the end-of-life with the objective to:

- Improve energy performance as the windows are no longer weather resistant;
- Prevent further damage to interior walls and facilities related components;
- Prevent further damage to the building exterior structure;
- Prevent damage to operational systems; and
- Reduce operational related costs.

Capital Investment (5.4.5.2.A.i)	Capital Investment (gross)	$300,000
	Customer Contribution	n/a
	Capital Investment (net)	n/a
	O&M Expenditure	n/a
Customer Attachments / Load (5.4.5.2.A.ii)	n/a	

Project Dates (5.4.5.2.A.iii)

Start Date	April 2015
In Service Date	December 2015

Expenditure Timing

Q1	Q2	Q3	Q4
0%	35%	65%	0%

Schedule Risk and Risk Mitigation (5.4.5.2.A.iv**)**

Project timelines and costs exceeding the budget are risks. The project manager will report regularly on project timelines and adherence to budget and will escalate issues for resolution.

Comparative Information from Equivalent Projects (5.4.5.2.A.v)

n/a

Total Capital OM&A Costs Associated with REG Investments (5.4.5.2.A.vi)

n/a

Leave to Construct Approval (5.4.5.2.A.vii)

n/a

Evaluation Criteria and Information	**Project Name:** 2015 John Street Windows Replacement Table 2
	Efficiency, Customer Value, Reliability (5.4.5.2.B.1) **Investment Driver (5.4.5.2.B.1.a)** General Plant – 100% **Secondary Driver (5.4.5.2.B.1.a)** n/a
	Investment Priority (5.4.5.2.B.1.b) High
	Analysis of Project and Project Alternatives (5.4.5.2.B.1.c) Horizon Utilities engaged the MMM Group Limited in 2013 to conduct a window condition assessment using visual inspections, air leakage testing and building energy simulation air testing. Recommendations are based on the results of the tests and inspections.
	Safety (5.4.5.2.B.2) n/a
	Cyber-Security and Privacy (5.4.5.2.B.3) (where applicable) n/a
	Co-ordination and Interoperability (5.4.5.2.B.4) **Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.5.2.B.4.a) (where applicable)** n/a **Enabling of Future Technology and/or Future Operational Requirements (5.4.5.2.B.4.b)** n/a
	Economic Development (5.4.5.2.B.5) **(where applicable)** n/a **Environmental Benefits** (5.4.5.2.B.6) **(where applicable)** n/a

General Plant Specific Requirements	**Project Name** 2015 John Street Windows Replacement Table 3
	General Plant Specific Requirements (5.4.5.2.C.d) **Summary of Qualitative and Quantitative Analysis (5.4.5.2.C.d.i)** Horizon Utilities engaged the MMM Group Limited in 2013 to conduct a window condition assessment using visual inspections, air leakage testing and building energy simulation air testing. Recommendations are based on the results of the tests and inspections. **Business Case Justification Documentation (5.4.5.2.C.d.i)** The windows are no longer weather resistant or energy efficient and allow cold drafts to enter the building. The windows collect frost on the inside in the winter which melts and damages interior walls and carpeting. The assessment was conducted using visual inspections, air leakage testing and building energy simulations. The testing concluded that the condition of the operable windows in the John Street office building is poor. 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.

Capital Project Summary

Project Name	2015 Vehicle Replacement
Budget Year	2015
Investment Category	General Plant

Project Summary;

Between 2015 and 2019 Horizon Utilities has identified a number of current vehicles that will require replacement as they have reached end-of-life as per the criteria within Horizon Utilities' Fleet Replacement Plan.

Other expected objectives and outcomes are to:

- Maintain vehicle reliability and availability;
- Reduce fuel consumption;
- Reduce emissions;
- Reduce down time required to conduct maintenance and repairs; and
- Maintain customer response time.

Capital Investment (5.4.5.2.A.i)	Capital Investment (gross)	$778,000
	Customer Contribution	n/a
	Capital Investment (net)	n/a
	O&M Expenditure	n/a
Customer Attachments / Load (5.4.5.2.A.ii)	n/a	

Project Dates (5.4.5.2.A.iii)

Start Date	March 2015
In Service Date	December 2015

Expenditure Timing

Q1	Q2	Q3	Q4
0%	0%	50%	50%

Schedule Risk and Risk Mitigation (5.4.5.2.A.iv**)**

Risk – The primary risk to this project is product availability and adherence to delivery schedules from suppliers.

Risk Mitigation – Work closely with suppliers to schedule orders based on required delivery times.

Comparative Information from Equivalent Projects (5.4.5.2.A.v)

Comparable gross investments for vehicle replacements for the 2010 to 2013 Historical Years and the 2014 Bridge Year are:

2010 (CGAAP)- $ 1,590,516
2011 (CGAAP)- $ 1,033,975
2012 (MIFRS) - $ 1,057,410
2013 (MIFRS) - $ 36,365
2014 (MIFRS) - $ 785,000

Total Capital OM&A Costs Associated with REG Investments (5.4.5.2.A.vi)

n/a

Leave to Construct Approval (5.4.5.2.A.vii)
n/a

Evaluation Criteria and Information

Project Name:	2015 Vehicle Replacement	Table 2

Efficiency, Customer Value, Reliability (5.4.5.2.B.1)

Investment Driver (5.4.5.2.B.1.a)

General Plant – 100%

Secondary Driver (5.4.5.2.B.1.a)
n/a

Investment Priority (5.4.5.2.B.1.b)

High

Analysis of Project and Project Alternatives (5.4.5.2.B.1.c)

n/a

Safety (5.4.5.2.B.2)

n/a

Cyber-Security and Privacy (5.4.5.2.B.3) (where applicable)

N/A

Co-ordination and Interoperability (5.4.5.2.B.4)

Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.5.2.B.4.a) (where applicable)

n/a

Enabling of Future Technology and/or Future Operational Requirements (5.4.5.2.B.4.b)

n/a

Economic Development (5.4.5.2.B.5) **(where applicable)**

n/a

Environmental Benefits (5.4.5.2.B.6) **(where applicable)**
n/a

General Plant Specific Requirements

Project Name	2015 Vehicle Replacement	Table 3

General Plant Specific Requirements (5.4.5.2.C.d)

Summary of Qualitative and Quantitative Analysis (5.4.5.2.C.d.i)
Horizon Utilities uses the data collected from electronic fleet and fuel management system, the Global Positional System (“GPS”) data which includes engine hours, power take-off (“PTO”), engine idling hours, traffic patterns, utilization, and mileage to determine the optimal maintenance schedule and vehicle maintenance and repairs activities in order to determine the optimal maintenance plan and vehicles replacements.

Business Case Justification Documentation (5.4.5.2.C.d.i)

To maintain the quality, reliability and availability of Horizon Utilities’ vehicle fleet for the Construction and Maintenance, Metering Services and corporate group activities, vehicles are assessed annually based on a replacement criteria matrix defined within the Fleet Replacement Plan.

Replacement strategies also ensure that Horizon Utilities maintains safe vehicles for employees, while targeting reduced emissions, as well as reduced fuel, operating and maintenance costs. During the next six years, Horizon Utilities will not be procuring any net new vehicles and instead will focus on the replacement of end of life vehicles.

Due to budget mitigation efforts in 2011, 2012, and 2013 a number of vehicles scheduled for replacement were kept in operation and rescheduled for replacement in 2014. It is now critical that these vehicles be replaced as maintenance and repairs costs have increased and the vehicles no longer operate at full capacity, reducing vehicle availability and impacting service delivery.

Regular vehicle replacement is necessary to avoid undue vehicle down and associated negative impacts to customer response time and employee productivity.

Capital Project Summary

Project Name	2015 Tools, Shop and Garage Equipment
Budget Year	2015
Investment Category	General Plant

Project Summary
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 risks.

Capital Investment (5.4.5.2.A.i)	Capital Investment (gross)	$556,000
	Customer Contribution	n/a
	Capital Investment (net)	n/a
	O&M Expenditure	n/a
Customer Attachments / Load (5.4.5.2.A.ii)	n/a	

Project Dates (5.4.5.2.A.iii)

Start Date	January 2015
In Service Date	December 2015

Expenditure Timing

Q1	Q2	Q3	Q4
25%	25%	25%	25%

Schedule Risk and Risk Mitigation (5.4.5.2.A.iv**)**

Risk – n/a

Risk Mitigation – n/a

Comparative Information from Equivalent Projects (5.4.5.2.A.v)

Comparable gross investments for tools shop, and garage equipment for the 2010 to 2013 Historical Years and the 2014 Bridge Year are:

2010 (CGAAP)- $ 515,236
2011 (CGAAP)- $ 493,820
2012 (MIFRS) - $ 279,587
2013 (MIFRS) - $ 417,572
2014 (MIFRS) - $ 511,300

Total Capital OM&A Costs Associated with REG Investments (5.4.5.2.A.vi)

n/a

Leave to Construct Approval (5.4.5.2.A.vii)
n/a

Evaluation Criteria and Information

Project Name: 2015 Tools, Shop and Garage Equipment Table 2

Efficiency, Customer Value, Reliability (5.4.5.2.B.1)

Investment Driver (5.4.5.2.B.1.a)

General Plant (100%)

Secondary Driver (5.4.5.2.B.1.a)
n/a

Investment Priority (5.4.5.2.B.1.b)

High

Analysis of Project and Project Alternatives (5.4.5.2.B.1.c)

Tools and equipment over $5000 are procured through a competitive process and alternatives are considered at the time of requisition.

Safety (5.4.5.2.B.2)

Tools and equipment meet Canadian Standards Association ("CSA") requirements and are reviewed for conformance to requirements by Horizon Utilities' Tool & Equipment Committee.

Cyber-Security and Privacy (5.4.5.2.B.3) (where applicable)

N/A

Co-ordination and Interoperability (5.4.5.2.B.4)

Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.5.2.B.4.a) (where applicable)

n/a

Enabling of Future Technology and/or Future Operational Requirements (5.4.5.2.B.4.b)

n/a

Economic Development (5.4.5.2.B.5) **(where applicable)**

n/a

Environmental Benefits (5.4.5.2.B.6) **(where applicable)**

n/a

General Plant Specific Requirements

Project Name	2015 Tools, Shop and Garage Equipment	Table 3

General Plant Specific Requirements (5.4.5.2.C.d)

Summary of Qualitative and Quantitative Analysis (5.4.5.2.C.d.i)

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.

Business Case Justification Documentation (5.4.5.2.C.d.i)

n/a

Capital Project Summary

Project Name	Nebo Road Business Continuity
Budget Year	2015
Investment Category	General Plant

Project Summary

This project covers the installation of a 300kW permanent backup generator at Nebo Road service center to allow the facility to function and operate independent of the electrical distribution grid during power outages.

Capital Investment (5.4.5.2.A.i)	Capital Investment (gross)	$300,000
	Customer Contribution	n/a
	Capital Investment (net)	n/a
	O&M Expenditure	n/a
Customer Attachments / Load (5.4.5.2.A.ii)	n/a	

Project Dates (5.4.5.2.A.iii)

Start Date	April 2015
In Service Date	September 2015

Expenditure Timing

Q1	Q2	Q3	Q4
	35%	65%	

Schedule Risk and Risk Mitigation (5.4.5.2.A.iv**)**

Project timelines and costs exceeding the budget are risks. The project manager will report regularly on project timelines and adherence to budget and escalates issues for resolution.

Comparative Information from Equivalent Projects (5.4.5.2.A.v)

Horizon Utilities has no recently completed project which is comparable in scope and scale which can be used as a reasonable comparator.

Total Capital OM&A Costs Associated with REG Investments (5.4.5.2.A.vi)

n/a

Leave to Construct Approval (5.4.5.2.A.vii)

n/a

Evaluation Criteria and Information	**Project Name:** Nebo Road Business Continuity — Table 2
	Efficiency, Customer Value, Reliability (5.4.5.2.B.1) **Investment Driver (5.4.5.2.B.1.a)** General Plant (100%) **Secondary Driver (5.4.5.2.B.1.a)** n/a **Investment Priority (5.4.5.2.B.1.b)** High
	Analysis of Project and Project Alternatives (5.4.5.2.B.1.c) The evaluation and recommendations for this project was conducted by T. Lloyd Electric Ontario Ltd. (T. Lloyd Electric”).
	Safety (5.4.5.2.B.2) n/a
	Cyber-Security and Privacy (5.4.5.2.B.3) (where applicable) N/A
	Co-ordination and Interoperability (5.4.5.2.B.4) **Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.5.2.B.4.a) (where applicable)** n/a **Enabling of Future Technology and/or Future Operational Requirements (5.4.5.2.B.4.b)** Maintain continuous uninterrupted supply of power for continued operations of the service centre.
	Economic Development (5.4.5.2.B.5) **(where applicable)** n/a
	Environmental Benefits (5.4.5.2.B.6) **(where applicable)** n/a

General Plant Specific Requirements

Project Name	Nebo Road Business Continuity	Table 3

General Plant Specific Requirements (5.4.5.2.C.d)

Summary of Qualitative and Quantitative Analysis (5.4.5.2.C.d.i)

The evaluation and recommendations for this project was conducted by T. Lloyd Electric.

Business Case Justification Documentation (5.4.5.2.C.d.i)

Nebo Road, Horizon Utilities' largest Service Center, supports all customers in the 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, and the dispatching of emergency crews and contractors was hindered as a result. 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. Their findings were that a new generator is required in order to power up the Service Centre in the event of a power failure and that the current mobile generator unit was not manufactured to safely support this type of service connection.

Capital Project Summary

Project Name	2015 Building Renovations
Budget Year	2015
Investment Category	General Plant

Project Summary

The objective of this project planned for 2015 is to reclaim the Hughson Substation decommissioned in 2014 to relocate the current training/meeting room facilities on the 5th floor of John St to build space capacity for the IT, HR, Health and Safety and Communication groups employees that are currently located on different floors.

Capital Investment (5.4.5.2.A.i)	Capital Investment (gross)	$2,000,000
	Customer Contribution	n/a
	Capital Investment (net)	n/a
	O&M Expenditure	n/a
Customer Attachments / Load (5.4.5.2.A.ii)	n/a	

Project Dates (5.4.5.2.A.iii)	Start Date	March 2015		
	In Service Date	December 2015		
	Expenditure Timing			
	Q1	Q2	Q3	Q4
	25%	25%	25%	25%

Schedule Risk and Risk Mitigation (5.4.5.2.A.iv**)**

Project timelines and costs exceeding the budget are risks. The project manager will report regularly on project timelines and adherence to budget and escalates issues for resolution.

Comparative Information from Equivalent Projects (5.4.5.2.A.v)

Comparable gross investments for building renovations for the 2010 to 2013 Historical Years and the 2014 Bridge Year are:
2010 (CGAAP)- $ 0
2011 (CGAAP)- $ 0
2012 (MIFRS) - $ 1,767,000
2013 (MIFRS) - $ 5,490,000
2014 (MIFRS) - $ 3,700,000

Total Capital OM&A Costs Associated with REG Investments (5.4.5.2.A.vi)

n/a

Leave to Construct Approval (5.4.5.2.A.vii)
This project does not require “Leave to Construct” under Section 92 of the *Ontario Energy Board Act* 1998.

Evaluation Criteria and Information	**Project Name:** 2015 Building Renovations	Table 2
	Efficiency, Customer Value, Reliability (5.4.5.2.B.1) **Investment Driver (5.4.5.2.B.1.a)** General Plant – 100% **Secondary Driver (5.4.5.2.B.1.a)** n/a	
	Investment Priority (5.4.5.2.B.1.b) High	
	Analysis of Project and Project Alternatives (5.4.5.2.B.1.c) Horizon Utilities' building renovation plans were developed through a facilities planning process that utilized the outputs of a space planning study and multiple building assessments.	
	Safety (5.4.5.2.B.2) [redacted] safety of all facilities, employees, assets, critical for supporting life and safety systems.	
	Cyber-Security and Privacy (5.4.5.2.B.3) (where applicable) n/a	
	Co-ordination and Interoperability (5.4.5.2.B.4) **Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.5.2.B.4.a) (where applicable)** n/a **Enabling of Future Technology and/or Future Operational Requirements (5.4.5.2.B.4.b)** Installation of high efficiency lighting systems and HVAC units to reduce electricity consumption and operating costs.	
	Economic Development (5.4.5.2.B.5) **(where applicable)** n/a	
	Environmental Benefits (5.4.5.2.B.6) **(where applicable)** n/a	

General Plant Specific Requirements	**Project Name** 2015 Building Renovations Table 3

General Plant Specific Requirements

General Plant Specific Requirements (5.4.5.2.C.d)

Summary of Qualitative and Quantitative Analysis (5.4.5.2.C.d.i)

n/a

Business Case Justification Documentation (5.4.5.2.C.d.i)

The Hughson Substation built in early 1900 is being decommissioned during 2013-2014 and reclaimed as the future location of the corporate training room. The corporate training room is being relocated from the John St 5th floor, creating the much needed office space to bring the IT, HR, Health and Safety and Communications groups together from other floors.

These projects were identified as part of the multiyear building renewal & renovation plan in 2012. It included: reclaiming substation space for office space; replacing aging and end-of-life equipment; relocating business units; improving air and climate levels; and removing hazardous materials.

John St. – Partial renovation of the 5th floor in an effort to consolidate all IT, HR. Health and Safety and Communications employees into one workspace.

Hughson Substation – Reclamation of the Hughson Substation building as office space and the site of the relocated main corporate training room, reducing employee travel time that was necessary to drive to the Stoney Creek service center and improving productivity.

Capital Project Summary

General Information on Project (5.4.5.2.A)

Project Name	2016 Meters
Budget Year	2016
Investment Category	System Access

Project Summary

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;
- 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.

Capital Investment (5.4.5.2.A.i)		
	Capital Investment	$ 2,101,174
	Total	$ 2,101,174
	O&M Expenditure	$ 0

Customer Attachments / Load (kVA) (5.4.5.2.A.ii)

n/a

Project Dates (5.4.5.2.A.iii)

Start Date	2016/01/01
In Service Date	2016/12/31

Expenditure Timing

Q1	Q2	Q3	Q4
25%	25%	25%	25%

Schedule Risk and Risk Mitigation (5.4.5.2.A.iv**)**

Schedule risk for the installation of meters at new service locations may be caused by customer delays or restricted access to work sites. Horizon Utilities co-ordinates the connection of new services with customers to mitigate this risk.

Comparative Information from Equivalent Projects (5.4.5.2.A.v)
Metering investments for the 2010 to 2013 Historical Years and the 2014 Bridge Year are:

2010 (CGAAP) - $1,715,716
2011 (CGAAP)- $3,467,413
2012 (MIFRS) - $25,168,043
2013 (MIFRS) - $1,658,707
2014 (MIFRS) - $2,499,104

The increased investment in 2012 was due to the implementation of Smart Meters at a cumulative capital cost of $23,277,588. 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.

	Total Capital OM&A Costs Associated with REG Investments (5.4.5.2.A.vi) This project is not associated with an REG investment and as such no associated OM&A costs related to REG will be incurred.
	Leave to Construct Approval (5.4.5.2.A.vii) This project does not require "Leave to Construct" under Section 92 of the *Ontario Energy Board Act* 1998.

Evaluation Criteria and Information (5.4.5.2.B)	**Project Name** 2016 Meters Table 2
	Efficiency, Customer Value, Reliability (5.4.5.2.B.1) **Investment Driver (5.4.5.2.B.1.a)** System Access (80%) **Secondary Driver (5.4.5.2.B.1.a)** System Renewal (20%) Replacement of commercial meters with Smart Meters. **Investment Priority (5.4.5.2.B.1.b)** 5 – Mandatory Project
	Analysis of Project and Project Alternatives (5.4.5.2.B.1.c) Metering asset management is governed by Measurement Canada regulation and customer requirements for new and upgraded services.
	Safety (5.4.5.2.B.2) This project is not intended to address safety concerns with the distribution system.
	Cyber-Security and Privacy (5.4.5.2.B.3) (where applicable) Horizon Utilities' Smart Meter and related AMI network have been procured through Elster. Elster's system supports a multi-layered security approach including: access control; authorization; authentication; and data integrity protocols. As part of its continuous improvement model, Horizon Utilities performs periodic security assessments to identify opportunities for enhanced system hardening.
	Co-ordination and Interoperability (5.4.5.2.B.4) **Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.5.2.B.4.a) (where applicable)** Co-ordination with utilities and regional planning is not required. Horizon Utilities coordinates with customers as required by the scope of the work involved.

	Enabling of Future Technology and/or Future Operational Requirements (5.4.5.2.B.4.b) A component of this investment supports the capital investment required for the ongoing operation, maintenance, and installation of the Smart Meter infrastructure.
	Economic Development (5.4.5.2.B.5) Horizon Utilities ensures that policies and practices do not unnecessarily create barriers to economic development which are primarily focused within its communities.
	Environmental Benefits (5.4.5.2.B.6) The Smart Meter infrastructure supports the province's conservation culture. Smart metering also provides environmental benefits through reduction in field visits associated with manual meter reading.

System Access Specific Requirements (5.4.5.2.C.a)			
	Project Name	2016 Meters	Table 3
	System Access Specific Requirements (5.4.5.2.C.a) **Factors Affecting Implementing Project Timing/Priority (5.4.5.2.C.a.i)** Compliance sampling work completed to comply with Measurement Canada regulations may impact project timing. The schedule is created to smooth the annual sampling requirements from the original Smart Meter mass deployments. New and replacement meters are provided on demand to address new load growth and meter failures.		
	Factors Related to Customer Preference or 3rd Party Input (5.4.5.2.C.a.ii) Metering for new and upgraded connection projects are customer initiated and are designed to meet customer identified requirements.		
	Factors Affecting Final Project Cost (5.4.5.2.C.a.iii) Please refer to Note I for an explanation on the factors affecting the final project cost.		
	Controllable Cost Minimization (5.4.5.2.C.a.iv) Please refer to Note I for an explanation regarding controllable cost mitigation. **Other Planning Objectives (5.4.5.2.C.a.v)** Horizon Utilities combines work from multiple work groups to reduce costs and increase efficiency. The line work and meter work is combined when connecting new customers to allow the work to be completed by a single work group. **Assessment of Technical or Implementation Options (5.4.5.2.C.a.vi)** Metering work is Measurement Canada and customer driven and the technology is primarily based on the metering products available from a sole source supplier.		

Summary of Options Analysis (5.4.5.2.C.a.vii)

Metering supplier selected as part of the Smart Meter implementation program.

Final Economic Evaluation Results (5.4.5.2.C.a.viii)

Horizon Utilities completes the economic evaluation for any customer system access project which requires the construction of new facilities to the main distribution system or an increase in the existing capacity of distribution facilities. For further details please see Appendix E of Horizon Utilities' Conditions of Service. The economic evaluation is completed in accordance with section 3.2 of the Distribution System Code (DSC). For the 2015-2019 forecast period, Horizon Utilities has no known projects for which to provide the final economic evaluation. When a road authority requests a relocation of Horizon Utilities' plant located on the public road allowance, the costs shall be shared, as outlined in the Ontario *Public Service Works on Highways Act*. Other projects within this category will have an economic evaluation completed where applicable in accordance with both the DSC and Appendix E of Horizon Utilities' Conditions of Service.

Identification of System Impacts (5.4.5.2.C.a.ix)

System expansion, if required, to connect customers within this category are governed by Horizon Utilities' Conditions of Service Section 2.1.2.1.

Capital Project Summary

General Information on Project (5.4.5.2.A)

Project Name	2016 Road Relocations			
Budget Year	2016			
Investment Category	System Access			
Project Description	Projects in this category involve 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, the Ministry of Transportation, and the Region of Niagara.			
Capital Investment (5.4.5.2.A.i)	Capital Investment (gross)	$3,244,035		
	Customer Contribution	$ $904,359		
	Capital Investment (net)	$ 2,339,675		
	O&M Expenditure	n/a		
Customer Attachments / Load (kVA) (5.4.5.2.A.ii)	n/a			
Project Dates (5.4.5.2.A.iii)	Start Date	Various – driven by road authority schedules		
	In Service Date	Various – driven by road authority schedules		
	Expenditure Timing			
	Q1	Q2	Q3	Q4
	25%	25%	25%	25%

Schedule Risk and Risk Mitigation (5.4.5.2.A.iv**)**

The initiation and timing of these projects are dictated by the City of Hamilton, City of St. Catharines, the Ministry of Transportation, or the Region of Niagara. Consequently, the timing and value of investment required by Horizon Utilities is subject to change.

Comparative Information from Equivalent Projects (5.4.5.2.A.v)

Road relocations for the 2010 to 2013 Historical Years and the 2014 Bridge Year are:

2010 (CGAAP) - $ 2,889,575
2011 (CGAAP)- $ 895,524
2012 (MIFRS) - $ 3,151,887
2013 (MIFRS) - $ 340,491
2014 (MIFRS) - $ 977,024

Total Capital OM&A Costs Associated with REG Investments (5.4.5.2.A.vi)
This project is not associated with an REG investment and therefore OM&A costs related to REG will not be incurred.

Leave to Construct Approval (5.4.5.2.A.vii)

This project does not require "Leave to Construct" under Section 92 of the *Ontario Energy Board Act* 1998.

Evaluation Criteria and Information (5.4.5.2.B)

Project Name	2016 Road Relocations	Table 2

Efficiency, Customer Value, Reliability (5.4.5.2.B.1)

Investment Driver (5.4.5.2.B.1.a)

System Access (90%)

Secondary Driver (5.4.5.2.B.1.a)

System Renewal (5%)
System Service (5%)

Investment Priority (5.4.5.2.B.1.b)
5 – Mandatory Project

Analysis of Project and Project Alternatives (5.4.5.2.B.1.c)

Horizon Utilities co-ordinates project design and discusses design alternatives for each project with the organization (City, Region, Ministry of Transportation) originating the request to relocate distribution assets.

Safety (5.4.5.2.B.2)

These projects are not intended to address safety concerns with the distribution system.

Cyber-Security and Privacy (5.4.5.2.B.3) (where applicable)

n/a

Co-ordination and Interoperability (5.4.5.2.B.4)

Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.5.2.B.4.a) (where applicable)

Timelines for the execution of these projects are dictated by the City of Hamilton, City of 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.

Enabling of Future Technology and/or Future Operational Requirements (5.4.5.2.B.4.b)

Please refer to Note IV for an explanation enabling of future technology and future operational requirements.

Economic Development (5.4.5.2.B.5) **(where applicable)**

Horizon Utilities ensures that policies and practices do not unnecessarily create barriers to economic development which are primarily focused within its communities.

	Environmental Benefits (5.4.5.2.B.6) **(where applicable)** n/a

System Access Specific Requirements (5.4.5.2.C.a)

Project Name	2016 Road Relocations	Table 3

System Access Specific Requirements (5.4.5.2.C.a)

Factors Affecting Implementing Project Timing/Priority (5.4.5.2.C.a.i)

The road authority's schedule and timing of the road project will affect Horizon Utilities' project implementation and timing.

Factors Related to Customer Preference or 3rd Party Input (5.4.5.2.C.a.ii)

Road relocation projects involve a co-ordinated design process and the initiating organization (City, Municipality, or Ministry of Transportation) has input into the design of the project.
The designs for all projects within the public right-of-way are reviewed with the City as Municipal Consents are required prior to construction. Consideration is given by the road authority to coordinate all utilities within the right-of-way in the least disruptive manner.

Factors Affecting Final Project Cost (5.4.5.2.C.a.iii)

Please refer to Note I for an explanation on the factors that can affect the final project cost.

Controllable Cost Minimization (5.4.5.2.C.a.iv)

50% of Labour, Labour saving devices and Equipment rentals are recovered from the road authority. Please refer to Note I for an explanation on controllable cost minimization.

Other Planning Objectives (5.4.5.2.C.a.v)

Horizon Utilities combines work to reduce overall costs and increase efficiency. The most common opportunity is during city road relocation projects where a new water main is being installed. Horizon Utilities may be able to take advantage of the fact that installing duct structure is less costly since the road is already excavated. Horizon Utilities may also be able to change the schedule of a renewal project to align with the road authority's work to maximize these benefits. The cost of the additional work is allocated to either system service or system renewal where applicable. Horizon Utilities can maximize the amount of work that can be completed at the lowest cost to benefit ratepayers in these cases.

Assessment of Technical or Implementation Options (5.4.5.2.C.a.vi)

Horizon Utilities co-ordinates project design and discusses design alternatives for each project with the road authority (City, Municipality, Ministry of Transportation) originating the request to relocate distribution assets.

Summary of Options Analysis (5.4.5.2.C.a.vii)

Horizon Utilities reviews proposed design with municipalities and the Ministry of Transportation, as applicable, in an effort to determine the most cost effective solution.

Final Economic Evaluation Results (5.4.5.2.C.a.viii)

This is not applicable to road relocations projects.

Identification of System Impacts (5.4.5.2.C.a.ix)

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.

Capital Project Summary

General Information on Project (5.4.5.2.A)

Project Name	2016 Customer Connections
Budget Year	2016
Investment Category	System Access
Project Summary	Projects in this category include multiple projects required to connect, upgrade, or disconnect customers to the distribution system. Horizon Utilities' obligation to connect new customers is governed by the *Electricity Act, 1998, Schedule 28.*

Capital Investment (5.4.5.2.A.i)		
	Capital Investment (gross)	$ 4,781,689
	Customer Contribution	$ 750,586
	Capital Investment (net)	$ 4,031,103
	O&M Expenditure	$0

Customer Attachments / Load (kVA) (5.4.5.2.A.ii)	Horizon Utilities completes approximately 1800 connections annually; 1500 through subdivisions and 300 customer projects, contributing approximately 25MVA in system load growth.

Project Dates (5.4.5.2.A.iii)

Start Date	Various – as driven by the customer
In Service Date	Various – as driven by the customer

Expenditure Timing

Q1	Q2	Q3	Q4
25%	25%	25%	25%

Schedule Risk and Risk Mitigation (5.4.5.2.A.iv**)**

Please refer to Note I for risk and risk mitigation.

Comparative Information from Equivalent Projects (5.4.5.2.A.v)

Comparable investments, net of capital contributions, for the 2010 to 2013 Historical Years and the 2014 Bridge Year are:

2010 (CGAAP)- $ 1,023,336
2011 (CGAAP)- $ 2,030,541
2012 (MIFRS) - $ 1,652,000
2013 (MIFRS) - $ 3,541,455
2014 (MIFRS) - $ 4,063,471

Total Capital OM&A Costs Associated with REG Investments (5.4.5.2.A.vi)

This project is not associated with an REG investment and therefore OM&A costs related to REG will not be incurred.

Evaluation Criteria and Information (5.4.5.2.B)

Leave to Construct Approval (5.4.5.2.A.vii)

This project does not require "Leave to Construct" under Section 92 of the *Ontario Energy Board Act* 1998.

Project Name	2016 Customer Connections	Table 2

Efficiency, Customer Value, Reliability (5.4.5.2.B.1)

Investment Driver (5.4.5.2.B.1.a)
System Access (100%)

Secondary Driver (5.4.5.2.B.1.a)
N/A

Investment Priority (5.4.5.2.B.1.b)
5 – Mandatory Project

Analysis of Project and Project Alternatives (5.4.5.2.B.1.c)

Customer connection projects are driven by customer requests and the customer's specific technical requirements. To build efficiencies into the process, Horizon Utilities utilizes a set of design standards that have been engineered and approved. Customer connections requests are fulfilled consistent with Horizon Utilities' Conditions of Service, designed to meet the customer requirements and maintain system reliability.

Safety (5.4.5.2.B.2)

These projects are not intended to address safety concerns with the distribution system.

Cyber-Security and Privacy (5.4.5.2.B.3) (where applicable)

Cyber-Security and Privacy are not applicable to this project.

Co-ordination and Interoperability (5.4.5.2.B.4)

Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.5.2.B.4.a) (where applicable)
Please refer to Note II for an explanation on co-ordination with utilities, regional planning and/or links with 3rd parties.

Enabling of Future Technology and/or Future Operational Requirements (5.4.5.2.B.4.b)

This is not applicable for these projects.

Economic Development (5.4.5.2.B.5)

Horizon Utilities ensures that policies and practices do not unnecessarily create barriers to economic development which are primarily focused within its communities.

	Environmental Benefits (5.4.5.2.B.6) n/a

System Access Specific Requirements (5.4.5.2.C.a)	**Project Name** 2016 Customer Connections Table 3
	System Access Specific Requirements (5.4.5.2.C.a) **Factors Affecting Implementing Project Timing/Priority (5.4.5.2.C.a.i)** Schedule of work based on customer expectations; customer request may not be standard design. **Factors Related to Customer Preference or 3rd Party Input (5.4.5.2.C.a.ii)** There projects are customer initiated and are designed to meet customer identified requirements. **Factors Affecting Final Project Cost (5.4.5.2.C.a.iii)** Please refer to Note I for an explanation on the factors affecting final project cost. **Controllable Cost Minimization (5.4.5.2.C.a.iv)** Please refer to Note I for an explanation on the factors affecting controllable cost. **Other Planning Objectives (5.4.5.2.C.a.v)** n/a **Assessment of Technical or Implementation Options (5.4.5.2.C.a.vi)** Please refer to Note III for information on the technical and implementation options. **Summary of Options Analysis (5.4.5.2.C.a.vii)** Please refer to Note III for information on the technical and implementation options. **Final Economic Evaluation Results (5.4.5.2.C.a.viii)** Horizon Utilities completes the economic evaluation for any customer system access project which requires the construction of new facilities to the main distribution system or an increase in the existing capacity of distribution facilities. For further details please see Appendix E of Horizon Utilities' Conditions of Service. The economic evaluation is completed in accordance with section 3.2 of the Distribution System Code (DSC). For the 2015-2019 forecast period, Horizon Utilities has no known projects for which to provide the final economic evaluation. When a road authority requests a relocation of Horizon Utilities' plant located on the public road allowance, the costs shall be shared, as outlined in the *Ontario Public Service Works on Highways Act*. Other projects within this category will have an economic evaluation completed where applicable in accordance with both

	the DSC and Appendix E of Horizon Utilities' Conditions of Service. **Identification of System Impacts (5.4.5.2.C.a.ix)** System expansion, if required, to connect customers within this category are governed by Horizon Utilities' Conditions of Service Section 2.1.2.1.

2016 System Renewal Investments

Capital Project Summary

General Information on Project (5.4.5.2.A)

Project Name	CE-F4 Renewal – Hunter/Stinson St			
Budget Year	2016			
Investment Category	System Renewal			
Project Summary	This project involves the renewal of the Central Substation F4 feeder in central Hamilton.			
Capital Investment (5.4.5.2.A.i)	Capital Investment (gross)	$ 1,556,498		
	Customer Contribution	$ 0		
	Capital Investment (net)	$ 1,556,498		
	O&M Expenditure	$0		
Customer Attachments / Load (kVA) (5.4.5.2.A.ii)	This project affects 756 customers and 2,520kVA of transformation.			
Project Dates (5.4.5.2.A.iii)	Start Date	2016/03/01		
	In Service Date	2016/10/18		
	Expenditure Timing			
	Q1	Q2	Q3	Q4
	12.5%	37.5%	37.5%	12.5%

Schedule Risk and Risk Mitigation (5.4.5.2.A.iv**)**

Please refer to Note I for risk and risk mitigation.

Comparative Information from Equivalent Projects (5.4.5.2.A.v)

There is no direct comparator in scope, size and design characteristics for this project. This project is one phase of a multi-year investment to renew the area served by Central substation as part of the 4kV and 8kV Renewal Program. The 2016 investment for the renewal of Central substation is $1,556,498. The 2016 investment in the 4kV and 8kV Renewal Program is $10,160,000.

Comparable gross investments for the 4kv and 8kV Renewal Program for the 2010 to 2013 Historical Years and the 2014 Bridge Year are:

2010 (CGAAP)- $ 2,556,076
2011 (CGAAP)- $ 8,820,000
2012 (MIFRS) - $ 5,268,441
2013 (MIFRS) - $ 5,072,233
2014 (MIFRS) - $ 6,434,000

Total Capital OM&A Costs Associated with REG Investments (5.4.5.2.A.vi)

This project is not associated with an REG investment and therefore OM&A costs related to REG will not be incurred.

Leave to Construct Approval (5.4.5.2.A.vii)

This project does not require "Leave to Construct" under Section 92 of the *Ontario Energy Board Act* 1998.

Evaluation Criteria and Information (5.4.5.2.B)

Project Name	CE-F4 Renewal – Hunter/Stinson St	Table 2

Efficiency, Customer Value, Reliability (5.4.5.2.B.1)

Investment Driver (5.4.5.2.B.1.a)

System Renewal (80%)

Secondary Driver (5.4.5.2.B.1.a)

System Service (20%)

Investment Priority (5.4.5.2.B.1.b)

3 – Required project

Analysis of Project and Project Alternatives (5.4.5.2.B.1.c)

This project is part of the multi-year 4kV and 8kV Renewal Program. Both the 4kV and 8kV distribution system and the Horizon Utilities-owned substations are at the end of their useful life. Horizon Utilities has chosen to renew the 4kV and 8kV distribution systems to a higher voltage to avoid the cost of the investment in the renewal of the substations. The total avoided substation renewal investment over the remaining 35 years of the plan is $70,000,000 for all 28 substations. Therefore the renewal of the distribution assets at the current 4kV level was not a feasible alternative.

The renewal of the area serviced by Central substation starts in 2016 and is scheduled to be completed in 2022.

Safety (5.4.5.2.B.2)

This project is not intended to address safety concerns with the distribution system.

Cyber-Security and Privacy (5.4.5.2.B.3) (where applicable)

Cyber-Security and Privacy are not applicable to this project.

Co-ordination and Interoperability (5.4.5.2.B.4)

Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.5.2.B.4.a) (where applicable)

Please refer to Note II for an explanation on co-ordination with utilities, regional planning and/or links with 3rd parties.

Enabling of Future Technology and/or Future Operational Requirements (5.4.5.2.B.4.b)

Please refer to Note IV for an explanation enabling of future technology and future operational requirements.

Economic Development (5.4.5.2.B.5) **(where applicable)**

Horizon Utilities ensures that policies and practices do not unnecessarily create barriers to economic development which are primarily focused within its communities.

Environmental Benefits (5.4.5.2.B.6) **(where applicable)**

n/a

System Renewal Specific Requirements (5.4.5.2.C.b)

Project Name	CE-F4 Renewal – Hunter/Stinson St	Table 3

System Renewal Specific Requirements (5.4.5.2.C.b)

Asset Performance Target and Asset Lifecycle Optimization (5.4.5.2.C.b.i.1)

The two substations servicing the downtown Hamilton operating area service a total of 7,400 customers and were constructed in 1950 and 1960. The overall Station Health Index for Aberdeen and Central substations is 53% and 56% respectively. 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 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.

Asset Condition Relative to Typical Life Cycle (5.4.5.2.C.b.i.2)

Generally the 4kV assets are the oldest vintage in the system. 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.

Number of Customers Impacted (5.4.5.2.C.b.i.3)

This project affects 756 customers.

Quantitative Customer Impact and Risk (5.4.5.2.C.b.i.4)

SAIDI of 0.039

Qualitative Customer Impact and Risk (5.4.5.2.C.b.i.5)

This project will address aging assets with inadequate backup. Aging assets represent an increased risk of service interruption to customers and inadequate backup would result in long duration service interruptions upon occurrence. These factors would lead to customer dissatisfaction in this area.

Value of Customer Impact (5.4.5.2.C.b.i.6)

High

Other Factors Affecting Project Timing (5.4.5.2.C.b.ii)

The renewal of the area serviced by Central substation is scheduled for 2016 to 2022. This project is required to be completed in 2016 to allow for the renewal of the remaining area to be completed on schedule.

Impact on System O&M Costs (5.4.5.2.C.b.iii)

This project will have no material impact on planned O&M costs. The renewal of the 4kV and 8kV distribution systems, as a whole, will provide a reduction in reactive O&M costs to address service interruptions caused by failed equipment. These reductions will not be material in the 2015 to 2019 Test Years.

Reliability and Safety Factors (5.4.5.2.C.b.iv)

The renewal of the 4kV and 8kV distribution system will provide reliability improvements through reduced service interruptions caused by failed equipment.

Analysis of Project Benefits and Timing (5.4.5.2.C.b.v)

The timing of this project, as part of the 4kV and 8kV Renewal Program, is determined through the assessment of the distribution system health and the health of the substation assets servicing the area. Renewal of this area will allow for the decommissioning of the substation assets by 2022, thereby avoiding the need for capital investment into these substations.

Like-for-Like Renewal Analysis (5.4.5.2.C.b.vi)

The like-for-like renewal of these assets (i.e. same system configuration and same distribution voltage) will perpetuate the existing operating constraints and require capital investment to renew substation assets. Renewal of the distribution assets at a higher voltage does not involve any material incremental costs over renewal at the existing voltage. Operating constraints (e.g. undersized conductor, radial feeds) are addressed on a case by case basis where appropriate.

Capital Project Summary

General Information on Project (5.4.5.2.A)

Project Name	2016 Reactive Renewal
Budget Year	2016
Investment Category	System Renewal
Project Summary	This category includes all projects required for the reactive renewal or repairs driven by emergency equipment failures and associated corrective action. Projects arise from trouble calls or inspection programs identifying an urgent need to replace system assets and the scope of the equipment replacement requires engineering. Also included in this category are projects to address customer power quality issues and Electrical Safety Authority ("ESA") due diligence inspection outcomes.

Capital Investment (5.4.5.2.A.i)	Capital Investment (gross)	$4,339,000
	Customer Contribution	n/a
	Capital Investment (net)	n/a
	O&M Expenditure	n/a
Customer Attachments / Load (kVA) (5.4.5.2.A.ii)	n/a	

Project Dates (5.4.5.2.A.iii)

Start Date	January 1, 2016
In Service Date	December 31, 2016

Expenditure Timing

Q1	Q2	Q3	Q4
25%	25%	25%	25%

Schedule Risk and Risk Mitigation (5.4.5.2.A.iv**)**

Please refer to Note I for risk and risk mitigation.

Comparative Information from Equivalent Projects (5.4.5.2.A.v)

Comparable investments for the 2010 to 2013 Historical Years and the 2014 Bridge Year are:

2010 (CGAAP)- $ 8,745,125
2011 (CGAAP)- $ 8,230,970
2012 (MIFRS) - $ 4,032,000
2013 (MIFRS) - $ 6.069,566
2014 (MIFRS) - $ 4,840,000

Total Capital OM&A Costs Associated with REG Investments (5.4.5.2.A.vi)

This project is not associated with an REG investment and therefore OM&A costs related to REG will not be incurred.

Leave to Construct Approval (5.4.5.2.A.vii)

This project does not require "Leave to Construct" under Section 92 of the *Ontario Energy Board Act* 1998.

Evaluation Criteria and Information (5.4.5.2.B)n	**Project Name** 2016 Reactive Renewal	Table 2
	Efficiency, Customer Value, Reliability (5.4.5.2.B.1) **Investment Driver (5.4.5.2.B.1.a)** System Renewal (80%) **Secondary Driver (5.4.5.2.B.1.a)** System Service (20%) **Investment Priority (5.4.5.2.B.1.b)** 5 – Mandatory project	
	Analysis of Project and Project Alternatives (5.4.5.2.B.1.c) No alternatives are considered for these projects as they involve the emergency replacement of failed equipment required to restore service.	
	Safety (5.4.5.2.B.2) These projects are intended to primarily address failed assets however investments required to address immediate safety issues, including issues presenting a potential risk to public safety identified by the ESA, are included in this project.	
	Cyber-Security and Privacy (5.4.5.2.B.3) (where applicable) Cyber-Security and Privacy are not applicable to this project	
	Co-ordination and Interoperability (5.4.5.2.B.4) **Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.5.2.B.4.a) (where applicable)** Please refer to Note II for an explanation on co-ordination with utilities, regional planning and/or links with 3rd parties. **Enabling of Future Technology and/or Future Operational Requirements (5.4.5.2.B.4.b)** Please refer to Note IV for an explanation enabling of future technology and future operational requirements.	
	Economic Development (5.4.5.2.B.5) **(where applicable)** Horizon Utilities ensures that policies and practices do not unnecessarily create barriers to economic development which are primarily focused within its communities.	
	Environmental Benefits (5.4.5.2.B.6) **(where applicable)** n/a	

System Renewal Specific Requirements (5.4.5.2.C.b)	**Project Name** 2016 Reactive Renewal Table 3
	System Renewal Specific Requirements (5.4.5.2.C.b) **Asset Performance Target and Asset Lifecycle Optimization (5.4.5.2.C.b.i.1)** These projects are reactive in nature and are initiated from equipment that has failed or that have a high risk of failure resulting in a service interruption. These projects have a very high probability of impact on Horizon Utilities' reliability targets. **Asset Condition Relative to Typical Life Cycle (5.4.5.2.C.b.i.2)** These projects address failed assets or assets with a high risk of imminent failure and as such, these assets are at the end of their useful life. The asset condition relative to their typical life cycle varies in each incident or outage. **Number of Customers Impacted (5.4.5.2.C.b.i.3)** The number of customers impacted varies in each incident or outage. **Quantitative Customer Impact and Risk (5.4.5.2.C.b.i.4)** The quantitative customer impact varies in each incident or outage. **Qualitative Customer Impact and Risk (5.4.5.2.C.b.i.5)** These projects address customer satisfaction as they are required to address failed assets that have either caused a system interruption, or have a high probability of causing a service interruption. **Value of Customer Impact (5.4.5.2.C.b.i.6)** The value of the customer impact varies in each incident or outage. **Other Factors Affecting Project Timing (5.4.5.2.C.b.ii)** These projects are reactive in nature and address failed assets, or assets at risk of imminent failure. Investments must be performed when identified. **Impact on System O&M Costs (5.4.5.2.C.b.iii)** These projects do not materially impact system O&M costs. **Reliability and Safety Factors (5.4.5.2.C.b.iv)** Improvements to reliability and security are expected as secondary benefits to this project. **Analysis of Project Benefits and Timing (5.4.5.2.C.b.v)** Investment for this project addresses failed assets, or assets at risk of imminent failure. Investments are not subject to project prioritization as they are reactive and non-discretionary. **Like-for-Like Renewal Analysis (5.4.5.2.C.b.vi)** Assets replaced reactively to replace failed assets, or assets at risk of imminent failure are performed on a like-for-like basis. No extra costs to address other distributor planning objectives are incurred with these projects.

Capital Project Summary

General Information on Project (5.4.5.2.A)

Project Name	Gage TS Egress Feeder Renewal
Budget Year	2016
Investment Category	System Renewal
Project Summary	This project involves relocating the station egress cables from the existing location at Gage TS to the new location of the switchgear to facilitate Hydro One's renewal of Gage TS.

Capital Investment (5.4.5.2.A.i)

Capital Investment (gross)	$ 4,793,056
Customer Contribution	$0
Capital Investment (net)	$ 4,793,056
O&M Expenditure	$0

Customer Attachments / Load (kVA) (5.4.5.2.A.ii)

This affects all customers served from Gage TS.

Project Dates (5.4.5.2.A.iii)

Start Date 2016/04/01

In Service Date 2016/11/30

Expenditure Timing

Q1	Q2	Q3	Q4
0%	37.5%	37.5%	25%

Schedule Risk and Risk Mitigation (5.4.5.2.A.iv**)**

Please refer to Note I for risk and risk mitigation.

Comparative Information from Equivalent Projects (5.4.5.2.A.v)

There are no equivalent projects for comparison.

Total Capital OM&A Costs Associated with REG Investments (5.4.5.2.A.vi)

This project is not associated with an REG investment and therefore OM&A costs related to REG will not be incurred.

Leave to Construct Approval (5.4.5.2.A.vii)

This project does not require "Leave to Construct" under Section 92 of the *Ontario Energy Board Act* 1998.

Evaluation Criteria and Information (5.4.5.2.B)	**Project Name** Gage TS Egress Feeder Renewal Table 2
	Efficiency, Customer Value, Reliability (5.4.5.2.B.1) **Investment Driver (5.4.5.2.B.1.a)** System Renewal (100%) **Secondary Driver (5.4.5.2.B.1.a)** N/A **Investment Priority (5.4.5.2.B.1.b)** 5 – Mandatory Project
	Analysis of Project and Project Alternatives (5.4.5.2.B.1.c) The design of the project will be co-ordinated with Hydro One. The scope of this project is dependent on Hydro One's final design and staging for the renewal of the station.
	Safety (5.4.5.2.B.2) This project is not intended to address safety concerns with the distribution system.
	Cyber-Security and Privacy (5.4.5.2.B.3) (where applicable) Cyber-Security and Privacy are not applicable to this project.
	Co-ordination and Interoperability (5.4.5.2.B.4) **Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.5.2.B.4.a) (where applicable)** Please refer to Note II for an explanation on co-ordination with utilities, regional planning and/or links with 3rd parties. **Enabling of Future Technology and/or Future Operational Requirements (5.4.5.2.B.4.b)** Please refer to Note IV for an explanation enabling of future technology and future operational requirements.
	Economic Development (5.4.5.2.B.5) **(where applicable)** Horizon Utilities ensures that policies and practices do not unnecessarily create barriers to economic development which are primarily focused within its communities.
	Environmental Benefits (5.4.5.2.B.6) **(where applicable)** n/a

System Renewal Specific Requirements (5.4.5.2.C.b)	**Project Name** Gage TS Egress Feeder Renewal Table 3
	System Renewal Specific Requirements (5.4.5.2.C.b) **Asset Performance Target and Asset Lifecycle Optimization (5.4.5.2.C.b.i.1)** Gage TS is one of the oldest transformer stations within Hydro One's inventory and the oldest station in Horizon Utilities' service territory. This station services Horizon Utilities' two largest industrial customers, and has experienced a number of major equipment failures that have affected these customers. **Asset Condition Relative to Typical Life Cycle (5.4.5.2.C.b.i.2)** Asset condition is not considered a driver for this project, however many assets connected to Gage TS are nearing their end of useful life. **Number of Customers Impacted (5.4.5.2.C.b.i.3)** Three large industrial customers are impacted by this project. **Quantitative Customer Impact and Risk (5.4.5.2.C.b.i.4)** n/a **Qualitative Customer Impact and Risk (5.4.5.2.C.b.i.5)** This project is required to maintain service continuity for these three large industrial customers. **Value of Customer Impact (5.4.5.2.C.b.i.6)** High **Other Factors Affecting Project Timing (5.4.5.2.C.b.ii)** Horizon Utilities has been in constant contact with its customers that are impacted by the work being performed by Hydro One and has endeavoured to ensure that their needs are met by Hydro One. **Impact on System O&M Costs (5.4.5.2.C.b.iii)** n/a **Reliability and Safety Factors (5.4.5.2.C.b.iv)** n/a **Analysis of Project Benefits and Timing (5.4.5.2.C.b.v)** n/a **Like-for-Like Renewal Analysis (5.4.5.2.C.b.vi)** Before Horizon Utilities can complete a like-for-like analysis, Hydro One needs to provide information on the type of connection for the feeder cables. This has not occurred yet but is expected to be completed once the station upgrade design is finalized

Capital Project Summary

General Information on Project (5.4.5.2.A)

Project Name	2016 Hamilton Mountain XLPE Renewal
Budget Year	2016
Investment Category	System Renewal
Project Summary	This project involves the renewal of XLPE primary cable and underground distribution assets in the Hamilton Mountain operating area. The area between Upper Sherman and Upper Wentworth south of the Lincoln Alexander Parkway will be renewed in 2016.

Capital Investment (5.4.5.2.A.i)		
	Capital Investment (gross)	$ 1,996,215
	Customer Contribution	$0
	Capital Investment (net)	$1,996,215
	O&M Expenditure	$0

Customer Attachments / Load (kVA) (5.4.5.2.A.ii)

Approximately 1,600 customers will be impacted by this project.

Project Dates (5.4.5.2.A.iii)

Start Date 2016/03/01

In Service Date 2016/11/01

Expenditure Timing

Q1	Q2	Q3	Q4
10%	40%	40%	10%

Schedule Risk and Risk Mitigation (5.4.5.2.A.iv**)**

Please refer to Note I for risk and risk mitigation.

Comparative Information from Equivalent Projects (5.4.5.2.A.v)

There is no direct comparator in scope, size and design characteristics for this project. This project is part of a multi-year investment to renew the XLPE primary cable. The 2016 investment in the XLPE Renewal Program is $4,926,000.

Comparable gross investments for the XLPE Renewal Program for the 2010 to 2013 Historical Years and the 2014 Bridge Year are:

2010 (CGAAP)- $ 0
2011 (CGAAP)- $ 0
2012 (MIFRS) - $ 0
2013 (MIFRS) - $ 1,572,090
2014 (MIFRS) - $ 893,000

Total Capital OM&A Costs Associated with REG Investments (5.4.5.2.A.vi)

This project is not associated with an REG investment and therefore OM&A costs related to REG will not be incurred.

Leave to Construct Approval (5.4.5.2.A.vii)

This project does not require "Leave to Construct" under Section 92 of the *Ontario Energy Board Act* 1998.

Evaluation Criteria and Information (5.4.5.2.B)

Project Name	2016 Hamilton Mountain XLPE Renewal	Table 2

Efficiency, Customer Value, Reliability (5.4.5.2.B.1)

Investment Driver (5.4.5.2.B.1.a)
System Renewal (60%)

Secondary Driver (5.4.5.2.B.1.a)
System Service (40%)

Investment Priority (5.4.5.2.B.1.b)
4 – Required Project

Analysis of Project and Project Alternatives (5.4.5.2.B.1.c)

This project is part of the multi-year XLPE Renewal Program. Horizon Utilities considered the four replacement philosophies for addressing risk inherent in the XLPE asset group: Area; Reactive; Selected; and Refurbishment. The area replacement philosophy will be utilized 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 area replacement philosophy will be employed for the Hamilton Mountain operating area due to the high volume of XLPE primary cable. 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.

Safety (5.4.5.2.B.2)

These projects are not intended to address safety concerns with the distribution system.

Cyber-Security and Privacy (5.4.5.2.B.3) (where applicable)

n/a

Co-ordination and Interoperability (5.4.5.2.B.4)

Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.5.2.B.4.a) (where applicable)

Please refer to Note II for an explanation on co-ordination with utilities, regional planning and/or links with 3rd parties.

Enabling of Future Technology and/or Future Operational Requirements (5.4.5.2.B.4.b)

Please refer to Note IV for an explanation enabling of future technology and future operational requirements.

Economic Development (5.4.5.2.B.5) **(where applicable)**

Horizon Utilities ensures that policies and practices do not unnecessarily create barriers to economic development which are primarily focused within its communities.

Environmental Benefits (5.4.5.2.B.6) **(where applicable)**

n/a

System Renewal Specific Requirements (5.4.5.2.C.b)

Project Name 2016 Hamilton Mountain XLPE Renewal Table 3

System Renewal Specific Requirements (5.4.5.2.C.b)

Asset Performance Target and Asset Lifecycle Optimization (5.4.5.2.C.b.i.1)

XLPE primary cable is the asset group with the largest investment requirement as identified by the Kinectrics ACA. 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.

The Hamilton Mountain operating area has 225km of XLPE primary cable with a Health Index of either "very poor" or "poor". 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.

Asset Condition Relative to Typical Life Cycle (5.4.5.2.C.b.i.2)

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.

Number of Customers Impacted (5.4.5.2.C.b.i.3)

Approximately 1,600 customers will be impacted by this project.

Quantitative Customer Impact and Risk (5.4.5.2.C.b.i.4)

The quantitative customer impact varies for customers affected by this project.

Qualitative Customer Impact and Risk (5.4.5.2.C.b.i.5)

This project will address aging assets at risk of failure. Failures of XLPE primary cable result in extended service interruptions; 30% of these outages exceeded four hours in duration, while 5% of these outages exceeded twelve hours in duration.

Value of Customer Impact (5.4.5.2.C.b.i.6)

High

Other Factors Affecting Project Timing (5.4.5.2.C.b.ii)

Proactive replacements are required because, as assets continue to age and degrade, the cable will fail at an exponential rate. In the worst case scenario it will exceed Horizon Utilities' ability to keep pace with repairs. Reliability will also deteriorate to unacceptable levels. Reactive replacements will be considerably more costly than proactive renewal.

Impact on System O&M Costs (5.4.5.2.C.b.iii)

This project will have no material impact on planned O&M costs. The renewal of the XLPE primary cable, as a whole, will provide a reduction in reactive O&M costs to address service interruptions caused by failed equipment. These reductions will not be material in the 2015 to 2019 Test Years.

Reliability and Safety Factors (5.4.5.2.C.b.iv)

The renewal of the XLPE primary cable system will provide reliability improvements through reduced service interruptions caused by failed equipment.

Analysis of Project Benefits and Timing (5.4.5.2.C.b.v)

Failure to invest in the proactive renewal of XLPE primary cable and associated underground assets would result in unacceptable levels of system failures and outages beyond the ability of Horizon Utilities to resolve within a reasonable timeframe. Reactive replacements will also be considerably more costly than the forecast expenditure required to execute the proposed proactive replacement.

Like-for-Like Renewal Analysis (5.4.5.2.C.b.vi)

XLPE renewal projects will include: the elimination of radial underground feeds; the replacement of below grade transformers with padmount transformers; and the introduction of fusing on the underground distribution systems where applicable.

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Capital Project Summary

General Information on Project (5.4.5.2.A)

Project Name	HI-F1 Renewal - U/G conversion to 2D14X				
Budget Year	2016				
Investment Category	System Renewal				
Project Summary	This project involves the renewal of the Highland Substation F1 feeder in Dundas.				
Capital Investment (5.4.5.2.A.i)	Capital Investment (gross)	$ 1,269,165			
	Customer Contribution	$0			
	Capital Investment (net)	$1,269,165			
	O&M Expenditure	$0			
Customer Attachments / Load (kVA) (5.4.5.2.A.ii)	This project impacts 745 customers and 2,793 kVA of transformation.				
Project Dates (5.4.5.2.A.iii)	Start Date	2016/04/01			
	In Service Date	2016/09/30			
	Expenditure Timing				
	Q1	Q2	Q3	Q4	
	0%	50%	50%	0%	

Schedule Risk and Risk Mitigation (5.4.5.2.A.iv**)**

Please refer to Note I for risk and risk mitigation.

Comparative Information from Equivalent Projects (5.4.5.2.A.v)

There is no direct comparator in scope, size and design characteristics for this project. This project is part of a multi-year investment to renew XLPE primary cable. The 2016 investment in the XLPE Renewal Program is $4,926,000.

Comparable gross investments for the XLPE Renewal Program for the 2010 to 2013 Historical Years and the 2014 Bridge Year are:

2010 (CGAAP)- $ 0
2011 (CGAAP)- $ 0
2012 (MIFRS) - $ 0
2013 (MIFRS) - $ 1,572,090
2014 (MIFRS) - $ 893,000

Total Capital OM&A Costs Associated with REG Investments (5.4.5.2.A.vi)

This project is not associated with an REG investment and therefore OM&A costs related to REG will not be incurred.

	Leave to Construct Approval (5.4.5.2.A.vii) This project does not require "Leave to Construct" under Section 92 of the *Ontario Energy Board Act* 1998.

Evaluation Criteria and Information (5.4.5.2.B)	
	Project Name HI-F1 Renewal - U/G conversion to 2D14X Table 2
	Efficiency, Customer Value, Reliability (5.4.5.2.B.1) **Investment Driver (5.4.5.2.B.1.a)** System Renewal (60%) **Secondary Driver (5.4.5.2.B.1.a)** System Service (40%) **Investment Priority (5.4.5.2.B.1.b)** 3 – Required project
	Analysis of Project and Project Alternatives (5.4.5.2.B.1.c) Renewal of assets at 4kV would not allow for the eventual decommissioning of Highland Substation. Horizon Utilities' Substation assets are being decommissioned over the life of the 4kV and 8kV Renewal Program to avoid capital investment required for the renewal of substation assets that are nearing the end of their useful lives.
	Safety (5.4.5.2.B.2) This project is not intended to address safety concerns with the distribution system.
	Cyber-Security and Privacy (5.4.5.2.B.3) (where applicable) Cyber-Security and Privacy are not applicable to this project.
	Co-ordination and Interoperability (5.4.5.2.B.4) **Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.5.2.B.4.a) (where applicable)** Please refer to Note II for an explanation on co-ordination with utilities, regional planning and/or links with 3rd parties. **Enabling of Future Technology and/or Future Operational Requirements (5.4.5.2.B.4.b)** Please refer to Note IV for an explanation enabling of future technology and future operational requirements.
	Economic Development (5.4.5.2.B.5) **(where applicable)** Horizon Utilities ensures that policies and practices do not unnecessarily create barriers to economic development which are primarily focused within its communities.
	Environmental Benefits (5.4.5.2.B.6) **(where applicable)** n/a

System Renewal Specific Requirements (5.4.5.2.C.b)

Project Name HI-F1 Renewal - U/G conversion to 2D14X Table 3

System Renewal Specific Requirements (5.4.5.2.C.b)

Asset Performance Target and Asset Lifecycle Optimization (5.4.5.2.C.b.i.1)

XLPE primary cable is the asset group with the largest investment requirement as identified by the Kinectrics ACA. 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

The Dundas operating area has 13.5km of XLPE cable with a Health Index of either "very poor" or "poor".

Asset Condition Relative to Typical Life Cycle (5.4.5.2.C.b.i.2)

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.

Number of Customers Impacted (5.4.5.2.C.b.i.3)

This project impacts 745 customers.

Quantitative Customer Impact and Risk (5.4.5.2.C.b.i.4)

SAIDI of 0.025

Qualitative Customer Impact and Risk (5.4.5.2.C.b.i.5)

This project will address aging assets with inadequate backup. Aging assets represent an increased risk of service interruption to customers and inadequate backup would result in long duration service interruptions upon occurrence. These factors would lead to customer dissatisfaction in this area.

Value of Customer Impact (5.4.5.2.C.b.i.6)

High

Other Factors Affecting Project Timing (5.4.5.2.C.b.ii)

The timing of this project is necessary to co-ordinate with the 4kV and 8kV Renewal Program as it involves both the renewal of XLPE primary cable and the renewal of the underground section of the Highland substation F1 feeder.

Impact on System O&M Costs (5.4.5.2.C.b.iii)

This project will have no material impact on planned O&M costs. The renewal of the 4kV and 8kV distribution systems, as a whole, will provide a reduction in reactive O&M costs to address service interruptions caused by failed equipment. These reductions will not be material in the 2015 to 2019 Test Years.

Reliability and Safety Factors (5.4.5.2.C.b.iv)

The renewal of XLPE primary cable will provide reliability improvements through reduced service interruptions caused by failed equipment. The cable renewed by this project is direct buried and therefore subject to extended outages, requiring multiple hours to repair, upon failure.

Analysis of Project Benefits and Timing (5.4.5.2.C.b.v)

The timing of this project is required to co-ordinate with the 4kV and 8kV Renewal Program as it involves both the renewal of XLPE primary cable and the renewal of the underground section of the Highland substation F1 feeder.

Like-for-Like Renewal Analysis (5.4.5.2.C.b.vi)

The like-for-like renewal of these assets (i.e. same system configuration and same distribution voltage) will perpetuate the existing operating constraints and require capital investment to renew substation assets. Renewal of the distribution assets at a higher voltage does not involve any material incremental costs over renewal at the existing voltage. Operating constraints (e.g. undersized conductor, radial feeds) are addressed on a case by case basis where appropriate.

Capital Project Summary

General Information on Project (5.4.5.2.A)

Project Name	2016 Pole Residual Replacements
Budget Year	2016
Investment Category	System renewal
Project Summary	This project involves the replacement of wood poles identified by pole residual testing as having a high risk of failure.
Capital Investment (5.4.5.2.A.i)	Capital Investment (gross): $1,261,663 Customer Contribution: $0 Capital Investment (net): $1,261,663 O&M Expenditure: $0.
Customer Attachments / Load (kVA) (5.4.5.2.A.ii)	n/a
Project Dates (5.4.5.2.A.iii)	Start Date 2016/01/01 In Service Date 2016/07/01

Expenditure Timing

Q1	Q2	Q3	Q4
50%	50%	0%	0%

Schedule Risk and Risk Mitigation (5.4.5.2.A.iv**)**

Please refer to Note I for risk and risk mitigation.

Comparative Information from Equivalent Projects (5.4.5.2.A.v)

Comparable gross investments for the 2010 to 2013 Historical Years and the 2014 Bridge Year are:

2010 (CGAAP)- $ 1,326,407
2011 (CGAAP)- $ 895,000
2012 (MIFRS) - $ 930,000
2013 (MIFRS) - $ 718,074
2014 (MIFRS) - $ 1,190,000

Total Capital OM&A Costs Associated with REG Investments (5.4.5.2.A.vi)

This project is not associated with an REG investment and therefore OM&A costs related to REG will not be incurred.

Leave to Construct Approval (5.4.5.2.A.vii)

This project does not require "Leave to Construct" under Section 92 of the *Ontario Energy Board Act* 1998.

Evaluation Criteria and Information (5.4.5.2.B)

Project Name 2016 Pole Residual Replacements Table 2

Efficiency, Customer Value, Reliability (5.4.5.2.B.1)

Investment Driver (5.4.5.2.B.1.a)
System Renewal (100%)

Secondary Driver (5.4.5.2.B.1.a)
N/A

Investment Priority (5.4.5.2.B.1.b)
3 – Required project

Analysis of Project and Project Alternatives (5.4.5.2.B.1.c)

The replacement of wood poles in this project is identified through Horizon Utilities' pole testing maintenance program. The pole testing categorizes the poles requiring replacement into two categories: 1) requiring immediate replacement; and 2) requiring replacement within five years.

Horizon Utilities replaces poles requiring immediate replacement as soon as possible to mitigate the risk of service interruptions and the risk to public safety resulting from a failure of the pole.

Horizon Utilities replaces poles requiring replacement within five years in the following year. Failure to replace in the following year compounds the volume of work in subsequent years resulting in cascading delays and compounded volumes in subsequent years.

Poles replaced in this project are replaced on a like-for-like basis where possible.

Safety (5.4.5.2.B.2)

This project will address wood poles requiring replacement as identified through testing. Renewal of these assets prior to failure avoids the potential risk to public safety that would result from a failure of a wood pole.

Cyber-Security and Privacy (5.4.5.2.B.3) (where applicable)

n/a

Co-ordination and Interoperability (5.4.5.2.B.4)

Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.5.2.B.4.a) (where applicable)
Please refer to Note II for an explanation on co-ordination with utilities, regional planning and/or links with 3rd parties.

Enabling of Future Technology and/or Future Operational Requirements (5.4.5.2.B.4.b) (where applicable)
n/a

Economic Development (5.4.5.2.B.5) **(where applicable)**

Horizon Utilities ensures that policies and practices do not unnecessarily create barriers to economic development which are primarily focused within its communities.

Environmental Benefits (5.4.5.2.B.6) **(where applicable)**

n/a

System Renewal Specific Requirements (5.4.5.2.C.b)

Project Name	2016 Pole Residual Replacements	Table 3

System Renewal Specific Requirements (5.4.5.2.C.b)

Asset Performance Target and Asset Lifecycle Optimization (5.4.5.2.C.b.i.1)

This project is reactive in nature. The work required is initiated through Horizon Utilities' maintenance and inspection programs. This project has a very high probability of impacting Horizon Utilities' reliability targets if the poles are not replaced.

Asset Condition Relative to Typical Life Cycle (5.4.5.2.C.b.i.2)

This project addresses wood poles that have been identified as having a high risk of failure and as such, these assets are at the end of their useful life. The asset condition relative to their typical life cycle varies in case.

Number of Customers Impacted (5.4.5.2.C.b.i.3)

The number of customers impacted varies in each incident or outage.

Quantitative Customer Impact and Risk (5.4.5.2.C.b.i.4)

The quantitative customer impact varies in each incident or outage.

Qualitative Customer Impact and Risk (5.4.5.2.C.b.i.5)

These projects address customer satisfaction as they are required to address assets at risk of failure which would result in a service interruption.

Value of Customer Impact (5.4.5.2.C.b.i.6)

The value of the customer impact varies in each incident or outage.

Other Factors Affecting Project Timing (5.4.5.2.C.b.ii)

These projects are reactive in nature and address assets at risk of failure. Horizon Utilities replaces poles requiring immediate replacement as soon as possible to mitigate the risk of service interruptions and the risk to public safety resulting from a failure of the pole.

Horizon Utilities replaces poles requiring replacement within five years in the following year. Failure to replace in the following year compounds the volume of work in subsequent years resulting in cascading delays and compounded volumes in subsequent years.

Impact on System O&M Costs (5.4.5.2.C.b.iii)

These projects do not materially impact system O&M costs.

Reliability and Safety Factors (5.4.5.2.C.b.iv)

This project will provide reliability and safety benefits as the project involves the replacement of wood poles that are at risk of failure. Failure of the asset would result in a service interruption and a potential risk to public safety.

Analysis of Project Benefits and Timing (5.4.5.2.C.b.v)

n/a

Like-for-Like Renewal Analysis (5.4.5.2.C.b.vi)

Poles replaced in this project are replaced on a like-for-like basis where possible as this presents the lowest cost option. No additional costs are incurred to address other distributor planning objectives.

Capital Project Summary

General Information on Project (5.4.5.2.A)

Project Name	ST-F7 Renewal - Part 2
Budget Year	2016
Investment Category	System Renewal
Project Summary	The project involves the renewal of the Strouds Substation F7 feeder in the Hamilton West operating area. This project is part of the 4kV and 8kV Renewal Program.

Capital Investment (5.4.5.2.A.i)

Capital Investment (gross)	$1,533,308
Customer Contribution	$0
Capital Investment (net)	$1,533,308
O&M Expenditure	$0

Customer Attachments / Load (kVA) (5.4.5.2.A.ii)

This project impacts 1,818kVA of transformation.

Project Dates (5.4.5.2.A.iii)

Start Date 2016/03/01

In Service Date 2016/10/31

Expenditure Timing

Q1	Q2	Q3	Q4
12.5%	37.5%	37.5%	12.5%

Schedule Risk and Risk Mitigation (5.4.5.2.A.iv**)**

Please refer to Note I for risk and risk mitigation.

Comparative Information from Equivalent Projects (5.4.5.2.A.v)

There is no direct comparator in scope, size and design characteristics for this project. This project is one phase of a multi-year investment to renew the area served by Strouds substation as part of the 4kV and 8kV Renewal Program. The 2016 investment for the renewal of Strouds substation is $1,533,000. The 2015 investment in the 4kV and 8kV Renewal Program is $8,160,000.

Comparable gross investments for the 4kv and 8kV Renewal Program for the 2010 to 2013 Historical Years and the 2014 Bridge Year are:

2010 (CGAAP)- $ 2,556,076
2011 (CGAAP)- $ 8,820,000
2012 (MIFRS) - $ 5,268,441
2013 (MIFRS) - $ 5,072,233
2014 (MIFRS) - $ 6,434,000

Total Capital OM&A Costs Associated with REG Investments (5.4.5.2.A.vi)

This project is not associated with an REG investment and therefore OM&A costs related to REG will not be incurred.

Leave to Construct Approval (5.4.5.2.A.vii)

This project does not require “Leave to Construct” under Section 92 of the *Ontario Energy Board Act* 1998.

Evaluation Criteria and Information (5.4.5.2.B)

Project Name	ST-F7 Renewal – Part 2	Table 2

Efficiency, Customer Value, Reliability (5.4.5.2.B.1)

Investment Driver (5.4.5.2.B.1.a)
System Renewal (80%)

Secondary Driver (5.4.5.2.B.1.a)
System Service (20%)

Investment Priority (5.4.5.2.B.1.b)
4 – Required project

Analysis of Project and Project Alternatives (5.4.5.2.B.1.c)

This project is part of the multi-year 4kV and 8kV Renewal Program. Both the 4kV and 8kV distribution system and the Horizon Utilities-owned substations are at the end of their useful life. Horizon Utilities has chosen to renew the 4kV and 8kV distribution systems to a higher voltage to avoid the cost of the investment in the renewal of the substations. The total avoided substation renewal investment over the remaining 35 years of the plan is $70,000,000 for all 28 substations. Therefore the renewal of the distribution assets at the current 4kV level was not a feasible alternative.

The renewal of the area serviced by the Strouds substation started in 2014 and is scheduled to be completed in 2018. Strouds substation was constructed in 1938. The switchgear at this substation is 44 years old and has a Health Index of ‘very poor’ as identified in the Substation Asset Condition Assessment (“SACA”) and confirmed by the Kinectrics ACA.

Safety (5.4.5.2.B.2)

This project is not intended to address safety concerns with the distribution system.

Cyber-Security and Privacy (5.4.5.2.B.3) (where applicable)

Cyber-Security and Privacy are not applicable to this project.

Co-ordination and Interoperability (5.4.5.2.B.4)

Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.5.2.B.4.a) (where applicable)

Please refer to Note II for an explanation on co-ordination with utilities, regional planning and/or links with 3rd parties.

Enabling of Future Technology and/or Future Operational Requirements (5.4.5.2.B.4.b)

Please refer to Note IV for an explanation enabling of future technology and future operational requirements.

Economic Development (5.4.5.2.B.5) **(where applicable)**

Horizon Utilities ensures that policies and practices do not unnecessarily create barriers to economic development which are primarily focused within its communities.

Environmental Benefits (5.4.5.2.B.6) **(where applicable)**

n/a

System Renewal Specific Requirements (5.4.5.2.C.b)

Project Name	ST-F7 Renewal – Part 2	Table 3

System Renewal Specific Requirements (5.4.5.2.C.b)

Asset Performance Target and Asset Lifecycle Optimization (5.4.5.2.C.b.i.1)

The distribution assets in the Hamilton West operating area are in poor health and the switchgear in both substations servicing this area has switchgear with a 'very poor' Health Index.

Asset Condition Relative to Typical Life Cycle (5.4.5.2.C.b.i.2)

Generally the 4kV assets are the oldest vintage in the system. 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.

Number of Customers Impacted (5.4.5.2.C.b.i.3)

This project impacts 474 customers.

Quantitative Customer Impact and Risk (5.4.5.2.C.b.i.4)

SAIDI of 0.024

Qualitative Customer Impact and Risk (5.4.5.2.C.b.i.5)

This project will address aging assets with inadequate backup. Aging assets represent an increased risk of service interruption to customers and inadequate backup would result in long duration service interruptions upon occurrence. These factors would lead to customer dissatisfaction in this area.

Value of Customer Impact (5.4.5.2.C.b.i.6)

High

Other Factors Affecting Project Timing (5.4.5.2.C.b.ii)

The renewal of the area serviced by the Strouds substation is scheduled for 2014 to 2018. This project is required to be completed in 2016 to allow for the renewal of the remaining area to be completed on schedule.

Impact on System O&M Costs (5.4.5.2.C.b.iii)

This project will have no material impact on planned O&M costs. The renewal of the 4kV and 8kV distribution systems, as a whole, will provide a reduction in reactive O&M costs to address service interruptions caused by failed equipment. These reductions will not be material in the 2015 to 2019 Test Years.

Reliability and Safety Factors (5.4.5.2.C.b.iv)

The renewal of the 4kV and 8kV distribution system will provide reliability improvements through reduced service interruptions caused by failed equipment.

Analysis of Project Benefits and Timing (5.4.5.2.C.b.v)

The timing of this project, as part of the 4kV and 8kV Renewal Program, is determined through the assessment of the distribution system health and the health of the substation assets servicing the area. Kinectrics identified that both substations' switchgear had a high probability of failure within one to three years. Failure of both substations would leave the 5400 customers serviced by these substations without power until the substation assets were repaired. Renewal of this area will allow for the decommissioning of the substation assets by 2018 thereby avoiding the need for capital investment into these substations

Like-for-Like Renewal Analysis (5.4.5.2.C.b.vi)

The like-for-like renewal of these assets (i.e. same system configuration and same distribution voltage) will perpetuate the existing operating constraints and require capital investment to renew substation assets. Renewal of the distribution assets at a higher voltage does not involve any material incremental costs over renewal at the existing voltage. Operating constraints (e.g. undersized conductor, radial feeds) are addressed on a case by case basis where appropriate.

Capital Project Summary

General Information on Project (5.4.5.2.A)

Project Name	WH-F5 Renewal - Main St W
Budget Year	2016
Investment Category	System Renewal
Project Summary	This project involves the renewal of Whitney substation F3 feeder in the Hamilton West operating area. This project is part of the 4kV and 8kV Renewal Program.

Capital Investment (5.4.5.2.A.i)	Capital Investment (gross)	$ 1,966,071
	Customer Contribution	0
	Capital Investment (net)	$1,966,071
	O&M Expenditure	$0

Customer Attachments / Load (kVA) (5.4.5.2.A.ii)	This project impacts 2,971 customers and 3,000 kVA of transformation.

Project Dates (5.4.5.2.A.iii)

Start Date	2016/02/01
In Service Date	2016/12/31

Expenditure Timing

Q1	Q2	Q3	Q4
18.18%	27.7%	27.7%	27.7%

Schedule Risk and Risk Mitigation (5.4.5.2.A.iv**)**

Please refer to Note I for risk and risk mitigation.

Comparative Information from Equivalent Projects (5.4.5.2.A.v)

There is no direct comparator in scope, size and design characteristics for this project. This project is one phase of a multi-year investment to renew the area served by Whitney substation as part of the 4kV and 8kV Renewal Program. The 2016 investment for the renewal of Whitney substation is $1,966,000. The 2016 investment in the 4kV and 8kV Renewal Program is $10,160,000.

Comparable gross investments for the 4kv and 8kV Renewal Program for the 2010 to 2013 Historical Years and the 2014 Bridge Year are:

2010 (CGAAP)- $ 2,556,076
2011 (CGAAP)- $ 8,820,000
2012 (MIFRS) - $ 5,268,441
2013 (MIFRS) - $ 5,072,233
2014 (MIFRS) - $ 6,434,000

Total Capital OM&A Costs Associated with REG Investments (5.4.5.2.A.vi)

This project is not associated with an REG investment and therefore OM&A costs related to REG will not be incurred.

Leave to Construct Approval (5.4.5.2.A.vii)

This project does not require "Leave to Construct" under Section 92 of the *Ontario Energy Board Act* 1998.

Evaluation Criteria and Information (5.4.5.2.B)

Project Name	WH-F5 Renewal - Main St W	Table 2

Efficiency, Customer Value, Reliability (5.4.5.2.B.1)

Investment Driver (5.4.5.2.B.1.a)
System Renewal (80%)

Secondary Driver (5.4.5.2.B.1.a)
System Service (20%)

Investment Priority (5.4.5.2.B.1.b)
3 – Required project

Analysis of Project and Project Alternatives (5.4.5.2.B.1.c)

This project is part of the multi-year 4kV and 8kV Renewal Program. Both the 4kV and 8kV distribution system and the Horizon Utilities-owned substations are at the end of their useful life. Horizon Utilities has chosen to renew the 4kV and 8kV distribution systems to a higher voltage to avoid the cost of the investment in the renewal of the substations. The total avoided substation renewal investment over the remaining 35 years of the plan is $70,000,000 for all 28 substations. Therefore the renewal of these distribution assets at the current 4kV level was not a feasible alternative.

The renewal of the area serviced by the Whitney substation started in 2014 and is scheduled to be completed in 2018. Whitney substation was constructed in 1962. The switchgear at this substation is 46 years old and has a Health Index of 'very poor' as identified in the Substation Asset Condition Assessment ("SACA") and confirmed by the Kinectrics ACA.

Safety (5.4.5.2.B.2)

This project is not intended to address safety concerns with the distribution system.

Cyber-Security and Privacy (5.4.5.2.B.3) (where applicable)

Cyber-Security and Privacy are not applicable to this project.

Co-ordination and Interoperability (5.4.5.2.B.4)

Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.5.2.B.4.a) (where applicable)

Please refer to Note II for an explanation on co-ordination with utilities, regional planning and/or links with 3rd parties.

Enabling of Future Technology and/or Future Operational Requirements (5.4.5.2.B.4.b)

Please refer to Note IV for an explanation enabling of future technology and future operational requirements.

Economic Development (5.4.5.2.B.5) **(where applicable)**

Horizon Utilities ensures that policies and practices do not unnecessarily create barriers to economic development which are primarily focused within its communities.

Environmental Benefits (5.4.5.2.B.6) **(where applicable)**

n/a

System Renewal Specific Requirements (5.4.5.2.C.b)

Project Name WH-F5 Renewal - Main St W Table 3

System Renewal Specific Requirements (5.4.5.2.C.b)

Asset Performance Target and Asset Lifecycle Optimization (5.4.5.2.C.b.i.1)

The distribution assets in the Hamilton West operating area are in poor health and the switchgear in both substations servicing this area have switchgear with a 'very poor' Health Index

Asset Condition Relative to Typical Life Cycle (5.4.5.2.C.b.i.2)

Generally the 4kV assets are the oldest vintage in the system. 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.

Number of Customers Impacted (5.4.5.2.C.b.i.3)

This project impacts 2,971 customers.

Quantitative Customer Impact and Risk (5.4.5.2.C.b.i.4)

SAIDI of 0.102

Qualitative Customer Impact and Risk (5.4.5.2.C.b.i.5)

This project will address aging assets with inadequate backup. Aging assets represent an increased risk of service interruption to customers and inadequate backup would result in long duration service interruptions upon occurrence. These factors would lead to customer dissatisfaction in this area.

Value of Customer Impact (5.4.5.2.C.b.i.6)

High

Other Factors Affecting Project Timing (5.4.5.2.C.b.ii)

The renewal of the area serviced by the Whitney substation is scheduled for 2014 to 2018. This project is required to be completed in 2016 to allow for the renewal of the remaining area to be completed on schedule.

Impact on System O&M Costs (5.4.5.2.C.b.iii)

This project will have no material impact on planned O&M costs. The renewal of the 4kV and 8kV distribution systems, as a whole, will provide a reduction in reactive O&M costs to address service interruptions caused by failed equipment. These reductions will not be material in the 2015 to 2019 Test Years.

Reliability and Safety Factors (5.4.5.2.C.b.iv)

The renewal of the 4kV and 8kV distribution system will provide reliability improvements through reduced service interruptions caused by failed equipment.

Analysis of Project Benefits and Timing (5.4.5.2.C.b.v)

The timing of this project, as part of the 4kV and 8kV Renewal Program, is determined through the assessment of the distribution system health and the health of the substation assets servicing the area. Kinectrics identified that both substations' switchgear had a high probability of failure within one to three years. Failure of both substations would leave the 5400 customers serviced by these substations without power until the substation assets were repaired. Renewal of this area will allow for the decommissioning of the substation assets by 2018 thereby avoiding the need for capital investment into these substations.

Like-for-Like Renewal Analysis (5.4.5.2.C.b.vi)

The like-for-like renewal of these assets (i.e. same system configuration and same distribution voltage) will perpetuate the existing operating constraints and require capital investment to renew substation assets. Renewal of the distribution assets at a higher voltage does not involve any material incremental costs over renewal at the existing voltage. Operating constraints (e.g. undersized conductor, radial feeds) are addressed on a case by case basis where appropriate.

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Capital Project Summary

General Information on Project (5.4.5.2.A)

Project Name	GR-F1 Renewal – South of Facer St			
Budget Year	2016			
Investment Category	System Renewal			
Project Summary	This project involves the renewal of the Grantham Substation F1 feeder in St. Catharines south of Facer St.			
Capital Investment (5.4.5.2.A.i)	Capital Investment (gross)	$ 1,570,191		
	Customer Contribution	$0		
	Capital Investment (net)	$1,570,191		
	O&M Expenditure	$0.		
Customer Attachments / Load (kVA) (5.4.5.2.A.ii)	This project affects 2,250 kVA of transformation			
Project Dates (5.4.5.2.A.iii)	Start Date	2016/03/01		
	In Service Date	2016/10/31		
	Expenditure Timing			
	Q1	Q2	Q3	Q4
	12.5%	37.5%	37.5%	12.5%

Schedule Risk and Risk Mitigation (5.4.5.2.A.iv**)**

Please refer to Note I for risk and risk mitigation.

Comparative Information from Equivalent Projects (5.4.5.2.A.v)

There is no direct comparator in scope, size and design characteristics for this project. This project is one phase of a multi-year investment to renew the area served by Grantham substation as part of the 4kV and 8kV Renewal Program. The 2016 investment for the renewal of Grantham substation is $2,633,000. The 2016 investment in the 4kV and 8kV Renewal Program is $10,160,000.

Comparable gross investments for the 4kv and 8kV Renewal Program for the 2010 to 2013 Historical Years and the 2014 Bridge Year are:

2010 (CGAAP)- $ 2,556,076
2011 (CGAAP)- $ 8,820,000
2012 (MIFRS) - $ 5,268,441
2013 (MIFRS) - $ 5,072,233
2014 (MIFRS) - $ 6,434,000

Total Capital OM&A Costs Associated with REG Investments (5.4.5.2.A.vi)

This project is not associated with an REG investment and therefore OM&A costs related to REG will not be incurred.

Leave to Construct Approval (5.4.5.2.A.vii)

This project does not require "Leave to Construct" under Section 92 of the *Ontario Energy Board Act* 1998.

Evaluation Criteria and Information (5.4.5.2.B)

Project Name	GR-F1 Renewal – South of Facer St	Table 2

Efficiency, Customer Value, Reliability (5.4.5.2.B.1)

Investment Driver (5.4.5.2.B.1.a)
System Renewal (80%)

Secondary Driver (5.4.5.2.B.1.a)
System Service (20%)

Investment Priority (5.4.5.2.B.1.b)
3 – Required project

Analysis of Project and Project Alternatives (5.4.5.2.B.1.c)

This project is part of the multi-year 4kV and 8kV Renewal Program. Both the 4kV and 8kV distribution system and the Horizon Utilities owned substations are at the end of their useful life. Horizon Utilities has chosen to renew the 4kV and 8kV distribution systems to a higher voltage to avoid the cost of the investment in the renewal of the substations. The total avoided substation renewal investment over the remaining 35 years of the plan is $70,000,000 for all 28 substations. Therefore the renewal of these distribution assets at the current 4kV level was not a feasible alternative.

This is the second year of the multi-year project to renew the area serviced by Grantham substation. Renewal of this area is schedule to be completed in 2017.

Safety (5.4.5.2.B.2)

This project is not intended to address safety concerns with the distribution system.

Cyber-Security and Privacy (5.4.5.2.B.3) (where applicable)

Cyber-Security and Privacy are not applicable to this project.

Co-ordination and Interoperability (5.4.5.2.B.4)

Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.5.2.B.4.a) (where applicable)

Please refer to Note II for an explanation on co-ordination with utilities, regional planning and/or links with 3rd parties.

Enabling of Future Technology and/or Future Operational Requirements (5.4.5.2.B.4.b)

Please refer to Note IV for an explanation enabling of future technology and future operational requirements.

Economic Development (5.4.5.2.B.5) **(where applicable)**

Horizon Utilities ensures that policies and practices do not unnecessarily create barriers to economic development which are primarily focused within its communities.

Environmental Benefits (5.4.5.2.B.6) **(where applicable)**

n/a.

System Renewal Specific Requirements (5.4.5.2.C.b)

Project Name	GR-F1 Renewal – South of Facer St	Table 3

System Renewal Specific Requirements (5.4.5.2.C.b)

Asset Performance Target and Asset Lifecycle Optimization (5.4.5.2.C.b.i.1)

The 4kV distribution assets and substations assets in the St. Catharines operating area are in poor health and require renewal. The overall substation Health Index for Vine, Welland and Grantham substations is 57%, 59%, 58% respectively. 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. 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.

Asset Condition Relative to Typical Life Cycle (5.4.5.2.C.b.i.2)

Generally the 4kV assets are the oldest vintage in the system. 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.

Number of Customers Impacted (5.4.5.2.C.b.i.3)

This project will impact 300 customers.

Quantitative Customer Impact and Risk (5.4.5.2.C.b.i.4)

SAIDI of 0.010

Qualitative Customer Impact and Risk (5.4.5.2.C.b.i.5)

This project will address aging assets with inadequate backup. Aging assets represent an increased risk of service interruption to customers and inadequate backup would result in long duration service interruptions upon occurrence. These factors would lead to customer dissatisfaction in this area.

Value of Customer Impact (5.4.5.2.C.b.i.6)

High

Other Factors Affecting Project Timing (5.4.5.2.C.b.ii)

The renewal of the area serviced by the Grantham substation is scheduled for 2015 to 2017. This project is required to be completed in 2016 to allow for the renewal of the remaining area to be completed on schedule.

Impact on System O&M Costs (5.4.5.2.C.b.iii)

This project will have no material impact on planned O&M costs. The renewal of the 4kV and 8kV distribution systems, as a whole, will provide a reduction in reactive O&M costs to address service interruptions caused by failed equipment. These reductions will not be material in the 2015 to 2019 Test Years.

Reliability and Safety Factors (5.4.5.2.C.b.iv)

The renewal of the 4kV and 8kV distribution system will provide reliability improvements through reduced service interruptions caused by failed equipment.

Analysis of Project Benefits and Timing (5.4.5.2.C.b.v)

The timing of this project, as part of the 4kV and 8kV Renewal Program, is determined through the assessment of the distribution system health and the health of the substation assets servicing the area. 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. Renewal of this area will allow for the decommissioning of the substation assets by 2017 thereby avoiding the need for capital investment into these substations.

Like-for-Like Renewal Analysis (5.4.5.2.C.b.vi)

The like-for-like renewal of these assets (i.e. same system configuration and same distribution voltage) will perpetuate the existing operating constraints and require capital investment to renew substation assets. Renewal of the distribution assets at a higher voltage does not involve any material incremental costs over renewal at the existing voltage. Operating constraints (e.g. undersized conductor, radial feeds) are addressed on a case by case basis where appropriate.

Capital Project Summary

General Information on Project (5.4.5.2.A)

Project Name	GR-F2 Renewal - Roehampton XLPE
Budget Year	2016
Investment Category	System Renewal
Project Summary	This project involves the renewal of the Grantham Substation F2 feeder in St. Catharines. This project deals with a section of XLPE cable serving customers in the Roehampton Avenue area of St. Catharines.
Capital Investment (5.4.5.2.A.i)	Capital Investment (gross): $911,383 Customer Contribution: $0 Capital Investment (net): $911,383 O&M Expenditure: $0
Customer Attachments / Load (kVA) (5.4.5.2.A.ii)	This project impacts 100 customers and 375 kVA of transformation.
Project Dates (5.4.5.2.A.iii)	Start Date 2016/05/01 In Service Date 2016/10/31

Expenditure Timing

Q1	Q2	Q3	Q4
0%	30%	50%	20%

Schedule Risk and Risk Mitigation (5.4.5.2.A.iv**)**

Please refer to Note I for risk and risk mitigation.

Comparative Information from Equivalent Projects (5.4.5.2.A.v)

There is no direct comparator in scope, size and design characteristics for this project. This project supports both the 4kV and 8kV Renewal Program and the XLPE Renewal Program.

Total Capital OM&A Costs Associated with REG Investments (5.4.5.2.A.vi)

This project is not associated with an REG investment and therefore OM&A costs related to REG will not be incurred.

Leave to Construct Approval (5.4.5.2.A.vii)

This project does not require "Leave to Construct" under Section 92 of the *Ontario Energy Board Act* 1998.

Evaluation Criteria and Information (5.4.5.2.B)	**Project Name** GR-F2 Renewal - Roehampton URD	Table 2
	Efficiency, Customer Value, Reliability (5.4.5.2.B.1) **Investment Driver (5.4.5.2.B.1.a)** System Renewal (80%) **Secondary Driver (5.4.5.2.B.1.a)** System Service (20%) **Investment Priority (5.4.5.2.B.1.b)** 3 – Required project **Analysis of Project and Project Alternatives (5.4.5.2.B.1.c)** This is currently a 4kV underground distribution and Horizon Utilities has chosen to renew the 4kV and 8kV distribution systems to a higher voltage to avoid the cost of the investment in the renewal of the substations. The total avoided substation renewal investment over the remaining 35 years of the plan is $70,000,000 for all 28 substations. Therefore, the renewal of the distribution assets at the current 4kV level was not a feasible alternative.	
	Safety (5.4.5.2.B.2) This project is not intended to address safety concerns with the distribution system.	
	Cyber-Security and Privacy (5.4.5.2.B.3) (where applicable) Cyber-Security and Privacy are not applicable to this project.	
	Co-ordination and Interoperability (5.4.5.2.B.4) **Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.5.2.B.4.a) (where applicable)** Please refer to Note II for an explanation on co-ordination with utilities, regional planning and/or links with 3rd parties. **Enabling of Future Technology and/or Future Operational Requirements (5.4.5.2.B.4.b)** Please refer to Note IV for an explanation enabling of future technology and future operational requirements.	
	Economic Development (5.4.5.2.B.5) **(where applicable)** Horizon Utilities ensures that policies and practices do not unnecessarily create barriers to economic development which are primarily focused within its communities.	
	Environmental Benefits (5.4.5.2.B.6) **(where applicable)** n/a	

Project Name	GR-F2 Renewal - Roehampton URD	Table 3

System Renewal Specific Requirements (5.4.5.2.C.b)

System Renewal Specific Requirements (5.4.5.2.C.b)

Asset Performance Target and Asset Lifecycle Optimization (5.4.5.2.C.b.i.1)

The 4kV distribution assets and substations assets in the St. Catharines operating area are in poor health and require renewal. The overall substation Health Index for Vine, Welland and Grantham substations is 57%, 59%, 58% respectively. 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. 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.

Asset Condition Relative to Typical Life Cycle (5.4.5.2.C.b.i.2)

Generally the 4kV assets are of the oldest vintage in the system. 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.

Number of Customers Impacted (5.4.5.2.C.b.i.3)

This project impacts 100 customers.

Quantitative Customer Impact and Risk (5.4.5.2.C.b.i.4)

SAIDI of 0.003

Qualitative Customer Impact and Risk (5.4.5.2.C.b.i.5)

This project will address aging assets with inadequate backup. Aging assets represent an increased risk of service interruption to customers and inadequate backup would result in long duration service interruptions upon occurrence. These factors would lead to customer dissatisfaction in this area.

Value of Customer Impact (5.4.5.2.C.b.i.6)

High

Other Factors Affecting Project Timing (5.4.5.2.C.b.ii)

The renewal of the area serviced by Grantham substation is schedule for 2015 to 2017. This project is required to be completed in 2016 to allow for the renewal of the remaining area to be completed on schedule.

Impact on System O&M Costs (5.4.5.2.C.b.iii)

This project will have no material impact on planned O&M costs. The renewal of the 4kV and 8kV distribution systems, as a whole, will provide a reduction in reactive O&M costs to address service interruptions caused by failed equipment. These reductions will not be material in the 2015 to 2019 Test Years.

Reliability and Safety Factors (5.4.5.2.C.b.iv)

The renewal of the 4kV and 8kV distribution system will provide reliability improvements through reduced service interruptions caused by failed equipment

Analysis of Project Benefits and Timing (5.4.5.2.C.b.v)

The timing of this project, as part of the 4kV and 8kV Renewal Program, is determined through the assessment of the distribution system health and the health of the substation assets servicing the area. 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. Renewal of this area will allow for the decommissioning of the substation assets by 2017 thereby avoiding the need for capital investment into these substations.

Like-for-Like Renewal Analysis (5.4.5.2.C.b.vi)

The like-for-like renewal of these assets (i.e. same system configuration and same distribution voltage) will perpetuate the existing operating constraints and require capital investment to renew substation assets. Renewal of the distribution assets at a higher voltage does not involve any material incremental costs over renewal at the existing voltage. Operating constraints (e.g. undersized conductor, radial feeds) are addressed on a case by case basis where appropriate.

Capital Project Summary

General Information on Project (5.4.5.2.A)

Project Name	GR-F2 Renewal – West of Vine Ave
Budget Year	2016
Investment Category	System Renewal
Project Summary	This project involves the renewal of the Grantham substation F2 feeder in St. Catharines, west of Vine Ave.

Capital Investment (5.4.5.2.A.i)

Capital Investment (gross)	$1,063,220
Customer Contribution	$0
Capital Investment (net)	$1,063,220
O&M Expenditure	$0

Customer Attachments / Load (kVA) (5.4.5.2.A.ii)

This project impacts 300 customers and 2,250 kVA of transformation.

Project Dates (5.4.5.2.A.iii)

Start Date	2016/04/01
In Service Date	2016/11/30

Expenditure Timing

Q1	Q2	Q3	Q4
0%	37.5%	37.5%	25%

Schedule Risk and Risk Mitigation (5.4.5.2.A.iv**)**

Please refer to Note I for risk and risk mitigation.

Comparative Information from Equivalent Projects (5.4.5.2.A.v)

There is no direct comparator in scope, size and design characteristics for this project. This project is one phase of a multi-year investment to renew the area served by Grantham substation as part of the 4kV and 8kV Renewal Program. The 2016 investment for the renewal of Grantham substation is $2,633,000. The 2016 investment in the 4kV and 8kV Renewal Program is $10,160,000.

Comparable gross investments for the 4kv and 8kV Renewal Program for the 2010 to 2013 Historical Years and the 2014 Bridge Year are:

2010 (CGAAP)- $ 2,556,076
2011 (CGAAP)- $ 8,820,000
2012 (MIFRS) - $ 5,268,441
2013 (MIFRS) - $ 5,072,233
2014 (MIFRS) - $ 6,434,000

Total Capital OM&A Costs Associated with REG Investments (5.4.5.2.A.vi)

This project is not associated with an REG investment and therefore OM&A costs related to REG will not be incurred.

Leave to Construct Approval (5.4.5.2.A.vii)

This project does not require "Leave to Construct" under Section 92 of the *Ontario Energy Board Act* 1998.

Evaluation Criteria and Information (5.4.5.2.B)	**Project Name** GR-F2 Renewal – West of Vine Ave Table 2
	Efficiency, Customer Value, Reliability (5.4.5.2.B.1) **Investment Driver (5.4.5.2.B.1.a)** System Renewal (80%) **Secondary Driver (5.4.5.2.B.1.a)** System Service (20%) **Investment Priority (5.4.5.2.B.1.b)** 3 – Required project
	Analysis of Project and Project Alternatives (5.4.5.2.B.1.c) This project is part of the multi-year 4kV and 8kV Renewal Program. Both the 4kV and 8kV distribution system and the Horizon Utilities-owned substations are at the end of their useful life. Horizon Utilities has chosen to renew the 4kV and 8kV distribution systems to a higher voltage to avoid the cost of the investment in the renewal of the substations. The total avoided substation renewal investment over the remaining 35 years of the plan is $70,000,000 for all 28 substations. Therefore, the renewal of the distribution assets at the current 4kV level was not a feasible alternative. This is the initial year of the multi-year project to renewal the area serviced by Grantham substation. Renewal of this area is schedule to be completed in 2017.
	Safety (5.4.5.2.B.2) This project is not intended to address safety concerns with the distribution system.
	Cyber-Security and Privacy (5.4.5.2.B.3) (where applicable) Cyber-Security and Privacy are not applicable to this project.
	Co-ordination and Interoperability (5.4.5.2.B.4) **Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.5.2.B.4.a) (where applicable)** Please refer to Note II for an explanation on co-ordination with utilities, regional planning and/or links with 3rd parties. **Enabling of Future Technology and/or Future Operational Requirements (5.4.5.2.B.4.b)** Please refer to Note IV for an explanation enabling of future technology and future operational requirements.
	Economic Development (5.4.5.2.B.5) **(where applicable)** Horizon Utilities ensures that policies and practices do not unnecessarily create barriers to economic development which are primarily focused within its communities.
	Environmental Benefits (5.4.5.2.B.6) **(where applicable)** n/a

System Renewal Specific Requirements (5.4.5.2.C.b)

Project Name	GR-F2 Renewal – West of Vine Ave	Table 3

System Renewal Specific Requirements (5.4.5.2.C.b)

Asset Performance Target and Asset Lifecycle Optimization (5.4.5.2.C.b.i.1)

The 4kV distribution assets and substations assets in the St. Catharines operating area are in poor health and require renewal. The overall substation Health Index for Vine, Welland and Grantham substations is 57%, 59%, 58% respectively. 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. 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.

Asset Condition Relative to Typical Life Cycle (5.4.5.2.C.b.i.2)

Generally the 4kV assets are the oldest vintage in the system. 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.

Number of Customers Impacted (5.4.5.2.C.b.i.3)

This project impacts 300 customers.

Quantitative Customer Impact and Risk (5.4.5.2.C.b.i.4)

SAIDI of 0.010

Qualitative Customer Impact and Risk (5.4.5.2.C.b.i.5)

This project will address aging assets with inadequate backup. Aging assets represent an increased risk of service interruption to customers and inadequate backup would result in long duration service interruptions upon occurrence. These factors would lead to customer dissatisfaction in this area

Value of Customer Impact (5.4.5.2.C.b.i.6)

High

Other Factors Affecting Project Timing (5.4.5.2.C.b.ii)

The renewal of the area serviced by Grantham substation is schedule for 2015 to 2017. This project is required to be completed in 2016 to allow for the renewal of the remaining area to be completed on schedule.

Impact on System O&M Costs (5.4.5.2.C.b.iii)

This project will have no material impact on planned O&M costs. The renewal of the 4kV and 8kV distribution systems, as a whole, will provide a reduction in reactive O&M costs to address service interruptions caused by failed equipment. These reductions will not be material in the 2015 to 2019 Test Years.

Reliability and Safety Factors (5.4.5.2.C.b.iv)

The renewal of the 4kV and 8kV distribution system will provide reliability improvements through reduced service interruptions caused by failed equipment.

Analysis of Project Benefits and Timing (5.4.5.2.C.b.v)

The timing of this project, as part of the 4kV and 8kV Renewal Program, is determined through the assessment of the distribution system health and the health of the substation assets servicing the area. 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. Renewal of this area will allow for the decommissioning of the substation assets by 2017 thereby avoiding the need for capital investment into these substations.

Like-for-Like Renewal Analysis (5.4.5.2.C.b.vi)

The like-for-like renewal of these assets (i.e. same system configuration and same distribution voltage) will perpetuate the existing operating constraints and require capital investment to renew substation assets. Renewal of the distribution assets at a higher voltage does not involve any material incremental costs over renewal at the existing voltage. Operating constraints (e.g. undersized conductor, radial feeds) are addressed on a case by case basis where appropriate.

Capital Project Summary

General Information on Project (5.4.5.2.A)

Project Name	2016 Rear Lot Conversion				
Budget Year	2016				
Investment Category	System Renewal				
Project Summary	This project involves the replacement of rear lot overhead construction. Replacement options include relocating primary only, or relocating all assets to either overhead or underground in the front lot. Options are dependent on many factors (e.g. presence of trees and availability of room in the road allowance) and are assessed on a case by case basis. This project will involve the renewal of end of life rear lot overhead distribution assets serviced at 13.8kV and therefore not included in the 4kV and 8kV renewal programs.				
Capital Investment (5.4.5.2.A.i)	Capital Investment (gross)	$1,342,000			
	Customer Contribution	$0			
	Capital Investment (net)	$1,342,000			
	O&M Expenditure	$0			
Customer Attachments / Load (kVA) (5.4.5.2.A.ii)	The customer and load impacted by this project will vary depending upon the final scope of the project.				
Project Dates (5.4.5.2.A.iii)	Start Date	2016/05/01			
	In Service Date	2016/09/30			
	Expenditure Timing				
	Q1	Q2	Q3	Q4	
	0%	40%	60%	0%	

Schedule Risk and Risk Mitigation (5.4.5.2.A.iv**)**

Please refer to Note I for risk and risk mitigation.

Comparative Information from Equivalent Projects (5.4.5.2.A.v)

There are no equivalent projects for comparison.

Total Capital OM&A Costs Associated with REG Investments (5.4.5.2.A.vi)

This project is not associated with an REG investment and therefore OM&A costs related to REG will not be incurred.

Leave to Construct Approval (5.4.5.2.A.vii)

This project does not require "Leave to Construct" under Section 92 of the *Ontario Energy Board Act* 1998.

Evaluation Criteria and Information (5.4.5.2.B)

Project Name	2016 Rear Lot Conversion	Table 2

Efficiency, Customer Value, Reliability (5.4.5.2.B.1)

Investment Driver (5.4.5.2.B.1.a)
System Renewal (60%)

Secondary Driver (5.4.5.2.B.1.a)

System Service (40%)

Investment Priority (5.4.5.2.B.1.b)

3 – Required project

Analysis of Project and Project Alternatives (5.4.5.2.B.1.c)

Replacement options considered on a project by project basis include relocating primary only, or relocating all assets to either overhead or underground in the front lot. Options are dependent on many factors (e.g., presence of trees and availability of room in the road allowance).

Safety (5.4.5.2.B.2)

This project is not intended to address safety concerns with the distribution system.

Cyber-Security and Privacy (5.4.5.2.B.3) (where applicable)

Cyber-Security and Privacy are not applicable to this project.

Co-ordination and Interoperability (5.4.5.2.B.4)

Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.5.2.B.4.a) (where applicable)

Please refer to Note II for an explanation on co-ordination with utilities, regional planning and/or links with 3rd parties.

Enabling of Future Technology and/or Future Operational Requirements (5.4.5.2.B.4.b)

Please refer to Note IV for an explanation enabling of future technology and future operational requirements.

Economic Development (5.4.5.2.B.5) **(where applicable)**

Horizon Utilities ensures that policies and practices do not unnecessarily create barriers to economic development which are primarily focused within its communities.

Environmental Benefits (5.4.5.2.B.6) **(where applicable)**

n/a.

System Renewal Specific Requirements (5.4.5.2.C.b)

Project Name	2016 Rear Lot Conversion	Table 3

System Renewal Specific Requirements (5.4.5.2.C.b)

Asset Performance Target and Asset Lifecycle Optimization (5.4.5.2.C.b.i.1)

Horizon Utilities has identified several residential areas serviced by a rear lot overhead distribution system. Horizon Utilities has experienced a dramatic increase in reliability issues surrounding rear lot distribution systems due to damaged caused from customer owned trees and lack of access for utility crews to repair or replace equipment. The poles are a mix of wood and concrete that, by design, are unsafe to scale to repair, and replacement of poles and equipment is labour intensive and requires specialized equipment access rear yards. Access is poor and therefore failure restoration time is significantly extended. These identified assets are nearing or beyond end of life and should be replaced. In the past several years, storm related failures in these areas have increased and have resulted in long outage durations (in excess of 24 hours).

Asset Condition Relative to Typical Life Cycle (5.4.5.2.C.b.i.2)

Overhead distribution assets located in rear lots typically do not perform as well as assets of similar age resulting in a shorter life cycle.

Number of Customers Impacted (5.4.5.2.C.b.i.3)

This project will impact a varying number of customers depending upon the scope of the rear lot conversion.

Quantitative Customer Impact and Risk (5.4.5.2.C.b.i.4)

n/a

Qualitative Customer Impact and Risk (5.4.5.2.C.b.i.5)

This project will improve the service received by the customers impacted. Service interruptions of rear lot distribution systems involve longer restoration times due to the difficulty in accessing the assets. The service interruption restoration times will be reduced once the assets have been relocated.

Value of Customer Impact (5.4.5.2.C.b.i.6)

High

Other Factors Affecting Project Timing (5.4.5.2.C.b.ii)

n/a

Impact on System O&M Costs (5.4.5.2.C.b.iii)

This project will not have a material impact on system O&M costs in the 2015 to 2019 Test Years.

Reliability and Safety Factors (5.4.5.2.C.b.iv)

Reliability will be improved through the relocation of these assets through reduced service interruption restoration times. Safety will be improved due to improved and easier access to the assets and the ability to work on the assets from aerial bucket trucks versus having to manually climb poles when located in the rear lot.

Analysis of Project Benefits and Timing (5.4.5.2.C.b.v)

n/a.

Like-for-Like Renewal Analysis (5.4.5.2.C.b.vi)

The cost of this project is required to remove rear lot assets and is specifically designed not to renew using a like-for-like methodology. Horizon Utilities will determine whether to relocate the primary only to the front lot or to relocate all plant to either underground and/or overhead front lot. The decision will be made on a project by project basis.

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Capital Project Summary

General Information on Project (5.4.5.2.A)

Project Name	2016 St. Catharines XLPE Renewal			
Budget Year	2016			
Investment Category	System Renewal			
Project Summary	Renewal of end-of-life XLPE cable assets in the St. Catharines area.			
Capital Investment (5.4.5.2.A.i)	Capital Investment (gross)	$ 1,661,000		
	Customer Contribution	$0		
	Capital Investment (net)	$1,661,000		
	O&M Expenditure	$0		
Customer Attachments / Load (kVA) (5.4.5.2.A.ii)	The customer and load impacted by this project will vary depending upon the final scope of the project.			
Project Dates (5.4.5.2.A.iii)	Start Date 2016/03/01			
	In Service Date 2016/11/30			
	Expenditure Timing			
	Q1	Q2	Q3	Q4
	10%	40%	40%	10%

Schedule Risk and Risk Mitigation (5.4.5.2.A.iv**)**

Please refer to Note I for risk and risk mitigation.

Comparative Information from Equivalent Projects (5.4.5.2.A.v)

There is no direct comparator in scope, size and design characteristics for this project. This project is part of a multi-year investment to renewal XLPE primary cable. The 2016 investment in the XLPE Renewal Program is $4,926,000.

Comparable gross investments for the XLPE Renewal Program for the 2010 to 2013 Historical Years and the 2014 Bridge Year are:

2010 (CGAAP)- $ 0
2011 (CGAAP)- $ 0
2012 (MIFRS) - $ 0
2013 (MIFRS) - $ 1,572,090
2014 (MIFRS) - $ 893,000

Total Capital OM&A Costs Associated with REG Investments (5.4.5.2.A.vi)

This project is not associated with an REG investment and therefore OM&A costs related to REG will not be incurred.

Leave to Construct Approval (5.4.5.2.A.vii)

This project does not require "Leave to Construct" under Section 92 of the *Ontario Energy Board Act* 1998.

Evaluation Criteria and Information (5.4.5.2.B)

Project Name	2016 St. Catharines XLPE Renewal	Table 2

Efficiency, Customer Value, Reliability (5.4.5.2.B.1)

Investment Driver (5.4.5.2.B.1.a)
System Renewal (80%)

Secondary Driver (5.4.5.2.B.1.a)
System Service (20%)

Investment Priority (5.4.5.2.B.1.b)
4 – Required Project

Analysis of Project and Project Alternatives (5.4.5.2.B.1.c)

This project is part of the multi-year XLPE Renewal Program. Horizon Utilities considered the four replacement philosophies for addressing risk inherent in the XLPE asset group: Area; Reactive; Selected; and Refurbishment. The area replacement philosophy will be utilized 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 St. Catharines operating area contains many small pockets of direct buried XLPE primary cable. The XLPE renewal projects in the St. Catharines operating area will involve the full renewal of each pocket of XLPE cable. Project selection will be guided by: asset health; operating history; and reliability of each of the underground pockets of XLPE.

Safety (5.4.5.2.B.2)

These projects are not intended to address safety concerns with the distribution system.

Cyber-Security and Privacy (5.4.5.2.B.3) (where applicable)

n/a

Co-ordination and Interoperability (5.4.5.2.B.4)

Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.5.2.B.4.a) (where applicable)

Please refer to Note II for an explanation on co-ordination with utilities, regional planning and/or links with 3rd parties.

Enabling of Future Technology and/or Future Operational Requirements (5.4.5.2.B.4.b)

Please refer to Note IV for an explanation enabling of future technology and future operational requirements.

Economic Development (5.4.5.2.B.5) **(where applicable)**

Horizon Utilities ensures that policies and practices do not unnecessarily create barriers to economic development which are primarily focused within its communities.

Environmental Benefits (5.4.5.2.B.6) **(where applicable)**

n/a

System Renewal Specific Requirements (5.4.5.2.C.b)

Project Name 2016 St. Catharines XLPE Renewal Table 3

System Renewal Specific Requirements (5.4.5.2.C.b)

Asset Performance Target and Asset Lifecycle Optimization (5.4.5.2.C.b.i.1)

XLPE primary cable is the asset group with the largest investment requirement as identified by the Kinectrics ACA. 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.

Asset Condition Relative to Typical Life Cycle (5.4.5.2.C.b.i.2)

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.

Number of Customers Impacted (5.4.5.2.C.b.i.3)

The number of customers impacted will vary depending upon the area.

Quantitative Customer Impact and Risk (5.4.5.2.C.b.i.4)

Varies

Qualitative Customer Impact and Risk (5.4.5.2.C.b.i.5)

This project will address aging assets at risk of failure. Failures of XLPE primary cable result in extended service interruptions; 30% of these outages exceeded four hours in duration, while 5% of these outages exceeded twelve hours in duration.

Value of Customer Impact (5.4.5.2.C.b.i.6)

High

Other Factors Affecting Project Timing (5.4.5.2.C.b.ii)

Proactive replacements are required because, as assets continue to age and degrade, the cable will fail at an exponential rate. In the worst case, it would exceed Horizon Utilities' ability to keep pace with repairs. Reliability will also deteriorate to unacceptable levels. Reactive replacements will be considerably more costly than proactive renewal.

Impact on System O&M Costs (5.4.5.2.C.b.iii)

This project will have no material impact on planned O&M costs. The renewal of the XLPE primary cable, as a whole, will provide a reduction in reactive O&M costs to address service interruptions caused by failed equipment. These reductions will not be material in the 2015 to 2019 Test Years.

Reliability and Safety Factors (5.4.5.2.C.b.iv)

The renewal of the XLPE primary cable system will provide reliability improvements through reduced service interruptions caused by failed equipment.

Analysis of Project Benefits and Timing (5.4.5.2.C.b.v)

Failure to invest in the proactive renewal of XLPE primary cable and associated underground assets would result in unacceptable levels of system failures and outages beyond the ability of Horizon Utilities to resolve within a reasonable timeframe as these assets continue to age and degrade. Reactive replacements will also be considerably more costly than the forecast expenditure required to execute the proposed proactive replacement.

Like-for-Like Renewal Analysis (5.4.5.2.C.b.vi)

XLPE renewal projects will include: the elimination of radial underground feeds; replacement of below grade transformers with padmount transformers; and the introduction of fusing on the underground distribution systems where applicable.

Capital Project Summary

General Information on Project (5.4.5.2.A)

Project Name	VE-F1 Renewal – Queenston St			
Budget Year	2016			
Investment Category	System Renewal			
Project Summary	This project involves the renewal of the Vine Substation F1 feeder in St. Catharines along Queenston St.			
Capital Investment (5.4.5.2.A.i)	Capital Investment (gross)	$ 1,057,505		
	Customer Contribution	$0		
	Capital Investment (net)	$1,057,505		
	O&M Expenditure	$0		
Customer Attachments / Load (kVA) (5.4.5.2.A.ii)	This project impacts 1500 kVA of transformation.			
Project Dates (5.4.5.2.A.iii)	Start Date	2016/02/01		
	In Service Date	2016/08/31		
	Expenditure Timing			
	Q1	Q2	Q3	Q4
	25%	30%	45%	0%

Schedule Risk and Risk Mitigation (5.4.5.2.A.iv**)**

Please refer to Note I for risk and risk mitigation.

Comparative Information from Equivalent Projects (5.4.5.2.A.v)

There is no direct comparator in scope, size and design characteristics for this project. This project is one phase of a multi-year investment to renew the area served by Vine substation as part of the 4kV and 8kV Renewal Program. The 2016 investment for the renewal of Vine substation is $2,472,000. The 2016 investment in the 4kV and 8kV Renewal Program is $10,160,000.

Comparable gross investments for the 4kv and 8kV Renewal Program for the 2010 to 2013 Historical Years and the 2014 Bridge Year are:

2010 (CGAAP)- $ 2,556,076
2011 (CGAAP)- $ 8,820,000
2012 (MIFRS) - $ 5,268,441
2013 (MIFRS) - $ 5,072,233
2014 (MIFRS) - $ 6,434,000

Total Capital OM&A Costs Associated with REG Investments (5.4.5.2.A.vi)

This project is not associated with an REG investment and therefore OM&A costs related to REG will not be incurred.

Leave to Construct Approval (5.4.5.2.A.vii)

This project does not require "Leave to Construct" under Section 92 of the *Ontario Energy Board Act* 1998.

Evaluation Criteria and Information (5.4.5.2.B)

Project Name VE-F1 Conversion – Queenston St Table 2

Efficiency, Customer Value, Reliability (5.4.5.2.B.1)

Investment Driver (5.4.5.2.B.1.a)
System Renewal (80%)

Secondary Driver (5.4.5.2.B.1.a)
System Service (20%)

Investment Priority (5.4.5.2.B.1.b)
3 – Required project

Analysis of Project and Project Alternatives (5.4.5.2.B.1.c)

This project is part of the multi-year 4kV and 8kV Renewal Program. Both the 4kV and 8kV distribution system and the Horizon Utilities-owned substations are at the end of their useful life. Horizon Utilities has chosen to renew the 4kV and 8kV distribution systems to a higher voltage to avoid the cost of the investment in the renewal of the substations. The total avoided substation renewal investment over the remaining 35 years of the plan is $70,000,000 for all 28 substations. Therefore the renewal of the distribution assets at the current 4kV level was not a feasible alternative.

Safety (5.4.5.2.B.2)

These projects are not intended to address safety concerns with the distribution system.

Cyber-Security and Privacy (5.4.5.2.B.3) (where applicable)

Cyber-Security and Privacy are not applicable to this project.

Co-ordination and Interoperability (5.4.5.2.B.4)

Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.5.2.B.4.a) (where applicable)
Please refer to Note II for an explanation on co-ordination with utilities, regional planning and/or links with 3rd parties.

Enabling of Future Technology and/or Future Operational Requirements (5.4.5.2.B.4.b)

Please refer to Note IV for an explanation enabling of future technology and future operational requirements.

	Economic Development (5.4.5.2.B.5) **(where applicable)** Horizon Utilities ensures that policies and practices do not unnecessarily create barriers to economic development which are primarily focused within its communities.
	Environmental Benefits (5.4.5.2.B.6) **(where applicable)** n/a

System Renewal Specific Requirements (5.4.5.2.C.b)	**Project Name** VE-F1 Conversion – Queenston St	Table 3
	System Renewal Specific Requirements (5.4.5.2.C.b) **Asset Performance Target and Asset Lifecycle Optimization (5.4.5.2.C.b.i.1)** The 4kV distribution assets and substations assets in the St. Catharines operating area are in poor health and require renewal. The overall substation Health Index for Vine, Welland and Grantham substations is 57%, 59%, 58% respectively. 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. 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. **Asset Condition Relative to Typical Life Cycle (5.4.5.2.C.b.i.2)** Generally the 4kV assets are of the oldest vintage in the system. 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. . **Number of Customers Impacted (5.4.5.2.C.b.i.3)** This project impacts 430 customers. **Quantitative Customer Impact and Risk (5.4.5.2.C.b.i.4)** SAIDI of 0.015 **Qualitative Customer Impact and Risk (5.4.5.2.C.b.i.5)** This project will address aging assets with inadequate backup. Aging assets represent an increased risk of service interruption to customers and inadequate backup would result in long duration service interruptions upon occurrence. These factors would lead to customer dissatisfaction in this area. **Value of Customer Impact (5.4.5.2.C.b.i.6)** High	

Other Factors Affecting Project Timing (5.4.5.2.C.b.ii)

The renewal of the area serviced by Vine substation is scheduled for 2015 to 2017. This project is required to be completed in 2016 to allow for the renewal of the remaining area to be completed on schedule.

Impact on System O&M Costs (5.4.5.2.C.b.iii)

This project will have no material impact on planned O&M costs. The renewal of the 4kV and 8kV distribution systems, as a whole, will provide a reduction in reactive O&M costs to address service interruptions caused by failed equipment. These reductions will not be material in the 2015 to 2019 Test Years.

Reliability and Safety Factors (5.4.5.2.C.b.iv)

The renewal of the 4kV and 8kV distribution system will provide reliability improvements through reduced service interruptions caused by failed equipment.

Analysis of Project Benefits and Timing (5.4.5.2.C.b.v)

The timing of this project, as part of the 4kV and 8kV Renewal Program, is determined through the assessment of the distribution system health and the health of the substation assets servicing the area.

Like-for-Like Renewal Analysis (5.4.5.2.C.b.vi)

The like-for-like renewal of these assets (i.e. same system configuration and same distribution voltage) will perpetuate the existing operating constraints and require capital investment to renew substation assets. Renewal of the distribution assets at a higher voltage does not involve any material incremental costs over renewal at the existing voltage. Operating constraints (e.g. undersized conductor, radial feeds) are addressed on a case by case basis where appropriate.

Capital Project Summary

General Information on Project (5.4.5.2.A)

Project Name	VE-F5 Renewal – West of Haynes Ave
Budget Year	2016
Investment Category	System Renewal
Project Summary	This project involves the renewal of the Vine Substation F5 feeder in St. Catharines west of Haynes Ave.

Capital Investment (5.4.5.2.A.i)		
	Capital Investment (gross)	$ 1,414,741
	Customer Contribution	$0
	Capital Investment (net)	$1,414,741
	O&M Expenditure	$0

Customer Attachments / Load (kVA) (5.4.5.2.A.ii)

This project impacts 2,000 kVA of transformation

Project Dates (5.4.5.2.A.iii)

Start Date 2016/01/01

In Service Date 2016/09/30

Expenditure Timing

Q1	Q2	Q3	Q4
30%	35%	35%	0%

Schedule Risk and Risk Mitigation (5.4.5.2.A.iv**)**

Please refer to Note I for risk and risk mitigation.

Comparative Information from Equivalent Projects (5.4.5.2.A.v)

There is no direct comparator in scope, size and design characteristics for this project. This project is one phase of a multi-year investment to renew the area served by Vine substation as part of the 4kV and 8kV Renewal Program. The 2016 investment for the renewal of Vine substation is $2,472,000. The 2016 investment in the 4kV and 8kV Renewal Program is $10,160,000.

Comparable gross investments for the 4kv and 8kV Renewal Program for the 2010 to 2013 Historical Years and the 2014 Bridge Year are:

2010 (CGAAP)- $ 2,556,076
2011 (CGAAP)- $ 8,820,000
2012 (MIFRS) - $ 5,268,441
2013 (MIFRS) - $ 5,072,233
2014 (MIFRS) - $ 6,434,000

Total Capital OM&A Costs Associated with REG Investments (5.4.5.2.A.vi)

This project is not associated with an REG investment and therefore OM&A costs related to REG will not be incurred.

Leave to Construct Approval (5.4.5.2.A.vii)

This project does not require "Leave to Construct" under Section 92 of the *Ontario Energy Board Act* 1998.

Evaluation Criteria and Information (5.4.5.2.B)

Project Name	VE-F5 Renewal – West of Haynes Ave	Table 2

Efficiency, Customer Value, Reliability (5.4.5.2.B.1)

Investment Driver (5.4.5.2.B.1.a)
System Renewal (80%)

Secondary Driver (5.4.5.2.B.1.a)
System Service (20%)

Investment Priority (5.4.5.2.B.1.b)
3 – Required project

Analysis of Project and Project Alternatives (5.4.5.2.B.1.c)

This project is part of the multi-year 4kV and 8kV Renewal Program. Both the 4kV and 8kV distribution system and the Horizon Utilities owned substations are at the end of their useful life. Horizon Utilities has chosen to renew the 4kV and 8kV distribution systems to a higher voltage to avoid the cost of the investment in the renewal of the substations. The total avoided substation renewal investment over the remaining 35 years of the plan is $70,000,000 for all 28 substations. Therefore the renewal of the distribution assets at the current 4kV level was not a feasible alternative.

Safety (5.4.5.2.B.2)

These projects are not intended to address safety concerns with the distribution system.

Cyber-Security and Privacy (5.4.5.2.B.3) (where applicable)

Cyber-Security and Privacy are not applicable to this project.

Co-ordination and Interoperability (5.4.5.2.B.4)

Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.5.2.B.4.a) (where applicable)

Please refer to Note II for an explanation on co-ordination with utilities, regional planning and/or links with 3rd parties.

Enabling of Future Technology and/or Future Operational Requirements (5.4.5.2.B.4.b)

Please refer to Note IV for an explanation enabling of future technology and future operational requirements.

	Economic Development (5.4.5.2.B.5) **(where applicable)** Horizon Utilities ensures that policies and practices do not unnecessarily create barriers to economic development which are primarily focused within its communities.
	Environmental Benefits (5.4.5.2.B.6) **(where applicable)** n/a

System Renewal Specific Requirements (5.4.5.2.C.b)	**Project Name** VE-F5 Renewal – West of Haynes Ave Table 3
	System Renewal Specific Requirements (5.4.5.2.C.b) **Asset Performance Target and Asset Lifecycle Optimization (5.4.5.2.C.b.i.1)** The 4kV distribution assets and substations assets in the St. Catharines operating area are in poor health and require renewal. The overall substation Health Index for Vine, Welland and Grantham substations is 57%, 59%, 58% respectively. 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. 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. **Asset Condition Relative to Typical Life Cycle (5.4.5.2.C.b.i.2)** Generally the 4kV assets are the oldest vintage in the system. 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. **Number of Customers Impacted (5.4.5.2.C.b.i.3)** This project impacts 592 customers. **Quantitative Customer Impact and Risk (5.4.5.2.C.b.i.4)** SAIDI of 0.020 **Qualitative Customer Impact and Risk (5.4.5.2.C.b.i.5)** This project will address aging assets with inadequate backup. Aging assets represent an increased risk of service interruption to customers and inadequate backup would result in long duration service interruptions upon occurrence. These factors would lead to customer dissatisfaction in this area. **Value of Customer Impact (5.4.5.2.C.b.i.6)** High

Other Factors Affecting Project Timing (5.4.5.2.C.b.ii)

The renewal of the area serviced by Vine substation is scheduled for 2015 to 2017. This project is required to be completed in 2016 to allow for the renewal of the remaining area to be completed on schedule.

Impact on System O&M Costs (5.4.5.2.C.b.iii)

This project will have no material impact on planned O&M costs. The renewal of the 4kV and 8kV distribution systems, as a whole, will provide a reduction in reactive O&M costs to address service interruptions caused by failed equipment. These reductions will not be material in the 2015 to 2019 Test Years.

Reliability and Safety Factors (5.4.5.2.C.b.iv)

The renewal of the 4kV and 8kV distribution system will provide reliability improvements through reduced service interruptions caused by failed equipment.

Analysis of Project Benefits and Timing (5.4.5.2.C.b.v)

The timing of this project, as part of the 4kV and 8kV Renewal Program, is determined through the assessment of the distribution system health and the health of the substation assets servicing the area.

Like-for-Like Renewal Analysis (5.4.5.2.C.b.vi)

The like-for-like renewal of these assets (i.e. same system configuration and same distribution voltage) will perpetuate the existing operating constraints and require capital investment to renew substation assets. Renewal of the distribution assets at a higher voltage does not involve any material incremental costs over renewal at the existing voltage. Operating constraints (e.g. undersized conductor, radial feeds) are addressed on a case by case basis where appropriate.

Capital Project Summary

General Information on Project (5.4.5.2.A)

Project Name	2016 Substation Infrastructure Renewal
Budget Year	2016
Investment Category	System Renewal
Project Summary	This program involves the renewal of substation infrastructure throughout Horizon Utilities' service territory. Substation maintenance and inspection programs annually identify a number of required investments for the continued safe and reliable operation of Horizon Utilities' substations. Investments under this program include battery replacements, SCADA and communication upgrades, and grounding improvements .

Capital Investment (5.4.5.2.A.i)	Capital Investment (gross)	$473,000
	Customer Contribution	$0
	Capital Investment (net)	$473,000
	O&M Expenditure	$0
Customer Attachments / Load (kVA) (5.4.5.2.A.ii)	n/a	

Project Dates (5.4.5.2.A.iii)

Start Date	2016/01/01
In Service Date	2016/12/31

Expenditure Timing

Q1	Q2	Q3	Q4
25%	25%	25%	25%

Schedule Risk and Risk Mitigation (5.4.5.2.A.iv**)**

Please refer to Note I for risk and risk mitigation.

Comparative Information from Equivalent Projects (5.4.5.2.A.v)

Comparable gross investments for the 2010 to 2013 Historical Years and the 2014 Bridge Year are:

2010 (CGAAP)- $ 146,477
2011 (CGAAP)- $ 326,000
2012 (MIFRS) - $ 305,000
2013 (MIFRS) - $ 168,507
2014 (MIFRS) - $ 455,503

Total Capital OM&A Costs Associated with REG Investments (5.4.5.2.A.vi)

This project is not associated with an REG investment and therefore OM&A costs related to REG will not be incurred.

	Leave to Construct Approval (5.4.5.2.A.vii) This project does not require "Leave to Construct" under Section 92 of the *Ontario Energy Board Act* 1998.

Evaluation Criteria and Information (5.4.5.2.B)	
	Project Name 2016 Substation Infrastructure Renewal Table 2
	Efficiency, Customer Value, Reliability (5.4.5.2.B.1) **Investment Driver (5.4.5.2.B.1.a)** System Renewal (80%) **Secondary Driver (5.4.5.2.B.1.a)** System Service (20%) **Investment Priority (5.4.5.2.B.1.b)** 3 – Required project
	Analysis of Project and Project Alternatives (5.4.5.2.B.1.c) This program is required for the ongoing safe and reliable operation of Horizon Utilities' municipal substations. The 4kV and 8kV Renewal Program is structured to decommission Horizon Utilities' 28 substations over the next 34 years. There is no investment in the renewal of the major electrical assets (power transformers, switchgear and breakers) forecasted for the 2015 to 2019 Test Years. The investments provided above are required to maintain the ancillary substation assets in safe working order. Substation investment requirements are identified though preventative maintenance programs performed on both routine maintenance cycles and monthly inspections. 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. Investments are required to address both electrical assets within the substation (e.g. replacement of switchgear components and instrument transformers), and ancillary equipment (e.g. SCADA, communication equipment, or backup batteries). All of these components are critical to the continued safe and reliable operation of the substation. A failure to undertake these required investments could lead to premature failure of substation components that would result in a service interruption and increased operating or reactive capital expenditure.
	Safety (5.4.5.2.B.2) This project is not intended to address safety concerns with the distribution system.
	Cyber-Security and Privacy (5.4.5.2.B.3) (where applicable) n/a
	Co-ordination and Interoperability (5.4.5.2.B.4) **Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.5.2.B.4.a) (where applicable)** Please refer to Note II for an explanation on co-ordination with utilities, regional planning and/or links with 3rd parties.

Enabling of Future Technology and/or Future Operational Requirements (5.4.5.2.B.4.b)

Please refer to Note IV for an explanation enabling of future technology and future operational requirements.

Economic Development (5.4.5.2.B.5) **(where applicable)**

Horizon Utilities ensures that policies and practices do not unnecessarily create barriers to economic development which are primarily focused within its communities.

Environmental Benefits (5.4.5.2.B.6) **(where applicable)**

n/a

System Renewal Specific Requirements (5.4.5.2.C.b)

Project Name	2016 Substation Infrastructure Renewal	Table 3

System Renewal Specific Requirements (5.4.5.2.C.b)

Asset Performance Target and Asset Lifecycle Optimization (5.4.5.2.C.b.i.1)

This project involves investment to replace substation infrastructure required for the continued safe and reliable operation of Horizon Utilities' substations.

Asset Condition Relative to Typical Life Cycle (5.4.5.2.C.b.i.2)

n/a

Number of Customers Impacted (5.4.5.2.C.b.i.3)

n/a

Quantitative Customer Impact and Risk (5.4.5.2.C.b.i.4)

Qualitative Customer Impact and Risk (5.4.5.2.C.b.i.5)

n/a

Value of Customer Impact (5.4.5.2.C.b.i.6)

Medium

Other Factors Affecting Project Timing (5.4.5.2.C.b.ii)

The timing of investments in this project is dependent upon the timing of substation maintenance programs and the infrastructure requiring renewal identified while performing maintenance.

Impact on System O&M Costs (5.4.5.2.C.b.iii)

This project will have no material impact on O&M expenditures.

Reliability and Safety Factors (5.4.5.2.C.b.iv)

n/a

Analysis of Project Benefits and Timing (5.4.5.2.C.b.v)

n/a

Like-for-Like Renewal Analysis (5.4.5.2.C.b.vi)

The assets renewed in this program are replaced on a like-for-like basis.

Capital Project Summary

General Information on Project (5.4.5.2.A)

Project Name	2016 Load Break Disconnect Switch ("LBDS") Replacement
Budget Year	2016
Investment Category	System Renewal
Project Summary	This project involves the replacement of LBDS found to be either inoperable or beyond economic repair (where the cost of maintenance is not warranted) as found through Horizon Utilities' maintenance and inspection programs. Such switches will be replaced with automated switches where an operational benefit can be realized. This is a multi-year program based on 16 replacements per year.

Capital Investment (5.4.5.2.A.i)		
	Capital Investment (gross)	$324,000
	Customer Contribution	$0
	Capital Investment (net)	$324,000
	O&M Expenditure	$0

Customer Attachments / Load (kVA) (5.4.5.2.A.ii)	n/a

Project Dates (5.4.5.2.A.iii)

Start Date	2016/06/01
In Service Date	2016/12/31

Expenditure Timing

Q1	Q2	Q3	Q4
0%	0%	50%	50%

Schedule Risk and Risk Mitigation (5.4.5.2.A.iv**)**

Please refer to Note I for risk and risk mitigation.

Comparative Information from Equivalent Projects (5.4.5.2.A.v)

Comparable gross investments for the 2010 to 2013 Historical Years and the 2014 Bridge Year are:

2010 (CGAAP)- $ 0
2011 (CGAAP)- $ 0
2012 (MIFRS) - $ 0
2013 (MIFRS) - $ 212,000
2014 (MIFRS) - $ 312,000

Total Capital OM&A Costs Associated with REG Investments (5.4.5.2.A.vi)

This project is not associated with an REG investment and therefore OM&A costs related to REG will not be incurred.

Leave to Construct Approval (5.4.5.2.A.vii)

This project does not require "Leave to Construct" under Section 92 of the *Ontario Energy Board Act* 1998.

Evaluation Criteria and Information (5.4.5.2.B)

Project Name 2016 LBDS Replacement Table 2

Efficiency, Customer Value, Reliability (5.4.5.2.B.1)

Investment Driver (5.4.5.2.B.1.a)
System Renewal (80%)

Secondary Driver (5.4.5.2.B.1.a)
System Service (20%)

Investment Priority (5.4.5.2.B.1.b)
3 – Required project

Analysis of Project and Project Alternatives (5.4.5.2.B.1.c)

This project involves the replacement of LBDS switches identified as requiring replacement through Horizon Utilities' maintenance and inspection programs. When feasible, the switches are refurbished rather than replaced. Where refurbishment is not possible, the switches will be replaced with an automated switch where an operational benefit can be realized.

Safety (5.4.5.2.B.2)

This project is not intended to address safety concerns with the distribution system.

Cyber-Security and Privacy (5.4.5.2.B.3) (where applicable)

Horizon Utilities utilizes the Smart Meter communication infrastructure when communicating with automated switches. Horizon Utilities' Smart Meter and related AMI network have been procured through Elster. Elster's system supports a multi-layered security approach including: access control, authorization, authentication and data integrity protocols. As part of its continuous improvement model, Horizon Utilities performs periodic security assessments to identify opportunities for enhanced system hardening.

Co-ordination and Interoperability (5.4.5.2.B.4)

Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.5.2.B.4.a) (where applicable)
Please refer to Note II for an explanation on co-ordination with utilities, regional planning and/or links with 3rd parties.

Enabling of Future Technology and/or Future Operational Requirements (5.4.5.2.B.4.b)

This is not applicable to this project.

Economic Development (5.4.5.2.B.5) **(where applicable)**

Horizon Utilities ensures that policies and practices do not unnecessarily create barriers to economic development which are primarily focused within its communities.

Environmental Benefits (5.4.5.2.B.6) **(where applicable)**

n/a

System Renewal Specific Requirements (5.4.5.2.C.b)

Project Name	2016 LBDS Replacement	Table 3

System Renewal Specific Requirements (5.4.5.2.C.b)

Asset Performance Target and Asset Lifecycle Optimization (5.4.5.2.C.b.i.1)

LBDS are critical devices for the operation of the distribution system and are installed at key operating points (e.g. feeder tie points, feeder sectionalizing). Unplanned failures of these devices would impact Horizon Utilities' ability to restore power, resulting in extended outages.

Asset Condition Relative to Typical Life Cycle (5.4.5.2.C.b.i.2)

The asset condition of LBDS relative to their typical lifecycle varies from switch to switch depending upon the operational stresses experienced by the switch. LBDS that are identified for replacement are replaced because they would not operate properly when required and are beyond economical repair.

Number of Customers Impacted (5.4.5.2.C.b.i.3)

No customer impact if the project is planned.

Quantitative Customer Impact and Risk (5.4.5.2.C.b.i.4)

n/a

Qualitative Customer Impact and Risk (5.4.5.2.C.b.i.5)

Failure of a LBDS to operate when required can impact Horizon Utilities' operational ability which can adversely affect the service experienced by customers.

Value of Customer Impact (5.4.5.2.C.b.i.6)

The value of the customer impact varies in each instance.

Other Factors Affecting Project Timing (5.4.5.2.C.b.ii)

The timing of this project is dependent upon the timing of Horizon Utilities' LBDS maintenance program.

Impact on System O&M Costs (5.4.5.2.C.b.iii)

These projects do not materially impact system O&M costs.

Reliability and Safety Factors (5.4.5.2.C.b.iv)

Reliability can be adversely affected when a LBDS fails to operate when required as part of switching to restore service.

Analysis of Project Benefits and Timing (5.4.5.2.C.b.v)

n/a

Like-for-Like Renewal Analysis (5.4.5.2.C.b.vi)

LDBS are replaced with an automated switch where an operational benefit can be realized. Otherwise they are replaced on a like-for-like basis.

Capital Project Summary

General Information on Project (5.4.5.2.A)

Project Name	2016 Proactive Transformer Replacement
Budget Year	2016
Investment Category	System Renewal
Project Summary	This project was established to proactively replace distribution transformers as required. Renewal of distribution transformers in the past has either been reactive upon failure or proactive when included in the 4kV & 8KV Renewal or XLPE Primary Cable renewal programs. There are instances where proactive replacement of transformers is required even when the replacement is outside of the scope of the programs mentioned above. This is a multi-year project, based on 25 replacements per year.

Capital Investment (5.4.5.2.A.i)	Capital Investment (gross)	$361,000
	Customer Contribution	$0
	Capital Investment (net)	$361,000
	O&M Expenditure	$0

Customer Attachments / Load (kVA) (5.4.5.2.A.ii)	n/a

Project Dates (5.4.5.2.A.iii)

Start Date	2016/06/01
In Service Date	2016/12/31

Expenditure Timing

Q1	Q2	Q3	Q4
0%	0%	50%	50%

Schedule Risk and Risk Mitigation (5.4.5.2.A.iv**)**

Please refer to Note I for risk and risk mitigation.

Comparative Information from Equivalent Projects (5.4.5.2.A.v)

Comparable gross investments for the 2010 to 2013 Historical Years and the 2014 Bridge Year are:

2010 (CGAAP)- $ 0
2011 (CGAAP)- $ 104,447
2012 (MIFRS) - $ 185,523
2013 (MIFRS) - $ 276,978
2014 (MIFRS) - $ 339,000

Total Capital OM&A Costs Associated with REG Investments (5.4.5.2.A.vi)

This project is not associated with an REG investment and therefore OM&A costs related to REG will not be incurred.

Leave to Construct Approval (5.4.5.2.A.vii)

This project does not require "Leave to Construct" under Section 92 of the *Ontario Energy Board Act* 1998.

Evaluation Criteria and Information (5.4.5.2.B)

Project Name	2016 Proactive Transformer Replacement	Table 2

Efficiency, Customer Value, Reliability (5.4.5.2.B.1)

Investment Driver (5.4.5.2.B.1.a)
System Renewal (100%)

Secondary Driver (5.4.5.2.B.1.a)
N/A

Investment Priority (5.4.5.2.B.1.b)
3 – Required project

Analysis of Project and Project Alternatives (5.4.5.2.B.1.c)

Proactive transformer replacements are identified through Horizon Utilities' visual inspection programs and 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, in a reactive replacement scenario, the customer(s) may be subject to an extended outage duration;
- Transformers that have visible oil leaks; and
- Transformers that have been identified through testing as containing PCBs.

These criteria were selected due to the level of associated risk. Transformers with visible oil leaks or containing PCBs represent a significant environmental risk. All oil spills must be tracked, reported, and the oil reclaimed where possible. Obsolete transformers, where a replacement is not available in inventory, represent a risk of prolonged service interruption upon failure and are replaced to reduce the risk of outage to the customer.

Safety (5.4.5.2.B.2)

This project is not intended to address safety concerns with the distribution system.

Cyber-Security and Privacy (5.4.5.2.B.3) (where applicable)

n/a

Co-ordination and Interoperability (5.4.5.2.B.4)

Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.5.2.B.4.a) (where applicable)
Please refer to Note II for an explanation on co-ordination with utilities, regional planning and/or links with 3rd parties.

Enabling of Future Technology and/or Future Operational Requirements (5.4.5.2.B.4.b)

This is not applicable to this project.

Economic Development (5.4.5.2.B.5) **(where applicable)**

Horizon Utilities ensures that policies and practices do not unnecessarily create barriers to economic development which are primarily focused within its communities.

Environmental Benefits (5.4.5.2.B.6) **(where applicable)**

n/a

System Renewal Specific Requirements (5.4.5.2.C.b)

Project Name	2016 Proactive Transformer Replacement	Table 3

System Renewal Specific Requirements (5.4.5.2.C.b)

Asset Performance Target and Asset Lifecycle Optimization (5.4.5.2.C.b.i.1)

The transformers selected for proactive replacement represent a level of risk to Horizon Utilities and this project provides risk mitigation consistent with Horizon Utilities' asset management objectives.

Asset Condition Relative to Typical Life Cycle (5.4.5.2.C.b.i.2)

The asset condition of these transformers relative to their typical lifecycle varies from transformer to transformer. Transformers selected for replacement present a level of risk to Horizon Utilities either through imminent failure of the transformer or through the need to address environmental risk associated with PCBs; or through the risks associated with transformers that have visible oil leaks.

Number of Customers Impacted (5.4.5.2.C.b.i.3)

Varies and is project dependent.

Quantitative Customer Impact and Risk (5.4.5.2.C.b.i.4)

n/a

Qualitative Customer Impact and Risk (5.4.5.2.C.b.i.5)

These criteria were selected due to the level of associated risk. Transformers with visible oil leaks or containing PCBs represent a significant environmental risk. All oil spills must be tracked, reported, and the oil reclaimed where possible. Obsolete transformers, where a replacement is not available in inventory, represent a risk of prolonged service interruption upon failure and are replaced to reduce the risk of outage to the customer.

Value of Customer Impact (5.4.5.2.C.b.i.6)

The value of the customer impact varies in each instance.

Other Factors Affecting Project Timing (5.4.5.2.C.b.ii)

n/a

Impact on System O&M Costs (5.4.5.2.C.b.iii)

These projects do not materially impact system O&M costs.

Reliability and Safety Factors (5.4.5.2.C.b.iv)

n/a

Analysis of Project Benefits and Timing (5.4.5.2.C.b.v)

n/a

Like-for-Like Renewal Analysis (5.4.5.2.C.b.vi)

n/a

2016 General Plant Investments

Capital Project Summary

Project Name	2016 Annual Corporate Computer Replacement			
Budget Year	2016			
Investment Category	General Plant			
Project Summary	This project is part of an ongoing business requirement to refresh end user computers. Horizon Utilities utilizes a three-year lifecycle for replacement of end user computers. On an annual basis, approximately one third of all Horizon Utilities' computers (~150 PCs/year) are replaced.			
Capital Investment (5.4.5.2.A.i)	Capital Investment (gross)	$323,500		
	Customer Contribution	n/a		
	Capital Investment (net)	n/a		
	O&M Expenditure	n/a		
Customer Attachments / Load (5.4.5.2.A.ii)	n/a			
Project Dates (5.4.5.2.A.iii)	Start Date	Jan. 2016		
	In Service Date	Dec. 2016		
	Expenditure Timing			
	Q1	Q2	Q3	Q4
	25%	25%	25%	25%

Schedule Risk and Risk Mitigation (5.4.5.2.A.iv**)**

Schedule - Implementation is phased throughout the year starting in January and ending in December based on the age of PCs being replaced.

Risk – The primary risk to this project is product availability from suppliers.
Risk Mitigation – Work closely with suppliers to schedule orders based on required delivery times.

Comparative Information from Equivalent Projects (5.4.5.2.A.v)

Comparable gross investments for the annual corporate computer replacement for the 2010 to 2013 Historical Years and the 2014 Bridge Year are:

2010 (CGAAP)- $ 336,000
2011 (CGAAP)- $ 227,000
2012 (MIFRS) - $ 312,000
2013 (MIFRS) - $ 364,947
2014 (MIFRS) - $ 366,200

Total Capital and OM&A Costs Associated with REG Investments (5.4.5.2.A.vi)
n/a

Leave to Construct Approval (5.4.5.2.A.vii)
n/a

Evaluation Criteria and Information

Project Name	2016 Annual Corporate Computer Replacement	Table 2

Efficiency, Customer Value, Reliability (5.4.5.2.B.1)

Investment Driver (5.4.5.2.B.1.a)
General Plant (100%)

Secondary Driver (5.4.5.2.B.1.a)
n/a

Investment Priority (5.4.5.2.B.1.b)

High Priority – Personal computers are treated as a strategic asset. They are Horizon Utilities' primary staff productivity tool. They are used to: maintain and deliver services to customers; improve staff productivity; cost-effectively manage total cost of PC ownership; and support investments in new applications, infrastructure and business capabilities.

Analysis of Project and Project Alternatives (5.4.5.2.B.1.c)
n/a

Safety (5.4.5.2.B.2)
n/a

Cyber-Security and Privacy (5.4.5.2.B.3) (where applicable)
n/a

Co-ordination and Interoperability (5.4.5.2.B.4)

Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.5.2.B.4.a) (where applicable)
n/a

Enabling of Future Technology and/or Future Operational Requirements (5.4.5.2.B.4.b)

Suppliers of enterprise systems such as: GIS; OMS; SCADA; AMI; and IFS ERP, are constantly upgrading their products to deliver new processes and functionality. As new versions are released, up-to-date hardware is required in order to perform necessary upgrades to maintain vendor support for the systems.

	Economic Development (5.4.5.2.B.5) **(where applicable)** n/a
	Environmental Benefits (5.4.5.2.B.6) **(where applicable)** n/a

General Plant Specific Requirements

Project Name 2016 Annual Corporate Computer Replacement Table 3

General Plant Specific Requirements (5.4.5.2.C.d)

Summary of Qualitative and Quantitative Analysis (5.4.5.2.C.d.i)

n/a

Business Case Justification Documentation (5.4.5.2.C.d.i)

Horizon Utilities' PCs are treated as a strategic asset, because they are the primary staff productivity tool. Horizon Utilities has streamlined its PC lifecycle management processes utilizing a PC refresh cycle of three years, in order to: deliver, maintain and improve services to customers; to improve staff productivity; to cost-effectively manage total cost of PC ownership; and to support investments in new applications, infrastructure and business capabilities.

A three-year PC refresh cycle reduces the total cost of ownership by reducing the number of models of PCs supported, which results in the reduction of the IST service desk effort required to deploy, secure, and manage new systems and applications. The reduction in the number of supported models has allowed Horizon Utilities to introduce mobile computing for remote field workers and to increase the number of supported PCs by over 100 devices since 2011, without an increase in IST service desk support staff.

A refresh lifecycle of three years reduces the likelihood of device failures that lead to a loss of staff productivity and increased IT support effort. Over 50% of Horizon Utilities' staff utilizes a mobile PC (laptop or tablet) in the performance of their daily activities, many in harsh operating environments outside the office, which increases the likelihood of failure due to operating environment and the age of the device.

Horizon Utilities has introduced several new enterprise business and engineering systems to: mitigate business risks related to aging systems (e.g. GIS); improve electricity system operation (i.e. GIS, OMS); and to address end of vendor support for systems (i.e. IFS ERP, Microsoft Windows XP). Maintaining a three-year PC lifecycle refresh program allows Horizon Utilities' to migrate to these applications without a need to make large one-time investments in PCs to meet the minimum operating requirements of new applications.

PCs are the primary productivity tool used by Horizon Utilities' staff. Unreliable and slow PCs impact productivity and customer service.

Minimizing the number of supported models reduces the IST support effort required to manage, order, configure, and deploy PCs and it reduces the total cost of ownership for PCs.

Capital Project Summary

Project Name	2016 Capital Lease – IBM
Budget Year	2016
Investment Category	General Plant
Project Summary	This project is the end of lease replacement of the IBM iSeries server hardware environment used to run the Daffron Customer Information System ("CIS") which supports Horizon Utilities' customer management and meter-to-cash processes. The hardware is a three-year lease with planned renewals in 2016 and 2019. The environment includes a production IBM iSeries server in Hamilton and an identical IBM iSeries server at the Disaster Recovery Data Centre in St. Catharines.

Capital Investment (5.4.5.2.A.i)	Capital Investment (gross)	$900,000
	Customer Contribution	n/a
	Capital Investment (net)	n/a
	O&M Expenditure	n/a

Customer Attachments / Load (5.4.5.2.A.ii)	N/A

Project Dates (5.4.5.2.A.iii)

Start Date	Jan. 2016
In Service Date	Jan. 2016

Expenditure Timing

Q1	Q2	Q3	Q4
100%	0%	0%	0%

Schedule Risk and Risk Mitigation (5.4.5.2.A.iv**)**

Schedule - Implementation Jan. 2016

Risk – The primary risk to this project is product availability from suppliers.

Risk Mitigation – Work closely with suppliers to schedule orders based on required delivery times.

Comparative Information from Equivalent Projects (5.4.5.2.A.v)

There are no comparable projects in scope and nature for comparison.

Total Capital and OM&A Costs Associated with REG Investments (5.4.5.2.A.vi)
n/a

Leave to Construct Approval (5.4.5.2.A.vii)
n/a

Evaluation Criteria and Information	**Project Name** 2016 Capital Lease – IBM	Table 2
	Efficiency, Customer Value, Reliability (5.4.5.2.B.1) **Investment Driver (5.4.5.2.B.1.a)** General Plant (100%) **Secondary Driver (5.4.5.2.B.1.a)** n/a **Investment Priority (5.4.5.2.B.1.b)** High Priority – This project is required for the continued operation of Horizon Utilities' CIS system.	
	Analysis of Project and Project Alternatives (5.4.5.2.B.1.c) n/a	
	Safety (5.4.5.2.B.2) n/a	
	Cyber-Security and Privacy (5.4.5.2.B.3) (where applicable) n/a	
	Co-ordination and Interoperability (5.4.5.2.B.4) **Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.5.2.B.4.a) (where applicable)** n/a **Enabling of Future Technology and/or Future Operational Requirements (5.4.5.2.B.4.b)**	
	n/a **Economic Development** (5.4.5.2.B.5) **(where applicable)**	
	n/a **Environmental Benefits** (5.4.5.2.B.6) **(where applicable)** n/a	

General Plant Specific Requirements			
	Project Name	2016 Capital Lease – IBM	Table 3

General Plant Specific Requirements (5.4.5.2.C.d)

Summary of Qualitative and Quantitative Analysis (5.4.5.2.C.d.i)

N/A

Business Case Justification Documentation (5.4.5.2.C.d.i)

The IBM iSeries hardware lease will expire December 31, 2015 and December 31, 2018. This environment is required to maintain the continued operation of Horizon Utilities' Daffron CIS system to ensure appropriate technology for the customer management and meter-to-cash processes. Replacement of the IBM iSeries hardware at end-of-life reduces the likelihood of hardware failures that could disrupt normal business operations, impacting Horizon Utilities' ability to: read Smart Meters; bill customers; apply customer payments; manage customer interactions; and manage customer work orders.

Capital Project Summary

Project Name	2016 John Street Windows Replacement
Budget Year	2016
Investment Category	General Plant

Project Summary;

This project is scheduled to take place between 2015 to 2017 to replace the existing windows of the John Street building as they have reached the end-of-lie with the objective to:

- Improve energy performance as the windows are no longer weather resistant;
- Prevent further damage to interior walls and facilities related components;
- Prevent further damage to the building exterior stricture;
- Prevent damage to operational systems; and
- Reduce operational related costs.

Capital Investment (5.4.5.2.A.i)	Capital Investment (gross)	$300,000
	Customer Contribution	n/a
	Capital Investment (net)	n/a
	O&M Expenditure	n/a

Customer Attachments / Load (5.4.5.2.A.ii)	n/a

Project Dates (5.4.5.2.A.iii)

Start Date	April 2016
In Service Date	December 2016

Expenditure Timing

Q1	Q2	Q3	Q4
	35%	65%	

Schedule Risk and Risk Mitigation (5.4.5.2.A.iv**)**

Project timelines and costs exceeding the budget are risks. The project manager will report regularly on project timelines and adherence to budget and escalates issues for resolution.

Comparative Information from Equivalent Projects (5.4.5.2.A.v)

n/a

Total Capital OM&A Costs Associated with REG Investments (5.4.5.2.A.vi)

n/a

Leave to Construct Approval (5.4.5.2.A.vii)

n/a

Evaluation Criteria and Information

Project Name:	2016 John Street Windows Replacement	Table 2

Efficiency, Customer Value, Reliability (5.4.5.2.B.1)

Investment Driver (5.4.5.2.B.1.a)

General Plant – 100%

Secondary Driver (5.4.5.2.B.1.a)
n/a

Investment Priority (5.4.5.2.B.1.b)

High

Analysis of Project and Project Alternatives (5.4.5.2.B.1.c)

Horizon Utilities engaged the MMM Group Limited in 2013 to conduct a condition assessment using visual inspections, air leakage testing and building energy simulations air test. Recommendations are based on the results of the tests and inspections.

Safety (5.4.5.2.B.2)
n/a

Cyber-Security and Privacy (5.4.5.2.B.3) (where applicable)

N/A

Co-ordination and Interoperability (5.4.5.2.B.4)

Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.5.2.B.4.a) (where applicable)

n/a

Enabling of Future Technology and/or Future Operational Requirements (5.4.5.2.B.4.b)

n/a

Economic Development (5.4.5.2.B.5) **(where applicable)**
n/a

Environmental Benefits (5.4.5.2.B.6) **(where applicable)**
n/a

Gener

Project Name	2016 John Street Windows Replacement	Table 3

General Plant Specific Requirements (5.4.5.2.C.d)

Summary of Qualitative and Quantitative Analysis (5.4.5.2.C.d.i)

Horizon Utilities engaged the MMM Group Limited in 2013 to conduct a condition assessment using visual inspections, air leakage testing and building energy simulations air test. Recommendations are based on the results of the tests and inspections.

Business Case Justification Documentation (5.4.5.2.C.d.i)

The windows are no longer weather resistant or energy efficient and they allow cold drafts to enter the building. The windows collect frost on the inside in the winter which melts and damages interior walls and carpeting. The assessment was conducted using visual inspections, air leakage testing and building energy simulations. The testing concluded that the condition of the operable windows in the John Street office building is poor. 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.

Capital Project Summary

Project Name	2016 Vehicle Replacement
Budget Year	2016
Investment Category	General Plant

Project Summary;

Between 2015 and 2019, Horizon Utilities has identified a number of current vehicles that required replacement as they have reached end-of-life as per the criteria within Horizon Utilities' Fleet Replacement Plan.

Other expected objectives and outcomes are to:

- Maintain vehicle reliability and availability;
- Reduce fuel consumption;
- Reduce emissions;
- Reduce down time required to conduct maintenance and repairs; and
- Maintain customer response time.

O

Capital Investment (5.4.5.2.A.i)	Capital Investment (gross)	$780,000
	Customer Contribution	n/a
	Capital Investment (net)	n/a
	O&M Expenditure	n/a

Customer Attachments / Load (5.4.5.2.A.ii)	

Project Dates (5.4.5.2.A.iii)

Start Date	March 2016
In Service Date	December 2016

Expenditure Timing

Q1	Q2	Q3	Q4
0%	0%	50%	50%

Schedule Risk and Risk Mitigation (5.4.5.2.A.iv)

Risk – The primary risk to this project is product availability and adherence to delivery schedules from suppliers.
Risk Mitigation – Work closely with suppliers to schedule orders based on required delivery times.

Comparative Information from Equivalent Projects (5.4.5.2.A.v)

Comparable gross investments for vehicle replacements for the 2010 to 2013 Historical Years and the 2014 Bridge Year are:

2010 (CGAAP)- $ 1,590,516
2011 (CGAAP)- $ 1,033,975
2012 (MIFRS) - $ 1,057,410
2013 (MIFRS) - $ 36,365
2014 (MIFRS) - $ 785,000

Total Capital OM&A Costs Associated with REG Investments (5.4.5.2.A.vi)
n/a

Leave to Construct Approval (5.4.5.2.A.vii)
n/a

Evaluation Criteria and Information

Project Name: 2016 Vehicle Replacement Table 2

Efficiency, Customer Value, Reliability (5.4.5.2.B.1)

Investment Driver (5.4.5.2.B.1.a)

General Plant – 100%

Secondary Driver (5.4.5.2.B.1.a)
n/a

Investment Priority (5.4.5.2.B.1.b)

High

Analysis of Project and Project Alternatives (5.4.5.2.B.1.c)

n/a

Safety (5.4.5.2.B.2)

n/a

Cyber-Security and Privacy (5.4.5.2.B.3) (where applicable)
n/a

Co-ordination and Interoperability (5.4.5.2.B.4)

Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.5.2.B.4.a) (where applicable)

n/a

Enabling of Future Technology and/or Future Operational Requirements (5.4.5.2.B.4.b)

n/a

Economic Development (5.4.5.2.B.5) **(where applicable)**

n/a

Environmental Benefits (5.4.5.2.B.6) **(where applicable)**

n/a

General Plant Specific Requirements

Project Name	2016 Vehicle Replacement	Table 3

General Plant Specific Requirements (5.4.5.2.C.d)

Summary of Qualitative and Quantitative Analysis (5.4.5.2.C.d.i)

Horizon Utilities uses the data collected from electronic fleet and fuel management system, the Global Positional 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 and vehicle maintenance and repairs activities to determine the optimal maintenance scheduling and vehicles replacements.

Business Case Justification Documentation (5.4.5.2.C.d.i)

To maintain the quality, reliability and availability of Horizon Utilities' vehicle fleet for Construction and Maintenance, Metering Services and corporate group activities, vehicles are assessed annually based on a replacement criteria matrix defined within the Fleet Replacement Plan.

Replacement strategies also ensure that Horizon Utilities maintains safe vehicles for employees, while targeting reduced emissions, as well as reduced fuel, operating and maintenance costs. During the next six years, Horizon Utilities will not be procuring any net new vehicles and instead will focus on the replacement of end of life vehicles.

Due to budget mitigation efforts in 2011, 2012, and 2013 a number of vehicles that were scheduled for replacement were kept in operation and rescheduled for replacement in 2014. It is now critical that these vehicles be replaced as maintenance and repairs costs have increased and the vehicles no longer operate at full capacity, reducing vehicle availability and impacting service delivery.

Regular vehicle replacement is necessary to avoid undue vehicle down and associated negative impacts to customer response time and employee productivity.

Capital Project Summary

Project Name	2016 Tools, Shop and Garage Equipment
Budget Year	2016
Investment Category	General Plant

Project Summary
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 risks.

Capital Investment (5.4.5.2.A.i)	Capital Investment (gross)	$566,000
	Customer Contribution	n/a
	Capital Investment (net)	n/a
	O&M Expenditure	n/a

Customer Attachments / Load (5.4.5.2.A.ii)	n/a

Project Dates (5.4.5.2.A.iii)

Start Date	January 2016
In Service Date	December 2016

Expenditure Timing

Q1	Q2	Q3	Q4
25%	25%	25%	25%

Schedule Risk and Risk Mitigation (5.4.5.2.A.iv**)**

Risk – n/a

Risk Mitigation – n/a

Comparative Information from Equivalent Projects (5.4.5.2.A.v)

n/a

Total Capital OM&A Costs Associated with REG Investments (5.4.5.2.A.vi)
n/a

Leave to Construct Approval (5.4.5.2.A.vii)
n/a

Evaluation Criteria and Information	**Project Name:** 2016 Tools, Shop and Garage Equipment Table 2
	Efficiency, Customer Value, Reliability (5.4.5.2.B.1) **Investment Driver (5.4.5.2.B.1.a)** General Plant (100%) **Secondary Driver (5.4.5.2.B.1.a)** n/a
	Investment Priority (5.4.5.2.B.1.b) High **Analysis of Project and Project Alternatives (5.4.5.2.B.1.c)** Tools and equipment over $5000 are procured through a competitive process and alternatives are considered at the time of requisition.
	Safety (5.4.5.2.B.2) Tools and equipment meet CSA requirements and are reviewed for conformance to requirements by Horizon Utilities' Tool & Equipment Committee.
	Cyber-Security and Privacy (5.4.5.2.B.3) (where applicable) N/A
	Co-ordination and Interoperability (5.4.5.2.B.4) **Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.5.2.B.4.a) (where applicable)** n/a **Enabling of Future Technology and/or Future Operational Requirements (5.4.5.2.B.4.b)** n/a
	Economic Development (5.4.5.2.B.5) **(where applicable)** n/a
	Environmental Benefits (5.4.5.2.B.6) **(where applicable)** n/a

General Plant Specific Requirements

Project Name	2016 Tools, Shop and Garage Equipment	Table 3

General Plant Specific Requirements (5.4.5.2.C.d)

Su**mmary of Qualitative and Quantitative Analysis (5.4.5.2.C.d.i)**

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, are 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

Business Case Justification Documentation (5.4.5.2.C.d.i)

n/a

Capital Project Summary

Project Name	[redacted]
Budget Year	2016
Investment Category	General Plant

Project Summary

The objective of this 3 year project that started in 2014 is to [redacted]

Capital Investment (5.4.5.2.A.i)	Capital Investment (gross)	$200,000	
	Customer Contribution	n/a	
	Capital Investment (net)	n/a	
	O&M Expenditure	n/a	
Customer Attachments / Load (5.4.5.2.A.ii)	n/a		

Project Dates (5.4.5.2.A.iii)

Start Date March 2016

In Service Date September 2016

Expenditure Timing

Q1	Q2	Q3	Q4
0%	50%	50%	0%

Schedule Risk and Risk Mitigation (5.4.5.2.A.iv**)**
Project timelines and costs exceeding the budget are risks. The project manager will report regularly on project timelines and adherence to budget and escalates issues for resolution.

Comparative Information from Equivalent Projects (5.4.5.2.A.v)

n/a.

Total Capital OM&A Costs Associated with REG Investments (5.4.5.2.A.vi)

n/a

Leave to Construct Approval (5.4.5.2.A.vii)

n/a

Evaluation Criteria and Information	**Project Name** 2016 Building Security Systems Replacement Table 2
	Efficiency, Customer Value, Reliability (5.4.5.2.B.1) **Investment Driver (5.4.5.2.B.1.a)** General Plant 100% **Secondary Driver (5.4.5.2.B.1.a)** n/a **Investment Priority (5.4.5.2.B.1.b)** High
	Analysis of Project and Project Alternatives (5.4.5.2.B.1.c) [redacted]
	Safety (5.4.5.2.B.2) n/a.
	Cyber-Security and Privacy (5.4.5.2.B.3) (where applicable) n/a
	Co-ordination and Interoperability (5.4.5.2.B.4) **Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.5.2.B.4.a) (where applicable)** n/a **Enabling of Future Technology and/or Future Operational Requirements (5.4.5.2.B.4.b)** n/a
	Economic Development (5.4.5.2.B.5) **(where applicable)** N/A
	Environmental Benefits (5.4.5.2.B.6) **(where applicable)** n/a

General Plant Specific Requirements	Project Name	2016 Building Security Systems Replacement	Table 3

General Plant Specific Requirements (5.4.5.2.C.d)

Summary of Qualitative and Quantitative Analysis (5.4.5.2.C.d.i)

[redacted]

Business Case Justification Documentation (5.4.5.2.C.d.i)

[redacted]

[redacted]

[redacted]

Capital Project Summary

Project Name	2016 Building Renovations – John St
Budget Year	2016
Investment Category	General Plant

Project Summary

This project involves the renovation of the second floor at the John Street location to consolidate Customer Service and CDM employees into contiguous workgroups for organizational efficiency and to improve employee security and safety by relocating Customer Service cashiers 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 Ontario Building Code ("OBC"). All Heating, Ventilation and Air Conditioning ("HVAC") components will be replaced and redirected as required to ensure air quality meets appropriate standards.

The second floor is largely original to the 1950 building and much of the infrastructure, equipment and systems have reach end-of-life.

Capital Investment (5.4.5.2.A.i)	Capital Investment (gross)	$1,600,000
	Customer Contribution	n/a
	Capital Investment (net)	n/a
	O&M Expenditure	n/a
Customer Attachments / Load (5.4.5.2.A.ii)	n/a	

Project Dates (5.4.5.2.A.iii)

Start Date	March 2016
In Service Date	December 2016

Expenditure Timing

Q1	Q2	Q3	Q4
0%	30%	30%	40%

Schedule Risk and Risk Mitigation (5.4.5.2.A.iv**)**

Project timelines and costs exceeding the budget are risks. The project manager will report regularly on project timelines and adherence to budget and escalates issues for resolution.

Comparative Information from Equivalent Projects (5.4.5.2.A.v)

Comparable gross investments for building renovations for the 2010 to 2013 Historical Years and the 2014 Bridge Year are:

2010 (CGAAP)- $ 0
2011 (CGAAP)- $ 0
2012 (MIFRS) - $ 1,767,000
2013 (MIFRS) - $ 5,490,000
2014 (MIFRS) - $ 3,700,000

Total Capital OM&A Costs Associated with REG Investments (5.4.5.2.A.vi)

n/a

Leave to Construct Approval (5.4.5.2.A.vii)
n/a

Evaluation Criteria and Information

Project Name: 2016 Building Renovations – John St Table 2

Efficiency, Customer Value, Reliability (5.4.5.2.B.1)

Investment Driver (5.4.5.2.B.1.a)

General Plant – 100%

Secondary Driver (5.4.5.2.B.1.a)
n/a

Investment Priority (5.4.5.2.B.1.b)

High

Analysis of Project and Project Alternatives (5.4.5.2.B.1.c)

Horizon Utilities' building renovation plans were developed through a facilities planning process that utilized the outputs of a space planning study and multiple building assessments.

Safety (5.4.5.2.B.2)

n/a

Cyber-Security and Privacy (5.4.5.2.B.3) (where applicable)

n/a

Co-ordination and Interoperability (5.4.5.2.B.4)

Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.5.2.B.4.a) (where applicable)

n/a

Enabling of Future Technology and/or Future Operational Requirements (5.4.5.2.B.4.b)

n/a

Economic Development (5.4.5.2.B.5) (where applicable)

n/a

Environmental Benefits (5.4.5.2.B.6) (where applicable)

n/a

General Plant Specific Requirements

Project Name 2016 Building Renovations – John St Table 3

General Plant Specific Requirements (5.4.5.2.C.d)

Summary of Qualitative and Quantitative Analysis (5.4.5.2.C.d.i)

n/a

Business Case Justification Documentation (5.4.5.2.C.d.i)

The second floor of the Head Office 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.

Capital Project Summary

General Information on Project (5.4.5.2.A)

Project Name	2017 Meters
Budget Year	2017
Investment Category	System Access

Capital Investment (5.4.5.2.A.i)	Capital Investment	$ 2,046,000
	Total	$ 2,046,000
	O&M Expenditure	$0
Customer Attachments / Load (kVA) (5.4.5.2.A.ii)	n/a	

Project Dates (5.4.5.2.A.iii)

Start Date	2017/01/01
In Service Date	2017/12/31

Expenditure Timing

Q1	Q2	Q3	Q4
25%	25%	25%	25%

Schedule Risk and Risk Mitigation (5.4.5.2.A.iv**)**

Schedule risk for the installation of meters at new service locations is due to customer delays or restricted access to work sites. Horizon Utilities co-ordinates the connection of new services with customers to mitigate this risk.

Comparative Information from Equivalent Projects (5.4.5.2.A.v)

Metering investments for the 2010 to 2013 Historical Years and the 2014 Bridge Year are:

2010 (CGAAP) - $1,715,716
2011 (CGAAP)- $3,467,413
2012 (MIFRS) - $25,168,043
2013 (MIFRS) - $1,658,707
2014 (MIFRS) - $2,499,104

The increased investment in 2012 was due to the implementation of Smart Meters at a cumulative capital cost of $23,277,588. 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.

Total Capital OM&A Costs Associated with REG Investments (5.4.5.2.A.vi)

This project is not associated with an REG investment and as such no associated OM&A costs related to REG will be incurred.

	Leave to Construct Approval (5.4.5.2.A.vii) This project does not require “Leave to Construct” under Section 92 of the *Ontario Energy Board Act* 1998.

Evaluation Criteria and Information (5.4.5.2.B)	
	Project Name 2017 Meters Table 2
	Efficiency, Customer Value, Reliability (5.4.5.2.B.1) **Investment Driver (5.4.5.2.B.1.a)** System Access (80%) **Secondary Driver (5.4.5.2.B.1.a)** System Renewal (20%) Replacement of commercial meters with Smart Meters. **Investment Priority (5.4.5.2.B.1.b)** 5 – Mandatory Project
	Analysis of Project and Project Alternatives (5.4.5.2.B.1.c) Metering asset management is governed by Measurement Management regulation and customer requirements new and upgraded services.
	Safety (5.4.5.2.B.2) This project is not intended to address safety concerns with the distribution system
	Cyber-Security and Privacy (5.4.5.2.B.3) (where applicable) Horizon Utilities’ Smart Meter and related AMI network have been procured through Elster. Elster’s system supports a multi-layered security approach including: access control, authorization, authentication and data integrity protocols. As part of its continuous improvement model, Horizon Utilities performs periodic security assessments to identify opportunities for enhanced system hardening.
	Co-ordination and Interoperability (5.4.5.2.B.4) **Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.5.2.B.4.a) (where applicable)** Please refer to Note II for an explanation on co-ordination with utilities, regional planning and/or links with 3rd parties. **Enabling of Future Technology and/or Future Operational Requirements (5.4.5.2.B.4.b)** Please refer to Note IV for an explanation enabling of future technology and future operational requirements.
	Economic Development (5.4.5.2.B.5) **(where applicable)** Horizon Utilities ensures that policies and practices do not unnecessarily create barriers to economic development which are primarily focused within its communities.

Environmental Benefits (5.4.5.2.B.6) **(where applicable)**

The Smart Meter infrastructure supports the provinces' conservation culture. Smart metering also provides environmental benefits through reduction in field visits associated with manual meter reading.

System Access Specific Requirements (5.4.5.2.C.a)

Project Name 2017 Meters Table 3

System Access Specific Requirements (5.4.5.2.C.a)

Factors Affecting Implementing Project Timing/Priority (5.4.5.2.C.a.i)
Compliance sampling work is completed to comply with Measurement Canada regulations. The schedule is created to smooth the annual sampling requirements from the original Smart Meter mass deployments.

New and replacement metering is provided on demand to address new load growth and meter failures.

Factors Related to Customer Preference or 3rd Party Input (5.4.5.2.C.a.ii)

Metering for new and upgraded connection projects are customer initiated and are designed to meet customer identified requirements.

Factors Affecting Final Project Cost (5.4.5.2.C.a.iii)
Please refer to Note I for an explanation on the factors affecting the final project cost.

Controllable Cost Minimization (5.4.5.2.C.a.iv)

Please refer to Note I for an explanation regarding controllable cost mitigation.

Other Planning Objectives (5.4.5.2.C.a.v)

Horizon Utilities combines work from multiple work groups to reduce costs and increase efficiency. The line work and meter work is combined when connecting new customers to allow the work to be completed by a single work group.

Assessment of Technical or Implementation Options (5.4.5.2.C.a.vi)

Metering work is Measurement Canada and customer driven and the technology is primarily based on the metering products available from a sole source supplier.

Summary of Options Analysis (5.4.5.2.C.a.vii)

The meter supplier was selected as part of the Smart Meter implementation program.

Final Economic Evaluation Results (5.4.5.2.C.a.viii)

n/a

	Identification of System Impacts (5.4.5.2.C.a.ix) System expansion, if required, to connect customers within this category, is governed by Horizon Utilities' Conditions of Service Section 2.1.2.1.

Capital Project Summary

General Information on Project (5.4.5.2.A)

Project Name	2017 Road Relocations				
Budget Year	2017				
Investment Category	System Access				
Project Description	Projects in this category involve 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, the Ministry of Transportation, and the Region of Niagara				
Capital Investment (5.4.5.2.A.i)	Capital Investment (gross)	$2,615,311			
	Customer Contribution	$ 904,360			
	Capital Investment (net)	$1,710,951			
	O&M Expenditure	$0			
Customer Attachments / Load (kVA) (5.4.5.2.A.ii)	n/a.				
Project Dates (5.4.5.2.A.iii)	Start Date	Various – driven by road authority schedules			
	In Service Date	Various – driven by road authority schedules			
	Expenditure Timing				
	Q1	Q2	Q3	Q4	
	25%	25%	25%	25%	

Schedule Risk and Risk Mitigation (5.4.5.2.A.iv**)**

The initiation and timing of these projects are dictated by the City of Hamilton, City of St. Catharines, the Ministry of Transportation, or the Region of Niagara. Consequently, the timing and value of investment required by Horizon Utilities is subject to change.

Comparative Information from Equivalent Projects (5.4.5.2.A.v)

Road relocations for the 2010 to 2013 Historical Years and the 2014 Bridge Year are:

2010 (CGAAP) - $ 2,889,575
2011 (CGAAP)- $ 895,524
2012 (MIFRS) - $ 3,151,887
2013 (MIFRS) - $ 340,491
2014 (MIFRS) - $ 977,024

Total Capital OM&A Costs Associated with REG Investments (5.4.5.2.A.vi)

This project is not associated with an REG investment and therefore OM&A costs related to REG will not be incurred.

Leave to Construct Approval (5.4.5.2.A.vii)

This project does not require "Leave to Construct" under Section 92 of the *Ontario Energy Board Act* 1998.

Evaluation Criteria and Information (5.4.5.2.B)	**Project Name** 2017 Road Relocations Table 2
	Efficiency, Customer Value, Reliability (5.4.5.2.B.1) **Investment Driver (5.4.5.2.B.1.a)** System Access (90%) **Secondary Driver (5.4.5.2.B.1.a)** System Renewal (5%) System Service (5%) **Investment Priority (5.4.5.2.B.1.b)** 5 – Mandatory Project
	Analysis of Project and Project Alternatives (5.4.5.2.B.1.c) Horizon Utilities co-ordinates project design and discusses design alternatives for each project with the organization (City, Municipality, Ministry of Transportation) originating the request to relocate distribution assets.
	Safety (5.4.5.2.B.2) These projects are not intended to address safety concerns with the distribution system.
	Cyber-Security and Privacy (5.4.5.2.B.3) (where applicable) n/a
	Co-ordination and Interoperability (5.4.5.2.B.4) **Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.5.2.B.4.a) (where applicable)** Timelines for the execution of these projects are dictated by the City of Hamilton, City of 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. **Enabling of Future Technology and/or Future Operational Requirements (5.4.5.2.B.4.b)** Please refer to Note IV for an explanation enabling of future technology and future operational requirements.
	Economic Development (5.4.5.2.B.5) **(where applicable)** Horizon Utilities ensures that policies and practices do not unnecessarily create barriers to economic development which are primarily focused within its communities.
	Environmental Benefits (5.4.5.2.B.6) **(where applicable)** n/a

System Access Specific Requirements (5.4.5.2.C.a)	**Project Name** 2017 Road Relocations Table 3

System Access Specific Requirements (5.4.5.2.C.a)

Factors Affecting Implementing Project Timing/Priority (5.4.5.2.C.a.i)

The road authority's schedule and timing of the road project will affect the Horizon Utilities' project implementation and timing.

Factors Related to Customer Preference or 3rd Party Input (5.4.5.2.C.a.ii)

Road relocation projects involve a co-ordinated design process and the initiating organization (City, Municipality, or Ministry of Transportation) has input into the design of the project.
The designs for all projects within the public right-of-way are reviewed with the City as Municipal Consents are required prior to construction. Consideration is given by the road authority to coordinate all utilities within the right–of-way in the least disruptive manner.

Factors Affecting Final Project Cost (5.4.5.2.C.a.iii)

Please refer to Note I for an explanation on the factors that can affect the final project cost.

Controllable Cost Minimization (5.4.5.2.C.a.iv)

50% of Labour, Labour saving devices and Equipment rentals are recovered from the road authority. Please refer to Note I for an explanation on controllable cost minimization.

Other Planning Objectives (5.4.5.2.C.a.v)

Horizon Utilities combines work to reduce overall costs and increase efficiency. The most common opportunity is during city road relocation projects where a new water main is being installed. Horizon Utilities may be able to take advantage of the fact that installing duct structure is less costly since the road is already excavated. Horizon Utilities may also be able to change the schedule of a renewal project to align with the road authority's work to maximize these benefits. The cost of the additional work is allocated either to system service or system renewal where applicable. Horizon Utilities can maximize the amount of work that can be completed at the lowest cost to benefit ratepayers in these cases.

Assessment of Technical or Implementation Options (5.4.5.2.C.a.vi)

Horizon Utilities co-ordinates project design and discusses design alternatives for each project with the road authority (City, Municipality, Ministry of Transportation) originating the request to relocate distribution assets.

Summary of Options Analysis (5.4.5.2.C.a.vii)

Horizon Utilities reviews proposed design with municipalities and the Ministry of Transportation, as applicable, in an effort to determine the most cost effective solution

Final Economic Evaluation Results (5.4.5.2.C.a.viii)

This is not applicable to road relocations projects.

Identification of System Impacts (5.4.5.2.C.a.ix)

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.

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Capital Project Summary

General Information on Project (5.4.5.2.A)

Project Name	2017 Customer Connections
Budget Year	2017
Investment Category	System Access
Project Summary	Projects in this category include multiple projects required to connect, upgrade, or disconnect customers to the distribution system. Horizon Utilities' obligation to connect new customers is governed by the *Electricity Act, 1998, Schedule 28.*

Capital Investment (5.4.5.2.A.i)

Capital Investment (gross)	$4,912,181
Customer Contribution	$773,104
Capital Investment (net)	$4,139,076
O&M Expenditure	$0

Customer Attachments / Load (kVA) (5.4.5.2.A.ii)

Horizon Utilities completes approximately 1800 connections annually; 1500 through subdivisions and 300 customer projects, contributing approximately 25MVA in system load growth.

Project Dates (5.4.5.2.A.iii)

Start Date	Various – as driven by the customer
In Service Date	Various – as driven by the customer

Expenditure Timing

Q1	Q2	Q3	Q4
25%	25%	25%	25%

Schedule Risk and Risk Mitigation (5.4.5.2.A.iv**)**

Please refer to Note I for risk and risk mitigation.

Comparative Information from Equivalent Projects (5.4.5.2.A.v)

Comparable investments, net of capital contributions, for the 2010 and 2013 Historical Years and the 2014 Bridge Year are:

2010 (CGAAP)- $ 1,023,336
2011 (CGAAP)- $ 2,030,541
2012 (MIFRS) - $ 1,652,000
2013 (MIFRS) - $ 3,541,455
2014 (MIFRS) - $ 4,063,471

Total Capital OM&A Costs Associated with REG Investments (5.4.5.2.A.vi)

This project is not associated with an REG investment and therefore OM&A costs related to REG will not be incurred.

Leave to Construct Approval (5.4.5.2.A.vii)

This project does not require "Leave to Construct" under Section 92 of the *Ontario Energy Board Act* 1998.

Evaluation Criteria and Information (5.4.5.2.B)	**Project Name** 2017 Customer Connections — Table 2
	Efficiency, Customer Value, Reliability (5.4.5.2.B.1) **Investment Driver (5.4.5.2.B.1.a)** System Access (100%) **Secondary Driver (5.4.5.2.B.1.a)** N/A **Investment Priority (5.4.5.2.B.1.b)** 5 – Mandatory Project
	Analysis of Project and Project Alternatives (5.4.5.2.B.1.c) Customer connection projects are driven by customer requests and the customer's specific technical requirements. To build efficiencies into the process, Horizon Utilities utilizes a set of design standards that have been engineered and approved. Customer connections requests are fulfilled consistent with Horizon Utilities' Conditions of Service, designed to meet the customer requirements and maintain system reliability.
	Safety (5.4.5.2.B.2) These projects are not intended to address safety concerns with the distribution system.
	Cyber-Security and Privacy (5.4.5.2.B.3) (where applicable) Cyber-Security and Privacy are not applicable to this project.
	Co-ordination and Interoperability (5.4.5.2.B.4) **Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.5.2.B.4.a) (where applicable)** Please refer to Note II for an explanation on co-ordination with utilities, regional planning and/or links with 3rd parties. **Enabling of Future Technology and/or Future Operational Requirements (5.4.5.2.B.4.b)** This is not applicable for these projects.
	Economic Development (5.4.5.2.B.5) **(where applicable)** Horizon Utilities ensures that policies and practices do not unnecessarily create barriers to economic development which are primarily focused within its communities.
	Environmental Benefits (5.4.5.2.B.6) **(where applicable)** n/a

System Access Specific Requirements (5.4.5.2.C.a)

Project Name	2017 Customer Connections	Table 3

System Access Specific Requirements (5.4.5.2.C.a)

Factors Affecting Implementing Project Timing/Priority (5.4.5.2.C.a.i)

Schedule of work based on customer expectations, customer request may not be standard design

Factors Related to Customer Preference or 3rd Party Input (5.4.5.2.C.a.ii)

There projects are customer initiated and are designed to meet customer identified requirements.

Factors Affecting Final Project Cost (5.4.5.2.C.a.iii)

Please refer to Note I for an explanation on the factors affecting final project cost.

Controllable Cost Minimization (5.4.5.2.C.a.iv)

Please refer to Note I for an explanation on the factors affecting controllable cost.

Other Planning Objectives (5.4.5.2.C.a.v)

n/a

Assessment of Technical or Implementation Options (5.4.5.2.C.a.vi)

Please refer to Note III for information on the technical and implementation options.

Summary of Options Analysis (5.4.5.2.C.a.vii)

Please refer to Note III for information on the technical and implementation options.

Final Economic Evaluation Results (5.4.5.2.C.a.viii)

Horizon Utilities completes the economic evaluation for any customer system access project which requires the construction of new facilities to the main distribution system or an increase in the existing capacity of distribution facilities. For further details please see Appendix E of Horizon Utilities' Conditions of Service. The economic evaluation is completed in accordance with section 3.2 of the Distribution System Code ("DSC"). For the 2015-2019 Test Year period, Horizon Utilities has no known projects for which to provide the final economic evaluation. When a road authority requests a relocation of Horizon Utilities' plant located on the public road allowance, the costs shall be shared, as outlined in the *Ontario Public Service Works on Highways Act*. Other projects within this category will have an economic evaluation completed where applicable in accordance with both the DSC and Appendix E of Horizon Utilities' Conditions of Service.

Identification of System Impacts (5.4.5.2.C.a.ix)

System expansion, if required, to connect customers within this category are governed by Horizon Utilities Conditions of Service Section 2.1.2.1.

horizon UTILITIES Looking beyond...

Capital Project Summary

General Information on Project (5.4.5.2.A)

Project Name	AB-F5 Renewal – Dundurn St				
Budget Year	2017				
Investment Category	System Renewal				
Project Summary	The project involves the renewal of the Aberdeen Substation F5 feeder in the Hamilton Downtown operating area. This project is part of the 4kV and 8kV Renewal Program.				
Capital Investment (5.4.5.2.A.i)	Capital Investment (gross)	$2,418,419			
	Customer Contribution	$0			
	Capital Investment (net)	$2,418,419			
	O&M Expenditure	$0			
Customer Attachments / Load (kVA) (5.4.5.2.A.ii)	This project impacts 2,673 customers and 2,000kVA of transformation.				
Project Dates (5.4.5.2.A.iii)	Start Date	2017/04/02			
	In Service Date	2017/11/30			
	Expenditure Timing				
	Q1	Q2	Q3	Q4	
		37.5%	37.5%	25%	

Schedule Risk and Risk Mitigation (5.4.5.2.A.iv)

Please refer to Note I for risk and risk mitigation.

Comparative Information from Equivalent Projects (5.4.5.2.A.v)

There is no direct comparator in scope, size and design characteristics for this project. This project is one phase of a multi-year investment to renew the area served by Aberdeen substation as part of the 4kV and 8kV Renewal Program. The 2017 investment for the renewal of Aberdeen substation is $2,418,000. The 2017 investment in the 4kV and 8kV Renewal Program is $15,764,000.

Comparable gross investments for the 4kV and 8kV Renewal Program for the 2010 and 2013 Historical Years and the 2014 Bridge Year are:

2010 (CGAAP)- $ 2,556,076
2011 (CGAAP)- $ 8,820,000
2012 (MIFRS) - $ 5,268,441
2013 (MIFRS) - $ 5,072,233
2014 (MIFRS) - $ 6,434,000

Total Capital OM&A Costs Associated with REG Investments (5.4.5.2.A.vi)

This project is not associated with an REG investment and therefore OM&A costs related to REG will not be incurred.

Leave to Construct Approval (5.4.5.2.A.vii)

This project does not require “Leave to Construct” under Section 92 of the *Ontario Energy Board Act* 1998.

Evaluation Criteria and Information (5.4.5.2.B)

Project Name	AB-F5 Renewal – Dundurn St	Table 2

Efficiency, Customer Value, Reliability (5.4.5.2.B.1)

Investment Driver (5.4.5.2.B.1.a)
System Renewal (80%)

Secondary Driver (5.4.5.2.B.1.a)
System Service (20%)

Investment Priority (5.4.5.2.B.1.b)
3 – Required project

Analysis of Project and Project Alternatives (5.4.5.2.B.1.c)

This project is part of the multi-year 4kV and 8kV Renewal Program. It is necessary to renew both the 4kV and 8kV distribution system and the Horizon Utilities-owned substations. Horizon Utilities has chosen to renew the 4kV and 8kV distribution systems to a higher voltage to avoid the cost of the investment in the renewal of the substations. The total avoided substation renewal investment over the remaining 35 years of the plan is $70,000,000 for all 28 substations. Therefore, the renewal of the distribution assets at the current 4kV level was not a feasible alternative.

The renewal of the area serviced by Aberdeen substation starts in 2017 and is scheduled to be completed in 2021.

Safety (5.4.5.2.B.2)

This project is not intended to address safety concerns with the distribution system.

Cyber-Security and Privacy (5.4.5.2.B.3) (where applicable)

Cyber-Security and Privacy are not applicable to this project.

Co-ordination and Interoperability (5.4.5.2.B.4)

Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.5.2.B.4.a) (where applicable)

Please refer to Note II for an explanation on co-ordination with utilities, regional planning and/or links with 3rd parties.

Enabling of Future Technology and/or Future Operational Requirements (5.4.5.2.B.4.b)

Please refer to Note IV for an explanation enabling of future technology and future operational requirements.

Economic Development (5.4.5.2.B.5) **(where applicable)**

Horizon Utilities ensure that policies and practices do not unnecessarily create barriers to economic development which are primarily focused within its communities.

Environmental Benefits (5.4.5.2.B.6) **(where applicable)**

n/a

System Renewal Specific Requirements (5.4.5.2.C.b)

Project Name	AB-F5 Renewal – Dundurn St	Table 3

System Renewal Specific Requirements (5.4.5.2.C.b)

Asset Performance Target and Asset Lifecycle Optimization (5.4.5.2.C.b.i.1)

The two substations servicing the downtown Hamilton operating area service a total of 7,400 customers and were constructed in 1950 and 1960. The overall Station Health Index for Aberdeen and Central substations is 53% and 56% respectively. 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.

Asset Condition Relative to Typical Life Cycle (5.4.5.2.C.b.i.2)

Generally the 4kV assets are the oldest vintage in the system. 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.

Number of Customers Impacted (5.4.5.2.C.b.i.3)

This project impacts approximately 2,673 customers.

Quantitative Customer Impact and Risk (5.4.5.2.C.b.i.4)

SAIDI of 0.137

Qualitative Customer Impact and Risk (5.4.5.2.C.b.i.5)

This project will address aging assets with inadequate backup. Aging assets represent an increased risk of service interruption to customers and inadequate backup would result in long duration service interruptions upon occurrence. These factors would lead to customer dissatisfaction in this area.

Value of Customer Impact (5.4.5.2.C.b.i.6)

High

Other Factors Affecting Project Timing (5.4.5.2.C.b.ii)

The renewal of the area serviced by Aberdeen substation is scheduled for 2017 to 2021. This project is required to be completed in 2017 to allow for the renewal of the remaining area to be completed on schedule.

Impact on System O&M Costs (5.4.5.2.C.b.iii)

This project will have no material impact on planned O&M costs. The renewal of the 4kV and 8kV distribution systems, as a whole, will provide a reduction in reactive O&M costs to address service interruptions caused by failed equipment. These reductions will not be material in the 2015 to 2019 Test Years.

Reliability and Safety Factors (5.4.5.2.C.b.iv)

The renewal of the 4kV and 8kV distribution system will provide reliability improvements through reduced service interruptions caused by failed equipment.

Analysis of Project Benefits and Timing (5.4.5.2.C.b.v)

The timing of this project, as part of the 4kV and 8kV Renewal Program, is determined through the assessment of the distribution system health and the health of the substation assets servicing the area. Renewal of this area will allow for the decommissioning of the substation assets by 2021 thereby avoiding the need for capital investment into these substations.

Like-for-Like Renewal Analysis (5.4.5.2.C.b.vi)

The like-for-like renewal of these assets (i.e. same system configuration and same distribution voltage) will perpetuate the existing operating constraints and require capital investment to renew substation assets. Renewal of the distribution assets at a higher voltage does not involve any material incremental costs over renewal at the existing voltage. Operating constraints (e.g. undersized conductor, radial feeds) are addressed on a case by case basis where appropriate.

horizon UTILITIES Looking beyond...

Capital Project Summary

General Information on Project (5.4.5.2.A)

Project Name	CE-F5 Renewal – Forest Ave			
Budget Year	2017			
Investment Category	System Renewal			
Project Summary	The project involves the renewal of the Central Substation F5 feeder in the Hamilton Downtown operating area. This project is part of the 4kV and 8kV Renewal Program.			
Capital Investment (5.4.5.2.A.i)	Capital Investment (gross)	$1,876,203		
	Customer Contribution	$0		
	Capital Investment (net)	$1,876,203		
	O&M Expenditure	$0		
Customer Attachments / Load (kVA) (5.4.5.2.A.ii)	This project impacts approximately 300 customers and 1,200kVA of transformation			
Project Dates (5.4.5.2.A.iii)	Start Date 2017/04/02			
	In Service Date 2017/11/30			
	Expenditure Timing			
	Q1	Q2	Q3	Q4
	0%	37.5%	37.5%	25%

Schedule Risk and Risk Mitigation (5.4.5.2.A.iv**)**

Please refer to Note I for risk and risk mitigation.

Comparative Information from Equivalent Projects (5.4.5.2.A.v)

There is no direct comparator in scope, size and design characteristics for this project. This project is one phase of a multi-year investment to renew the area served by Central substation as part of the 4kV and 8kV Renewal Program. The 2017 investment for the renewal of Central substation is $1,876,000. The 2017 investment in the 4kV and 8kV Renewal Program is $15,764,000.

Comparable gross investments for the 4kV and 8kV Renewal Program for the 2010 and 2013 Historical Year and the 2014 Bridge Year are:

2010 (CGAAP)- $ 2,556,076
2011 (CGAAP)- $ 8,820,000
2012 (MIFRS) - $ 5,268,441
2013 (MIFRS) - $ 5,072,233
2014 (MIFRS) - $ 6,434,000

Total Capital OM&A Costs Associated with REG Investments (5.4.5.2.A.vi)

This project is not associated with an REG investment and therefore OM&A costs related to REG will not be incurred.

Leave to Construct Approval (5.4.5.2.A.vii)

This project does not require “Leave to Construct” under Section 92 of the *Ontario Energy Board Act* 1998.

Evaluation Criteria and Information (5.4.5.2.B)

Project Name	CE-F5 Renewal – Forest Ave	Table 2

Efficiency, Customer Value, Reliability (5.4.5.2.B.1)

Investment Driver (5.4.5.2.B.1.a)
System Renewal (80%)

Secondary Driver (5.4.5.2.B.1.a)
System Service (20%)

Investment Priority (5.4.5.2.B.1.b)
3 – Required project

Analysis of Project and Project Alternatives (5.4.5.2.B.1.c)

This project is part of the multi-year 4kV and 8kV Renewal Program. It is necessary to renew both the 4kV and 8kV distribution system and the Horizon Utilities-owned substations. Horizon Utilities has chosen to renew the 4kV and 8kV distribution systems to a higher voltage to avoid the cost of the investment in the renewal of the substations. The total avoided substation renewal investment over the remaining 35 years of the plan is $70,000,000 for all 28 substations. Therefore the renewal of the distribution assets at the current 4kV level was not a feasible alternative

The renewal of the area serviced by Central substation started in 2016 and is scheduled to be completed in 2022.

Safety (5.4.5.2.B.2)

This project is not intended to address safety concerns with the distribution system.

Cyber-Security and Privacy (5.4.5.2.B.3) (where applicable)

Cyber-Security and Privacy are not applicable to this project.

Co-ordination and Interoperability (5.4.5.2.B.4)

Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.5.2.B.4.a) (where applicable)
Please refer to Note II for an explanation on co-ordination with utilities, regional planning and/or links with 3rd parties.

Enabling of Future Technology and/or Future Operational Requirements (5.4.5.2.B.4.b)

Please refer to Note IV for an explanation enabling of future technology and future operational requirements.

Economic Development (5.4.5.2.B.5)

Horizon Utilities ensures that policies and practices do not unnecessarily create barriers to economic development which are primarily focused within its communities.

Environmental Benefits (5.4.5.2.B.6)

n/a

System Renewal Specific Requirements (5.4.5.2.C.b)

Project Name	CE-F5 Renewal – Forest Ave	Table 3

System Renewal Specific Requirements (5.4.5.2.C.b)

Asset Performance Target and Asset Lifecycle Optimization (5.4.5.2.C.b.i.1)

The two substations servicing the downtown Hamilton operating area service a total of 7,400 customers and were constructed in 1950 and 1960. The overall Station Health Index for Aberdeen and Central substations is 53% and 56% respectively. Central substation has ten feeders; six of which are obsolete, oil-filled breakers that are at end-of-life. The Health Index for these breakers is "very poor" and Kinectrics forecasted that these circuit breakers have 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.

Asset Condition Relative to Typical Life Cycle (5.4.5.2.C.b.i.2)

Generally the 4kV assets are the oldest vintage in the system. 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.

Number of Customers Impacted (5.4.5.2.C.b.i.3)

This project impacts approximately 300 customers.

Quantitative Customer Impact and Risk (5.4.5.2.C.b.i.4)

SAIDI of 0.242

Qualitative Customer Impact and Risk (5.4.5.2.C.b.i.5)

This project will address aging assets with inadequate backup. Aging assets represent an increased risk of service interruption to customers and inadequate backup would result in long duration service interruptions upon occurrence. These factors would lead to customer dissatisfaction in this area.

Value of Customer Impact (5.4.5.2.C.b.i.6)

High

Other Factors Affecting Project Timing (5.4.5.2.C.b.ii)

The renewal of the area serviced by Central substation is scheduled for 2016 to 2022. This project is required to be completed in 2017 to allow for the renewal of the remaining area to be completed on schedule.

Impact on System O&M Costs (5.4.5.2.C.b.iii)

This project will have no material impact on planned O&M costs. The renewal of the 4kV and 8kV distribution systems, as a whole, will provide a reduction in reactive O&M costs to address service interruptions caused by failed equipment. These reductions will not be material in the 2015 to 2019 Test Years.

Reliability and Safety Factors (5.4.5.2.C.b.iv)

The renewal of the 4kV and 8kV distribution system will provide reliability improvements through reduced service interruptions caused by failed equipment.

Analysis of Project Benefits and Timing (5.4.5.2.C.b.v)

The timing of this project, as part of the 4kV and 8kV Renewal Program, is determined through the assessment of the distribution system health and the health of the substation assets servicing the area. Renewal of this area will allow for the decommissioning of the substation assets by 2022 thereby avoiding the need for capital investment into these substations.

Like-for-Like Renewal Analysis (5.4.5.2.C.b.vi)

The like-for-like renewal of these assets (i.e. same system configuration and same distribution voltage) will perpetuate the existing operating constraints and require capital investment to renew substation assets. Renewal of the distribution assets at a higher voltage does not involve any material incremental costs over renewal at the existing voltage. Operating constraints (e.g. undersized conductor, radial feeds) are addressed on a case by case basis where appropriate.

Capital Project Summary

General Information on Project (5.4.5.2.A)

Project Name	2017 Reactive Renewal
Budget Year	2017
Investment Category	System Renewal
Project Summary	This category includes all projects required for the reactive renewal or repairs driven by emergency equipment failures and associated corrective action. Projects arise from trouble calls or inspection programs identifying an urgent need to replace system assets and the scope of the equipment replacement requires engineering. Also included in this category are projects to address customer power quality issues, and Electrical Safety Authority ("ESA") due diligence inspection outcomes.

Capital Investment (5.4.5.2.A.i)	Capital Investment (gross)	$1,508,241
	Customer Contribution	n/a
	Capital Investment (net)	n/a
	O&M Expenditure	n/a
Customer Attachments / Load (kVA) (5.4.5.2.A.ii)	n/a	

Project Dates (5.4.5.2.A.iii)

Start Date	January 1, 2017
In Service Date	December 31, 2017

Expenditure Timing

Q1	Q2	Q3	Q4
25%	25%	25%	25%

Schedule Risk and Risk Mitigation (5.4.5.2.A.iv**)**

Please refer to Note I for risk and risk mitigation.

Comparative Information from Equivalent Projects (5.4.5.2.A.v)

Comparable investments for the 2010 and 2013 Historical Years and the 2014 Bridge Year are:

2010 (CGAAP)- $ 8,745,125
2011 (CGAAP)- $ 8,230,970
2012 (MIFRS) - $ 4,032,000
2013 (MIFRS) - $ 6.069,566
2014 (MIFRS) - $ 4,840,000

Total Capital OM&A Costs Associated with REG Investments (5.4.5.2.A.vi)

This project is not associated with an REG investment and therefore OM&A costs related to REG will not be incurred.

	Leave to Construct Approval (5.4.5.2.A.vii) This project does not require "Leave to Construct" under Section 92 of the *Ontario Energy Board Act* 1998.

Evaluation Criteria and Information (5.4.5.2.B)	**Project Name** 2017 Reactive Renewal Table 2
	Efficiency, Customer Value, Reliability (5.4.5.2.B.1) **Investment Driver (5.4.5.2.B.1.a)** System Renewal (80%) **Secondary Driver (5.4.5.2.B.1.a)** System Service (20%) **Investment Priority (5.4.5.2.B.1.b)** 3 – Required project
	Analysis of Project and Project Alternatives (5.4.5.2.B.1.c) No alternatives are considered for these projects as they involve the emergency replacement of failed equipment required to restore service.
	Safety (5.4.5.2.B.2) These projects are intended to primarily address failed assets however investments required to address immediate safety issues, including issues presenting a potential risk to public safety identified by the ESA, are included in this project.
	Cyber-Security and Privacy (5.4.5.2.B.3) (where applicable) n/a
	Co-ordination and Interoperability (5.4.5.2.B.4) **Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.5.2.B.4.a) (where applicable)** Please refer to Note II for an explanation on co-ordination with utilities, regional planning and/or links with 3rd parties. **Enabling of Future Technology and/or Future Operational Requirements (5.4.5.2.B.4.b)** Please refer to Note IV for an explanation enabling of future technology and future operational requirements.
	Economic Development (5.4.5.2.B.5) **(where applicable)** Horizon Utilities ensures that policies and practices do not unnecessarily create barriers to economic development which are primarily focused within its communities.

Environmental Benefits (5.4.5.2.B.6) **(where applicable)**

n/a

System Renewal Specific Requirements (5.4.5.2.C.b)

Project Name	2017 Reactive Renewal	Table 3

System Renewal Specific Requirements (5.4.5.2.C.b)

Asset Performance Target and Asset Lifecycle Optimization (5.4.5.2.C.b.i.1)

These projects are reactive in nature and are initiated from equipment that has failed or that has a high risk of failure resulting in a service interruption. These projects have a very high probability of impacting Horizon Utilities' reliability targets.

Asset Condition Relative to Typical Life Cycle (5.4.5.2.C.b.i.2)

These projects address failed assets or assets with a high risk of imminent failure and as such, these assets are at the end of their useful life. The asset condition relative to their typical life cycle varies in each incident or outage.

Number of Customers Impacted (5.4.5.2.C.b.i.3)

The number of customers impacted varies in each incident or outage.

Quantitative Customer Impact and Risk (5.4.5.2.C.b.i.4)

The quantitative customer impact varies in each incident or outage.

Qualitative Customer Impact and Risk (5.4.5.2.C.b.i.5)

These projects address customer satisfaction as they are required to address failed assets that have either caused a system interruption, or have a high probability of causing a service interruption.

Value of Customer Impact (5.4.5.2.C.b.i.6)

The value of the customer impact varies in each incident or outage.

Other Factors Affecting Project Timing (5.4.5.2.C.b.ii)

These projects are reactive in nature and address failed assets, or assets at risk of imminent failure. Investments must be performed when identified.

Impact on System O&M Costs (5.4.5.2.C.b.iii)

These projects do not materially impact system O&M costs.

Reliability and Safety Factors (5.4.5.2.C.b.iv)

Improvements to reliability and security are expected as secondary benefits to this project.

Analysis of Project Benefits and Timing (5.4.5.2.C.b.v)

Investment for this project address failed assets, or assets at risk of imminent failure. Investments are not subject to project prioritization as they are reactive and non-discretionary.

	Like-for-Like Renewal Analysis (5.4.5.2.C.b.vi) Assets replaced reactively to replace failed assets, or assets at risk of imminent failure are performed on a like-for-like basis. No extra costs to address other distributor planning objectives are incurred with these projects.

Capital Project Summary

General Information on Project (5.4.5.2.A)

Project Name	2017 Hamilton Mountain XLPE Renewal
Budget Year	2017
Investment Category	System Renewal
Project Summary	This project involves the renewal of XLPE primary cable and underground distribution assets in the Hamilton Mountain operating area. The area between Upper Sherman and Upper Gage south of the Lincoln Alexander Parkway will be renewed in 2017 and in the Upper Ottawa and Rymal area as well as the replacement of underground infrastructure at various locations surrounding this area.

Capital Investment (5.4.5.2.A.i)	Capital Investment (gross)	$6,606,889
	Customer Contribution	$0
	Capital Investment (net)	$6,606,889
	O&M Expenditure	$0

Customer Attachments / Load (kVA) (5.4.5.2.A.ii)	The customer and load impacted by this project will vary depending upon the final scope of the project.

Project Dates (5.4.5.2.A.iii)

Start Date	2016/03/01
In Service Date	2016/11/30

Expenditure Timing

Q1	Q2	Q3	Q4
10%	40%	10%	40%

Schedule Risk and Risk Mitigation (5.4.5.2.A.iv**)**

Please refer to Note I for risk and risk mitigation.

Comparative Information from Equivalent Projects (5.4.5.2.A.v)

There is no direct comparator in scope, size and design characteristics for this project. This project is part of a multi-year investment to renewal XLPE primary cable. The 2017 investment in the XLPE Renewal Program is $8,866,000.

Comparable gross investments for the XLPE Renewal Program for the 2010 to 2013 Historical Years and the 2014 Bridge Year are:

2010 (CGAAP)- $ 0
2011 (CGAAP)- $ 0
2012 (MIFRS) - $ 0
2013 (MIFRS) - $ 1,572,090
2014 (MIFRS) - $ 893,000

Total Capital OM&A Costs Associated with REG Investments (5.4.5.2.A.vi)

This project is not associated with an REG investment and therefore OM&A costs related to REG will not be incurred.

Leave to Construct Approval (5.4.5.2.A.vii)

This project does not require "Leave to Construct" under Section 92 of the *Ontario Energy Board Act* 1998.

Evaluation Criteria and Information (5.4.5.2.B)

Project Name	2017 Hamilton Mountain XLPE Renewal	Table 2

Efficiency, Customer Value, Reliability (5.4.5.2.B.1)

Investment Driver (5.4.5.2.B.1.a)
System Renewal (80%)

Secondary Driver (5.4.5.2.B.1.a)
System Service (20%)

Investment Priority (5.4.5.2.B.1.b)
5 – Mandatory Project

Analysis of Project and Project Alternatives (5.4.5.2.B.1.c)

This project is part of the multi-year XLPE Renewal Program. Horizon Utilities considered the four replacement philosophies for addressing risk inherent in the XLPE asset group: Area; Reactive; Selected; and Refurbishment. The area replacement philosophy will be utilized for selected areas of the service territory where the asset health analysis and the failure history indicate a substantial risk of continued failures. A reactive replacement philosophy will continued to be used for the remaining areas of the service territory.

The area replacement philosophy will be employed for the Hamilton Mountain operating area due to the high volume of XLPE primary cable. 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.

Safety (5.4.5.2.B.2)

These projects are not intended to address safety concerns with the distribution system.

Cyber-Security and Privacy (5.4.5.2.B.3) (where applicable)

Cyber-Security and Privacy are not applicable to this project.

Co-ordination and Interoperability (5.4.5.2.B.4)

Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.5.2.B.4.a) (where applicable)
Please refer to Note II for an explanation on co-ordination with utilities, regional planning and/or links with 3rd parties.

Enabling of Future Technology and/or Future Operational Requirements (5.4.5.2.B.4.b)

Please refer to Note IV for an explanation enabling of future technology and future operational requirements.

Economic Development (5.4.5.2.B.5) **(where applicable)**

Horizon Utilities ensures that policies and practices do not unnecessarily create barriers to economic development which are primarily focused within its communities.

Environmental Benefits (5.4.5.2.B.6) **(where applicable)**

n/a

System Renewal Specific Requirements (5.4.5.2.C.b)

Project Name	2017 Hamilton Mountain XLPE Renewal	Table 3

System Renewal Specific Requirements (5.4.5.2.C.b)

Asset Performance Target and Asset Lifecycle Optimization (5.4.5.2.C.b.i.1)

XLPE primary cable is the asset group with the largest investment requirement as identified by the Kinectrics ACA. 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.

The Hamilton Mountain operating area has 225km of XLPE primary cable with a Health Index of either "very poor" or "poor". 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 they are not addressed in a systematic manner.

Asset Condition Relative to Typical Life Cycle (5.4.5.2.C.b.i.2)

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.

Number of Customers Impacted (5.4.5.2.C.b.i.3)

Approximately 1000 customers will be impacted by this project.

Quantitative Customer Impact and Risk (5.4.5.2.C.b.i.4)

The quantitative customer impact varies for customers affected by this project.

Qualitative Customer Impact and Risk (5.4.5.2.C.b.i.5)

This project will address aging assets at risk of failure. Failure of XLPE primary cable results in extended service interruptions; 30% of these outages have exceeded four hours in duration, while 5% of these outages have exceeded twelve hours in duration.

Value of Customer Impact (5.4.5.2.C.b.i.6)

High

Other Factors Affecting Project Timing (5.4.5.2.C.b.ii)

Proactive replacements are required because, as assets continue to age and degrade, the cable will fail at an exponential rate. In the worst case scenario, it will exceed Horizon Utilities' ability to keep pace with repairs. Reliability will also deteriorate to unacceptable levels. Reactive replacements will be considerably more costly than proactive renewal.

Impact on System O&M Costs (5.4.5.2.C.b.iii)

This project will have no material impact on planned O&M costs. The renewal of the XLPE primary cable, as a whole, will provide a reduction in reactive O&M costs to address service interruptions caused by failed equipment. These reductions will not be material in the 2015 to 2019 Test Years.

Reliability and Safety Factors (5.4.5.2.C.b.iv)

The renewal of the XLPE primary cable system will provide reliability improvements through reduced service interruptions caused by failed equipment.

Analysis of Project Benefits and Timing (5.4.5.2.C.b.v)

Failure to invest in the proactive renewal of XLPE primary cable and associated underground assets would result in unacceptable levels of system failures and outages beyond Horizon Utilities' ability to resolve within a reasonable timeframe as these assets continue to age and degrade. Reactive replacements will also be considerably more costly than the forecast expenditure required to execute the proposed proactive replacement.

Like-for-Like Renewal Analysis (5.4.5.2.C.b.vi)

XLPE renewal projects will include the elimination of radial underground feeds; replacement of below grade transformers with padmount transformers; and the introduction of fusing on the underground distribution systems where applicable.

Capital Project Summary

General Information on Project (5.4.5.2.A)

Project Name	HI-F2 Renewal conversion to 2D7X
Budget Year	2017
Investment Category	System Renewal
Project Summary	This project involves the renewal of the Highland F2 feeder in the Dundas area and connecting the new assets to the existing 2D7X, 27.6kV feeder.

Capital Investment (5.4.5.2.A.i)		
	Capital Investment (gross)	$657,602
	Customer Contribution	$0
	Capital Investment (net)	$657,602
	O&M Expenditure	$0

Customer Attachments / Load (kVA) (5.4.5.2.A.ii)

This project impacts 100 customers and 300 kVA of transformation.

Project Dates (5.4.5.2.A.iii)

Start Date 2017/03/01

In Service Date 2017/10/31

Expenditure Timing

Q1	Q2	Q3	Q4
12.5%	37.5%	37.5%	12.5%

Schedule Risk and Risk Mitigation (5.4.5.2.A.iv**)**

Please refer to Note I for risk and risk mitigation.

Comparative Information from Equivalent Projects (5.4.5.2.A.v)

There is no direct comparator in scope, size and design characteristics for this project. This project is one phase of a multi-year investment to renew the area served by Highland substation as part of the 4kV and 8kV Renewal Program. The 2017 investment for the renewal of Highland substation is $658,000. The 2017 investment in the 4kV and 8kV Renewal Program is $15,764,000.

Comparable gross investments for the 4kv and 8kV Renewal Program for the 2010 to 2013 Historical Years and the 2014 Bridge Year are:

2010 (CGAAP)- $ 2,556,076
2011 (CGAAP)- $ 8,820,000
2012 (MIFRS) - $ 5,268,441
2013 (MIFRS) - $ 5,072,233
2014 (MIFRS) - $ 6,434,000

Total Capital OM&A Costs Associated with REG Investments (5.4.5.2.A.vi)

This project is not associated with an REG investment and therefore OM&A costs related to REG will not be incurred.

Leave to Construct Approval (5.4.5.2.A.vii)

This project does not require "Leave to Construct" under Section 92 of the *Ontario Energy Board Act* 1998.

Evaluation Criteria and Information (5.4.5.2.B)

Project Name HI-F2 Renewal conversion to 2D7X Table 2

Efficiency, Customer Value, Reliability (5.4.5.2.B.1)

Investment Driver (5.4.5.2.B.1.a)
System Renewal (80%)

Secondary Driver (5.4.5.2.B.1.a)
System Service (20%)

Investment Priority (5.4.5.2.B.1.b)
3 – Required project

Analysis of Project and Project Alternatives (5.4.5.2.B.1.c)

This project is part of the multi-year 4kV and 8kV Renewal Program. Both the 4kV and 8kV distribution system and the Horizon Utilities-owned substations are at the end of their useful life. Horizon Utilities has chosen to renew the 4kV and 8kV distribution systems to a higher voltage to avoid the cost of the investment in the renewal of the substations. The total avoided substation renewal investment over the remaining 35 years of the plan is $70,000,000 for all 28 substations. Therefore the renewal of the distribution assets at the current 4kV level was not a feasible alternative.

This project is one of multiple projects required to renew the service territory serviced by Highland substation.

Safety (5.4.5.2.B.2)

This project is not intended to address safety concerns with the distribution system.

Cyber-Security and Privacy (5.4.5.2.B.3) (where applicable)

Cyber-Security and Privacy are not applicable to this project.

Co-ordination and Interoperability (5.4.5.2.B.4)

Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.5.2.B.4.a) (where applicable)

Please refer to Note II for an explanation on co-ordination with utilities, regional planning and/or links with 3rd parties.

Enabling of Future Technology and/or Future Operational Requirements (5.4.5.2.B.4.b)

Please refer to Note IV for an explanation enabling of future technology and future operational requirements.

Economic Development (5.4.5.2.B.5) **(where applicable)**

Horizon Utilities ensures that policies and practices do not unnecessarily create barriers to economic development which are primarily focused within its communities

Environmental Benefits (5.4.5.2.B.6) **(where applicable)**

n/a

System Renewal Specific Requirements (5.4.5.2.C.b)

Project Name	HI-F2 Renewal conversion to 2D7X	Table 3

System Renewal Specific Requirements (5.4.5.2.C.b)

Asset Performance Target and Asset Lifecycle Optimization (5.4.5.2.C.b.i.1)

The distribution assets in the Dundas operating area are in poor health and have significant operating constraints. 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'.

Asset Condition Relative to Typical Life Cycle (5.4.5.2.C.b.i.2)

Generally the 4kV assets are the oldest vintage in the system. 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.

Number of Customers Impacted (5.4.5.2.C.b.i.3)

This project impacts 100 customers.

Quantitative Customer Impact and Risk (5.4.5.2.C.b.i.4)

SAIDI of 0.003

Qualitative Customer Impact and Risk (5.4.5.2.C.b.i.5)

This project will address aging assets with inadequate backup. Aging assets represent an increased risk of service interruption to customers and inadequate backup would result in long duration service interruptions upon occurrence. These factors would lead to customer dissatisfaction in this area.

Value of Customer Impact (5.4.5.2.C.b.i.6)

High

Other Factors Affecting Project Timing (5.4.5.2.C.b.ii)

The renewal of the area serviced by Highland substation is scheduled for renewal in 2015, 2016 and 2017.

Reliability and Safety Factors (5.4.5.2.C.b.iv)

The renewal of the 4kV and 8kV distribution system will provide reliability improvements through reduced service interruptions caused by failed equipment.

Analysis of Project Benefits and Timing (5.4.5.2.C.b.v)

The timing of this project, as part of the 4kV and 8kV Renewal Program, is determined through the assessment of the distribution system health and the health of the substation assets servicing the area. Renewal of this area will allow for the decommissioning of the substation assets by 2017 thereby avoiding the need for capital investment into these substations.

Like-for-Like Renewal Analysis (5.4.5.2.C.b.vi)

The like-for-like renewal of these assets (i.e. same system configuration and same distribution voltage) will perpetuate the existing operating constraints and require capital investment to renew substation assets. Renewal of the distribution assets at a higher voltage does not involve any material incremental costs over renewal at the existing voltage. Operating constraints (e.g. undersized conductor, radial feeds) are addressed on a case by case basis where appropriate.

Reliability and Safety Factors (5.4.5.2.C.b.iv)

The renewal of the 4kV and 8kV distribution system will provide reliability improvements through reduced service interruptions caused by failed equipment.

Capital Project Summary

General Information on Project (5.4.5.2.A)

Project Name	2017 Pole Residual Replacements
Budget Year	2017
Investment Category	System Renewal
Project Summary	This project involves the replacement of wood poles that are identified by pole residual testing as having a high risk of failure.

Capital Investment (5.4.5.2.A.i)		
	Capital Investment (gross)	$1,297,407
	Customer Contribution	$0
	Capital Investment (net)	$1,297,407
	O&M Expenditure	$0

Customer Attachments / Load (kVA) (5.4.5.2.A.ii)	n/a

Project Dates (5.4.5.2.A.iii)

Start Date	2017/01/01
In Service Date	2017/06/30

Expenditure Timing

Q1	Q2	Q3	Q4
50%	50%	0%	0%

Schedule Risk and Risk Mitigation (5.4.5.2.A.iv**)**

Please refer to Note I for risk and risk mitigation.

Comparative Information from Equivalent Projects (5.4.5.2.A.v)

Comparable gross investments for the 2010 to 2013 Historical Years and the 2014 Bridge Year are:

2010 (CGAAP)- $ 1,326,407
2011 (CGAAP)- $ 895,000
2012 (MIFRS) - $ 930,000
2013 (MIFRS) - $ 718,074
2014 (MIFRS) - $ 1,190,000

Total Capital OM&A Costs Associated with REG Investments (5.4.5.2.A.vi)

This project is not associated with an REG investment and therefore OM&A costs related to REG will not be incurred.

Leave to Construct Approval (5.4.5.2.A.vii)

This project does not require "Leave to Construct" under Section 92 of the *Ontario Energy Board Act* 1998.

Evaluation Criteria and Information (5.4.5.2.B)	**Project Name** 2017 Pole Residual Replacements Table 2
	Efficiency, Customer Value, Reliability (5.4.5.2.B.1) **Investment Driver (5.4.5.2.B.1.a)** System Renewal (100%) **Secondary Driver (5.4.5.2.B.1.a)** N/A **Investment Priority (5.4.5.2.B.1.b)** 3 – Required project
	Analysis of Project and Project Alternatives (5.4.5.2.B.1.c) The replacement of wood poles in this project is identified through Horizon Utilities' pole testing maintenance program. The pole testing categorized the poles requiring replacement into two categories: 1) requiring immediate replacement; and 2) requiring replacement within five years. Horizon Utilities replaces poles requiring immediate replacement as soon as possible to mitigate the risk of service interruptions and the risk to public safety resulting from a failure of the pole. Horizon Utilities replace poles requiring replacement within five years in the following year. Failure to replace in the following year compounds the volume of work in subsequent years resulting in cascading delays and compounded volumes in subsequent years. Poles replaced in this project are replaced on a like-for-like basis where possible.
	Safety (5.4.5.2.B.2) This project will address wood poles requiring replacement as identified through testing. Renewal of these assets prior to failure avoids the potential risk to public safety that would result from a failure of a wood pole.
	Cyber-Security and Privacy (5.4.5.2.B.3) (where applicable) Cyber-Security and Privacy are not applicable to this project.
	Co-ordination and Interoperability (5.4.5.2.B.4) **Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.5.2.B.4.a) (where applicable)** Please refer to Note II for an explanation on co-ordination with utilities, regional planning and/or links with 3rd parties. **Enabling of Future Technology and/or Future Operational Requirements (5.4.5.2.B.4.b) (where applicable)** This is not applicable to this project.
	Economic Development (5.4.5.2.B.5) **(where applicable)** Horizon Utilities ensures that its policies and practices do not unnecessarily create barriers to economic development which are primarily focused within its communities.

Environmental Benefits (5.4.5.2.B.6) **(where applicable)**

n/a

System Renewal Specific Requirements (5.4.5.2.C.b)

Project Name	2017 Pole Residual Replacements	Table 3

System Renewal Specific Requirements (5.4.5.2.C.b)

Asset Performance Target and Asset Lifecycle Optimization (5.4.5.2.C.b.i.1)

This project is reactive in nature; the work required is initiated through Horizon Utilities' maintenance and inspection programs. This project has a very high probability of impacting Horizon Utilities' reliability targets if the poles are not replaced.

Asset Condition Relative to Typical Life Cycle (5.4.5.2.C.b.i.2)

This project addresses wood poles that have been identified as having a high risk of failure and as such, these assets are at the end of their useful life. The asset condition relative to their typical life cycle varies in case.

Number of Customers Impacted (5.4.5.2.C.b.i.3)

The number of customers impacted varies in each incident or outage.

Quantitative Customer Impact and Risk (5.4.5.2.C.b.i.4)

The quantitative customer impact varies in each incident or outage.

Qualitative Customer Impact and Risk (5.4.5.2.C.b.i.5)

These projects address customer satisfaction as they are required to address assets at risk of failure which would result in a service interruption.

Value of Customer Impact (5.4.5.2.C.b.i.6)

The value of the customer impact varies in each incident or outage.

Other Factors Affecting Project Timing (5.4.5.2.C.b.ii)

These projects are reactive in nature and address assets at risk of failure. Horizon Utilities replaces poles requiring immediate replacement as soon as possible to mitigate the risk of service interruptions and the risk to public safety resulting from a failure of the pole.

Horizon Utilities replaces poles requiring replacement within five years in the following year. Failure to replace in the following year compounds the volume of work in subsequent years resulting in cascading delays and compounded volumes in subsequent years.

Impact on System O&M Costs (5.4.5.2.C.b.iii)

These projects do not materially impact system O&M costs.

Reliability and Safety Factors (5.4.5.2.C.b.iv)

This project will provide reliability and safety benefits as the project involves the replacement of wood poles that are at risk of failure. Failure of the asset would result in a service interruption and a potential risk to public safety.

Analysis of Project Benefits and Timing (5.4.5.2.C.b.v)

n/a

Like-for-Like Renewal Analysis (5.4.5.2.C.b.vi)

Poles replaced in this project are replaced on a like-for-like basis where possible as this presents the lowest cost option. No additional costs are incurred to address other distributor planning objectives.

Capital Project Summary

General Information on Project (5.4.5.2.A)

Project Name	2017 Load Break Disconnect Switch ("LBDS") Replacement
Budget Year	2017
Investment Category	System Renewal
Project Summary	This project involves the replacement of LBDS found to be either inoperable or beyond economic repair (where the cost of maintenance is not warranted) as found through Horizon Utilities' maintenance and inspection programs. Such switches will be replaced with automated switches where an operational benefit can be realized. This is a multi-year program based on 16 replacements per year.

Capital Investment (5.4.5.2.A.i)		
	Capital Investment (gross)	$345,000
	Customer Contribution	$0
	Capital Investment (net)	$345,000
	O&M Expenditure	$0

Customer Attachments / Load (kVA) (5.4.5.2.A.ii)	n/a

Project Dates (5.4.5.2.A.iii)

Start Date	2017/06/01
In Service Date	2017/12/31

Expenditure Timing

Q1	Q2	Q3	Q4
0%	0%	50%	50%

Schedule Risk and Risk Mitigation (5.4.5.2.A.iv**)**

Please refer to Note I for risk and risk mitigation.

Comparative Information from Equivalent Projects (5.4.5.2.A.v)

Comparable gross investments for the 2010 to 2013 Historical Years and the 2014 Bridge Year are:

2010 (CGAAP)- $ 0
2011 (CGAAP)- $ 0
2012 (MIFRS) - $ 0
2013 (MIFRS) - $ 212,000
2014 (MIFRS) - $ 312,000

Total Capital OM&A Costs Associated with REG Investments (5.4.5.2.A.vi)

This project is not associated with an REG investment and therefore OM&A costs related to REG will not be incurred.

	Leave to Construct Approval (5.4.5.2.A.vii) This project does not require "Leave to Construct" under Section 92 of the *Ontario Energy Board Act* 1998.

Evaluation Criteria and Information (5.4.5.2.B)	
	Project Name 2017 LBDS Replacement Table 2
	Efficiency, Customer Value, Reliability (5.4.5.2.B.1) **Investment Driver (5.4.5.2.B.1.a)** System Renewal (80%) **Secondary Driver (5.4.5.2.B.1.a)** System Service (20%) **Investment Priority (5.4.5.2.B.1.b)** 3 – Required project
	Analysis of Project and Project Alternatives (5.4.5.2.B.1.c) This project involves the replacement of LBDS identified as requiring replacement through Horizon Utilities' maintenance and inspection programs. When feasible, the switches are refurbished rather than replaced. Where refurbishment is not possible, the switches will be replaced with an automated switch where an operational benefit can be realized.
	Safety (5.4.5.2.B.2) This project is not intended to address safety concerns with the distribution system
	Cyber-Security and Privacy (5.4.5.2.B.3) (where applicable) Horizon Utilities utilizes the Smart Meter communication infrastructure when communicating with automated switches. Horizon Utilities' Smart Meter and related AMI network have been procured through Elster. Elster's system supports a multi-layered security approach including: access control, authorization, authentication and data integrity protocols. As part of its continuous improvement model, Horizon Utilities performs periodic security assessments to identify opportunities for enhanced system hardening.
	Co-ordination and Interoperability (5.4.5.2.B.4) **Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.5.2.B.4.a) (where applicable)** Please refer to Note II for an explanation on co-ordination with utilities, regional planning and/or links with 3rd parties. **Enabling of Future Technology and/or Future Operational Requirements (5.4.5.2.B.4.b)** This is not applicable to this project.
	Economic Development (5.4.5.2.B.5) **(where applicable)** Horizon Utilities ensures that policies and practices do not unnecessarily create barriers to economic development which are primarily focused within its communities.

Environmental Benefits (5.4.5.2.B.6) **(where applicable)**

n/a

System Renewal Specific Requirements (5.4.5.2.C.b)

Project Name	2017 LBDS Replacement	Table 3

System Renewal Specific Requirements (5.4.5.2.C.b)

Asset Performance Target and Asset Lifecycle Optimization (5.4.5.2.C.b.i.1)

LBDS are critical devices for the operation of the distribution system and are installed at key operating points (e.g. feeder tie points, feeder sectionalizing). Unplanned failures of these devices would impact Horizon Utilities' ability to restore power, resulting in extended outages.

Asset Condition Relative to Typical Life Cycle (5.4.5.2.C.b.i.2)

The asset condition of LBDS relative to their typical lifecycle varies from switch to switch depending upon the operational stresses experienced by the switch. LBDS that are identified for replacement are replaced because they would not operate properly when required and are beyond economical repair.

Number of Customers Impacted (5.4.5.2.C.b.i.3)

None if project is planned.

Quantitative Customer Impact and Risk (5.4.5.2.C.b.i.4)

n/a

Qualitative Customer Impact and Risk (5.4.5.2.C.b.i.5)

Failure of a LBDS to operate when required can impact Horizon Utilities' operational ability which can adversely affect the service experienced by customers.

Value of Customer Impact (5.4.5.2.C.b.i.6)

The value of the customer impact varies in each instance.

Other Factors Affecting Project Timing (5.4.5.2.C.b.ii)

The timing of this project is dependent upon the timing of Horizon Utilities' LBDS maintenance program.

Impact on System O&M Costs (5.4.5.2.C.b.iii)

These projects do not materially impact system O&M costs.

Reliability and Safety Factors (5.4.5.2.C.b.iv)

Reliability can be adversely affected when an LBDS fails to operate when required as part of switching to restore service.

Analysis of Project Benefits and Timing (5.4.5.2.C.b.v)

n/a

Like-for-Like Renewal Analysis (5.4.5.2.C.b.vi)

LDBS are replaced with an automated switch where an operational benefit can be realized. Otherwise they are replaced on a like-for-like basis.

Capital Project Summary

General Information on Project (5.4.5.2.A)

Project Name	2017 Proactive Transformer Replacement		
Budget Year	2017		
Investment Category	System Renewal		
Project Summary	This project was established to proactively replace distribution transformers as required. Renewal of distribution transformers in the past has either been reactive upon failure or proactive when included in the 4kV & 8KV Renewal or XLPE Primary Cable Renewal Programs. There are instances where proactive replacement of transformers is required even when the replacement is outside of the scope of the programs mentioned above. This is a multi-year project, based on 25 replacements per year		
Capital Investment (5.4.5.2.A.i)	Capital Investment (gross)	$361,000	
	Customer Contribution	$0	
	Capital Investment (net)	$361,000	
	O&M Expenditure	$0	
Customer Attachments / Load (kVA) (5.4.5.2.A.ii)	n/a		
Project Dates (5.4.5.2.A.iii)	Start Date	2017/06/01	
	In Service Date	2017/12/31	

Expenditure Timing

Q1	Q2	Q3	Q4
0%	0%	50%	50%

Schedule Risk and Risk Mitigation (5.4.5.2.A.iv**)**

Please refer to Note I for risk and risk mitigation.

Comparative Information from Equivalent Projects (5.4.5.2.A.v)

Comparable gross investments for the 2010 to 2013 Historical Years and the 2014 Bridge Year are:

2010 (CGAAP)- $ 0
2011 (CGAAP)- $ 104,447
2012 (MIFRS) - $ 185,523
2013 (MIFRS) - $ 276,978
2014 (MIFRS) - $ 339,000

Total Capital OM&A Costs Associated with REG Investments (5.4.5.2.A.vi)

This project is not associated with an REG investment and therefore OM&A costs related to REG will not be incurred.

Leave to Construct Approval (5.4.5.2.A.vii)

This project does not require "Leave to Construct" under Section 92 of the *Ontario Energy Board Act* 1998.

Evaluation Criteria and Information (5.4.5.2.B)

Project Name	2017 Proactive Transformer Replacement	Table 2

Efficiency, Customer Value, Reliability (5.4.5.2.B.1)

Investment Driver (5.4.5.2.B.1.a)
System Renewal (100%)

Secondary Driver (5.4.5.2.B.1.a)
N/A

Investment Priority (5.4.5.2.B.1.b)
3 – Required project

Analysis of Project and Project Alternatives (5.4.5.2.B.1.c)

Proactive transformer replacements are identified through Horizon Utilities' visual inspection programs and 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, in a reactive replacement scenario, the customer(s) may be subject to an extended outage duration;
- Transformers that have visible oil leaks; and
- Transformers that have been identified through testing as containing PCBs.

These criteria were selected due to the level of associated risk. Transformers with visible oil leaks or containing PCBs represent a significant environmental risk. All oil spills must be tracked, reported, and the oil reclaimed where possible. Obsolete transformers, where a replacement is not available in inventory, represent a risk of prolonged service interruption upon failure and are replaced to reduce the risk of outage to the customer.

Safety (5.4.5.2.B.2)

This project is not intended to address safety concerns with the distribution system

Cyber-Security and Privacy (5.4.5.2.B.3) (where applicable)

Cyber-Security and Privacy are not applicable to this project.

Co-ordination and Interoperability (5.4.5.2.B.4)

Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.5.2.B.4.a) (where applicable)

Please refer to Note II for an explanation on co-ordination with utilities, regional planning and/or links with 3rd parties.

Enabling of Future Technology and/or Future Operational Requirements (5.4.5.2.B.4.b)

This is not applicable to this project.

Economic Development (5.4.5.2.B.5) **(where applicable)**

Horizon Utilities ensures that policies and practices do not unnecessarily create barriers to economic development which are primarily focused within its communities.

Environmental Benefits (5.4.5.2.B.6) **(where applicable)**

n/a

System Renewal Specific Requirements (5.4.5.2.C.b)

Project Name 2017 Proactive Transformer Replacement Table 3

System Renewal Specific Requirements (5.4.5.2.C.b)

Asset Performance Target and Asset Lifecycle Optimization (5.4.5.2.C.b.i.1)

The transformers selected for proactive replacement represent a level of risk to Horizon Utilities and this project provides risk mitigation consistent with Horizon Utilities' asset management objectives.

Asset Condition Relative to Typical Life Cycle (5.4.5.2.C.b.i.2)

The asset condition of these transformers relative to their typical lifecycle varies from transformer to transformer. Transformers selected for replacement present a level of risk to Horizon Utilities either through imminent failure of the transformer or through the need to address environmental risk associated with PCBs; or through the risks associated with transformers that have visible oil leaks.

Number of Customers Impacted (5.4.5.2.C.b.i.3)
Varies depending on the project.

Quantitative Customer Impact and Risk (5.4.5.2.C.b.i.4)

n/a

Qualitative Customer Impact and Risk (5.4.5.2.C.b.i.5)

These criteria were selected due to the level of associated risk. Transformers with visible oil leaks or containing PCBs represent a significant environmental risk. All oil spills must be tracked, reported, and the oil reclaimed where possible. Obsolete transformers, where a replacement is not available in inventory, represent a risk of prolonged service interruption upon failure and are replaced to reduce the risk of outage to the customer.

Value of Customer Impact (5.4.5.2.C.b.i.6)

The value of the customer impact varies in each instance.

Other Factors Affecting Project Timing (5.4.5.2.C.b.ii)

n/a

Impact on System O&M Costs (5.4.5.2.C.b.iii)

These projects do not materially impact system O&M costs.

Reliability and Safety Factors (5.4.5.2.C.b.iv)

n/a.

Analysis of Project Benefits and Timing (5.4.5.2.C.b.v)

n/a

Like-for-Like Renewal Analysis (5.4.5.2.C.b.vi)

n/a.

Capital Project Summary

General Information on Project (5.4.5.2.A)

Project Name	2017 Substation Infrastructure Renewal		
Budget Year	2017		
Investment Category	System Renewal		
Project Summary	This program involves the renewal of substation infrastructure throughout Horizon Utilities' service territory. Substation maintenance and inspection programs annually identify a number of required investments for the continued safe and reliable operation of Horizon Utilities' substations. Investments under this program include battery replacements, SCADA and communication upgrades, and grounding improvements .		
Capital Investment (5.4.5.2.A.i)	Capital Investment (gross)	$482,000	
	Customer Contribution	$0	
	Capital Investment (net)	$482,000	
	O&M Expenditure	$0	
Customer Attachments / Load (kVA) (5.4.5.2.A.ii)	n/a		
Project Dates (5.4.5.2.A.iii)	Start Date	2017/01/01	
	In Service Date	2017/12/31	

Expenditure Timing

Q1	Q2	Q3	Q4
25%	25%	25%	25%

Schedule Risk and Risk Mitigation (5.4.5.2.A.iv**)**

Please refer to Note I for risk and risk mitigation.

Comparative Information from Equivalent Projects (5.4.5.2.A.v)

Comparable gross investments for the 2010 to 2013 Historical Years and the 2014 Bridge Year are:

2010 (CGAAP)- $ 146,477
2011 (CGAAP)- $ 326,000
2012 (MIFRS) - $ 305,000
2013 (MIFRS) - $ 168,507
2014 (MIFRS) - $ 455,503

Total Capital OM&A Costs Associated with REG Investments (5.4.5.2.A.vi)

This project is not associated with an REG investment and therefore OM&A costs related to REG will not be incurred.

Leave to Construct Approval (5.4.5.2.A.vii)

This project does not require "Leave to Construct" under Section 92 of the *Ontario Energy Board Act* 1998.

Evaluation Criteria and Information (5.4.5.2.B)

Project Name	2017 Substation Infrastructure Renewal	Table 2

Efficiency, Customer Value, Reliability (5.4.5.2.B.1)

Investment Driver (5.4.5.2.B.1.a)
System Renewal (80%)

Secondary Driver (5.4.5.2.B.1.a)
System Service (20%)

Investment Priority (5.4.5.2.B.1.b)
3 – Required project

Analysis of Project and Project Alternatives (5.4.5.2.B.1.c)

This program is required for the ongoing safe and reliable operation of Horizon Utilities' municipal substations. The 4kV and 8kV Renewal Program is structured to decommission Horizon Utilities' 28 substations over the next 34 years. There is no investment in the renewal of the major electrical assets (power transformers, switchgear and breakers) forecasted for the 2015 to 2019 Test Years. The investments provided above are required to maintain the ancillary substation assets in safe working order. Substation investment requirements are identified though preventative maintenance programs performed on both routine maintenance cycles and monthly inspections. 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. Investments are required to address both electrical assets within the substation (e.g. replacement of switchgear components and instrument transformers), and ancillary equipment (e.g. SCADA, communication equipment, or backup batteries). All of these components are critical to the continued safe and reliable operation of the substation. A failure to undertake these required investments could lead to premature failure of substation components that would result in a service interruption and increased operating or reactive capital expenditure.

Safety (5.4.5.2.B.2)

This project is not intended to address safety concerns with the distribution system.

Cyber-Security and Privacy (5.4.5.2.B.3) (where applicable)

Cyber-Security and Privacy are not applicable to this project.

Co-ordination and Interoperability (5.4.5.2.B.4)

Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.5.2.B.4.a) (where applicable)

Please refer to Note II for an explanation on co-ordination with utilities, regional planning and/or links with 3rd parties.

Enabling of Future Technology and/or Future Operational Requirements (5.4.5.2.B.4.b)

Please refer to Note IV for an explanation enabling of future technology and future operational requirements.

Economic Development (5.4.5.2.B.5) **(where applicable)**

Horizon Utilities ensures that policies and practices do not unnecessarily create barriers to economic development which are primarily focused within its communities.

Environmental Benefits (5.4.5.2.B.6) **(where applicable)**

n/a.

System Renewal Specific Requirements (5.4.5.2.C.b)

Project Name 2017 Substation Infrastructure Renewal Table 3

System Renewal Specific Requirements (5.4.5.2.C.b)

Asset Performance Target and Asset Lifecycle Optimization (5.4.5.2.C.b.i.1)

This project involves investment to replace substation infrastructure required for the continued safe and reliable operation of Horizon Utilities' substations.

Asset Condition Relative to Typical Life Cycle (5.4.5.2.C.b.i.2)

n/a

Number of Customers Impacted (5.4.5.2.C.b.i.3)

n/a.

Quantitative Customer Impact and Risk (5.4.5.2.C.b.i.4)

Qualitative Customer Impact and Risk (5.4.5.2.C.b.i.5)

n/a

Value of Customer Impact (5.4.5.2.C.b.i.6)

Medium

Other Factors Affecting Project Timing (5.4.5.2.C.b.ii)

The timing of investments in this project is dependent upon the timing of substation maintenance programs and the infrastructure requiring renewal identified while performing maintenance.

Impact on System O&M Costs (5.4.5.2.C.b.iii)

This project will have no material impact on O&M expenditures.

Reliability and Safety Factors (5.4.5.2.C.b.iv)
n/a

Analysis of Project Benefits and Timing (5.4.5.2.C.b.v)
n/a

Like-for-Like Renewal Analysis (5.4.5.2.C.b.vi).
The assets renewed in this program are replaced on a like-for-like basis.

Capital Project Summary

General Information on Project (5.4.5.2.A)

Project Name	2017 Rear Lot Conversion
Budget Year	2017
Investment Category	System Renewal
Project Summary	This project involves the replacement of rear lot overhead construction. Replacement options include relocating primary only, or relocating all assets to either overhead or underground in the front lot. Options are dependent on many factors (e.g. presence of trees and availability of room in the road allowance) and are assessed on a case by case basis. This project will involve the renewal of end of life rear lot overhead distribution assets serviced at 13.8kV and therefore not included in the 4kV and 8kV renewal programs.

Capital Investment (5.4.5.2.A.i)	Capital Investment (gross)	$1,382,000
	Customer Contribution	$0
	Capital Investment (net)	$1,382,000
	O&M Expenditure	$0

Customer Attachments / Load (kVA) (5.4.5.2.A.ii)	The customer and load impacted by this project will vary depending upon the final scope of the project.

Project Dates (5.4.5.2.A.iii)

Start Date 2017/05/01

In Service Date 2017/09/30

Expenditure Timing

Q1	Q2	Q3	Q4
0%	40%	60%	0%

Schedule Risk and Risk Mitigation (5.4.5.2.A.iv**)**

Please refer to Note I for risk and risk mitigation.

Comparative Information from Equivalent Projects (5.4.5.2.A.v)

There are no equivalent projects for comparison.

Total Capital OM&A Costs Associated with REG Investments (5.4.5.2.A.vi)

This project is not associated with an REG investment and therefore OM&A costs related to REG will not be incurred.

Leave to Construct Approval (5.4.5.2.A.vii)

This project does not require “Leave to Construct” under Section 92 of the *Ontario Energy Board Act* 1998.

Evaluation Criteria and Information (5.4.5.2.B)	**Project Name** 2017 Rear Lot Conversion Table 2
	Efficiency, Customer Value, Reliability (5.4.5.2.B.1) **Investment Driver (5.4.5.2.B.1.a)** System Renewal (60%) **Secondary Driver (5.4.5.2.B.1.a)** System Service (40%) **Investment Priority (5.4.5.2.B.1.b)** 3 – Required project
	Analysis of Project and Project Alternatives (5.4.5.2.B.1.c) Replacement options considered on a project by project basis include relocating primary only, or relocating all assets to either overhead or underground in the front lot. Options are dependent on many factors (e.g. presence of trees and availability of room in the road allowance).
	Safety (5.4.5.2.B.2) This project is not intended to address safety concerns with the distribution system.
	Cyber-Security and Privacy (5.4.5.2.B.3) (where applicable) Cyber-Security and Privacy are not applicable to this project.
	Co-ordination and Interoperability (5.4.5.2.B.4) **Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.5.2.B.4.a) (where applicable)** Please refer to Note II for an explanation on co-ordination with utilities, regional planning and/or links with 3rd parties. **Enabling of Future Technology and/or Future Operational Requirements (5.4.5.2.B.4.b)** Please refer to Note IV for an explanation enabling of future technology and future operational requirements.
	Economic Development (5.4.5.2.B.5) **(where applicable)** Horizon Utilities ensures that policies and practices do not unnecessarily create barriers to economic development which are primarily focused within its communities.
	Environmental Benefits (5.4.5.2.B.6) **(where applicable)** n/a.

System Renewal Specific Requirements (5.4.5.2.C.b)

Project Name	2017 Rear Lot Conversion	Table 3

System Renewal Specific Requirements (5.4.5.2.C.b)

Asset Performance Target and Asset Lifecycle Optimization (5.4.5.2.C.b.i.1)

Horizon Utilities has identified several residential areas serviced by a rear lot overhead distribution system. Horizon Utilities has experienced a dramatic increase in reliability issues surrounding rear lot distribution systems due to damaged caused from customer owned trees and lack of access for utility crews to repair or replace equipment. The poles are a mix of wood and concrete that, by design, are unsafe to scale to repair, and replacement of poles and equipment is labour intensive and requires specialized equipment access rear yards. Access is poor and therefore failure restoration time is significantly extended. These identified assets are nearing or beyond end of life and should be replaced. In the past several years, storm related failures in these areas have increased and with corresponding long outage durations (in excess of 24 hours).

Asset Condition Relative to Typical Life Cycle (5.4.5.2.C.b.i.2)

Overhead distribution assets located in rear lots typically do not perform as well as well as similar assets of similar age resulting in a shorter life cycle.

Number of Customers Impacted (5.4.5.2.C.b.i.3)

This project will impact a varying number of customers depending upon the scope of the rear lot conversion.

Quantitative Customer Impact and Risk (5.4.5.2.C.b.i.4)

n/a

Qualitative Customer Impact and Risk (5.4.5.2.C.b.i.5)

This project will improve the service received by the customers impacted. Service interruptions of rear lot distribution systems involve longer restoration times due to the difficulty in accessing the assets. The service interruption restoration times will be reduced once the assets have been relocated.

Value of Customer Impact (5.4.5.2.C.b.i.6)

High

Other Factors Affecting Project Timing (5.4.5.2.C.b.ii)

n/a

Impact on System O&M Costs (5.4.5.2.C.b.iii)

This project will not have a material impact on system O&M costs in the 2015 to 2019 Test Years.

Reliability and Safety Factors (5.4.5.2.C.b.iv)

Reliability will be improved through the relocation of these assets through reduced service interruption restoration times. Safety will be improved due to improved and easier access to the assets and the ability to work on the assets from aerial bucket trucks versus having to manually climb poles when located in the rear lot.

Analysis of Project Benefits and Timing (5.4.5.2.C.b.v)

n/a.

Like-for-Like Renewal Analysis (5.4.5.2.C.b.vi)

This project is required to remove rear lot assets and is specifically designed not to renew using a like-for-like methodology. Horizon Utilities will determine whether to relocate the primary only to the front lot or to relocate all plant to either underground and/or overhead front lot. The decision will be made on a project by project basis.

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Capital Project Summary

General Information on Project (5.4.5.2.A)

Project Name	ST-F2 & ST-F6 Renewal
Budget Year	2017
Investment Category	System Renewal
Project Summary	This project involves the renewal of the Strouds Substation F2 and F6 feeders in the Hamilton West operating area. This project is part of the 4kV and 8kV Renewal Program.

Capital Investment (5.4.5.2.A.i)	Capital Investment (gross)	$1,787,341
	Customer Contribution	$0
	Capital Investment (net)	$1,787,341
	O&M Expenditure	$0

Customer Attachments / Load (kVA) (5.4.5.2.A.ii)

This project impacts 973 customers and 3,300kVA of transformation

Project Dates (5.4.5.2.A.iii)

Start Date 2017/03/01

In Service Date 2017/10/31

Expenditure Timing

Q1	Q2	Q3	Q4
12.5%	37.5%	37.5%	12.5%

Schedule Risk and Risk Mitigation (5.4.5.2.A.iv**)**

Please refer to Note I for risk and risk mitigation.

Comparative Information from Equivalent Projects (5.4.5.2.A.v)

There is no direct comparator in scope, size and design characteristics for this project. This project is one phase of a multi-year investment to renew the area served by Strouds substation as part of the 4kV and 8kV Renewal Program. The 2017 investment for the renewal of Strouds substation is $1,787,000. The 2017 investment in the 4kV and 8kV Renewal Program is $15,764,000.

Comparable gross investments for the 4kV and 8kV Renewal Program for the 2010 to 2013 Historical Years and the 2014 Bridge Year are:

2010 (CGAAP)- $ 2,556,076
2011 (CGAAP)- $ 8,820,000
2012 (MIFRS) - $ 5,268,441
2013 (MIFRS) - $ 5,072,233
2014 (MIFRS) - $ 6,434,000

Total Capital OM&A Costs Associated with REG Investments (5.4.5.2.A.vi)

This project is not associated with an REG investment and therefore OM&A costs related to REG will not be incurred.

Leave to Construct Approval (5.4.5.2.A.vii)

This project does not require "Leave to Construct" under Section 92 of the *Ontario Energy Board Act* 1998.

Evaluation Criteria and Information (5.4.5.2.B)

Project Name	ST-2 & ST-6 Renewal	Table 2

Efficiency, Customer Value, Reliability (5.4.5.2.B.1)

Investment Driver (5.4.5.2.B.1.a)
System Renewal (80%)

Secondary Driver (5.4.5.2.B.1.a)
System Service (20%)

Investment Priority (5.4.5.2.B.1.b)
3 – Required project

Analysis of Project and Project Alternatives (5.4.5.2.B.1.c)

This project is part of the multi-year 4kV and 8kV Renewal Program. Both the 4kV and 8kV distribution system and the Horizon Utilities-owned substations are at the end of their useful life. Horizon Utilities has chosen to renew the 4kV and 8kV distribution systems to a higher voltage to avoid the cost of the investment in the renewal of the substations. The total avoided substation renewal investment over the remaining 35 years of the plan is $70,000,000 for all 28 substations. Therefore the renewal of the distribution assets at the current 4kV level was not a feasible alternative.

The renewal of the area serviced by the Strouds substation started in 2014 and is scheduled to be completed in 2018. Strouds substation was constructed in 1938. The switchgear at this substation is 44 years old and has a Health Index of 'very poor' as identified in the Substation Asset Condition Assessment ("SACA") and confirmed by the Kinectrics ACA.

Safety (5.4.5.2.B.2)

This project is not intended to address safety concerns with the distribution system

Cyber-Security and Privacy (5.4.5.2.B.3) (where applicable)

Cyber-Security and Privacy are not applicable to this project

Co-ordination and Interoperability (5.4.5.2.B.4)

Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.5.2.B.4.a) (where applicable)

Please refer to Note II for an explanation on co-ordination with utilities, regional planning and/or links with 3rd parties.

Enabling of Future Technology and/or Future Operational Requirements (5.4.5.2.B.4.b)

Please refer to Note IV for an explanation enabling of future technology and future operational requirements.

Economic Development (5.4.5.2.B.5) **(where applicable)**

Horizon Utilities ensures that policies and practices do not unnecessarily create barriers to economic development which are primarily focused within its communities.

Environmental Benefits (5.4.5.2.B.6) **(where applicable)**

n/a

System Renewal Specific Requirements (5.4.5.2.C.b)

Project Name	ST-2 & ST-6 Renewal	Table 3

System Renewal Specific Requirements (5.4.5.2.C.b)

Asset Performance Target and Asset Lifecycle Optimization (5.4.5.2.C.b.i.1)

The distribution assets in the Hamilton West operating area are in poor health and the switchgear in both substations servicing this area has switchgear with a 'very poor' Health Index.

Asset Condition Relative to Typical Life Cycle (5.4.5.2.C.b.i.2)

Generally the 4kV assets are the oldest vintage in the system. 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.

Number of Customers Impacted (5.4.5.2.C.b.i.3)

This project impacts 973 customers.

Quantitative Customer Impact and Risk (5.4.5.2.C.b.i.4)

SAIDI of 0.050

Qualitative Customer Impact and Risk (5.4.5.2.C.b.i.5)

This project will address aging assets with inadequate backup. Aging assets represent an increased risk of service interruption to customers and inadequate backup would result in long duration service interruptions upon occurrence. These factors would lead to customer dissatisfaction in this area.

Value of Customer Impact (5.4.5.2.C.b.i.6)

High

Other Factors Affecting Project Timing (5.4.5.2.C.b.ii)

The renewal of the area serviced by the Strouds substation is scheduled for 2014 to 2018. This project is required to be completed in 2017 to allow for the renewal of the remaining area to be completed on schedule.

Impact on System O&M Costs (5.4.5.2.C.b.iii)

This project will have no material impact on planned O&M costs. The renewal of the 4kV and 8kV distribution systems, as a whole, will provide a reduction in reactive O&M costs to address service interruptions caused by failed equipment. These reductions will not be material in the 2015 to 2019 Test Years.

Reliability and Safety Factors (5.4.5.2.C.b.iv)

The renewal of the 4kV and 8kV distribution system will provide reliability improvements through reduced service interruptions caused by failed equipment

Analysis of Project Benefits and Timing (5.4.5.2.C.b.v)

The timing of this project, as part of the 4kV and 8kV Renewal Program, is determined through the assessment of the distribution system health and the health of the substation assets servicing the area. 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. Renewal of this area will allow for the decommissioning of the substation assets by 2018 thereby avoiding the need for capital investment into these substations.

Like-for-Like Renewal Analysis (5.4.5.2.C.b.vi)

The like-for-like renewal of these assets (i.e. same system configuration and same distribution voltage) will perpetuate the existing operating constraints and require capital investment to renew substation assets. Renewal of the distribution assets at a higher voltage does not involve any material incremental costs over renewal at the existing voltage. Operating constraints (e.g. undersized conductor, radial feeds) are addressed on a case by case basis where appropriate.

Capital Project Summary

General Information on Project (5.4.5.2.A)

Project Name	2017 Stoney Creek XLPE Renewal			
Budget Year	2017			
Investment Category	System Renewal			
Project Summary	Renewal of end-of-life XLPE cable assets in the Stoney Creek area.			
Capital Investment (5.4.5.2.A.i)	Capital Investment (gross)	$500,000		
	Customer Contribution	$0		
	Capital Investment (net)	$500,000		
	O&M Expenditure	$0		
Customer Attachments / Load (kVA) (5.4.5.2.A.ii)	The customer and load impacted by this project will vary depending upon the final scope of the project			
Project Dates (5.4.5.2.A.iii)	Start Date	2017/03/01		
	In Service Date	2017/11/30		
	Expenditure Timing			
	Q1	Q2	Q3	Q4
	10%	40%	10%	40%

Schedule Risk and Risk Mitigation (5.4.5.2.A.iv**)**

Please refer to Note I for risk and risk mitigation.

Comparative Information from Equivalent Projects (5.4.5.2.A.v)

There is no direct comparator in scope, size and design characteristics for this project. This project is part of a multi-year investment to renewal XLPE primary cable. The 2017 investment in the XLPE Renewal Program is $8,866,000.

Comparable gross investments for the XLPE Renewal Program for the 2010 to 2013 Historical Years and the 2014 Bridge Year are:

2010 (CGAAP)- $ 0
2011 (CGAAP)- $ 0
2012 (MIFRS) - $ 0
2013 (MIFRS) - $ 1,572,090
2014 (MIFRS) - $ 893,000

Total Capital OM&A Costs Associated with REG Investments (5.4.5.2.A.vi)

This project is not associated with an REG investment and therefore OM&A costs related to REG will not be incurred.

Leave to Construct Approval (5.4.5.2.A.vii)

This project does not require "Leave to Construct" under Section 92 of the *Ontario Energy Board Act* 1998.

Evaluation Criteria and Information (5.4.5.2.B)

Project Name	2017 Stoney Creek XLPE Renewal	Table 2

Efficiency, Customer Value, Reliability (5.4.5.2.B.1)

Investment Driver (5.4.5.2.B.1.a)
System Renewal (80%)

Secondary Driver (5.4.5.2.B.1.a)
System Service (20%)

Investment Priority (5.4.5.2.B.1.b)
4 – Required Project

Analysis of Project and Project Alternatives (5.4.5.2.B.1.c)

This project is part of the multi-year XLPE Renewal Program. Horizon Utilities considered the four replacement philosophies for addressing risk inherent in the XLPE asset group: Area; Reactive; Selected; and Refurbishment. The area replacement philosophy for will be utilized 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 Stoney Creek operating area contains many small pockets of direct buried XLPE primary cable. The XLPE renewal projects in the Stoney Creek operating area will involve the full renewal of each pocket of XLPE cable. Project selection will be guided by asset health, operating history, and reliability of each of the underground pockets of XLPE.

Safety (5.4.5.2.B.2)

These projects are not intended to address safety concerns with the distribution system.

Cyber-Security and Privacy (5.4.5.2.B.3) (where applicable)

Cyber-Security and Privacy are not applicable to this project.

Co-ordination and Interoperability (5.4.5.2.B.4)

Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.5.2.B.4.a) (where applicable)

Please refer to Note II for an explanation on co-ordination with utilities, regional planning and/or links with 3rd parties.

Enabling of Future Technology and/or Future Operational Requirements (5.4.5.2.B.4.b)

Please refer to Note IV for an explanation enabling of future technology and future operational requirements.

Economic Development (5.4.5.2.B.5) **(where applicable)**

Horizon Utilities ensures that policies and practices do not unnecessarily create barriers to economic development which are primarily focused within its communities.

Environmental Benefits (5.4.5.2.B.6) **(where applicable)**

n/a

System Renewal Specific Requirements (5.4.5.2.C.b)

Project Name	2017 Stoney Creek XLPE Renewal	Table 3

System Renewal Specific Requirements (5.4.5.2.C.b)

Asset Performance Target and Asset Lifecycle Optimization (5.4.5.2.C.b.i.1)

XLPE primary cable is the asset group with the largest investment requirement as identified by the Kinectrics ACA. 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

Asset Condition Relative to Typical Life Cycle (5.4.5.2.C.b.i.2)

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.

Number of Customers Impacted (5.4.5.2.C.b.i.3)

The number of customers impacted will vary depending upon the area

Quantitative Customer Impact and Risk (5.4.5.2.C.b.i.4)

Qualitative Customer Impact and Risk (5.4.5.2.C.b.i.5)

This project will address aging assets at risk of failure. Failure of XLPE primary cable results in extended service interruptions; 30% of these outages exceeded four hours in duration, while 5% of these outages exceeded twelve hours in duration.

Value of Customer Impact (5.4.5.2.C.b.i.6)

High

Other Factors Affecting Project Timing (5.4.5.2.C.b.ii)

Proactive replacements are required because, 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 proactive renewal.

Impact on System O&M Costs (5.4.5.2.C.b.iii)

This project will have no material impact on planned O&M costs. The renewal of the XLPE primary cable, as a whole, will provide a reduction in reactive O&M costs to address service interruptions caused by failed equipment. These reductions will not be material in the 2015 to 2019 Test Years.

Reliability and Safety Factors (5.4.5.2.C.b.iv)

The renewal of the XLPE primary cable system will provide reliability improvements through reduced service interruptions caused by failed equipment.

Analysis of Project Benefits and Timing (5.4.5.2.C.b.v)

Failure to invest in the proactive renewal of XLPE primary cable and associated underground assets would result in unacceptable levels of system failures and outages beyond Horizon Utilities' ability to resolve within a reasonable timeframe as these assets continue to age and degrade. Reactive replacements will also be considerably more costly than the forecast expenditure required to execute the proposed proactive replacement.

Like-for-Like Renewal Analysis (5.4.5.2.C.b.vi)

XLPE renewal projects will include the elimination of radial underground feeds; the replacement of below grade transformers with padmount transformers; and the introduction of fusing on the underground distribution systems where applicable.

Capital Project Summary

General Information on Project (5.4.5.2.A)

Project Name	WH-F6 - Ewen St
Budget Year	2017
Investment Category	System Renewal
Project Summary	The project involves the renewal of the Whitney substation F6 feeder in the West Hamilton operating area along Ewen St. This project is part of the 4kV and 8kV Renewal Program.

Capital Investment (5.4.5.2.A.i)		
	Capital Investment (gross)	$1,508,763
	Customer Contribution	$0
	Capital Investment (net)	$1,508,763
	O&M Expenditure	$0

Customer Attachments / Load (kVA) (5.4.5.2.A.ii)

This project impacts 234 customers and 850KVA of transformation

Project Dates (5.4.5.2.A.iii)

Start Date	2017/04/01
In Service Date	2017/11/30

Expenditure Timing

Q1	Q2	Q3	Q4
	37.5%	37.5%	25%

Schedule Risk and Risk Mitigation (5.4.5.2.A.iv**)**

Please refer to Note I for risk and risk mitigation.

Comparative Information from Equivalent Projects (5.4.5.2.A.v)

There is no direct comparator in scope, size and design characteristics for this project. This project is one phase of a multi-year investment to renew the area served by Whitney substation as part of the 4kV and 8kV Renewal Program. The 2017 investment for the renewal of Whitney substation is $1,509,000. The 2017 investment in the 4kV and 8kV Renewal Program is $15,764,000.

Comparable gross investments for the 4kv and 8kV Renewal Program for the 2010 to 2013 Historical Years and the 2014 Bridge Year are:

2010 (CGAAP)- $ 2,556,076
2011 (CGAAP)- $ 8,820,000
2012 (MIFRS) - $ 5,268,441
2013 (MIFRS) - $ 5,072,233
2014 (MIFRS) - $ 6,434,000

Total Capital OM&A Costs Associated with REG Investments (5.4.5.2.A.vi)

This project is not associated with an REG investment and therefore OM&A costs related to REG will not be incurred.

Leave to Construct Approval (5.4.5.2.A.vii)

This project does not require "Leave to Construct" under Section 92 of the *Ontario Energy Board Act* 1998.

Evaluation Criteria and Information (5.4.5.2.B)

Project Name	WH-F6 - Ewen St	Table 2

Efficiency, Customer Value, Reliability (5.4.5.2.B.1)

Investment Driver (5.4.5.2.B.1.a)
System Renewal (80%)

Secondary Driver (5.4.5.2.B.1.a)
System Service (20%)

Investment Priority (5.4.5.2.B.1.b)
3 – Required project

Analysis of Project and Project Alternatives (5.4.5.2.B.1.c)

This project is part of the multi-year 4kV and 8kV Renewal Program. Both the 4kV and 8kV distribution system and the Horizon Utilities-owned substations are at the end of their useful life. Horizon Utilities has chosen to renew the 4kV and 8kV distribution systems to a higher voltage to avoid the cost of the investment in the renewal of the substations. The total avoided substation renewal investment over the remaining 35 years of the plan is $70,000,000 for all 28 substations. Therefore the renewal of these distribution assets at the current 4kV level was not a feasible alternative.

The renewal of the area serviced by the Whitney substation started in 2014 and is scheduled to be completed in 2018. Whitney substation was constructed in 1962. The switchgear at this substation is 46 years old and has a Health Index of 'very poor' as identified in Substation Asset Condition Assessment ("SACA") and confirmed by the Kinectrics ACA.

Safety (5.4.5.2.B.2)

This project is not intended to address safety concerns with the distribution system.

Cyber-Security and Privacy (5.4.5.2.B.3) (where applicable)

n/a

Co-ordination and Interoperability (5.4.5.2.B.4)

Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.5.2.B.4.a) (where applicable)

Please refer to Note II for an explanation on co-ordination with utilities, regional planning and/or links with 3rd parties.

	Enabling of Future Technology and/or Future Operational Requirements (5.4.5.2.B.4.b) Please refer to Note IV for an explanation enabling of future technology and future operational requirements.
	Economic Development (5.4.5.2.B.5) **(where applicable)** Horizon Utilities ensures that policies and practices do not unnecessarily create barriers to economic development which are primarily focused within its communities.
	Environmental Benefits (5.4.5.2.B.6) **(where applicable)** n/a

System Renewal Specific Requirements (5.4.5.2.C.b)	**Project Name**	WH-F6 - Ewen St	Table 3
	System Renewal Specific Requirements (5.4.5.2.C.b) **Asset Performance Target and Asset Lifecycle Optimization (5.4.5.2.C.b.i.1)** The distribution assets in the Hamilton West operating area are in poor health and the switchgear in both substations servicing this area have switchgear with a 'very poor' Health Index. **Asset Condition Relative to Typical Life Cycle (5.4.5.2.C.b.i.2)** Generally the 4kV assets are the oldest vintage in the system. 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. **Number of Customers Impacted (5.4.5.2.C.b.i.3)** This project impacts 234 customers. **Quantitative Customer Impact and Risk (5.4.5.2.C.b.i.4)** SAIDI of 0.008 **Qualitative Customer Impact and Risk (5.4.5.2.C.b.i.5)** Renewal of assets at 4kV would not allow for the eventual decommissioning of Whitney Substation. Horizon Utilities' substation assets are being decommissioned over the life of the 4kV and 8kV Renewal Plan to avoid capital investment required for the renewal of substation assets that are nearing the end of their useful lives. **Value of Customer Impact (5.4.5.2.C.b.i.6)** High		

Qualitative Customer Impact and Risk (5.4.5.2.C.b.i.5)

This project will address aging assets with inadequate backup. Aging assets represent an increased risk of service interruption to customers and inadequate backup would result in long duration service interruptions upon occurrence. These factors would lead to customer dissatisfaction in this area.

Value of Customer Impact (5.4.5.2.C.b.i.6)

High

Other Factors Affecting Project Timing (5.4.5.2.C.b.ii)

The renewal of the area serviced by the Whitney substation is schedule for 2014 to 2018. This project is required to be completed in 2017 to allow for the renewal of the remaining area to be completed on schedule.

Impact on System O&M Costs (5.4.5.2.C.b.iii)

This project will have no material impact on planned O&M costs. The renewal of the 4kV and 8kV distribution systems, as a whole, will provide a reduction in reactive O&M costs to address service interruptions caused by failed equipment. These reductions will not be material in the 2015 to 2019 Test Years.

Reliability and Safety Factors (5.4.5.2.C.b.iv)

The renewal of the 4kV and 8kV distribution system will provide reliability improvements through reduced service interruptions caused by failed equipment.

Capital Project Summary

General Information on Project (5.4.5.2.A)

Project Name	GR-F2 Renewal – East of Vine Ave
Budget Year	2017
Investment Category	System Renewal
Project Summary	The project involves the renewal of the Grantham Substation feeder in the St. Catharines operating area on the Grantham F2 feeder specifically for portions East of Vine Ave. This project is part of the 4kV and 8kV Renewal Program.

Capital Investment (5.4.5.2.A.i)

Capital Investment (gross)	$1,871,452
Customer Contribution	$0
Capital Investment (net)	$1,871,452
O&M Expenditure	$0

Customer Attachments / Load (kVA) (5.4.5.2.A.ii)

This project affects 737 customers and 2,000kVA of transformation.

Project Dates (5.4.5.2.A.iii)

Start Date 2017/03/01

In Service Date 2017/10/31

Expenditure Timing

Q1	Q2	Q3	Q4
12.5%	37.5%	37.5%	12.5%

Schedule Risk and Risk Mitigation (5.4.5.2.A.iv**)**

Please refer to Note I for risk and risk mitigation.

Comparative Information from Equivalent Projects (5.4.5.2.A.v)

There is no direct comparator in scope, size and design characteristics for this project. This project is one phase of a multi-year investment to renew the area served by Grantham substation as part of the 4kV and 8kV Renewal Program. The 2017 investment for the renewal of Grantham substation is $1,871,000. The 2017 investment in the 4kV and 8kV Renewal Program is $15,764,000.

Comparable gross investments for the 4kV and 8kV Renewal Program for the 2010 to 2013 Historical Years and the 2014 Bridge Year are:

2010 (CGAAP)- $ 2,556,076
2011 (CGAAP)- $ 8,820,000
2012 (MIFRS) - $ 5,268,441
2013 (MIFRS) - $ 5,072,233
2014 (MIFRS) - $ 6,434,000

Total Capital OM&A Costs Associated with REG Investments (5.4.5.2.A.vi)

This project is not associated with an REG investment and therefore OM&A costs related to REG will not be incurred.

Leave to Construct Approval (5.4.5.2.A.vii)

This project does not require "Leave to Construct" under Section 92 of the *Ontario Energy Board Act* 1998.

Evaluation Criteria and Information (5.4.5.2.B)

Project Name	GR-F2 Renewal – East of Vine Ave	Table 2

Efficiency, Customer Value, Reliability (5.4.5.2.B.1)

Investment Driver (5.4.5.2.B.1.a)
System Renewal (80%)

Secondary Driver (5.4.5.2.B.1.a)
System Service (20%)

Investment Priority (5.4.5.2.B.1.b)
3 – Required project

Analysis of Project and Project Alternatives (5.4.5.2.B.1.c)

This project is part of the multi-year 4kV and 8kV Renewal Program. Both the 4kV and 8kV distribution system and the Horizon Utilities owned substations are at the end of their useful life. Horizon Utilities has chosen to renew the 4kV and 8kV distribution systems to a higher voltage to avoid the cost of the investment in the renewal of the substations. The total avoided substation renewal investment over the remaining 35 years of the plan is $70,000,000 for all 28 substations. Therefore the renewal of these distribution assets at the current 4kV level was not a feasible alternative.

Safety (5.4.5.2.B.2)

This project is not intended to address safety concerns with the distribution system.

Cyber-Security and Privacy (5.4.5.2.B.3) (where applicable)

Cyber-Security and Privacy are not applicable to this project.

Co-ordination and Interoperability (5.4.5.2.B.4)

Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.5.2.B.4.a) (where applicable)

Please refer to Note II for an explanation on co-ordination with utilities, regional planning and/or links with 3rd parties.

Enabling of Future Technology and/or Future Operational Requirements (5.4.5.2.B.4.b)

Please refer to Note IV for an explanation enabling of future technology and future operational requirements.

	Economic Development (5.4.5.2.B.5) **(where applicable)** Horizon Utilities ensures that policies and practices do not unnecessarily create barriers to economic development which are primarily focused within its communities.
	Environmental Benefits (5.4.5.2.B.6) **(where applicable)** n/a.

System Renewal Specific Requirements (5.4.5.2.C.b)			
	Project Name	GR-F2 Renewal – East of Vine Ave	Table 3

System Renewal Specific Requirements (5.4.5.2.C.b)

Asset Performance Target and Asset Lifecycle Optimization (5.4.5.2.C.b.i.1)

The 4kV distribution assets and substations assets in the St. Catharines operating area are in poor health and require renewal. The overall substation Health Index for Vine, Welland and Grantham substations is 57%, 59%, 58% respectively. 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. 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.

Asset Condition Relative to Typical Life Cycle (5.4.5.2.C.b.i.2)

Generally the 4kV assets are the oldest vintage in the system. 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.

Number of Customers Impacted (5.4.5.2.C.b.i.3)

This project will impact 737 customers.

Quantitative Customer Impact and Risk (5.4.5.2.C.b.i.4)

SAIDI of 0.025

Qualitative Customer Impact and Risk (5.4.5.2.C.b.i.5)

This project will address aging assets with inadequate backup. Aging assets represent an increased risk of service interruption to customers and inadequate backup would result in long duration service interruptions upon occurrence. These factors would lead to customer dissatisfaction in this area.

Value of Customer Impact (5.4.5.2.C.b.i.6)

High

Other Factors Affecting Project Timing (5.4.5.2.C.b.ii)

The renewal of the area serviced by the Grantham substation is scheduled for 2015 to 2017.

Impact on System O&M Costs (5.4.5.2.C.b.iii)

This project will have no material impact on planned O&M costs. The renewal of the 4kV and 8kV distribution systems, as a whole, will provide a reduction in reactive O&M costs to address service interruptions caused by failed equipment. These reductions will not be material in the 2015 to 2019 Test Years.

Reliability and Safety Factors (5.4.5.2.C.b.iv)

The renewal of the 4kV and 8kV distribution system will provide reliability improvements through reduced service interruptions caused by failed equipment.

Analysis of Project Benefits and Timing (5.4.5.2.C.b.v)

The timing of this project, as part of the 4kV and 8kV Renewal Program, is determined through the assessment of the distribution system health and the health of the substation assets servicing the area. 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.

Like-for-Like Renewal Analysis (5.4.5.2.C.b.vi)

The like-for-like renewal of these assets (i.e. same system configuration and same distribution voltage) will perpetuate the existing operating constraints and require capital investment to renew substation assets. Renewal of the distribution assets at a higher voltage does not involve any material incremental costs over renewal at the existing voltage. Operating constraints (e.g. undersized conductor, radial feeds) are addressed on a case by case basis where appropriate.

Capital Project Summary

General Information on Project (5.4.5.2.A)

Project Name	2017 St. Catharines XLPE Renewal			
Budget Year	2017			
Investment Category	System Renewal			
Project Summary	Renewal of end-of-life XLPE cable assets in the St. Catharines operating area.			
Capital Investment (5.4.5.2.A.i)	Capital Investment (gross)	$1,758,558		
	Customer Contribution	$0		
	Capital Investment (net)	$1,758,558		
	O&M Expenditure	$0		
Customer Attachments / Load (kVA) (5.4.5.2.A.ii)	The customer and load impacted by this project will vary depending upon the final scope of the project.			
Project Dates (5.4.5.2.A.iii)	Start Date	2017/03/01		
	In Service Date	2017/11/30		
	Expenditure Timing			
	Q1	Q2	Q3	Q4
	10%	40%	10%	40%

Schedule Risk and Risk Mitigation (5.4.5.2.A.iv**)**

Please refer to Note I for risk and risk mitigation.

Comparative Information from Equivalent Projects (5.4.5.2.A.v)

There is no direct comparator in scope, size and design characteristics for this project. This project is part of a multi-year investment to renewal XLPE primary cable. The 2017 investment in the XLPE Renewal Program is $8,866,000.

Comparable gross investments for the XLPE Renewal Program for the 2010 to 2013 Historical Years and the 2014 Bridge Year are:
2010 (CGAAP)- $ 0
2011 (CGAAP)- $ 0
2012 (MIFRS) - $ 0
2013 (MIFRS) - $ 1,572,090
2014 (MIFRS) - $ 893,000

Total Capital OM&A Costs Associated with REG Investments (5.4.5.2.A.vi)
This project is not associated with an REG investment and therefore OM&A costs related to REG will not be incurred.

Leave to Construct Approval (5.4.5.2.A.vii)

This project does not require “Leave to Construct” under Section 92 of the *Ontario Energy Board Act* 1998.

Evaluation Criteria and Information (5.4.5.2.B)

Project Name	2017 St. Catharines XLPE Renewal	Table 2

Efficiency, Customer Value, Reliability (5.4.5.2.B.1)

Investment Driver (5.4.5.2.B.1.a)
System Renewal (80%)

Secondary Driver (5.4.5.2.B.1.a)
System Service (20%)

Investment Priority (5.4.5.2.B.1.b)
4 – Required Project

Analysis of Project and Project Alternatives (5.4.5.2.B.1.c)

This project is part of the multi-year XLPE Renewal Program. Horizon Utilities considered the four replacement philosophies for addressing risk inherent in the XLPE asset group: Area; Reactive; Selected; and Refurbishment. The area replacement philosophy for will be utilized 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 St. Catharines operating area contains many small pockets of direct buried XLPE primary cable. The XLPE renewal projects in the St. Catharines operating area will involve the full renewal of each pocket of XLPE cable. Project selection will be guided by asset health, operating history, and reliability of each of the underground pockets of XLPE.

Safety (5.4.5.2.B.2)

These projects are not intended to address safety concerns with the distribution system.

Cyber-Security and Privacy (5.4.5.2.B.3) (where applicable)

Cyber-Security and Privacy are not applicable to this project.

Co-ordination and Interoperability (5.4.5.2.B.4)

Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.5.2.B.4.a) (where applicable)
Please refer to Note II for an explanation on co-ordination with utilities, regional planning and/or links with 3rd parties.

Enabling of Future Technology and/or Future Operational Requirements (5.4.5.2.B.4.b)

Please refer to Note IV for an explanation enabling of future technology and future operational requirements.

Economic Development (5.4.5.2.B.5) **(where applicable)**

Horizon Utilities ensures that policies and practices do not unnecessarily create barriers to economic development which are primarily focused within its communities.

Environmental Benefits (5.4.5.2.B.6) **(where applicable)**

n/a

System Renewal Specific Requirements (5.4.5.2.C.b)

Project Name	2017 St. Catharines XLPE Renewal	Table 3

System Renewal Specific Requirements (5.4.5.2.C.b)

Asset Performance Target and Asset Lifecycle Optimization (5.4.5.2.C.b.i.1)

XLPE primary cable is the asset group with the largest investment requirement as identified by the Kinectrics ACA. 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

Asset Condition Relative to Typical Life Cycle (5.4.5.2.C.b.i.2)

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.

Number of Customers Impacted (5.4.5.2.C.b.i.3)

The number of customers impacted will vary depending upon the area.

Quantitative Customer Impact and Risk (5.4.5.2.C.b.i.4)

Qualitative Customer Impact and Risk (5.4.5.2.C.b.i.5)

This project will address aging assets at risk of failure. Failure of XLPE primary cable results in extended service interruptions; 30% of these outages exceeded four hours in duration, while 5% of these outages exceeded twelve hours in duration.

Value of Customer Impact (5.4.5.2.C.b.i.6)

High

Other Factors Affecting Project Timing (5.4.5.2.C.b.ii)

Proactive replacements are required because, as assets continue to age and degrade, the cable will fail at an exponential rate. In the worst case scenario, it will exceed Horizon Utilities' ability to keep pace with repairs. Reliability will also deteriorate to unacceptable levels. Reactive replacements will be considerably more costly than proactive renewal.

Impact on System O&M Costs (5.4.5.2.C.b.iii)

This project will have no material impact on planned O&M costs. The renewal of the XLPE primary cable, as a whole, will provide a reduction in reactive O&M costs to address service interruptions caused by failed equipment. These reductions will not be material in the 2015 to 2019 Test Years.

Reliability and Safety Factors (5.4.5.2.C.b.iv)

The renewal of the XLPE primary cable system will provide reliability improvements through reduced service interruptions caused by failed equipment.

Analysis of Project Benefits and Timing (5.4.5.2.C.b.v)

Failure to invest in the proactive renewal of XLPE primary cable and associated underground assets would result in unacceptable levels of system failures and outages beyond Horizon Utilities' ability to resolve within a reasonable timeframe as these assets continue to age and degrade. Reactive replacements will also be considerably more costly than the forecast expenditure required to execute the proposed proactive replacement

Like-for-Like Renewal Analysis (5.4.5.2.C.b.vi)

XLPE renewal projects will include the elimination of radial underground feeds, replace below grade transformers with padmount transformers, and introduce fusing on the underground distribution systems where applicable.

Capital Project Summary

General Information on Project (5.4.5.2.A)

Project Name	VE-F1 Renewal – North of Queenston St
Budget Year	2017
Investment Category	System Renewal
Project Summary	This project involves the renewal of the Vine substation F1 feeder in the St. Catharines operating area North of Queenston St.

Capital Investment (5.4.5.2.A.i)	Capital Investment (gross)	$1,883,830
	Customer Contribution	$0
	Capital Investment (net)	$1,883,830
	O&M Expenditure	$0

Customer Attachments / Load (kVA) (5.4.5.2.A.ii)	This project impacts approximately 430 customers and 1500kVA of transformation.
Project Dates (5.4.5.2.A.iii)	Start Date 2017/05/01 In Service Date 2017/11/30

Expenditure Timing

Q1	Q2	Q3	Q4
	30%	40%	30%

Schedule Risk and Risk Mitigation (5.4.5.2.A.iv**)**

Please refer to Note I for risk and risk mitigation.

Comparative Information from Equivalent Projects (5.4.5.2.A.v)

There is no direct comparator in scope, size and design characteristics for this project. This project is one phase of a multi-year investment to renew the area served by Vine substation as part of the 4kV and 8kV Renewal Program. The 2017 investment for the renewal of Vine substation is $5,645,000. The 2017 investment in the 4kV and 8kV Renewal Program is $15,764,000.

Comparable gross investments for the 4kv and 8kV Renewal Program for the 2010 to 2013 Historical Year and the 2014 Bridge Year are:

2010 (CGAAP)- $ 2,556,076
2011 (CGAAP)- $ 8,820,000
2012 (MIFRS) - $ 5,268,441
2013 (MIFRS) - $ 5,072,233
2014 (MIFRS) - $ 6,434,000

	Total Capital OM&A Costs Associated with REG Investments (5.4.5.2.A.vi) This project is not associated with an REG investment and therefore OM&A costs related to REG will not be incurred. **Leave to Construct Approval** (5.4.5.2.A.vii) This project does not require "Leave to Construct" under Section 92 of the *Ontario Energy Board Act* 1998.

Evaluation Criteria and Information (5.4.5.2.B)	
	Project Name VE-F1 Renewal – North of Queenston St Table 2
	Efficiency, Customer Value, Reliability (5.4.5.2.B.1) **Investment Driver (5.4.5.2.B.1.a)** System Renewal (80%) **Secondary Driver (5.4.5.2.B.1.a)** System Service (20%) **Investment Priority (5.4.5.2.B.1.b)** 3 – Required project
	Analysis of Project and Project Alternatives (5.4.5.2.B.1.c) This project is part of the multi-year 4kV and 8kV Renewal Program. Both the 4kV and 8kV distribution system and the Horizon Utilities-owned substations are at the end of their useful life. Horizon Utilities has chosen to renew the 4kV and 8kV distribution systems to a higher voltage to avoid the cost of the investment in the renewal of the substations. The total avoided substation renewal investment over the remaining 35 years of the plan is $70,000,000 for all 28 substations. Therefore the renewal of this project at the current 4kV level was not a feasible alternative.
	Safety (5.4.5.2.B.2) These projects are not intended to address safety concerns with the distribution system.
	Cyber-Security and Privacy (5.4.5.2.B.3) (where applicable) Cyber-Security and Privacy are not applicable to this project.
	Co-ordination and Interoperability (5.4.5.2.B.4) **Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.5.2.B.4.a) (where applicable)** Please refer to Note II for an explanation on co-ordination with utilities, regional planning and/or links with 3rd parties. **Enabling of Future Technology and/or Future Operational Requirements (5.4.5.2.B.4.b)** Please refer to Note IV for an explanation enabling of future technology and future operational requirements.
	Economic Development (5.4.5.2.B.5) **(where applicable)** Horizon Utilities ensures that policies and practices do not unnecessarily create barriers to economic development which are primarily focused within its communities.

Environmental Benefits (5.4.5.2.B.6) **(where applicable)**

n/a

System Renewal Specific Requirements (5.4.5.2.C.b)

Project Name	VE-F1 Renewal – North of Queenston St	Table 3

System Renewal Specific Requirements (5.4.5.2.C.b)

Asset Performance Target and Asset Lifecycle Optimization (5.4.5.2.C.b.i.1)

The 4kV distribution assets and substations assets in the St. Catharines operating area are in poor health and require renewal. The overall substation Health Index for Vine, Welland and Grantham substations is 57%, 59%, 58% respectively. 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. 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.

Asset Condition Relative to Typical Life Cycle (5.4.5.2.C.b.i.2)

Generally the 4kV assets are the oldest vintage in the system. 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.

Number of Customers Impacted (5.4.5.2.C.b.i.3)

This project impacts 430 customers.

Quantitative Customer Impact and Risk (5.4.5.2.C.b.i.4)

SAIDI of 0.015

Qualitative Customer Impact and Risk (5.4.5.2.C.b.i.5)

This project will address aging assets with inadequate backup. Aging assets represent an increased risk of service interruption to customers and inadequate backup would result in long duration service interruptions upon occurrence. These factors would lead to customer dissatisfaction in this area.

Value of Customer Impact (5.4.5.2.C.b.i.6)

High

Other Factors Affecting Project Timing (5.4.5.2.C.b.ii)

The renewal of the area serviced by Vine substation is scheduled for 2015 to 2017.

Impact on System O&M Costs (5.4.5.2.C.b.iii)

This project will have no material impact on planned O&M costs. The renewal of the 4kV and 8kV distribution systems, as a whole, will provide a reduction in reactive O&M costs to address service interruptions caused by failed equipment. These reductions will not be material in the 2015 to 2019 Test Years.

Reliability and Safety Factors (5.4.5.2.C.b.iv)

The renewal of the 4kV and 8kV distribution system will provide reliability improvements through reduced service interruptions caused by failed equipment.

Analysis of Project Benefits and Timing (5.4.5.2.C.b.v)

The timing of this project, as part of the 4kV and 8kV Renewal Program, is determined through the assessment of the distribution system health and the health of the substation assets servicing the area.

Like-for-Like Renewal Analysis (5.4.5.2.C.b.vi)

The like-for-like renewal of these assets (i.e. same system configuration and same distribution voltage) will perpetuate the existing operating constraints and require capital investment to renew substation assets. Renewal of the distribution assets at a higher voltage does not involve any material incremental costs over renewal at the existing voltage. Operating constraints (e.g. undersized conductor, radial feeds) are addressed on a case by case basis where appropriate.

Horizon Utilities — Looking beyond

Capital Project Summary

General Information on Project (5.4.5.2.A)

Project Name	VE-F3 Renewal
Budget Year	2017
Investment Category	System Renewal
Project Summary	This project involves the renewal of the Vine Substation F3 feeder in the St. Catharines operating area North of Queenston St.

Capital Investment (5.4.5.2.A.i)

Capital Investment (gross)	$1,624,436
Customer Contribution	$0
Capital Investment (net)	$1,624,436
O&M Expenditure	$0

Customer Attachments / Load (kVA) (5.4.5.2.A.ii)

This project impacts approximately 470 customers and 2000kVA of transformation.

Project Dates (5.4.5.2.A.iii)

Start Date 2017/03/01

In Service Date 2017/09/30

Expenditure Timing

Q1	Q2	Q3	Q4
15%	45%	40%	0%

Schedule Risk and Risk Mitigation (5.4.5.2.A.iv**)**

Please refer to Note I for risk and risk mitigation.

Comparative Information from Equivalent Projects (5.4.5.2.A.v)

There is no direct comparator in scope, size and design characteristics for this project. This project is one phase of a multi-year investment to renew the area served by Vine substation as part of the 4kV and 8kV Renewal Program. The 2017 investment for the renewal of Vine substation is $5,645,000. The 2017 investment in the 4kV and 8kV Renewal Program is $15,764,000.

Comparable gross investments for the 4kV and 8kV Renewal Program for the 2010 to 2013 Historical Years and the 2014 Bridge Year are:

2010 (CGAAP)- $ 2,556,076
2011 (CGAAP)- $ 8,820,000
2012 (MIFRS) - $ 5,268,441
2013 (MIFRS) - $ 5,072,233
2014 (MIFRS) - $ 6,434,000

Total Capital OM&A Costs Associated with REG Investments (5.4.5.2.A.vi)

This project is not associated with an REG investment and therefore OM&A costs related to REG will not be incurred.

Leave to Construct Approval (5.4.5.2.A.vii)

This project does not require "Leave to Construct" under Section 92 of the *Ontario Energy Board Act* 1998.

Evaluation Criteria and Information (5.4.5.2.B)

Project Name VE-F3 Renewal Table 2

Efficiency, Customer Value, Reliability (5.4.5.2.B.1)

Investment Driver (5.4.5.2.B.1.a)
System Renewal (80%)

Secondary Driver (5.4.5.2.B.1.a)
System Service (20%)

Investment Priority (5.4.5.2.B.1.b)
3 – Required project

Analysis of Project and Project Alternatives (5.4.5.2.B.1.c)

This project is part of the multi-year 4kV and 8kV Renewal Program. Both the 4kV and 8kV distribution system and the Horizon Utilities-owned substations are at the end of their useful life. Horizon Utilities has chosen to renew the 4kV and 8kV distribution systems to a higher voltage to avoid the cost of the investment in the renewal of the substations. The total avoided substation renewal investment over the remaining 35 years of the plan is $70,000,000 for all 28 substations. Therefore the renewal of these distribution assets at the current 4kV level was not a feasible alternative.

Safety (5.4.5.2.B.2)

These projects are not intended to address safety concerns with the distribution system.

Cyber-Security and Privacy (5.4.5.2.B.3) (where applicable)

n/a

Co-ordination and Interoperability (5.4.5.2.B.4)

Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.5.2.B.4.a) (where applicable)
Please refer to Note II for an explanation on co-ordination with utilities, regional planning and/or links with 3rd parties.

Enabling of Future Technology and/or Future Operational Requirements (5.4.5.2.B.4.b)

Please refer to Note IV for an explanation enabling of future technology and future operational requirements.

	Economic Development (5.4.5.2.B.5) **(where applicable)** Horizon Utilities ensures that policies and practices do not unnecessarily create barriers to economic development which are primarily focused within its communities.
	Environmental Benefits (5.4.5.2.B.6) **(where applicable)** n/a

System Renewal Specific Requirements (5.4.5.2.C.b)			
	Project Name	VE-F3 Renewal	Table 3

System Renewal Specific Requirements (5.4.5.2.C.b)

Asset Performance Target and Asset Lifecycle Optimization (5.4.5.2.C.b.i.1)

The 4kV distribution assets and substations assets in the St. Catharines operating area are in poor health and require renewal. The overall substation Health Index for Vine, Welland and Grantham substations is 57%, 59%, 58% respectively. 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. 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.

Asset Condition Relative to Typical Life Cycle (5.4.5.2.C.b.i.2)

Generally the 4kV assets are the oldest vintage in the system. 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.

Number of Customers Impacted (5.4.5.2.C.b.i.3)

This project impacts approximately 470 customers.

Quantitative Customer Impact and Risk (5.4.5.2.C.b.i.4)

SAIDI of 0.073

Qualitative Customer Impact and Risk (5.4.5.2.C.b.i.5)

This project will address aging assets with inadequate backup. Aging assets represent an increased risk of service interruption to customers and inadequate backup would result in long duration service interruptions upon occurrence. These factors would lead to customer dissatisfaction in this area.

Value of Customer Impact (5.4.5.2.C.b.i.6)

High

Other Factors Affecting Project Timing (5.4.5.2.C.b.ii)

The renewal of the area serviced by Vine substation is scheduled for 2015 to 2017.

Impact on System O&M Costs (5.4.5.2.C.b.iii)

This project will have no material impact on planned O&M costs. The renewal of the 4kV and 8kV distribution systems, as a whole, will provide a reduction in reactive O&M costs to address service interruptions caused by failed equipment. These reductions will not be material in the 2015 to 2019 Test Years.

Reliability and Safety Factors (5.4.5.2.C.b.iv)

The renewal of the 4kV and 8kV distribution system will provide reliability improvements through reduced service interruptions caused by failed equipment.

Analysis of Project Benefits and Timing (5.4.5.2.C.b.v)

The timing of this project, as part of the 4kV and 8kV Renewal Program, is determined through the assessment of the distribution system health and the health of the substation assets servicing the area.

Like-for-Like Renewal Analysis (5.4.5.2.C.b.vi)

The like-for-like renewal of these assets (i.e. same system configuration and same distribution voltage) will perpetuate the existing operating constraints and require capital investment to renew substation assets. Renewal of the distribution assets at a higher voltage does not involve any material incremental costs over renewal at the existing voltage. Operating constraints (e.g. undersized conductor, radial feeds) are addressed on a case by case basis where appropriate.

Capital Project Summary

General Information on Project (5.4.5.2.A)

Project Name	VE-F4 Renewal – Welland Ave and North St
Budget Year	2017
Investment Category	System Renewal
Project Summary	This project involves the renewal of the Vine Substation F4 feeder in the St. Catharines operating area north of Welland Ave.
Capital Investment (5.4.5.2.A.i)	Capital Investment (gross): $2,136,914 Customer Contribution: $0 Capital Investment (net): $2,136,914 O&M Expenditure: $0
Customer Attachments / Load (kVA) (5.4.5.2.A.ii)	This project impacts approximately 600 customers and 2000kVA of transformation.
Project Dates (5.4.5.2.A.iii)	Start Date 2017/04/01 In Service Date 2017/10/31

Expenditure Timing

Q1	Q2	Q3	Q4
10%	45%	45%	10%

Schedule Risk and Risk Mitigation (5.4.5.2.A.iv**)**

Please refer to Note I for risk and risk mitigation.

Comparative Information from Equivalent Projects (5.4.5.2.A.v)

There is no direct comparator in scope, size and design characteristics for this project. This project is one phase of a multi-year investment to renew the area served by Vine substation as part of the 4kV and 8kV Renewal Plan. The 2017 investment for the renewal of Vine substation is $5,645,000. The 2017 investment in the 4kV and 8kV Renewal Program is $15,764,000.

Comparable gross investments for the 4kV and 8kV Renewal Program for the 2010 to 2013 Historical Years and the 2014 Bridge Year are:

2010 (CGAAP)- $ 2,556,076
2011 (CGAAP)- $ 8,820,000
2012 (MIFRS) - $ 5,268,441
2013 (MIFRS) - $ 5,072,233
2014 (MIFRS) - $ 6,434,000

Total Capital OM&A Costs Associated with REG Investments (5.4.5.2.A.vi)

This project is not associated with an REG investment and therefore OM&A costs related to REG will not be incurred.

Leave to Construct Approval (5.4.5.2.A.vii)

This project does not require "Leave to Construct" under Section 92 of the *Ontario Energy Board Act* 1998.

Evaluation Criteria and Information (5.4.5.2.B)

Project Name VE-F4 Renewal – Welland Ave and North St Table 2

Efficiency, Customer Value, Reliability (5.4.5.2.B.1)

Investment Driver (5.4.5.2.B.1.a)
System Renewal (80%)

Secondary Driver (5.4.5.2.B.1.a)
System Service (20%)

Investment Priority (5.4.5.2.B.1.b)
3 – Required project

Analysis of Project and Project Alternatives (5.4.5.2.B.1.c)

This project is part of the multi-year 4kV and 8kV Renewal Program. Both the 4kV and 8kV distribution system and the Horizon Utilities-owned substations are at the end of their useful life. Horizon Utilities has chosen to renew the 4kV and 8kV distribution systems to a higher voltage to avoid the cost of the investment in the renewal of the substations. The total avoided substation renewal investment over the remaining 35 years of the plan is $70,000,000 for all 28 substations. Therefore the renewal of the distribution assets at the current 4kV level was not a feasible alternative.

Safety (5.4.5.2.B.2)

These projects are not intended to address safety concerns with the distribution system.

Cyber-Security and Privacy (5.4.5.2.B.3) (where applicable)

n/a

Co-ordination and Interoperability (5.4.5.2.B.4)

Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.5.2.B.4.a) (where applicable)
Please refer to Note II for an explanation on co-ordination with utilities, regional planning and/or links with 3rd parties.

Enabling of Future Technology and/or Future Operational Requirements (5.4.5.2.B.4.b)

Please refer to Note IV for an explanation enabling of future technology and future operational requirements.

	Economic Development (5.4.5.2.B.5) **(where applicable)** Horizon Utilities ensures that policies and practices do not unnecessarily create barriers to economic development which are primarily focused within its communities.
	Environmental Benefits (5.4.5.2.B.6) **(where applicable)** n/a

System Renewal Specific Requirements (5.4.5.2.C.b)	**Project Name** VE-F4 Renewal – Welland Ave and North St Table 3
	System Renewal Specific Requirements (5.4.5.2.C.b) **Asset Performance Target and Asset Lifecycle Optimization (5.4.5.2.C.b.i.1)** The 4kV distribution assets and substations assets in the St. Catharines operating area are in poor health and require renewal. The overall substation Health Index for Vine, Welland and Grantham substations is 57%, 59%, 58% respectively. 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. 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. **Asset Condition Relative to Typical Life Cycle (5.4.5.2.C.b.i.2)** Generally the 4kV assets are the oldest vintage in the system. 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. **Number of Customers Impacted (5.4.5.2.C.b.i.3)** This project impacts approximately 600 customers. **Quantitative Customer Impact and Risk (5.4.5.2.C.b.i.4)** SAIDI of 0.022 **Qualitative Customer Impact and Risk (5.4.5.2.C.b.i.5)** This project will address aging assets with inadequate backup. Aging assets represent an increased risk of service interruption to customers and inadequate backup would result in long duration service interruptions upon occurrence. These factors would lead to customer dissatisfaction in this area. **Value of Customer Impact (5.4.5.2.C.b.i.6)** High

Other Factors Affecting Project Timing (5.4.5.2.C.b.ii)

The renewal of the area serviced by Vine substation is scheduled for 2015 to 2017.

Impact on System O&M Costs (5.4.5.2.C.b.iii)

This project will have no material impact on planned O&M costs. The renewal of the 4kV and 8kV distribution systems, as a whole, will provide a reduction in reactive O&M costs to address service interruptions caused by failed equipment. These reductions will not be material in the 2015 to 2019 Test Years.

Reliability and Safety Factors (5.4.5.2.C.b.iv)

The renewal of the 4kV and 8kV distribution system will provide reliability improvements through reduced service interruptions caused by failed equipment.

Analysis of Project Benefits and Timing (5.4.5.2.C.b.v)

The timing of this project, as part of the 4kV and 8kV Renewal Program, is determined through the assessment of the distribution system health and the health of the substation assets servicing the area.

Like-for-Like Renewal Analysis (5.4.5.2.C.b.vi)

The like-for-like renewal of these assets (i.e. same system configuration and same distribution voltage) will perpetuate the existing operating constraints and require capital investment to renew substation assets. Renewal of the distribution assets at a higher voltage does not involve any material incremental costs over renewal at the existing voltage. Operating constraints (e.g. undersized conductor, radial feeds) are addressed on a case by case basis where appropriate.

Capital Project Summary

General Information on Project (5.4.5.2.A)

Project Name	Duct Structure – Elgin TS to King St			
Budget Year	2017			
Investment Category	System Service			
Project Summary	This project is involves the addition of civil capacity to support the renewal of the 4kV in this area and to address general load growth in the Hamilton downtown operating area.			
Capital Investment (5.4.5.2.A.i)	Capital Investment (gross)	$535,135		
	Customer Contribution	$0		
	Capital Investment (net)	$535,135		
	O&M Expenditure	$0		
Customer Attachments / Load (kVA) (5.4.5.2.A.ii)	n/a			
Project Dates (5.4.5.2.A.iii)	Start Date	2017/05/01		
	In Service Date	2017/09/30		
	Expenditure Timing			
	Q1	Q2	Q3	Q4
	0%	40%	60%	0%

Schedule Risk and Risk Mitigation (5.4.5.2.A.iv**)**

Please refer to Note I for risk and risk mitigation.

Comparative Information from Equivalent Projects (5.4.5.2.A.v)

There are no equivalent projects for comparison.

Total Capital OM&A Costs Associated with REG Investments (5.4.5.2.A.vi)

This project is not associated with an REG investment and therefore OM&A costs related to REG will not be incurred.

Leave to Construct Approval (5.4.5.2.A.vii)

This project does not require “Leave to Construct” under Section 92 of the *Ontario Energy Board Act* 1998.

Evaluation Criteria and Information (5.4.5.2.B)	**Project Name** Duct Structure – Elgin TS to King St Table 2
	Efficiency, Customer Value, Reliability (5.4.5.2.B.1) **Investment Driver (5.4.5.2.B.1.a)** System Service (60%) **Secondary Driver (5.4.5.2.B.1.a)** System Renewal (40%) **Investment Priority (5.4.5.2.B.1.b)** 3 – Required project
	Analysis of Project and Project Alternatives (5.4.5.2.B.1.c) No feasible alternatives exist to provide this civil capacity. Construction of an overhead solution in this area of the downtown core would not be possible.
	Safety (5.4.5.2.B.2) These projects are not intended to address safety concerns with the distribution system.
	Cyber-Security and Privacy (5.4.5.2.B.3) (where applicable) Cyber-Security and Privacy are not applicable to this project.
	Co-ordination and Interoperability (5.4.5.2.B.4) **Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.5.2.B.4.a) (where applicable)** Please refer to Note II for an explanation on co-ordination with utilities, regional planning and/or links with 3rd parties. **Enabling of Future Technology and/or Future Operational Requirements (5.4.5.2.B.4.b)** Please refer to Note IV for an explanation enabling of future technology and future operational requirements.
	Economic Development (5.4.5.2.B.5) **(where applicable)** Horizon Utilities ensures that policies and practices do not unnecessarily create barriers to economic development which are primarily focused within its communities.
	Environmental Benefits (5.4.5.2.B.6) **(where applicable)** n/a

System Service Specific Requirements (5.4.5.2.C.c)	**Project Name** Duct Structure – Elgin TS to King St	Table 3

System Service Specific Requirements (5.4.5.2.C.c)

Benefit to Customers (5.4.5.2.C.c.i)

This project will enable additional redundancy and connections between stations will provide Horizon Utilities with additional operational contingencies to address service interruptions.

Regional Planning Requirements (5.4.5.2.C.c.i)

This project is not related or impacted by regional planning requirements.

Integration of Advance Technology (5.4.5.2.C.c.iii)

Please refer to Note IV for an explanation enabling of future technology and future operational requirements.

System Benefits to Reliability, Efficiency and Safety (5.4.5.2.C.c.iv)

n/a

Factors Affecting Implementing Timing/Priority (5.4.5.2.C.c.v)

n/a

Summary of Options Analysis (5.4.5.2.C.c.vi)

n/a

2017 General Plant Investments

Capital Project Summary

Project Name	2017 Annual Corporate Computer Replacement			
Budget Year	2017			
Investment Category	General Plant			
Project Summary	This project is part of an ongoing business requirement to refresh end user computers. Horizon Utilities utilizes a three-year lifecycle for replacement of end user computers. On an annual basis, approximately one third of all Horizon Utilities' computers (~150 PCs/year) are replaced.			
Capital Investment (5.4.5.2.A.i)	Capital Investment (gross)	$353,200		
	Customer Contribution	n/a		
	Capital Investment (net)	n/a		
	O&M Expenditure	n/a		
Customer Attachments / Load (5.4.5.2.A.ii)	n/a			
Project Dates (5.4.5.2.A.iii)	Start Date	Jan. 2017		
	In Service Date	Dec. 2017		
	Expenditure Timing			
	Q1	Q2	Q3	Q4
	25%	25%	25%	25%

Schedule Risk and Risk Mitigation (5.4.5.2.A.iv)

Schedule - Implementation is phased throughout the year starting in January and ending in December based on age of PCs being replaced.

Risk – The primary risk to this project is product availability from suppliers.

Risk Mitigation – Work closely with suppliers to schedule orders based on required delivery times.

Comparative Information from Equivalent Projects (5.4.5.2.A.v)

Comparable gross investments for the annual corporate computer replacement for the 2010 to 2013 Historical Years and the 2014 Bridge Year are:

2010 (CGAAP)- $ 336,000
2011 (CGAAP)- $ 227,000
2012 (MIFRS) - $ 312,000
2013 (MIFRS) - $ 364,947
2014 (MIFRS) - $ 366,200

Total Capital and OM&A Costs Associated with REG Investments (5.4.5.2.A.vi)
n/a

	Leave to Construct Approval (5.4.5.2.A.vii) n/a
Evaluation Criteria and Information	**Project Name** 2017 Annual Corporate Computer Replacement Table 2
	Efficiency, Customer Value, Reliability (5.4.5.2.B.1) **Investment Driver (5.4.5.2.B.1.a)** General Plant (100%) **Secondary Driver (5.4.5.2.B.1.a)** n/a **Investment Priority (5.4.5.2.B.1.b)** High Priority – Personal computers are treated as a strategic asset. They are Horizon Utilities' primary staff productivity tool. They are used to: maintain and deliver services to customers; improve staff productivity; cost-effectively manage total cost of PC ownership; and support investments in new applications, infrastructure and business capabilities
	Analysis of Project and Project Alternatives (5.4.5.2.B.1.c) n/a
	Safety (5.4.5.2.B.2) n/a
	Cyber-Security and Privacy (5.4.5.2.B.3) (where applicable) n/a
	Co-ordination and Interoperability (5.4.5.2.B.4) **Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.5.2.B.4.a) (where applicable)** n/a **Enabling of Future Technology and/or Future Operational Requirements (5.4.5.2.B.4.b)** Suppliers of enterprise systems such as: GIS; OMS; SCADA; AMI; and IFS ERP are constantly upgrading their products to deliver new processes and functionality. As new versions are released, up-to-date hardware is required in order to perform necessary upgrades to maintain vendor support for the systems.
	Economic Development (5.4.5.2.B.5) **(where applicable)** n/a
	Environmental Benefits (5.4.5.2.B.6) **(where applicable)** n/a

General Plant Specific Requirements	**Project Name** 2017 Annual Corporate Computer Replacement Table 3

General Plant Specific Requirements (5.4.5.2.C.d)

Summary of Qualitative and Quantitative Analysis (5.4.5.2.C.d.i)

n/a

Business Case Justification Documentation (5.4.5.2.C.d.i)

Horizon Utilities' PCs are treated as a strategic asset, because they are the primary staff productivity tool. Horizon Utilities has streamlined its PC lifecycle management processes utilizing a PC refresh cycle of three years, in order to: deliver, maintain and improve services to customers; to improve staff productivity; to cost-effectively manage total cost of PC ownership; and to support investments in new applications, infrastructure and business capabilities.

A three-year PC refresh cycle reduces the total cost of ownership by reducing the number of models of PCs supported, which results in the reduction of the IST service desk effort required to deploy, secure, and manage new systems and applications. The reduction in the number of supported models has allowed Horizon Utilities to introduce mobile computing for remote field workers and to increase the number of supported PCs by over 100 devices since 2011, without an increase in IST service desk support staff.

A refresh lifecycle of three years reduces the likelihood of device failures that lead to a loss of staff productivity and increased IT support effort. Over 50% of Horizon Utilities' staff utilizes a mobile PC (laptop or tablet) in the performance of their daily activities, many in harsh operating environments outside the office, which increases the likelihood of failure due to operating environment and the age of the device.

Horizon Utilities has introduced several new enterprise business and engineering systems to: mitigate business risks related to aging systems (e.g. GIS); improve electricity system operation (i.e. GIS, OMS); and to address end of vendor support for systems (i.e. IFS ERP, Microsoft Windows XP). Maintaining a three-year PC lifecycle refresh program allows Horizon Utilities' to migrate to these applications without a need to make large one-time investments in PCs to meet the minimum operating requirements of new applications.

PCs are the primary productivity tool used by Horizon Utilities' staff. Unreliable and slow PCs impact productivity and customer service.

Minimizing the number of supported models reduces the IST support effort required to manage, order, configure, and deploy PCs and it reduces the total cost of ownership for PCs.

Capital Project Summary

Project Name	2017 John Street Windows Replacement
Budget Year	2017
Investment Category	General Plant

Project Summary;

This project is scheduled to take place between 2015 to 2017 to replace the existing windows of the John Street building as they have reached the end-of-lie with the objective to:

- Improve energy performance as the they are no longer weather resistant;
- Prevent further damage to interior walls and facilities related components;
- Prevent further damage to the building exterior structure;
- Prevent damage to operational systems; and
- Reduce operational related costs.

Capital Investment (5.4.5.2.A.i)	Capital Investment (gross)	$200,000
	Customer Contribution	n/a
	Capital Investment (net)	n/a
	O&M Expenditure	n/a

Customer Attachments / Load (5.4.5.2.A.ii)	n/a

Project Dates (5.4.5.2.A.iii)

Start Date	March 2017
In Service Date	December 2017

Expenditure Timing			
Q1	Q2	Q1	Q2
10%	30%	30%	30%

Schedule Risk and Risk Mitigation (5.4.5.2.A.iv**)**

Project timelines and costs exceeding the budget are risks. The project manager will report regularly on project timelines and adherence to budget and escalates issues for resolution.

Comparative Information from Equivalent Projects (5.4.5.2.A.v)

n/a.

Total Capital OM&A Costs Associated with REG Investments (5.4.5.2.A.vi)

n/a

Leave to Construct Approval (5.4.5.2.A.vii)

n/a

Evaluation Criteria and Information	**Project Name:** 2017 John Street Windows Replacement	Table 2
	Efficiency, Customer Value, Reliability (5.4.5.2.B.1) **Investment Driver (5.4.5.2.B.1.a)** General Plant – 100% **Secondary Driver (5.4.5.2.B.1.a)** n/a **Investment Priority (5.4.5.2.B.1.b)** High	
	Analysis of Project and Project Alternatives (5.4.5.2.B.1.c) Horizon Utilities engaged the MMM Group Limited in 2013 to conduct a condition assessment using visual inspections, air leakage testing and building energy simulations air test. Recommendations are based on the results of the tests and inspections.	
	Safety (5.4.5.2.B.2) n/a	
	Cyber-Security and Privacy (5.4.5.2.B.3) (where applicable) N/A	
	Co-ordination and Interoperability (5.4.5.2.B.4) **Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.5.2.B.4.a) (where applicable)** n/a **Enabling of Future Technology and/or Future Operational Requirements (5.4.5.2.B.4.b)** n/a	
	Economic Development (5.4.5.2.B.5) **(where applicable)** n/a **Environmental Benefits** (5.4.5.2.B.6) **(where applicable)** n/a	

General Plant Specific Requirements

Project Name	2017 John Street Windows Replacement	Table 3

General Plant Specific Requirements (5.4.5.2.C.d)

Summary of Qualitative and Quantitative Analysis (5.4.5.2.C.d.i)

Horizon Utilities engaged the MMM Group Limited in 2013 to conduct a condition assessment using visual inspections, air leakage testing and building energy simulations air test. Recommendations are based on the results of the tests and inspections.

Business Case Justification Documentation (5.4.5.2.C.d.i)
The windows are no longer weather resistant or energy efficient and allow cold drafts to enter the building. The windows collect frost on the inside in the winter which melts and damages interior walls and carpeting. The assessment was conducted using visual inspections, air leakage testing and building energy simulations. The testing concluded that the condition of the operable windows in the John Street office building is poor. 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.

Capital Project Summary

Project Name	2017 Vehicle Replacement
Budget Year	2017
Investment Category	General Plant

Project Summary;

Horizon Utilities has identified a number of current vehicles that will require replacement as they have reached end-of-life as per the criteria within Horizon Utilities' Fleet Replacement Plan.

Other expected objectives and outcomes are to:

- Maintain vehicle reliability and availability;
- Reduce fuel consumption;
- Reduce emissions;
- Reduce down time required to conduct maintenance and repairs; and
- Maintain customer response time.

Capital Investment (5.4.5.2.A.i)	Capital Investment (gross)	$775,000
	Customer Contribution	n/a
	Capital Investment (net)	n/a
	O&M Expenditure	n/a
Customer Attachments / Load (5.4.5.2.A.ii)		

Project Dates (5.4.5.2.A.iii)

Start Date	March 2017
In Service Date	December 2017

Expenditure Timing

Q1	Q2	Q3	Q4
0%	0%	50%	50%

Schedule Risk and Risk Mitigation (5.4.5.2.A.iv**)**

Risk – The primary risk to this project is product availability and adherence to delivery schedules from suppliers.
Risk Mitigation – Work closely with suppliers to schedule orders based on required delivery times.

Comparative Information from Equivalent Projects (5.4.5.2.A.v)

Comparable gross investments for vehicle replacements for the 2010 to 2013 Historical Years and the 2014 Bridge Year are:

2010 (CGAAP)- $ 1,590,516
2011 (CGAAP)- $ 1,033,975
2012 (MIFRS) - $ 1,057,410
2013 (MIFRS) - $ 36,365
2014 (MIFRS) - $ 785,000

Total Capital OM&A Costs Associated with REG Investments (5.4.5.2.A.vi)

n/a

Leave to Construct Approval (5.4.5.2.A.vii)
n/a

Evaluation Criteria and Information

Project Name: 2017 Vehicle Replacement Table 2

Efficiency, Customer Value, Reliability (5.4.5.2.B.1)

Investment Driver (5.4.5.2.B.1.a)

General Plant – 100%

Secondary Driver (5.4.5.2.B.1.a)
n/a

Investment Priority (5.4.5.2.B.1.b)

High

Analysis of Project and Project Alternatives (5.4.5.2.B.1.c)

n/a

Safety (5.4.5.2.B.2)

n/a

Cyber-Security and Privacy (5.4.5.2.B.3) (where applicable)
n/a

Co-ordination and Interoperability (5.4.5.2.B.4)

Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.5.2.B.4.a) (where applicable)

n/a

Enabling of Future Technology and/or Future Operational Requirements (5.4.5.2.B.4.b)

n/a

Economic Development (5.4.5.2.B.5) **(where applicable)**

n/a

Environmental Benefits (5.4.5.2.B.6) **(where applicable)**

n/a

General Plant Specific Requirements

Project Name	2017 Vehicle Replacement	Table 3

General Plant Specific Requirements (5.4.5.2.C.d)

Summary of Qualitative and Quantitative Analysis (5.4.5.2.C.d.i)

Horizon Utilities uses the data collected from electronic fleet and fuel management system, the Global Positional 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 and vehicle maintenance and repairs activities to determine maintenance schedules and vehicles replacements..

Business Case Justification Documentation (5.4.5.2.C.d.i)

To maintain the quality, reliability and availability of Horizon Utilities’ vehicle fleet to Construction and Maintenance, Metering Services and corporate group activities, vehicles are assessed annually based on a replacement criteria matrix defined within the Fleet Replacement Plan.

Replacement strategies also ensure that Horizon Utilities maintains safe vehicles for employees, while targeting reduced emissions, as well as reduced fuel, operating and maintenance costs. Horizon Utilities will not be procuring any net new vehicles over the 2014-2019 period and instead will focus on the replacement of end of life vehicles.

Due to budget mitigation efforts in 2011, 2012, and 2013, a number of vehicles scheduled for replacement were kept in operation and rescheduled for replacement in 2014. It is now critical that these vehicles be replaced as maintenance and repairs costs have increased and the vehicles no longer operate at full capacity, reducing vehicle availability and impacting service delivery.

Regular vehicle replacement is necessary to avoid undue vehicle down time and associated negative impacts to customer response time and employee productivity.

Capital Project Summary

Project Name	2017 Tools, Shop and Garage Equipment
Budget Year	2017
Investment Category	General Plant

Project Summary
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

Capital Investment (5.4.5.2.A.i)	Capital Investment (gross)	$508,600
	Customer Contribution	n/a
	Capital Investment (net)	n/a
	O&M Expenditure	$0

Customer Attachments / Load (5.4.5.2.A.ii)	n/a
Project Dates (5.4.5.2.A.iii)	Start Date: January 2017 In Service Date: December 2017

Expenditure Timing

Q1	Q2	Q3	Q4
25%	25%	25%	25%

Schedule Risk and Risk Mitigation (5.4.5.2.A.iv**)**

Risk – n/a

Risk Mitigation – n/a

Comparative Information from Equivalent Projects (5.4.5.2.A.v)

n/a

Total Capital OM&A Costs Associated with REG Investments (5.4.5.2.A.vi)
n/a

Leave to Construct Approval (5.4.5.2.A.vii)
n/a

Evaluation Criteria and Information	
	Project Name: 2017 Tools, Shop and Garage Equipment Table 2
	Efficiency, Customer Value, Reliability (5.4.5.2.B.1) **Investment Driver (5.4.5.2.B.1.a)** General Plant (100%) **Secondary Driver (5.4.5.2.B.1.a)** n/a
	Investment Priority (5.4.5.2.B.1.b) High **Analysis of Project and Project Alternatives (5.4.5.2.B.1.c)** Tools and equipment over $5000 are procured through a competitive process and alternatives are considered at the time of requisition.
	Safety (5.4.5.2.B.2) Tools and equipment meet CSA requirements and are reviewed for conformance to requirements by Horizon Utilities' Tool & Equipment Committee.
	Cyber-Security and Privacy (5.4.5.2.B.3) (where applicable) N/A
	Co-ordination and Interoperability (5.4.5.2.B.4) **Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.5.2.B.4.a) (where applicable)** n/a **Enabling of Future Technology and/or Future Operational Requirements (5.4.5.2.B.4.b)** n/a
	Economic Development (5.4.5.2.B.5) **(where applicable)** n/a
	Environmental Benefits (5.4.5.2.B.6) **(where applicable)** n/a

General Plant Specific Requirements

Project Name	2017 Tools, Shop and Garage Equipment	Table 3

General Plant Specific Requirements (5.4.5.2.C.d)

Summary of Qualitative and Quantitative Analysis (5.4.5.2.C.d.i)

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.

Business Case Justification Documentation (5.4.5.2.C.d.i)

n/a

horizon UTILITIES Looking beyond...

Capital Project Summary

Project Name	2017 Building Renovations – John St
Budget Year	2017
Investment Category	General Plant

Project Summary

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

Capital Investment (5.4.5.2.A.i)	Capital Investment (gross)	$2,200,000
	Customer Contribution	n/a
	Capital Investment (net)	n/a
	O&M Expenditure	n/a
Customer Attachments / Load (5.4.5.2.A.ii)	n/a	

Project Dates (5.4.5.2.A.iii)

Start Date	April 2017
In Service Date	December 2017

Expenditure Timing

Q1	Q2	Q3	Q4
0%	30%	30%	40%

Schedule Risk and Risk Mitigation (5.4.5.2.A.iv**)**

Project timelines and costs exceeding the budget are risks. The project manager will report regularly on project timelines and adherence to budget and escalates issues for resolution.

Comparative Information from Equivalent Projects (5.4.5.2.A.v)

Comparable gross investments for building renovations for the 2010 to 2013 Historical Years and the 2014 Bridge Year are:

2010 (CGAAP)- $ 0
2011 (CGAAP)- $ 0
2012 (MIFRS) - $ 1,767,000
2013 (MIFRS) - $ 5,490,000
2014 (MIFRS) - $ 3,700,000

Total Capital OM&A Costs Associated with REG Investments (5.4.5.2.A.vi)

n/a

Leave to Construct Approval (5.4.5.2.A.vii)

N/A

Evaluation Criteria and Information	**Project Name:** 2017 Building Renovations – John St	Table 2
	Efficiency, Customer Value, Reliability (5.4.5.2.B.1) **Investment Driver (5.4.5.2.B.1.a)** General Plant – 100% **Secondary Driver (5.4.5.2.B.1.a)** n/a **Investment Priority (5.4.5.2.B.1.b)** High	
	Analysis of Project and Project Alternatives (5.4.5.2.B.1.c) Horizon Utilities' building renovation plans were developed through a facilities planning process that utilized the outputs of a space planning study and multiple building assessments	
	Safety (5.4.5.2.B.2) n/a	
	Cyber-Security and Privacy (5.4.5.2.B.3) (where applicable) n/a	
	Co-ordination and Interoperability (5.4.5.2.B.4) **Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.5.2.B.4.a) (where applicable)** n/a **Enabling of Future Technology and/or Future Operational Requirements (5.4.5.2.B.4.b)** n/a	
	Economic Development (5.4.5.2.B.5) **(where applicable)** n/a	
	Environmental Benefits (5.4.5.2.B.6) **(where applicable)** n/a	

General Plant Specific Requirements

Project Name	John St 6th Floor Building Renovation Project	Table 3

General Plant Specific Requirements (5.4.5.2.C.d)

Summary of Qualitative and Quantitative Analysis (5.4.5.2.C.d.i)

n/a

Business Case Justification Documentation (5.4.5.2.C.d.i)

One project is planned for 2017 to address congested office spaces at Head Office by renovating the sixth floor which is largely original to the 1960s building.

The office space study conducted in 2010 concluded that additional space for corporate offices, corporate business units, and meeting spaces was required on the 6^{th} floor of the John St. building. To help provide that space, Horizon Utilities reclaimed part of the 6^{th} floor from the City of Hamilton Water Division. This space has been used, and will continue to used, as “swing space” to support building renovation and renewals projects from 2012 to 2016. On completion of the 2012-2016 projects, the swing space will be renovated to provide the much needed office and meeting space, remediate hazardous materials, improve airflow, and reduce energy and water consumption.

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
- The creation of necessary meeting room space.

Capital Project Summary

General Information on Project (5.4.5.2.A)

Project Name	2018 Meters
Budget Year	2018
Investment Category	System Access

Capital Investment (5.4.5.2.A.i)		
	Capital Investment	$ 2,063,000
	Total	$ 2,063,000
	O&M Expenditure	$0

Customer Attachments / Load (kVA) (5.4.5.2.A.ii)

n/a

Project Dates (5.4.5.2.A.iii)

Start Date	2018/01/01
In Service Date	2018/12/31

Expenditure Timing

Q1	Q2	Q3	Q4
25%	25%	25%	25%

Schedule Risk and Risk Mitigation (5.4.5.2.A.iv**)**

Please refer to Note I for risk and risk mitigation.

Comparative Information from Equivalent Projects (5.4.5.2.A.v)

Metering investments for the 2010 to 2013 Historical Years and the 2014 Bridge Year are:

2010 (CGAAP) - $1,715,716
2011 (CGAAP)- $3,467,413
2012 (MIFRS) - $25,168,043
2013 (MIFRS) - $1,658,707
2014 (MIFRS) - $2,499,104

The increased investment in 2012 was due to the implementation of Smart Meters at a cumulative capital cost of $23,277,588. 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.

Total Capital OM&A Costs Associated with REG Investments (5.4.5.2.A.vi)

This project is not associated with an REG investment and as such no associated OM&A costs related to REG will be incurred.

Leave to Construct Approval (5.4.5.2.A.vii)

n/a

Evaluation Criteria and Information (5.4.5.2.B)

Project Name 2018 Meters — Table 2

Efficiency, Customer Value, Reliability (5.4.5.2.B.1)

Investment Driver (5.4.5.2.B.1.a)
System Access (80%)

Secondary Driver (5.4.5.2.B.1.a)
System Renewal (20%)

Replacement of commercial meters with Smart Meters.

Investment Priority (5.4.5.2.B.1.b)
5 – Mandatory Project

Analysis of Project and Project Alternatives (5.4.5.2.B.1.c)

Metering asset management is governed by Measurement Canada regulation and customer requirements for new and upgraded services.

Safety (5.4.5.2.B.2)

This project is not intended to address safety concerns with the distribution system

Cyber-Security and Privacy (5.4.5.2.B.3) (where applicable)

Horizon Utilities' Smart Meter and related AMI network have been procured through Elster. Elster's system supports a multi-layered security approach including: access control, authorization, authentication and data integrity protocols. As part of its continuous improvement model, Horizon Utilities performs periodic security assessments to identify opportunities for enhanced system hardening.

Co-ordination and Interoperability (5.4.5.2.B.4)

Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.5.2.B.4.a) (where applicable)
Please refer to Note II for an explanation on co-ordination with utilities, regional planning and/or links with 3rd parties.

Enabling of Future Technology and/or Future Operational Requirements (5.4.5.2.B.4.b)

Please refer to Note IV for an explanation enabling of future technology and future operational requirements.

Economic Development (5.4.5.2.B.5) **(where applicable)**

Horizon Utilities ensures that policies and practices do not unnecessarily create barriers to economic development which are primarily focused within its communities.

Environmental Benefits (5.4.5.2.B.6) **(where applicable)**

The Smart Meter infrastructure supports the provinces' conservation culture. Smart metering also provides environmental benefits through reduction in field visits associated with manual meter reading.

System Access Specific Requirements (5.4.5.2.C.a)

Project Name	2018 Meters	Table 3

System Access Specific Requirements (5.4.5.2.C.a)

Factors Affecting Implementing Project Timing/Priority (5.4.5.2.C.a.i)
Compliance sampling work completed to comply with Measurement Canada regulations. The schedule is created to smooth the annual sampling requirements from the original Smart Meter mass deployments.

New and replacement metering is provided on demand to address new load growth and meter failures.

Factors Related to Customer Preference or 3rd Party Input (5.4.5.2.C.a.ii)

Metering for new and upgraded connection projects are customer initiated and are designed to meet customer identified requirements.

Factors Affecting Final Project Cost (5.4.5.2.C.a.iii)
Please refer to Note I for an explanation on the factors affecting the final project cost.

Controllable Cost Minimization (5.4.5.2.C.a.iv)

Please refer to Note I for an explanation regarding controllable cost mitigation.

Other Planning Objectives (5.4.5.2.C.a.v)

Horizon Utilities combines work from multiple work groups to reduce costs and increase efficiency. The line work and meter work is combined when connecting new customers to allow the work to be completed by a single work group.

Assessment of Technical or Implementation Options (5.4.5.2.C.a.vi)

Metering work is Measurement Canada and customer driven and the technology is primarily based on the metering products available from a sole source supplier.

Summary of Options Analysis (5.4.5.2.C.a.vii)

Metering supplier selected as part of the smart meter implementation program.

Final Economic Evaluation Results (5.4.5.2.C.a.viii)

n/a

Identification of System Impacts (5.4.5.2.C.a.ix)

System expansion, if required, to connect customers within this category are governed by Horizon Utilities' Conditions of Service Section 2.1.2.1.

UTILITIES *Looking beyond...*

Capital Project Summary

General Information on Project (5.4.5.2.A)

Project Name	2018 Road Relocations
Budget Year	2018
Investment Category	System Access
Project Description	Projects in this category include all projects required for the relocation of system plant for roadway reconstruction work. Horizon Utilities follows the *Public Service Works on Highway Act*, 1990 and associated regulations governing the recovery of costs related to road reconstruction work by collecting contributed capital for 50% of labour and labour saving devices.

Capital Investment (5.4.5.2.A.i)	Capital Investment (gross)	$2,682,499
	Customer Contribution	$904,360
	Capital Investment (net)	$1,778,139
	O&M Expenditure	$0

Customer Attachments / Load (kVA) (5.4.5.2.A.ii)	n/a

Project Dates (5.4.5.2.A.iii)

Start Date	Various – driven by road authority schedules
In Service Date	Various – driven by road authority schedules

Expenditure Timing

Q1	Q2	Q3	Q4
25%	25%	25%	25%

Schedule Risk and Risk Mitigation (5.4.5.2.A.iv**)**

Please refer to Note I for risk and risk mitigation.

Comparative Information from Equivalent Projects (5.4.5.2.A.v)

Road relocations for the 2010 to 2013 Historical Years and the 2014 Bridge Year are:

2010 (CGAAP) - $ 2,889,575
2011 (CGAAP)- $ 895,524
2012 (MIFRS) - $ 3,151,887
2013 (MIFRS) - $ 340,491
2014 (MIFRS) - $ 977,024

Total Capital OM&A Costs Associated with REG Investments (5.4.5.2.A.vi)

This project is not associated with an REG investment and therefore OM&A costs related to REG will not be incurred.

Leave to Construct Approval (5.4.5.2.A.vii)

This project does not require "Leave to Construct" under Section 92 of the *Ontario Energy Board Act* 1998.

Evaluation Criteria and Information (5.4.5.2.B)	**Project Name** 2018 Road Relocations Table 2
	Efficiency, Customer Value, Reliability (5.4.5.2.B.1) **Investment Driver (5.4.5.2.B.1.a)** System Access (90%) **Secondary Driver (5.4.5.2.B.1.a)** System Renewal (5%) System Service (5%) **Investment Priority (5.4.5.2.B.1.b)** 5 – Mandatory Project
	Analysis of Project and Project Alternatives (5.4.5.2.B.1.c) Horizon Utilities co-ordinates project design and discusses design alternatives for each project with the organization (City, Municipality, Ministry of Transportation) originating the request to relocate distribution assets.
	Safety (5.4.5.2.B.2) These projects are not intended to address safety concerns with the distribution system.
	Cyber-Security and Privacy (5.4.5.2.B.3) (where applicable) Cyber-Security and Privacy are not applicable to this project.
	Co-ordination and Interoperability (5.4.5.2.B.4) **Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.5.2.B.4.a) (where applicable)** Timelines for the execution of these projects are dictated by the City of Hamilton, City of 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. **Enabling of Future Technology and/or Future Operational Requirements (5.4.5.2.B.4.b)** Please refer to Note IV for an explanation enabling of future technology and future operational requirements.
	Economic Development (5.4.5.2.B.5) **(where applicable)** Horizon Utilities ensures that policies and practices do not unnecessarily create barriers to economic development which are primarily focused within its communities.
	Environmental Benefits (5.4.5.2.B.6) **(where applicable)** n/a

System Access Specific Requirements (5.4.5.2.C.a)

Project Name	2018 Road Relocations	Table 3

System Access Specific Requirements (5.4.5.2.C.a)

Factors Affecting Implementing Project Timing/Priority (5.4.5.2.C.a.i)

The road authority's schedule and timing of the road project will affect Horizon Utilities' project implementation and timing.

Factors Related to Customer Preference or 3rd Party Input (5.4.5.2.C.a.ii)

Road relocation projects involve a co-ordinated design process and the initiating organization (City, Municipality, or Ministry of Transportation) has input into the design of the project.
The designs for all projects within the public right-of-way are reviewed with the City as Municipal Consents are required prior to construction. Consideration is given by the road authority to coordinate all utilities within the right-of-way in the least disruptive manner.

Factors Affecting Final Project Cost (5.4.5.2.C.a.iii)

Please refer to Note I for an explanation on the factors that can affect the final project cost.

Controllable Cost Minimization (5.4.5.2.C.a.iv)

50% of the labour, labour saving devices and equipment rentals are recovered from the road authority.

Please refer to Note I for an explanation on controllable cost minimization.

Other Planning Objectives (5.4.5.2.C.a.v)

Horizon Utilities combines work to reduce overall costs and increase efficiency. The most common opportunity is during city road relocation projects where a new water main is being installed. Horizon Utilities may be able to take advantage of the fact that installing duct structure is less costly since the road is already excavated. Horizon Utilities may also be able to change the schedule of a renewal project to align with the road authority's work to maximize these benefits. The costs of these additional works are allocated to either system service or system renewal where applicable. Horizon Utilities can maximize the amount of work that can be completed at the lowest cost to benefit ratepayers in these cases.

Assessment of Technical or Implementation Options (5.4.5.2.C.a.vi)

Horizon Utilities co-ordinates project design and discusses design alternatives for each project with the road authority (City, Municipality, Ministry of Transportation) originating the request to relocate distribution assets.

Summary of Options Analysis (5.4.5.2.C.a.vii)

Horizon Utilities reviews proposed design with municipalities and the Ministry of Transportation, as applicable, in an effort to determine the most cost effective solution.

Final Economic Evaluation Results (5.4.5.2.C.a.viii)

This is not applicable to road relocations projects.

Identification of System Impacts (5.4.5.2.C.a.ix)

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.

Capital Project Summary

General Information on Project (5.4.5.2.A)

Project Name	2018 Customer Connections
Budget Year	2018
Investment Category	System Access
Project Summary	Projects in this category include multiple projects required to connect, upgrade, or disconnect customers to the distribution system. Horizon Utilities' obligation to connect new customers is governed by the *Electricity Act, 1998, Schedule 28.*

Capital Investment (5.4.5.2.A.i)		
	Capital Investment (gross)	$5,046,586
	Customer Contribution	$796,297
	Capital Investment (net)	$4,250,288
	O&M Expenditure	$0

Customer Attachments / Load (kVA) (5.4.5.2.A.ii)	Horizon Utilities completes approximately 1800 connections annually; 1500 through subdivisions and 300 customer projects, contributing approximately 25MVA in system load growth.

Project Dates (5.4.5.2.A.iii)

Start Date	Various – as driven by the customer
In Service Date	Various – as driven by the customer

Expenditure Timing

Q1	Q2	Q3	Q4
25%	25%	25%	25%

Schedule Risk and Risk Mitigation (5.4.5.2.A.iv**)**

Please refer to Note I for risk and risk mitigation.

Comparative Information from Equivalent Projects (5.4.5.2.A.v)

Comparable investments, net of capital contributions, for the 2010 and 2013 Historical Years and the 2014 Bridge Year are:

2010 (CGAAP)- $ 1,023,336
2011 (CGAAP)- $ 2,030,541
2012 (MIFRS) - $ 1,652,000
2013 (MIFRS) - $ 3,541,455
2014 (MIFRS) - $ 4,063,471

Total Capital OM&A Costs Associated with REG Investments (5.4.5.2.A.vi)
This project is not associated with an REG investment and therefore OM&A costs related to REG will not be incurred.

	Leave to Construct Approval (5.4.5.2.A.vii) This project does not require "Leave to Construct" under Section 92 of the *Ontario Energy Board Act* 1998.

Evaluation Criteria and Information (5.4.5.2.B)			
	Project Name	2018 Customer Connections	Table 2
	Efficiency, Customer Value, Reliability (5.4.5.2.B.1) **Investment Driver (5.4.5.2.B.1.a)** System Access (100%) **Secondary Driver (5.4.5.2.B.1.a)** N/A **Investment Priority (5.4.5.2.B.1.b)** 5 – Mandatory Project		
	Analysis of Project and Project Alternatives (5.4.5.2.B.1.c) Customer connection projects are driven by customer requests and the customer's specific technical requirements. To build efficiencies into the process, Horizon Utilities utilizes a set of design standards that have been engineered and approved. Customer connections requests are fulfilled consistent with Horizon Utilities' Conditions of Service, designed to meet the customer requirements and maintain system reliability.		
	Safety (5.4.5.2.B.2) These projects are not intended to address safety concerns with the distribution system.		
	Cyber-Security and Privacy (5.4.5.2.B.3) (where applicable) Cyber-Security and Privacy are not applicable to this project.		
	Co-ordination and Interoperability (5.4.5.2.B.4) **Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.5.2.B.4.a) (where applicable)** Please refer to Note II for an explanation on co-ordination with utilities, regional planning and/or links with 3rd parties. **Enabling of Future Technology and/or Future Operational Requirements (5.4.5.2.B.4.b)** This is not applicable for these projects.		
	Economic Development (5.4.5.2.B.5) **(where applicable)** Horizon Utilities ensures that policies and practices do not unnecessarily create barriers to economic development which are primarily focused within its communities.		

	Environmental Benefits (5.4.5.2.B.6) **(where applicable)** n/a

System Access Specific Requirements (5.4.5.2.C.a)	**Project Name** 2018 Customer Connections Table 3
	System Access Specific Requirements (5.4.5.2.C.a) **Factors Affecting Implementing Project Timing/Priority (5.4.5.2.C.a.i)** Schedule of work based on customer expectations; customer request may not be standard design. **Factors Related to Customer Preference or 3rd Party Input (5.4.5.2.C.a.ii)** There projects are customer initiated and are designed to meet customer identified requirements. **Factors Affecting Final Project Cost (5.4.5.2.C.a.iii)** Please refer to Note I for an explanation on the factors affecting final project cost. **Controllable Cost Minimization (5.4.5.2.C.a.iv)** Please refer to Note I for an explanation on the factors affecting controllable cost. **Other Planning Objectives (5.4.5.2.C.a.v)** n/a **Assessment of Technical or Implementation Options (5.4.5.2.C.a.vi)** Please refer to Note III for information on the technical and implementation options. **Summary of Options Analysis (5.4.5.2.C.a.vii)** Please refer to Note III for information on the technical and implementation options.

Final Economic Evaluation Results (5.4.5.2.C.a.viii)

Horizon Utilities completes the economic evaluation for any customer system access project which requires the construction of new facilities to the main distribution system or an increase in the existing capacity of distribution facilities. For further details please see Appendix E of Horizon Utilities' Conditions of Service. The economic evaluation is completed in accordance with section 3.2 of the Distribution System Code ("DSC"). For the 2015-2019 forecast period Horizon Utilities has no known projects for which to provide the final economic evaluation. When a road authority requests a relocation of Horizon Utilities' plant located on the public road allowance, the costs shall be shared, as outlined in the Ontario *Public Service Works on Highways Act*. Other projects within this category will have an economic evaluation completed where applicable in accordance with both the DSC and Appendix E of Horizon Utilities' Conditions of Service.

Identification of System Impacts (5.4.5.2.C.a.ix)

System expansion, if required, to connect customers within this category is governed by Horizon Utilities' Conditions of Service Section 2.1.2.1.

Capital Project Summary

General Information on Project (5.4.5.2.A)

Project Name	AB-F2 & AB-F4 Renewal – Aberdeen East
Budget Year	2018
Investment Category	System Renewal
Project Summary	This project involves the renewal of the Aberdeen substation F2 & F4 feeders in central Hamilton along Aberdeen Rd East.

Capital Investment (5.4.5.2.A.i)	Capital Investment (gross)	$2,643,203
	Customer Contribution	$0
	Capital Investment (net)	$2,643,203
	O&M Expenditure	$0

Customer Attachments / Load (kVA) (5.4.5.2.A.ii)	This customer impacts approximately 2,600 customers and 5000kVA of transformation.

Project Dates (5.4.5.2.A.iii)

Start Date 2018/01/01

In Service Date 2018/12/31

Expenditure Timing

Q1	Q2	Q3	Q4
25%	25%	25%	25%

Schedule Risk and Risk Mitigation (5.4.5.2.A.iv**)**

Please refer to Note I for risk and risk mitigation.

Comparative Information from Equivalent Projects (5.4.5.2.A.v)

There is no direct comparator in scope, size and design characteristics for this project. This project is one phase of a multi-year investment to renew the area served by Aberdeen substation as part of the 4kV and 8kV Renewal Program. The 2018 investment for the renewal of Aberdeen substation is $2,643,000. The 2018 investment in the 4kV and 8kV Renewal Program is $15,684,000.

Comparable gross investments for the 4kV and 8kV Renewal Program for the 2010 and 2013 Historical Years and the 2014 Bridge Year are:

2010 (CGAAP)- $ 2,556,076
2011 (CGAAP)- $ 8,820,000
2012 (MIFRS) - $ 5,268,441
2013 (MIFRS) - $ 5,072,233
2014 (MIFRS) - $ 6,434,000

Total Capital OM&A Costs Associated with REG Investments (5.4.5.2.A.vi)

This project is not associated with an REG investment and therefore OM&A costs related to REG will not be incurred.

	Leave to Construct Approval (5.4.5.2.A.vii) This project does not require "Leave to Construct" under Section 92 of the *Ontario Energy Board Act* 1998.

Evaluation Criteria and Information (5.4.5.2.B)	**Project Name** AB-F2 & AB-F4 Renewal – Aberdeen East	Table 2
	Efficiency, Customer Value, Reliability (5.4.5.2.B.1) **Investment Driver (5.4.5.2.B.1.a)** System Renewal (80%) **Secondary Driver (5.4.5.2.B.1.a)** System Service (20%) **Investment Priority (5.4.5.2.B.1.b)** 3 – Required project	
	Analysis of Project and Project Alternatives (5.4.5.2.B.1.c) This project is part of the multi-year 4kV and 8kV Renewal Program. It is necessary to renew both the 4kV and 8kV distribution system and the Horizon Utilities-owned substations. Horizon Utilities has chosen to renew the 4kV and 8kV distribution systems to a higher voltage to avoid the cost of the investment in the renewal of the substations. The total avoided substation renewal investment over the remaining 35 years of the plan is $70,000,000 for all 28 substations. Therefore the renewal of these distribution assets at the current 4kV level was not a feasible alternative. The renewal of the area serviced by Aberdeen substation started in 2017 and is scheduled to be completed in 2021.	
	Safety (5.4.5.2.B.2) This project is not intended to address safety concerns with the distribution system.	
	Cyber-Security and Privacy (5.4.5.2.B.3) (where applicable) Cyber-Security and Privacy are not applicable to this project	
	Co-ordination and Interoperability (5.4.5.2.B.4) **Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.5.2.B.4.a) (where applicable)** Please refer to Note II for an explanation on co-ordination with utilities, regional planning and/or links with 3rd parties. **Enabling of Future Technology and/or Future Operational Requirements (5.4.5.2.B.4.b)** Please refer to Note IV for an explanation enabling of future technology and future operational requirements.	

Economic Development (5.4.5.2.B.5) **(where applicable)**

Horizon Utilities ensures that policies and practices do not unnecessarily create barriers to economic development which are primarily focused within its communities.

Environmental Benefits (5.4.5.2.B.6) **(where applicable)**

n/a

System Renewal Specific Requirements (5.4.5.2.C.b)

Project Name AB-F2 & AB-F4 Renewal – Aberdeen East Table 3

System Renewal Specific Requirements (5.4.5.2.C.b)

Asset Performance Target and Asset Lifecycle Optimization (5.4.5.2.C.b.i.1)

The two substations servicing the downtown Hamilton operating area service a total of 7,400 customers and were constructed in 1950 and 1960. The overall Station Health Index for Aberdeen and Central substations is 53% and 56% respectively. 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.

Asset Condition Relative to Typical Life Cycle (5.4.5.2.C.b.i.2)

Generally the 4kV assets are the oldest vintage in the system. 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.

Number of Customers Impacted (5.4.5.2.C.b.i.3)

This project impacts approximately 2,600 customers.

Quantitative Customer Impact and Risk (5.4.5.2.C.b.i.4)

SAIDI of 0.137

Qualitative Customer Impact and Risk (5.4.5.2.C.b.i.5)

This project will address aging assets with inadequate backup. Aging assets represent an increased risk of service interruption to customers and inadequate backup would result in long duration service interruptions upon occurrence. These factors would lead to customer dissatisfaction in this area.

Value of Customer Impact (5.4.5.2.C.b.i.6)

High

Other Factors Affecting Project Timing (5.4.5.2.C.b.ii)

The renewal of the area serviced by Aberdeen substation is scheduled for 2017 to 2021. This project is required to be completed in 2018 to allow for the renewal of the remaining area to be completed on schedule.

Impact on System O&M Costs (5.4.5.2.C.b.iii)

This project will have no material impact on planned O&M costs. The renewal of the 4kV and 8kV distribution systems, as a whole, will provide a reduction in reactive O&M costs to address service interruptions caused by failed equipment. These reductions will not be material in the 2015 to 2019 Test Years.

Reliability and Safety Factors (5.4.5.2.C.b.iv)

The renewal of the 4kV and 8kV distribution system will provide reliability improvements through reduced service interruptions caused by failed equipment

Analysis of Project Benefits and Timing (5.4.5.2.C.b.v)

The timing of this project, as part of the 4kV and 8kV Renewal Program, is determined through the assessment of the distribution system health and the health of the substation assets servicing the area. Renewal of this area will allow for the decommissioning of the substation assets by 2021 thereby avoiding the need for capital investment into these substations.

Like-for-Like Renewal Analysis (5.4.5.2.C.b.vi)

The like-for-like renewal of these assets (i.e. same system configuration and same distribution voltage) will perpetuate the existing operating constraints and require capital investment to renew substation assets. Renewal of the distribution assets at a higher voltage does not involve any material incremental costs over renewal at the existing voltage. Operating constraints (e.g. undersized conductor, radial feeds) are addressed on a case by case basis where appropriate.

Capital Project Summary

General Information on Project (5.4.5.2.A)

Project Name	BD-F1 Renewal - Cross St			
Budget Year	2018			
Investment Category	System Renewal			
Project Summary	This project involves the renewal of the Baldwin substation F1 feeder in Dundas along Cross St.			
Capital Investment (5.4.5.2.A.i)	Capital Investment (gross)	$1,540,148		
	Customer Contribution	$0		
	Capital Investment (net)	$1,540,148		
	O&M Expenditure	$0		
Customer Attachments / Load (kVA) (5.4.5.2.A.ii)	This project impacts approximately 800 customers and 2000kVA of transformation			
Project Dates (5.4.5.2.A.iii)	Start Date	2018/03/01		
	In Service Date	2018/09/30		
	Expenditure Timing			
	Q1	Q2	Q3	Q4
	15%	40%	45%	0%

Schedule Risk and Risk Mitigation (5.4.5.2.A.iv**)**

Please refer to Note I for risk and risk mitigation.

Comparative Information from Equivalent Projects (5.4.5.2.A.v)

There is no direct comparator in scope, size and design characteristics for this project. This project is one phase of a multi-year investment to renew the area served by Baldwin substation as part of the 4kV and 8kV Renewal Program. The 2018 investment for the renewal of Baldwin substation is $1,788,000. The 2018 investment in the 4kV and 8kV Renewal Program is $15,684,000. Comparable gross investments for the 4kv and 8kV Renewal Program for the 2010 to 2013 Historical Years and the 2014 Bridge Year are:

2010 (CGAAP)- $ 2,556,076
2011 (CGAAP)- $ 8,820,000
2012 (MIFRS) - $ 5,268,441
2013 (MIFRS) - $ 5,072,233
2014 (MIFRS) - $ 6,434,000

Total Capital OM&A Costs Associated with REG Investments (5.4.5.2.A.vi)

This project is not associated with an REG investment and therefore OM&A costs related to REG will not be incurred.

Leave to Construct Approval (5.4.5.2.A.vii)

This project does not require "Leave to Construct" under Section 92 of the *Ontario Energy Board Act* 1998.

Evaluation Criteria and Information (5.4.5.2.B)

Project Name	BD-F1 Renewal - Cross St	Table 2

Efficiency, Customer Value, Reliability (5.4.5.2.B.1)

Investment Driver (5.4.5.2.B.1.a)
System Renewal (80%)

Secondary Driver (5.4.5.2.B.1.a)
System Service (20%)

Investment Priority (5.4.5.2.B.1.b)

3 – Required project

Analysis of Project and Project Alternatives (5.4.5.2.B.1.c)

This project is part of the multi-year 4kV and 8kV Renewal Program. Both the 4kV and 8kV distribution system and the Horizon Utilities-owned substations are at the end of their useful life. Horizon Utilities has chosen to renew the 4kV and 8kV distribution systems to a higher voltage to avoid the cost of the investment in the renewal of the substations. The total avoided substation renewal investment over the remaining 35 years of the plan is $70,000,000 for all 28 substations. Therefore the renewal of these distribution assets at the current 4kV level was not a feasible alternative.

This project is the first project of multiple projects required to renew the service territory serviced by Baldwin substation.

Safety (5.4.5.2.B.2)

This project is not intended to address safety concerns with the distribution system.

Cyber-Security and Privacy (5.4.5.2.B.3) (where applicable)

Cyber-Security and Privacy are not applicable to this project.

Co-ordination and Interoperability (5.4.5.2.B.4)

Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.5.2.B.4.a) (where applicable)
Please refer to Note II for an explanation on co-ordination with utilities, regional planning and/or links with 3rd parties.

Enabling of Future Technology and/or Future Operational Requirements (5.4.5.2.B.4.b)

Please refer to Note IV for an explanation enabling of future technology and future operational requirements.

	Economic Development (5.4.5.2.B.5) **(where applicable)** Horizon Utilities ensures that policies and practices do not unnecessarily create barriers to economic development which are primarily focused within its communities.
	Environmental Benefits (5.4.5.2.B.6) **(where applicable)** n/a

System Renewal Specific Requirements (5.4.5.2.C.b)	
	Project Name BD-F1 Renewal - Cross St Table 3
	System Renewal Specific Requirements (5.4.5.2.C.b) **Asset Performance Target and Asset Lifecycle Optimization (5.4.5.2.C.b.i.1)** The distribution assets in the Dundas operating area are in poor health and have significant operating constraints. 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'. **Asset Condition Relative to Typical Life Cycle (5.4.5.2.C.b.i.2)** Generally the 4kV assets are the oldest vintage in the system. 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. **Number of Customers Impacted (5.4.5.2.C.b.i.3)** This project impacts 800 customers. **Quantitative Customer Impact and Risk (5.4.5.2.C.b.i.4)** SAIDI of 0.029 **Qualitative Customer Impact and Risk (5.4.5.2.C.b.i.5)** This project will address aging assets with inadequate backup. Aging assets represent an increased risk of service interruption to customers and inadequate backup would result in long duration service interruptions upon occurrence. These factors would lead to customer dissatisfaction in this area. **Value of Customer Impact (5.4.5.2.C.b.i.6)** High **Other Factors Affecting Project Timing (5.4.5.2.C.b.ii)** The renewal of the area serviced by Baldwin substation is scheduled for renewal in 2018 and 2019. This project is required to be completed in 2018 to allow for the renewal of the remaining area to be completed on schedule.

Impact on System O&M Costs (5.4.5.2.C.b.iii)

This project will have no material impact on planned O&M costs. The renewal of the 4kV and 8kV distribution systems, as a whole, will provide a reduction in reactive O&M costs to address service interruptions caused by failed equipment. These reductions will not be material in the 2015 to 2019 Test Years.

Reliability and Safety Factors (5.4.5.2.C.b.iv)

The renewal of the 4kV and 8kV distribution system will provide reliability improvements through reduced service interruptions caused by failed equipment.

Analysis of Project Benefits and Timing (5.4.5.2.C.b.v)

The timing of this project, as part of the 4kV and 8kV Renewal Program, is determined through the assessment of the distribution system health and the health of the substation assets servicing the area. Renewal of this area will allow for the decommissioning of the substation assets by 2019 thereby avoiding the need for capital investment into these substations.

Like-for-Like Renewal Analysis (5.4.5.2.C.b.vi)

The like-for-like renewal of these assets (i.e. same system configuration and same distribution voltage) will perpetuate the existing operating constraints and require capital investment to renew substation assets. Renewal of the distribution assets at a higher voltage does not involve any material incremental costs over renewal at the existing voltage. Operating constraints (e.g. undersized conductor, radial feeds) are addressed on a case by case basis where appropriate.

Capital Project Summary

General Information on Project (5.4.5.2.A)

Project Name	Bluebird Crescent Rear Lot Renewal
Budget Year	2018
Investment Category	System Renewal
Project Summary	This project involves the replacement of rear lot overhead construction. Replacement options include relocating primary only, or relocating all assets to either overhead or underground in the front lot. Options are dependent on many factors (e.g. presence of trees and availability of room in the road allowance) and are assessed on a case by case basis. This project will involve the renewal of end of life rear lot overhead distribution assets serviced at 13.8kV and therefore not included in the 4kV and 8kV Renewal Program.

Capital Investment (5.4.5.2.A.i)

Capital Investment (gross)	$695,002
Customer Contribution	n/a
Capital Investment (net)	$695,002
O&M Expenditure	n/a

Customer Attachments / Load (kVA) (5.4.5.2.A.ii)

This project affects approximately 30 customers and 65kVA of transformation.

Project Dates (5.4.5.2.A.iii)

Start Date 2018/05/01

In Service Date 2018/10/01

Expenditure Timing

Q1	Q2	Q3	Q4
0%	40%	60%	0%

Schedule Risk and Risk Mitigation (5.4.5.2.A.iv**)**

Please refer to Note I for risk and risk mitigation.

Comparative Information from Equivalent Projects (5.4.5.2.A.v)

There are no equivalent projects for comparison

Total Capital OM&A Costs Associated with REG Investments (5.4.5.2.A.vi)

This project is not associated with an REG investment and therefore OM&A costs related to REG will not be incurred.

	Leave to Construct Approval (5.4.5.2.A.vii) This project does not require “Leave to Construct” under Section 92 of the *Ontario Energy Board Act* 1998.

Evaluation Criteria and Information (5.4.5.2.B)	**Project Name** Bluebird Crescent Rear Lot – Phase 1 Table 2
	Efficiency, Customer Value, Reliability (5.4.5.2.B.1) **Investment Driver (5.4.5.2.B.1.a)** System Renewal (80%) **Secondary Driver (5.4.5.2.B.1.a)** System Service (20%) **Investment Priority (5.4.5.2.B.1.b)** 3 – Required project
	Analysis of Project and Project Alternatives (5.4.5.2.B.1.c) Replacement options considered on a project by project basis include relocating primary only, or relocating all assets to either overhead or underground in the front lot. Options are dependent on many factors (e.g. presence of trees and availability of room in the road allowance).
	Safety (5.4.5.2.B.2) This project is not intended to address safety concerns with the distribution system.
	Cyber-Security and Privacy (5.4.5.2.B.3) (where applicable) Cyber-Security and Privacy are not applicable to this project.
	Co-ordination and Interoperability (5.4.5.2.B.4) **Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.5.2.B.4.a) (where applicable)** Please refer to Note II for an explanation on co-ordination with utilities, regional planning and/or links with 3rd parties. **Enabling of Future Technology and/or Future Operational Requirements (5.4.5.2.B.4.b)** Please refer to Note IV for an explanation enabling of future technology and future operational requirements.
	Economic Development (5.4.5.2.B.5) **(where applicable)** Horizon Utilities ensures that policies and practices do not unnecessarily create barriers to economic development which are primarily focused within its communities.

Environmental Benefits (5.4.5.2.B.6) **(where applicable)**

n/a.

System Renewal Specific Requirements (5.4.5.2.C.b)

Project Name	Bluebird Crescent Rear Lot – Phase 1	Table 3

System Renewal Specific Requirements (5.4.5.2.C.b)

Asset Performance Target and Asset Lifecycle Optimization (5.4.5.2.C.b.i.1)

Horizon Utilities has identified several residential areas serviced by a rear lot overhead distribution system. Horizon Utilities has experienced a dramatic increase in reliability issues surrounding rear lot distribution systems due to damage caused from customer owned trees and lack of access for utility crews to repair or replace equipment. The poles are a mix of wood and concrete that, by design, are unsafe to scale to repair, and replacement of poles and equipment is labour intensive and requires specialized equipment access rear yards. Access is poor and therefore failure restoration time is significantly extended. These identified assets are nearing or beyond end of life and should be replaced. In the past several years, storm related failures in these areas have increased, as has the outage duration (in excess of 24 hours).

Asset Condition Relative to Typical Life Cycle (5.4.5.2.C.b.i.2)

The poles in this project are 51 years old and are not the current construction standards. Transformers are of a similar vintage. Many of the assets are nearing or beyond the end of their useful life.

Number of Customers Impacted (5.4.5.2.C.b.i.3)

This project impacts approximately 30 customers.

Quantitative Customer Impact and Risk (5.4.5.2.C.b.i.4)

SAIDI of 0.002

Qualitative Customer Impact and Risk (5.4.5.2.C.b.i.5)

This project will improve the service received by the customers impacted. Service interruptions of rear lot distribution systems involve longer restoration times due to the difficulty in accessing the assets. The service interruption restoration times will be reduced once the assets have been relocated.

Value of Customer Impact (5.4.5.2.C.b.i.6)

High

Other Factors Affecting Project Timing (5.4.5.2.C.b.ii)

n/a

Impact on System O&M Costs (5.4.5.2.C.b.iii)

This project will not have a material impact on system O&M costs in the 2015 to 2019 Test Years.

Reliability and Safety Factors (5.4.5.2.C.b.iv)

Reliability will be improved through the relocation of these assets which will result in reduced service interruption restoration times. Safety will be improved due to improved and easier access to the assets and the ability to work on the assets from aerial bucket trucks versus having to manually climb poles when they are located in the rear lot.

Analysis of Project Benefits and Timing (5.4.5.2.C.b.v)

n/a.

Like-for-Like Renewal Analysis (5.4.5.2.C.b.vi)

The cost of this project is required to remove rear lot assets and is specifically designed not to renew using a like-for-like methodology. Horizon Utilities will determine whether to relocate the primary only to the front lot or to relocate all plant to either underground and/or overhead front lot. The decision will be made on a project by project basis.

Capital Project Summary

General Information on Project (5.4.5.2.A)

Project Name	CE-F10 Renewal – John St S
Budget Year	2018
Investment Category	System Renewal
Project Summary	This project involves the renewal of the Central Substation F10 feeder in central Hamilton along John St South.

Capital Investment (5.4.5.2.A.i)	Capital Investment (gross)	$1,652,254
	Customer Contribution	$0
	Capital Investment (net)	$1,652,254
	O&M Expenditure	$0

Customer Attachments / Load (kVA) (5.4.5.2.A.ii)

This project impacts approximately 1,000 customers.

Project Dates (5.4.5.2.A.iii)

Start Date 2018/04/01

In Service Date 2018/11/30

Expenditure Timing

Q1	Q2	Q3	Q4
0%	40%	45%	15%

Schedule Risk and Risk Mitigation (5.4.5.2.A.iv**)**

Please refer to Note I for risk and risk mitigation.

Comparative Information from Equivalent Projects (5.4.5.2.A.v)

There is no directly comparator in scope, size and design characteristics for this project. This project is one phase of a multi-year investment to renew the area served by Central substation as part of the 4kV and 8kV Renewal Program. The 2018 investment for the renewal of Central substation is $1,652,000. The 2018 investment in the 4kV and 8kV Renewal Program is $15,684,000.

Comparable gross investments for the 4kv and 8kV Renewal Program for the 2010 and 2013 Historical Year and the 2014 Bridge Year are:
2010 (CGAAP)- $ 2,556,076
2011 (CGAAP)- $ 8,820,000
2012 (MIFRS) - $ 5,268,441
2013 (MIFRS) - $ 5,072,233
2014 (MIFRS) - $ 6,434,000

Total Capital OM&A Costs Associated with REG Investments (5.4.5.2.A.vi)

This project is not associated with an REG investment and therefore OM&A costs related to REG will not be incurred.

	Leave to Construct Approval (5.4.5.2.A.vii) This project does not require "Leave to Construct" under Section 92 of the *Ontario Energy Board Act* 1998.

Evaluation Criteria and Information (5.4.5.2.B)	**Project Name** CE-F10 Renewal – John St S Table 2
	Efficiency, Customer Value, Reliability (5.4.5.2.B.1) **Investment Driver (5.4.5.2.B.1.a)** System Renewal (80%) **Secondary Driver (5.4.5.2.B.1.a)** System Service (20%) **Investment Priority (5.4.5.2.B.1.b)** 3 – Required project
	Analysis of Project and Project Alternatives (5.4.5.2.B.1.c) This project is part of the multi-year 4kV and 8kV Renewal Program. It is necessary to renew both the 4kV and 8kV distribution system and the Horizon Utilities-owned substations. Horizon Utilities has chosen to renew the 4kV and 8kV distribution systems to a higher voltage to avoid the cost of the investment in the renewal of the substations. The total avoided substation renewal investment over the remaining 35 years of the plan is $70,000,000 for all 28 substations. Therefore the renewal of the distribution assets at the current 4kV level was not a feasible alternative. The renewal of the area serviced by Central substation started in 2016 and is scheduled to be completed in 2022.
	Safety (5.4.5.2.B.2) This project is not intended to address safety concerns with the distribution system.
	Cyber-Security and Privacy (5.4.5.2.B.3) (where applicable) Cyber-Security and Privacy are not applicable to this project.
	Co-ordination and Interoperability (5.4.5.2.B.4) **Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.5.2.B.4.a) (where applicable)** Please refer to Note II for an explanation on co-ordination with utilities, regional planning and/or links with 3rd parties. **Enabling of Future Technology and/or Future Operational Requirements (5.4.5.2.B.4.b)** Please refer to Note IV for an explanation enabling of future technology and future operational requirements.
	Economic Development (5.4.5.2.B.5) **(where applicable)** Horizon Utilities ensures that policies and practices do not unnecessarily create barriers to economic development which are primarily focused within its communities.

Environmental Benefits (5.4.5.2.B.6) **(where applicable)**

n/a

System Renewal Specific Requirements (5.4.5.2.C.b)

Project Name	CE-F10 Renewal – John St S	Table 3

System Renewal Specific Requirements (5.4.5.2.C.b)

Asset Performance Target and Asset Lifecycle Optimization (5.4.5.2.C.b.i.1)

The two substations servicing the downtown Hamilton operating area service a total of 7,400 customers and were constructed in 1950 and 1960. The overall Station Health Index for Aberdeen and Central substations is 53% and 56% respectively. Central substation has ten feeders; six of which are obsolete, oil-filled breakers are at end-of-life. Kinectrics forecasted that these circuit breakers have 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.

Asset Condition Relative to Typical Life Cycle (5.4.5.2.C.b.i.2)

Generally the 4kV assets are the oldest vintage in the system. 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.

Number of Customers Impacted (5.4.5.2.C.b.i.3)

This project impacts approximately 1,000 customers.

Quantitative Customer Impact and Risk (5.4.5.2.C.b.i.4)

SAIDI of 0.242

Qualitative Customer Impact and Risk (5.4.5.2.C.b.i.5)

This project will address aging assets with inadequate backup. Aging assets represent an increased risk of service interruption to customers and inadequate backup would result in long duration service interruptions upon occurrence. These factors would lead to customer dissatisfaction in this area.

Value of Customer Impact (5.4.5.2.C.b.i.6)

High

Other Factors Affecting Project Timing (5.4.5.2.C.b.ii)

The renewal of the area serviced by Central substation is schedule for 2016 to 2022. This project is required to be completed in 2018 to allow for the renewal of the remaining area to be completed on schedule.

Impact on System O&M Costs (5.4.5.2.C.b.iii)

This project will have no material impact on planned O&M costs. The renewal of the 4kV and 8kV distribution systems, as a whole, will provide a reduction in reactive O&M costs to address service interruptions caused by failed equipment. These reductions will not be material in the 2015 to 2019 Test Years.

Reliability and Safety Factors (5.4.5.2.C.b.iv)

The renewal of the 4kV and 8kV distribution system will provide reliability improvements through reduced service interruptions caused by failed equipment.

Analysis of Project Benefits and Timing (5.4.5.2.C.b.v)

The timing of this project, as part of the 4kV and 8kV Renewal Program, is determined through the assessment of the distribution system health and the health of the substation assets servicing the area. Renewal of this area will allow for the decommissioning of the substation assets by 2022 thereby avoiding the need for capital investment into these substations.

Like-for-Like Renewal Analysis (5.4.5.2.C.b.vi)

The like-for-like renewal of these assets (i.e. same system configuration and same distribution voltage) will perpetuate the existing operating constraints and require capital investment to renew substation assets. Renewal of the distribution assets at a higher voltage does not involve any material incremental costs over renewal at the existing voltage. Operating constraints (e.g. undersized conductor, radial feeds) are addressed on a case by case basis where appropriate.

Capital Project Summary

General Information on Project (5.4.5.2.A)

Project Name	2018 Reactive Renewal
Budget Year	2018
Investment Category	System Renewal
Project Summary	This category includes all projects required for the reactive renewal or repairs driven by emergency equipment failures and associated corrective action. Projects arise from trouble calls or inspection programs identifying an urgent need to replace system assets and the scope of the equipment replacement requires engineering. Also included in this category are projects to address customer power quality issues, and Electrical Safety Authority ("ESA") due diligence inspection outcomes.

Capital Investment (5.4.5.2.A.i)	Capital Investment (gross)	$1,549,868
	Customer Contribution	n/a
	Capital Investment (net)	n/a
	O&M Expenditure	n/a

Customer Attachments / Load (kVA) (5.4.5.2.A.ii)	n/a

Project Dates (5.4.5.2.A.iii)

Start Date	January 1, 2018
In Service Date	December 31, 2018

Expenditure Timing

Q1	Q2	Q3	Q4
25%	25%	25%	25%

Schedule Risk and Risk Mitigation (5.4.5.2.A.iv**)**

Please refer to Note I for risk and risk mitigation.

Comparative Information from Equivalent Projects (5.4.5.2.A.v)

Comparable investments for the 2010 and 2013 Historical Years and the 2014 Bridge Year are:

2010 (CGAAP)- $ 8,745,125
2011 (CGAAP)- $ 8,230,970
2012 (MIFRS) - $ 4,032,000
2013 (MIFRS) - $ 6.069,566
2014 (MIFRS) - $ 4,840,000

Total Capital OM&A Costs Associated with REG Investments (5.4.5.2.A.vi)

This project is not associated with an REG investment and therefore OM&A costs related to REG will not be incurred.

Leave to Construct Approval (5.4.5.2.A.vii)

This project does not require "Leave to Construct" under Section 92 of the *Ontario Energy Board Act* 1998.

Evaluation Criteria and Information (5.4.5.2.B)

Project Name	2018 Reactive Renewal	Table 2

Efficiency, Customer Value, Reliability (5.4.5.2.B.1)

Investment Driver (5.4.5.2.B.1.a)
System Renewal (80%)

Secondary Driver (5.4.5.2.B.1.a)
System Service (20%)

Investment Priority (5.4.5.2.B.1.b)
3 – Required project

Analysis of Project and Project Alternatives (5.4.5.2.B.1.c)

No alternatives are considered for these projects as they involve the emergency replacement of failed equipment required to restore service.

Safety (5.4.5.2.B.2)

These projects are intended to primarily address failed assets however investments required to address immediate safety issues, including issues presenting a potential risk to public safety identified by the ESA, are included in this project.

Cyber-Security and Privacy (5.4.5.2.B.3) (where applicable)

Cyber-Security and Privacy are not applicable to this project.

Co-ordination and Interoperability (5.4.5.2.B.4)

Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.5.2.B.4.a) (where applicable)

Please refer to Note II for an explanation on co-ordination with utilities, regional planning and/or links with 3rd parties.

Enabling of Future Technology and/or Future Operational Requirements (5.4.5.2.B.4.b)

Please refer to Note IV for an explanation enabling of future technology and future operational requirements.

Economic Development (5.4.5.2.B.5) **(where applicable)**

Horizon Utilities ensures that policies and practices do not unnecessarily create barriers to economic development which are primarily focused within its communities.

Environmental Benefits (5.4.5.2.B.6) **(where applicable)**

n/a

System Renewal Specific Requirements (5.4.5.2.C.b)

Project Name	2018 Reactive Renewal	Table 3

System Renewal Specific Requirements (5.4.5.2.C.b)

Asset Performance Target and Asset Lifecycle Optimization (5.4.5.2.C.b.i.1)

These projects are reactive in nature and are initiated from equipment that has failed or that have a high risk of failure resulting in a service interruption. These projects have a very high probability of impacting Horizon Utilities' reliability targets.

Asset Condition Relative to Typical Life Cycle (5.4.5.2.C.b.i.2)

These projects address failed assets or assets with a high risk of imminent failure and as such, these assets are at the end of their useful life. The asset condition relative to their typical life cycle varies in each incident or outage.

Number of Customers Impacted (5.4.5.2.C.b.i.3)

The number of customers impacted varies in each incident or outage.

Quantitative Customer Impact and Risk (5.4.5.2.C.b.i.4)

The quantitative customer impact varies in each incident or outage.

Qualitative Customer Impact and Risk (5.4.5.2.C.b.i.5)

These projects address customer satisfaction as they are required to address failed assets that have either caused a system interruption, or have a high probability of causing a service interruption.

Value of Customer Impact (5.4.5.2.C.b.i.6)

The value of the customer impact varies in each incident or outage.

Other Factors Affecting Project Timing (5.4.5.2.C.b.ii)

These projects are reactive in nature and address failed assets, or assets at risk of imminent failure. Investments must be performed when identified.

Impact on System O&M Costs (5.4.5.2.C.b.iii)

These projects do not materially impact system O&M costs.

Reliability and Safety Factors (5.4.5.2.C.b.iv)

Improvements to reliability and security are expected as secondary benefits to this project.

Analysis of Project Benefits and Timing (5.4.5.2.C.b.v)

Investment for this project address failed assets, or assets at risk of imminent failure. Investments are not subject to project prioritization as they are reactive and non-discretionary.

Like-for-Like Renewal Analysis (5.4.5.2.C.b.vi)

Assets replaced reactively to replace failed assets, or assets at risk of imminent failure are performed on a like-for-like basis. No extra costs to address other distributor planning objectives are incurred with these projects.

Capital Project Summary

General Information on Project (5.4.5.2.A)

Project Name	2018 Load Break Disconnect Switch ("LBDS") Replacement
Budget Year	2018
Investment Category	System Renewal
Project Summary	This project involves the replacement of LBDS found to be either inoperable or beyond economic repair (where the cost of maintenance is not warranted) as found through Horizon Utilities' maintenance and inspection programs. Such switches will be replaced with automated switches where an operational benefit can be realized. This is a multi-year program based on 16 replacements per year.
Capital Investment (5.4.5.2.A.i)	Capital Investment (gross): $357,000 Customer Contribution: $0 Capital Investment (net): $357,000 O&M Expenditure: $0
Customer Attachments / Load (kVA) (5.4.5.2.A.ii)	n/a
Project Dates (5.4.5.2.A.iii)	Start Date 2018/06/01 In Service Date 2018/11/30

Expenditure Timing

Q1	Q2	Q3	Q4
0%	0%	50%	50%

Schedule Risk and Risk Mitigation (5.4.5.2.A.iv**)**

Please refer to Note I for risk and risk mitigation.

Comparative Information from Equivalent Projects (5.4.5.2.A.v)

Comparable gross investments for the 2010 to 2013 Historical Years and the 2014 Bridge Year are:

2010 (CGAAP)- $ 0
2011 (CGAAP)- $ 0
2012 (MIFRS) - $ 0
2013 (MIFRS) - $ 212,000
2014 (MIFRS) - $ 312,000

Total Capital OM&A Costs Associated with REG Investments (5.4.5.2.A.vi)

This project is not associated with an REG investment and therefore OM&A costs related to REG will not be incurred.

	Leave to Construct Approval (5.4.5.2.A.vii) This project does not require "Leave to Construct" under Section 92 of the *Ontario Energy Board Act* 1998.

Evaluation Criteria and Information (5.4.5.2.B)	
	Project Name 2018 LBDS Replacement Table 2
	Efficiency, Customer Value, Reliability (5.4.5.2.B.1) **Investment Driver (5.4.5.2.B.1.a)** System Renewal (80%) **Secondary Driver (5.4.5.2.B.1.a)** System Service (20%) **Investment Priority (5.4.5.2.B.1.b)** 3 – Required project
	Analysis of Project and Project Alternatives (5.4.5.2.B.1.c) This project involves the replacement of LBDS identified as requiring replacement through Horizon Utilities' maintenance and inspection programs. When feasible, the switches are refurbished rather than replaced. Where refurbishment is not possible, the switches will be replaced with an automated switch where an operational benefit can be realized.
	Safety (5.4.5.2.B.2) This project is not intended to address safety concerns with the distribution system.
	Cyber-Security and Privacy (5.4.5.2.B.3) (where applicable) Horizon Utilities utilizes the Smart Meter communication infrastructure when communicating with automated switches. Horizon Utilities' Smart Meter and related AMI network have been procured through Elster. Elster's system supports a multi-layered security approach including: access control, authorization, authentication and data integrity protocols. As part of its continuous improvement model, Horizon Utilities performs periodic security assessments to identify opportunities for enhanced system hardening.
	Co-ordination and Interoperability (5.4.5.2.B.4) **Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.5.2.B.4.a) (where applicable)** Please refer to Note II for an explanation on co-ordination with utilities, regional planning and/or links with 3rd parties. **Enabling of Future Technology and/or Future Operational Requirements (5.4.5.2.B.4.b)** This is not applicable to this project.
	Economic Development (5.4.5.2.B.5) **(where applicable)** Horizon Utilities ensures that policies and practices do not unnecessarily create barriers to economic development which are primarily focused within its communities.

Environmental Benefits (5.4.5.2.B.6) **(where applicable)**

n/a

System Renewal Specific Requirements (5.4.5.2.C.b)

Project Name	2018 LBDS Replacement	Table 3

System Renewal Specific Requirements (5.4.5.2.C.b)

Asset Performance Target and Asset Lifecycle Optimization (5.4.5.2.C.b.i.1)

LBDS are critical devices for the operation of the distribution system and are installed at key operating points (e.g. feeder tie points, feeder sectionalizing). Unplanned failures of these devices would impact Horizon Utilities' ability to restore power, resulting in extended outages.

Asset Condition Relative to Typical Life Cycle (5.4.5.2.C.b.i.2)

The asset condition of load break switches relative to their typical lifecycle varies from switch to switch depending upon the operational stresses experienced by the switch. LBDS that are identified for replacement are replaced because they would not operate properly when required and are beyond economical repair.

Number of Customers Impacted (5.4.5.2.C.b.i.3)

n/a

Quantitative Customer Impact and Risk (5.4.5.2.C.b.i.4)

n/a

Qualitative Customer Impact and Risk (5.4.5.2.C.b.i.5)

Failure of an LBDS to operate when required can impact Horizon Utilities' operational ability which can adversely affect the service experienced by customers.

Value of Customer Impact (5.4.5.2.C.b.i.6)

The value of the customer impact varies in each instance.

Other Factors Affecting Project Timing (5.4.5.2.C.b.ii)

The timing of this project is dependent upon the timing of Horizon Utilities' LBDS maintenance program.

Impact on System O&M Costs (5.4.5.2.C.b.iii)

These projects do not materially impact system O&M costs.

Reliability and Safety Factors (5.4.5.2.C.b.iv)

Reliability can be adversely affected when a LBDS fails to operate when required as part of switching to restore service.

Analysis of Project Benefits and Timing (5.4.5.2.C.b.v)

n/a

Like-for-Like Renewal Analysis (5.4.5.2.C.b.vi)

LDBS are replaced with an automated switch where an operational benefit can be realized. Otherwise they are replaced on a like-for-like basis.

Capital Project Summary

General Information on Project (5.4.5.2.A)

Project Name	2018 Proactive Transformer Replacement
Budget Year	2018
Investment Category	System Renewal
Project Summary	This project was established to proactively replace distribution transformers as required. Renewal of distribution transformers in the past has either been reactive upon failure or proactive when included in the 4kV & 8KV Renewal or XLPE Primary Cable Renewal Programs. There are instances where proactive replacement of transformers is required even when the replacement is outside of the scope of the programs mentioned above. This is a multi-year project, based on 25 replacements per year.

Capital Investment (5.4.5.2.A.i)		
	Capital Investment (gross)	$384,000
	Customer Contribution	$0
	Capital Investment (net)	$384,000
	O&M Expenditure	$0

Customer Attachments / Load (kVA) (5.4.5.2.A.ii)	n/a

Project Dates (5.4.5.2.A.iii)

Start Date	2018/06/01
In Service Date	2018/12/31

Expenditure Timing

Q1	Q2	Q3	Q4
		50%	50%

Schedule Risk and Risk Mitigation (5.4.5.2.A.iv**)**

Please refer to Note I for risk and risk mitigation.

Comparative Information from Equivalent Projects (5.4.5.2.A.v)

Comparable gross investments for the 2010 to 2013 Historical Years and the 2014 Bridge Year are:

2010 (CGAAP)- $ 0
2011 (CGAAP)- $ 104,447
2012 (MIFRS) - $ 185,523
2013 (MIFRS) - $ 276,978
2014 (MIFRS) - $ 339,000

Total Capital OM&A Costs Associated with REG Investments (5.4.5.2.A.vi)

This project is not associated with an REG investment and therefore OM&A costs related to REG will not be incurred.

Leave to Construct Approval (5.4.5.2.A.vii)

This project does not require "Leave to Construct" under Section 92 of the *Ontario Energy Board Act* 1998.

Evaluation Criteria and Information (5.4.5.2.B)

Project Name	2018 Proactive Transformer Replacement	Table 2

Efficiency, Customer Value, Reliability (5.4.5.2.B.1)

Investment Driver (5.4.5.2.B.1.a)
System Renewal (100%)

Secondary Driver (5.4.5.2.B.1.a)
N/A

Investment Priority (5.4.5.2.B.1.b)
3 – Required project

Analysis of Project and Project Alternatives (5.4.5.2.B.1.c)

Proactive transformer replacements are identified through Horizon Utilities' visual inspection programs and 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, in a reactive replacement scenario, the customer(s) may be subject to an extended outage duration;
- Transformers that have visible oil leaks; and
- Transformers that have been identified through testing as containing PCBs.

These criteria were selected due to the level of associated risk. Transformers with visible oil leaks or containing PCBs represent a significant environmental risk. All oil spills must be tracked, reported, and the oil reclaimed where possible. Obsolete transformers, where a replacement is not available in inventory, pose a risk of prolonged service interruption upon failure and are replaced to reduce the risk of outage to the customer.

Safety (5.4.5.2.B.2)

This project is not intended to address safety concerns with the distribution system.

Cyber-Security and Privacy (5.4.5.2.B.3) (where applicable)

Cyber-Security and Privacy are not applicable to this project.

Co-ordination and Interoperability (5.4.5.2.B.4)

Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.5.2.B.4.a) (where applicable)

Please refer to Note II for an explanation on co-ordination with utilities, regional planning and/or links with 3rd parties.

Enabling of Future Technology and/or Future Operational Requirements (5.4.5.2.B.4.b)

This is not applicable to this project.

Economic Development (5.4.5.2.B.5) **(where applicable)**

Horizon Utilities ensures that policies and practices do not unnecessarily create barriers to economic development which are primarily focused within its communities.

Environmental Benefits (5.4.5.2.B.6) **(where applicable)**

n/a

System Renewal Specific Requirements (5.4.5.2.C.b)

Project Name 2018 Proactive Transformer Replacement Table 3

System Renewal Specific Requirements (5.4.5.2.C.b)

Asset Performance Target and Asset Lifecycle Optimization (5.4.5.2.C.b.i.1)

The transformers selected for proactive replacement represent a level of risk to Horizon Utilities and this project provides risk mitigation consistent with Horizon Utilities' asset management objectives.

Asset Condition Relative to Typical Life Cycle (5.4.5.2.C.b.i.2)

The asset condition of these transformers relative to their typical lifecycle varies from transformer to transformer. Transformers selected for replacement present a level of risk to Horizon Utilities either through imminent failure of the transformer or through the need to address environmental risk associated with PCBs; or through the risks associated with transformers that have visible oil leaks.

Number of Customers Impacted (5.4.5.2.C.b.i.3)

n/a

Quantitative Customer Impact and Risk (5.4.5.2.C.b.i.4)

n/a

Qualitative Customer Impact and Risk (5.4.5.2.C.b.i.5)

These criteria were selected due to the level of associated risk. Transformers with visible oil leaks or containing PCBs represent a significant environmental risk. All oil spills must be tracked, reported, and the oil reclaimed where possible. Obsolete transformers, where a replacement is not available in inventory, represent a risk of prolonged service interruption upon failure and are replaced to reduce the risk of outage to the customer.

Value of Customer Impact (5.4.5.2.C.b.i.6)

The value of the customer impact varies in each instance.

Other Factors Affecting Project Timing (5.4.5.2.C.b.ii)

n/a

Impact on System O&M Costs (5.4.5.2.C.b.iii)

These projects do not materially impact system O&M costs.

Reliability and Safety Factors (5.4.5.2.C.b.iv)

n/a.

Analysis of Project Benefits and Timing (5.4.5.2.C.b.v)

n/a

Like-for-Like Renewal Analysis (5.4.5.2.C.b.vi)

n/a.

Capital Project Summary

General Information on Project (5.4.5.2.A)

Project Name	2018 Substation Infrastructure Renewal
Budget Year	2018
Investment Category	System Renewal
Project Summary	This program involves the renewal of substation infrastructure throughout Horizon Utilities' service territory. Substation maintenance and inspection programs identify a number of required investments for the continued safe and reliable operation of Horizon Utilities' substations, annually. Investments under this program include battery replacements, SCADA and communication upgrades, and grounding improvements.

Capital Investment (5.4.5.2.A.i)	Capital Investment (gross)	$491,000
	Customer Contribution	$0
	Capital Investment (net)	$491,000
	O&M Expenditure	$0
Customer Attachments / Load (kVA) (5.4.5.2.A.ii)	n/a	

Project Dates (5.4.5.2.A.iii)

Start Date	2018/01/01
In Service Date	2018/12/31

Expenditure Timing			
Q1	Q2	Q3	Q4
25%	25%	25%	25%

Schedule Risk and Risk Mitigation (5.4.5.2.A.iv**)**

Please refer to Note I for risk and risk mitigation.

Comparative Information from Equivalent Projects (5.4.5.2.A.v)

Comparable gross investments for the 2010 to 2013 Historical Years and the 2014 Bridge Year are:

2010 (CGAAP)- $ 146,477
2011 (CGAAP)- $ 326,000
2012 (MIFRS) - $ 305,000
2013 (MIFRS) - $ 168,507
2014 (MIFRS) - $ 455,503

Total Capital OM&A Costs Associated with REG Investments (5.4.5.2.A.vi)

This project is not associated with an REG investment and therefore OM&A costs related to REG will not be incurred.

Leave to Construct Approval (5.4.5.2.A.vii)

This project does not require "Leave to Construct" under Section 92 of the *Ontario Energy Board Act* 1998.

Evaluation Criteria and Information (5.4.5.2.B)

Project Name	2018 Substation Infrastructure Renewal	Table 2

Efficiency, Customer Value, Reliability (5.4.5.2.B.1)

Investment Driver (5.4.5.2.B.1.a)
System Renewal (80%)

Secondary Driver (5.4.5.2.B.1.a)
System Service (20%)

Investment Priority (5.4.5.2.B.1.b)
3 – Required project

Analysis of Project and Project Alternatives (5.4.5.2.B.1.c)

This program is required for the ongoing safe and reliable operation of Horizon Utilities' municipal substations. The 4kV and 8kV Renewal Program is structured to decommission Horizon Utilities' 28 substations over the next 34 years. There is no investment in the renewal of the major electrical assets (power transformers, switchgear and breakers) forecasted for the 2015 to 2019 Test Years. The investments provided above are required to maintain the ancillary substation assets in safe working order. Substation investment requirements are identified though preventative maintenance programs performed on both routine maintenance cycles and monthly inspections. 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. Investments are required to address both electrical assets within the substation (e.g. replacement of switchgear components and instrument transformers) and ancillary equipment (e.g. SCADA, communication equipment, or backup batteries). All of these components are critical to the continued safe and reliable operation of the substation. A failure to undertake these required investments could lead to premature failure of substation components that would result in a service interruption and increased operating or reactive capital expenditure.

Safety (5.4.5.2.B.2)

This project is not intended to address safety concerns with the distribution system.

Cyber-Security and Privacy (5.4.5.2.B.3) (where applicable)

Cyber-Security and Privacy are not applicable to this project.

Co-ordination and Interoperability (5.4.5.2.B.4)

Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.5.2.B.4.a) (where applicable)

Please refer to Note II for an explanation on co-ordination with utilities, regional planning and/or links with 3rd parties.

Enabling of Future Technology and/or Future Operational Requirements (5.4.5.2.B.4.b)

Please refer to Note IV for an explanation enabling of future technology and future operational requirements.

	Economic Development (5.4.5.2.B.5) **(where applicable)** Horizon Utilities ensures that policies and practices do not unnecessarily create barriers to economic development which are primarily focused within its communities.
	Environmental Benefits (5.4.5.2.B.6) **(where applicable)** n/a.

System Renewal Specific Requirements (5.4.5.2.C.b)	**Project Name** 2018 Substation Infrastructure Renewal Table 3
	System Renewal Specific Requirements (5.4.5.2.C.b) **Asset Performance Target and Asset Lifecycle Optimization (5.4.5.2.C.b.i.1)** This project involves investment to replace substation infrastructure required for the continued safe and reliable operation of Horizon Utilities' substations. **Asset Condition Relative to Typical Life Cycle (5.4.5.2.C.b.i.2)** n/a **Number of Customers Impacted (5.4.5.2.C.b.i.3)** n/a. **Quantitative Customer Impact and Risk (5.4.5.2.C.b.i.4)** **Qualitative Customer Impact and Risk (5.4.5.2.C.b.i.5)** n/a **Value of Customer Impact (5.4.5.2.C.b.i.6)** Medium **Other Factors Affecting Project Timing (5.4.5.2.C.b.ii)** The timing of investments in this project are dependent upon the timing of substation maintenance programs and the infrastructure requiring renewal identified while performing maintenance. **Impact on System O&M Costs (5.4.5.2.C.b.iii)** This project will have no material impact on O&M expenditures. **Reliability and Safety Factors (5.4.5.2.C.b.iv)** n/a

Analysis of Project Benefits and Timing (5.4.5.2.C.b.v)
n/a

Like-for-Like Renewal Analysis (5.4.5.2.C.b.vi)
The assets renewed in this program are replaced on a like-for-like basis.

Capital Project Summary

General Information on Project (5.4.5.2.A)

Project Name	2018 Hamilton Mountain XLPE Renewal
Budget Year	2018
Investment Category	System Renewal
Project Summary	Renewal of end-of-life XLPE cable assets in the Hamilton Mountain area. Projects will include the renewal of XLPE on the Horning M63 feeder and the Mohawk M63 feeder.
Capital Investment (5.4.5.2.A.i)	Capital Investment (gross): $4,641,343 Customer Contribution: Capital Investment (net): $4,641,343 O&M Expenditure: $0
Customer Attachments / Load (kVA) (5.4.5.2.A.ii)	The customer and load impacted by this project will vary depending upon the final scope of the project
Project Dates (5.4.5.2.A.iii)	Start Date 2018/03/01 In Service Date 2018/12/31

Expenditure Timing

Q1	Q2	Q3	Q4
10%	40%	40%	10%

Schedule Risk and Risk Mitigation (5.4.5.2.A.iv**)**

Please refer to Note I for risk and risk mitigation.

Comparative Information from Equivalent Projects (5.4.5.2.A.v)

This project is part of a multi-year investment to renewal XLPE primary cable. The 2018 investment in the XLPE Renewal Program is $9,384,000.

Comparable gross investments for the XLPE Renewal Program for the 2010 to 2013 Historical Years and the 2014 Bridge Year are:

2010 (CGAAP)- $ 0
2011 (CGAAP)- $ 0
2012 (MIFRS) - $ 0
2013 (MIFRS) - $ 1,572,090
2014 (MIFRS) - $ 893,000

Total Capital OM&A Costs Associated with REG Investments (5.4.5.2.A.vi)

This project is not associated with an REG investment and therefore OM&A costs related to REG will not be incurred.

Leave to Construct Approval (5.4.5.2.A.vii)

This project does not require “Leave to Construct” under Section 92 of the *Ontario Energy Board Act* 1998.

Evaluation Criteria and Information (5.4.5.2.B)

Project Name	2018 Hamilton Mountain XLPE Renewal	Table 2

Efficiency, Customer Value, Reliability (5.4.5.2.B.1)

Investment Driver (5.4.5.2.B.1.a)
System Renewal (80%)

Secondary Driver (5.4.5.2.B.1.a)
System Service (20%)

Investment Priority (5.4.5.2.B.1.b)
5 – Mandatory Project

Analysis of Project and Project Alternatives (5.4.5.2.B.1.c)

This project is part of the multi-year XLPE Renewal Program. Horizon Utilities considered the four replacement philosophies for addressing risk inherent in the XLPE asset group: Area; Reactive; Selected; and Refurbishment. The area replacement philosophy will be utilized 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 area replacement philosophy will be employed for the Hamilton Mountain operating area due to the high volume of XLPE primary cable. 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.

Safety (5.4.5.2.B.2)

These projects are not intended to address safety concerns with the distribution system.

Cyber-Security and Privacy (5.4.5.2.B.3) (where applicable)

Cyber-Security and Privacy are not applicable to this project.

Co-ordination and Interoperability (5.4.5.2.B.4)

Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.5.2.B.4.a) (where applicable)

Please refer to Note II for an explanation on co-ordination with utilities, regional planning and/or links with 3rd parties.

Enabling of Future Technology and/or Future Operational Requirements (5.4.5.2.B.4.b)

Please refer to Note IV for an explanation enabling of future technology and future operational requirements.

Economic Development (5.4.5.2.B.5) **(where applicable)**

Horizon Utilities ensures that policies and practices do not unnecessarily create barriers to economic development which are primarily focused within its communities.

Environmental Benefits (5.4.5.2.B.6) **(where applicable)**

n/a

System Renewal Specific Requirements (5.4.5.2.C.b)

Project Name	2018 Hamilton Mountain XLPE Renewal	Table 3

System Renewal Specific Requirements (5.4.5.2.C.b)

Asset Performance Target and Asset Lifecycle Optimization (5.4.5.2.C.b.i.1)

XLPE primary cable is the asset group with the largest investment requirement as identified by the Kinectrics ACA. 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.

The Hamilton Mountain operating area has 225km of XLPE primary cable with a Health Index of either "very poor" or "poor". 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.

Asset Condition Relative to Typical Life Cycle (5.4.5.2.C.b.i.2)

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.

Number of Customers Impacted (5.4.5.2.C.b.i.3)

Approximately 1000 customers will be impacted by this project.

Quantitative Customer Impact and Risk (5.4.5.2.C.b.i.4)

The qualitative customer varies for customers affected by this project.

Qualitative Customer Impact and Risk (5.4.5.2.C.b.i.5)

This project will address aging assets at risk of failure. Failures of XLPE primary cable result in extended service interruptions; 30% of these outages exceeded four hours in duration, while 5% of these outages exceeded twelve hours in duration

Value of Customer Impact (5.4.5.2.C.b.i.6)

High

Other Factors Affecting Project Timing (5.4.5.2.C.b.ii)

Proactive replacements are required because, as assets continue to age and degrade, the cable will fail at an exponential rate. In the worst case scenario, it will exceed Horizon Utilities' ability to keep pace with repairs. Reliability will also deteriorate to unacceptable levels. Reactive replacements will be considerably more costly than proactive renewal.

Impact on System O&M Costs (5.4.5.2.C.b.iii)

This project will have no material impact on planned O&M costs. The renewal of the XLPE primary cable, as a whole, will provide a reduction in reactive O&M costs to address service interruptions caused by failed equipment. These reductions will not be material in the 2015 to 2019 Test Years

Reliability and Safety Factors (5.4.5.2.C.b.iv)

The renewal of the XLPE primary cable system will provide reliability improvements through reduced service interruptions caused by failed equipment.

Analysis of Project Benefits and Timing (5.4.5.2.C.b.v)

Failure to invest in the proactive renewal of XLPE primary cable and associated underground assets would result in unacceptable levels of system failures and outages beyond Horizon Utilities ability to resolve within a reasonable timeframe as these assets continue to age and degrade. Reactive replacements will also be considerably more costly than the forecast expenditure required to execute the proposed proactive replacement.

Like-for-Like Renewal Analysis (5.4.5.2.C.b.vi)

XLPE renewal projects will include: the elimination of radial underground feeds; replacement of below grade transformers with padmount transformers; and the introduction of fusing on the underground distribution systems where applicable.

Capital Project Summary

General Information on Project (5.4.5.2.A)

Project Name	JN-F1 Renewal			
Budget Year	2018			
Investment Category	System Renewal			
Project Summary	This project involves the renewal of 4kV distribution assets on the John F1 feeder as part of the 4kV and 8kV Renewal Program. The assets are located along Bond St and Melville St in Dundas.			
Capital Investment (5.4.5.2.A.i)	Capital Investment (gross)	$2,525,572		
	Customer Contribution	$0		
	Capital Investment (net)	$2,525,572		
	O&M Expenditure	$0		
Customer Attachments / Load (kVA) (5.4.5.2.A.ii)	This project will impact 1,048 customers and 5000kVA of transformation			
Project Dates (5.4.5.2.A.iii)	Start Date	2018/02/01		
	In Service Date	2018/09/30		
	Expenditure Timing			
	Q1	Q2	Q3	Q4
	20%	60%	20%	0%

Schedule Risk and Risk Mitigation (5.4.5.2.A.iv**)**

Please refer to Note I for risk and risk mitigation.

Comparative Information from Equivalent Projects (5.4.5.2.A.v)

There is no direct comparator in scope, size and design characteristics for this project. This project is one phase of a multi-year investment to renew the area served by John substation as part of the 4kV and 8kV Renewal Program. The 2018 investment for the renewal of John substation is $2,525,572. The 2018 investment in the 4kV and 8kV Renewal Program is $15,684,000.

Comparable gross investments for the 4kv and 8kV Renewal Program for the 2010 and 2013 Historical Years and the 2014 Bridge Year are:

2010 (CGAAP)- $ 2,556,076
2011 (CGAAP)- $ 8,820,000
2012 (MIFRS) - $ 5,268,441
2013 (MIFRS) - $ 5,072,233
2014 (MIFRS) - $ 6,434,000

Total Capital OM&A Costs Associated with REG Investments (5.4.5.2.A.vi)

This project is not associated with an REG investment and therefore OM&A costs related to REG will not be incurred.

	Leave to Construct Approval (5.4.5.2.A.vii) This project does not require "Leave to Construct" under Section 92 of the *Ontario Energy Board Act* 1998.

Evaluation Criteria and Information (5.4.5.2.B)			
	Project Name	JN-F1 Renewal	Table 2
	Efficiency, Customer Value, Reliability (5.4.5.2.B.1) **Investment Driver (5.4.5.2.B.1.a)** System Renewal (60%) **Secondary Driver (5.4.5.2.B.1.a)** System Service (40%) **Investment Priority (5.4.5.2.B.1.b)** 3 – Required project		
	Analysis of Project and Project Alternatives (5.4.5.2.B.1.c) Renewal of assets at 4kV would not allow for the eventual decommissioning of John substation. Horizon Utilities' substation assets are being decommissioned over the life of the 4kV and 8kV Renewal Program to avoid capital investment required for the renewal of substation assets that are nearing the end of their useful lives.		
	Safety (5.4.5.2.B.2) This project is not intended to address safety concerns with the distribution system.		
	Cyber-Security and Privacy (5.4.5.2.B.3) (where applicable) Cyber-Security and Privacy are not applicable to this project.		
	Co-ordination and Interoperability (5.4.5.2.B.4) **Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.5.2.B.4.a) (where applicable)** Please refer to Note II for an explanation on co-ordination with utilities, regional planning and/or links with 3rd parties. **Enabling of Future Technology and/or Future Operational Requirements (5.4.5.2.B.4.b)** Please refer to Note IV for an explanation enabling of future technology and future operational requirements.		
	Economic Development (5.4.5.2.B.5) **(where applicable)** Horizon Utilities ensures that policies and practices do not unnecessarily create barriers to economic development which are primarily focused within its communities.		
	Environmental Benefits (5.4.5.2.B.6) **(where applicable)** n/a		

System Renewal Specific Requirements (5.4.5.2.C.b)

Project Name	JN-F1 Renewal	Table 3

System Renewal Specific Requirements (5.4.5.2.C.b)

Asset Performance Target and Asset Lifecycle Optimization (5.4.5.2.C.b.i.1)

The distribution assets in the Dundas operating area are in poor health and have significant operating constraints. 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'.

Asset Condition Relative to Typical Life Cycle (5.4.5.2.C.b.i.2)

Generally the 4kV assets are of the oldest vintage in the system. 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.

Number of Customers Impacted (5.4.5.2.C.b.i.3)

This project impacts 1,048 customers.

Quantitative Customer Impact and Risk (5.4.5.2.C.b.i.4)

SAIDI of 0.025

Qualitative Customer Impact and Risk (5.4.5.2.C.b.i.5)

This project will address aging assets with inadequate backup. Aging assets represent an increased risk of service interruption to customers and inadequate backup would result in long duration service interruptions upon occurrence. These factors would lead to customer dissatisfaction in this area.

Value of Customer Impact (5.4.5.2.C.b.i.6)

High

Other Factors Affecting Project Timing (5.4.5.2.C.b.ii)

The timing of this project is required to co-ordinate with the 4kV and 8kV Renewal Program as it involves both the renewal of XLPE primary cable the renewal of the underground section of the John substation F1 feeder. Renewal of this area will allow for the decommissioning of the substation assets by 2019 thereby avoiding the need for capital investment into these substations.

Impact on System O&M Costs (5.4.5.2.C.b.iii)

This project will have no material impact on planned O&M costs. The renewal of the 4kV and 8kV distribution systems, as a whole, will provide a reduction in reactive O&M costs to address service interruptions caused by failed equipment. These reductions will not be material in the 2015 to 2019 Test Years.

Reliability and Safety Factors (5.4.5.2.C.b.iv)

The renewal of XLPE primary cable will provide reliability improvements through reduced service interruptions caused by failed equipment. The cable renewed by this project is direct buried and therefore subject to extended outages, requiring multiple hours to repair, upon failure.

Analysis of Project Benefits and Timing (5.4.5.2.C.b.v)

The timing of this project is required to co-ordinate with the 4kV and 8kV Renewal Program as it involves both the renewal of XLPE primary cable the renewal of the underground section of the John substation F1 feeder. Renewal of this area will allow for the decommissioning of the substation assets by 2019 thereby avoiding the need for capital investment into these substations.

Like-for-Like Renewal Analysis (5.4.5.2.C.b.vi)

The like-for-like renewal of these assets (i.e. same system configuration and same distribution voltage) will perpetuate the existing operating constraints and require capital investment to renew substation assets. Renewal of the distribution assets at a higher voltage does not involve any material incremental costs over renewal at the existing voltage. Operating constraints (e.g. undersized conductor, radial feeds) are addressed on a case by case basis where appropriate.

Capital Project Summary

General Information on Project (5.4.5.2.A)

Project Name	2018 Pole Residual Replacements
Budget Year	2018
Investment Category	System Renewal
Project Summary	This project involves the replacement of wood poles that have a high risk of failure, as identified by pole residual testing.

Capital Investment (5.4.5.2.A.i)		
	Capital Investment (gross)	$1,333,151
	Customer Contribution	$0
	Capital Investment (net)	$1,333,151
	O&M Expenditure	$0

Customer Attachments / Load (kVA) (5.4.5.2.A.ii)	n/a

Project Dates (5.4.5.2.A.iii)

Start Date 2018/01/01

In Service Date 2018/06/30

Expenditure Timing

Q1	Q2	Q3	Q4
50%	50%	0%	0%

Schedule Risk and Risk Mitigation (5.4.5.2.A.iv**)**

Please refer to Note I for risk and risk mitigation.

Comparative Information from Equivalent Projects (5.4.5.2.A.v)

Comparable gross investments for the 2010 to 2013 Historical Years and the 2014 Bridge Year are:

2010 (CGAAP)- $ 1,326,407
2011 (CGAAP)- $ 895,000
2012 (MIFRS) - $ 930,000
2013 (MIFRS) - $ 718,074
2014 (MIFRS) - $ 1,190,000

Total Capital OM&A Costs Associated with REG Investments (5.4.5.2.A.vi)

This project is not associated with an REG investment and therefore OM&A costs related to REG will not be incurred.

Leave to Construct Approval (5.4.5.2.A.vii)

This project does not require “Leave to Construct” under Section 92 of the *Ontario Energy Board Act* 1998.

Evaluation Criteria and Information (5.4.5.2.B)	**Project Name** 2018 Pole Residual Replacements Table 2
	Efficiency, Customer Value, Reliability (5.4.5.2.B.1) **Investment Driver (5.4.5.2.B.1.a)** System Renewal (100%) **Secondary Driver (5.4.5.2.B.1.a)** N/A **Investment Priority (5.4.5.2.B.1.b)** 5 – Mandatory Project
	Analysis of Project and Project Alternatives (5.4.5.2.B.1.c) The replacement of wood poles in this project is identified through Horizon Utilities' pole testing maintenance program. The pole testing categorized the poles requiring replacement into two categories: 1) requiring immediate replacement; and 2) requiring replacement within five years. Horizon Utilities replaces poles requiring immediate replacement as soon as possible to mitigate the risk of service interruptions and the risk to public safety resulting from a failure of the pole. Horizon Utilities replaces poles requiring replacement within five years in the following year. Failure to replace in the following year compounds the volume of work in subsequent years resulting in cascading delays and compounded volumes in subsequent years. Poles replaced in this project are replaced on a like-for-like basis where possible.
	Safety (5.4.5.2.B.2) This project will address wood poles requiring replacement as identified through testing. Renewal of these assets prior to failure avoids the potential risk to public safety that would result from a failure of a wood pole.
	Cyber-Security and Privacy (5.4.5.2.B.3) (where applicable) Cyber-Security and Privacy are not applicable to this project.
	Co-ordination and Interoperability (5.4.5.2.B.4) **Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.5.2.B.4.a) (where applicable)** Please refer to Note II for an explanation on co-ordination with utilities, regional planning and/or links with 3rd parties. **Enabling of Future Technology and/or Future Operational Requirements (5.4.5.2.B.4.b)** This is not applicable to this project.
	Economic Development (5.4.5.2.B.5) **(where applicable)** Horizon Utilities ensures that policies and practices do not unnecessarily create barriers to economic development which are primarily focused within its communities.

Environmental Benefits (5.4.5.2.B.6) **(where applicable)**

n/a

System Renewal Specific Requirements (5.4.5.2.C.b)

Project Name	2018 Pole Residual Replacements	Table 3

System Renewal Specific Requirements (5.4.5.2.C.b)

Asset Performance Target and Asset Lifecycle Optimization (5.4.5.2.C.b.i.1)

This project is reactive in nature. The work required is initiated through Horizon Utilities' maintenance and inspection programs. This project has a very high probability of impacting Horizon Utilities' reliability targets if the poles are not replaced.

Asset Condition Relative to Typical Life Cycle (5.4.5.2.C.b.i.2)

This project address wood poles that have been identified as having a high risk of failure and as such, these assets are at the end of their useful life. The asset condition relative to their typical life cycle varies in case.

Number of Customers Impacted (5.4.5.2.C.b.i.3)

The number of customers impacted varies in each incident or outage.

Quantitative Customer Impact and Risk (5.4.5.2.C.b.i.4)

The quantitative customer impact varies in each incident or outage.

Qualitative Customer Impact and Risk (5.4.5.2.C.b.i.5)

These projects address customer satisfaction as they are required to address assets at risk of failure which would result in a service interruption.

Value of Customer Impact (5.4.5.2.C.b.i.6)

The value of the customer impact varies in each incident or outage.

Other Factors Affecting Project Timing (5.4.5.2.C.b.ii)

These projects are reactive in nature and address assets at risk of failure. Horizon Utilities replaces poles requiring immediate replacement as soon as possible to mitigate the risk of service interruptions and the risk to public safety resulting from a failure of the pole.

Horizon Utilities replace poles requiring replacement within five years in the following year. Failure to replace in the following year compounds the volume of work in subsequent years resulting in cascading delays and compounded volumes in subsequent years.

Impact on System O&M Costs (5.4.5.2.C.b.iii)

These projects do not materially impact system O&M costs.

Reliability and Safety Factors (5.4.5.2.C.b.iv)

This project will provide reliability and safety benefits as the project involves the replacement of wood poles that are at risk of failure. Failure of the asset would result in a service interruption and a potential risk to public safety.

Analysis of Project Benefits and Timing (5.4.5.2.C.b.v)

n/a

Like-for-Like Renewal Analysis (5.4.5.2.C.b.vi)

Poles replaced in this project are replaced on a like-for-like basis where possible as this presents the lowest cost option. No additional costs are incurred to address other distributor planning objectives.

Capital Project Summary

General Information on Project (5.4.5.2.A)

Project Name	ST-F3 & ST-F4 Renewal			
Budget Year	2018			
Investment Category	System Renewal			
Project Summary	This project involves the renewal of the Strouds Substation F3 & F4 feeders in West Hamilton as part of the 4kV and 8kV Renewal Program.			
Capital Investment (5.4.5.2.A.i)	Capital Investment (gross)	$3,830,389		
	Customer Contribution	$0		
	Capital Investment (net)	$3,830,389		
	O&M Expenditure	$0		
Customer Attachments / Load (kVA) (5.4.5.2.A.ii)	This project will impact approximately 2,400 customers and 5000kVA of transformation			
Project Dates (5.4.5.2.A.iii)	Start Date	2018/04/01		
	In Service Date	2018/12/31		
	Expenditure Timing			
	Q1	Q2	Q3	Q4
	0%	30%	40%	30%

Schedule Risk and Risk Mitigation (5.4.5.2.A.iv**)**

Please refer to Note I for risk and risk mitigation.

Comparative Information from Equivalent Projects (5.4.5.2.A.v)

There is no direct comparator in scope, size and design characteristics for this project. This project is one phase of a multi-year investment to renew the area served by Strouds Substation as part of the 4kV and 8kV Renewal Program. The 2018 investment for the renewal of Strouds substation is $3,831,000. The 2018 investment in the 4kV and 8kV Renewal Program is $15,684,000.

Comparable gross investments for the 4kV and 8kV Renewal Program for the 2010 to 2013 Historical Years and the 2014 Bridge Year are:

2010 (CGAAP)- $ 2,556,076
2011 (CGAAP)- $ 8,820,000
2012 (MIFRS) - $ 5,268,441
2013 (MIFRS) - $ 5,072,233
2014 (MIFRS) - $ 6,434,000

Total Capital OM&A Costs Associated with REG Investments (5.4.5.2.A.vi)

This project is not associated with an REG investment and therefore OM&A costs related to REG will not be incurred.

	Leave to Construct Approval (5.4.5.2.A.vii) This project does not require "Leave to Construct" under Section 92 of the *Ontario Energy Board Act* 1998.

Evaluation Criteria and Information (5.4.5.2.B)	**Project Name**	ST-F3 & ST-F4 Renewal	Table 2
	Efficiency, Customer Value, Reliability (5.4.5.2.B.1) **Investment Driver (5.4.5.2.B.1.a)** System Renewal (80%) **Secondary Driver (5.4.5.2.B.1.a)** System Service (20%) **Investment Priority (5.4.5.2.B.1.b)** 3 – Required project		
	Analysis of Project and Project Alternatives (5.4.5.2.B.1.c) This project is part of the multi-year 4kV and 8kV Renewal Program. Both the 4kV and 8kV distribution system and the Horizon Utilities-owned substations are at the end of their useful life. Horizon Utilities has chosen to renew the 4kV and 8kV distribution systems to a higher voltage to avoid the cost of the investment in the renewal of the substations. The total avoided substation renewal investment over the remaining 35 years of the plan is $70,000,000 for all 28 substations. Therefore the renewal of the distribution assets at the current 4kV level was not a feasible alternative. The renewal of the area serviced by the Strouds substation started in 2014 and is scheduled to be completed in 2018. Strouds substation was constructed in 1938. The switchgear at this substation is 44 years old and has a Health Index of 'very poor' as identified in the Substation Asset Condition Assessment ("SACA") and confirmed by the Kinectrics ACA.		
	Safety (5.4.5.2.B.2) This project is not intended to address safety concerns with the distribution system.		
	Cyber-Security and Privacy (5.4.5.2.B.3) (where applicable) Cyber-Security and Privacy are not applicable to this project.		
	Co-ordination and Interoperability (5.4.5.2.B.4) **Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.5.2.B.4.a) (where applicable)** Please refer to Note II for an explanation on co-ordination with utilities, regional planning and/or links with 3rd parties. **Enabling of Future Technology and/or Future Operational Requirements (5.4.5.2.B.4.b)** Please refer to Note IV for an explanation enabling of future technology and future operational requirements.		

Economic Development (5.4.5.2.B.5) **(where applicable)**

Horizon Utilities ensures that policies and practices do not unnecessarily create barriers to economic development which are primarily focused within its communities.

Environmental Benefits (5.4.5.2.B.6) **(where applicable)**

n/a

System Renewal Specific Requirements (5.4.5.2.C.b)

Project Name	ST-2 & ST-6 Renewal	Table 3

System Renewal Specific Requirements (5.4.5.2.C.b)

Asset Performance Target and Asset Lifecycle Optimization (5.4.5.2.C.b.i.1)

The distribution assets in the Hamilton West operating area are in poor health and the switchgear in both substations servicing this area has switchgear with a 'very poor' Health Index.

Asset Condition Relative to Typical Life Cycle (5.4.5.2.C.b.i.2)

Generally the 4kV assets are the oldest vintage in the system. 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.

Number of Customers Impacted (5.4.5.2.C.b.i.3)

This project impacts 2,400 customers.

Quantitative Customer Impact and Risk (5.4.5.2.C.b.i.4)

SAIDI of 0.125

Qualitative Customer Impact and Risk (5.4.5.2.C.b.i.5)

This project will address aging assets with inadequate backup. Aging assets represent an increased risk of service interruption to customers and inadequate backup would result in long duration service interruptions upon occurrence. These factors would lead to customer dissatisfaction in this area.

Value of Customer Impact (5.4.5.2.C.b.i.6)

High

Other Factors Affecting Project Timing (5.4.5.2.C.b.ii)

The renewal of the area serviced by the Strouds substation is scheduled for 2014 to 2018.

Impact on System O&M Costs (5.4.5.2.C.b.iii)

This project will have no material impact on planned O&M costs. The renewal of the 4kV and 8kV distribution systems, as a whole, will provide a reduction in reactive O&M costs to address service interruptions caused by failed equipment. These reductions will not be material in the 2015 to 2019 Test Years.

Reliability and Safety Factors (5.4.5.2.C.b.iv)

The renewal of the 4kV and 8kV distribution system will provide reliability improvements through reduced service interruptions caused by failed equipment.

Analysis of Project Benefits and Timing (5.4.5.2.C.b.v)

The timing of this project, as part of the 4kV and 8kV Renewal Program, is determined through the assessment of the distribution system health and the health of the substation assets servicing the area. 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

Like-for-Like Renewal Analysis (5.4.5.2.C.b.vi)

The like-for-like renewal of these assets (i.e. same system configuration and same distribution voltage) will perpetuate the existing operating constraints and will require capital investment to renew substation assets. Renewal of the distribution assets at a higher voltage does not involve any material incremental costs over renewal at the existing voltage. Operating constraints (e.g. undersized conductor, radial feeds) are addressed on a case by case basis where appropriate.

Capital Project Summary

General Information on Project (5.4.5.2.A)

Project Name	2018 Stoney Creek XLPE Renewal
Budget Year	2018
Investment Category	System Renewal
Project Summary	Renewal of end-of-life XLPE cable assets in the Stoney Creek area.

Capital Investment (5.4.5.2.A.i)	Capital Investment (gross)	$1,908,000
	Customer Contribution	$0
	Capital Investment (net)	$1,908,000
	O&M Expenditure	$0

Customer Attachments / Load (kVA) (5.4.5.2.A.ii)	The customer and load impacted by this project will vary depending upon the final scope of the project.

Project Dates (5.4.5.2.A.iii)

Start Date	2018/03/01
In Service Date	2018/12/31

Expenditure Timing

Q1	Q2	Q3	Q4
10%	40%	40%	10%

Schedule Risk and Risk Mitigation (5.4.5.2.A.iv**)**

Please refer to Note I for risk and risk mitigation.

Comparative Information from Equivalent Projects (5.4.5.2.A.v)

There is no direct comparator in scope, size and design characteristics for this project. This project is part of a multi-year investment to renewal XLPE primary cable. The 2018 investment in the XLPE Renewal Program is $9,384,000.

Comparable gross investments for the XLPE Renewal Program for the 2010 to 2013 Historical Years and the 2014 Bridge Year are:

2010 (CGAAP)- $ 0
2011 (CGAAP)- $ 0
2012 (MIFRS) - $ 0
2013 (MIFRS) - $ 1,572,090
2014 (MIFRS) - $ 893,000

Total Capital OM&A Costs Associated with REG Investments (5.4.5.2.A.vi)

This project is not associated with an REG investment and therefore OM&A costs related to REG will not be incurred.

Leave to Construct Approval (5.4.5.2.A.vii)

This project does not require "Leave to Construct" under Section 92 of the *Ontario Energy Board Act* 1998.

Evaluation Criteria and Information (5.4.5.2.B)

Project Name	2018 Stoney Creek XLPE Renewal	Table 2

Efficiency, Customer Value, Reliability (5.4.5.2.B.1)

Investment Driver (5.4.5.2.B.1.a)
System Renewal (80%)

Secondary Driver (5.4.5.2.B.1.a)
System Service (20%)

Investment Priority (5.4.5.2.B.1.b)
4 – Required Project

Analysis of Project and Project Alternatives (5.4.5.2.B.1.c)

This project is part of the multi-year XLPE Renewal Program. Horizon Utilities considered the four replacement philosophies for addressing risk inherent in the XLPE asset group: Area; Reactive; Selected; and Refurbishment. The area replacement philosophy will be utilized 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 continue to be used for the remaining areas of the service territory. The Stoney Creek operating area contains many small pockets of direct buried XLPE primary cable. The XLPE renewal projects in the Stoney Creek operating area will involve the full renewal of each pocket of XLPE cable. Project selection will be guided by asset health, operating history, and reliability of each of the underground pockets of XLPE.

Safety (5.4.5.2.B.2)

These projects are not intended to address safety concerns with the distribution system.

Cyber-Security and Privacy (5.4.5.2.B.3) (where applicable)

Cyber-Security and Privacy are not applicable to this project.

Co-ordination and Interoperability (5.4.5.2.B.4)

Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.5.2.B.4.a) (where applicable)

Please refer to Note II for an explanation on co-ordination with utilities, regional planning and/or links with 3rd parties.

Enabling of Future Technology and/or Future Operational Requirements (5.4.5.2.B.4.b)

Please refer to Note IV for an explanation enabling of future technology and future operational requirements.

	Economic Development (5.4.5.2.B.5) **(where applicable)** Horizon Utilities ensures that policies and practices do not unnecessarily create barriers to economic development which are primarily focused within its communities.
	Environmental Benefits (5.4.5.2.B.6) **(where applicable)** n/a

System Renewal Specific Requirements (5.4.5.2.C.b)	**Project Name**	2018 Stoney Creek XLPE Renewal	Table 3

System Renewal Specific Requirements (5.4.5.2.C.b)

Asset Performance Target and Asset Lifecycle Optimization (5.4.5.2.C.b.i.1)

XLPE primary cable is the asset group with the largest investment requirement as identified by the Kinectrics ACA. 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.

Asset Condition Relative to Typical Life Cycle (5.4.5.2.C.b.i.2)

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.

Number of Customers Impacted (5.4.5.2.C.b.i.3)

The number of customers impacted will vary depending upon the area.

Quantitative Customer Impact and Risk (5.4.5.2.C.b.i.4)

The quantitative customer impact varies.

Qualitative Customer Impact and Risk (5.4.5.2.C.b.i.5)

This project will address aging assets at risk of failure. Failures of XLPE primary cable result in extended service interruptions; 30% of these outages exceeded four hours in duration, while 5% of these outages exceeded twelve hours in duration.

Value of Customer Impact (5.4.5.2.C.b.i.6)

High

Other Factors Affecting Project Timing (5.4.5.2.C.b.ii)

Proactive replacements are required because, as assets continue to age and degrade, the cable will fail at an exponential rate. In the worst case scenario, it will exceed Horizon Utilities' ability to keep pace with repairs. Reliability will also deteriorate to unacceptable levels. Reactive replacements will be considerably more costly than proactive renewal.

Impact on System O&M Costs (5.4.5.2.C.b.iii)

This project will have no material impact on planned O&M costs. The renewal of the XLPE primary cable, as a whole, will provide a reduction in reactive O&M costs to address service interruptions caused by failed equipment. These reductions will not be material in the 2015 to 2019 Test Years.

Reliability and Safety Factors (5.4.5.2.C.b.iv)

The renewal of the XLPE primary cable system will provide reliability improvements through reduced service interruptions caused by failed equipment.

Analysis of Project Benefits and Timing (5.4.5.2.C.b.v)

Failure to invest in the proactive renewal of XLPE primary cable and associated underground assets would result in unacceptable levels of system failures and outages beyond Horizon Utilities' ability to resolve within a reasonable timeframe as these assets continue to age and degrade. Reactive replacements will also be considerably more costly than the forecast expenditure required to execute the proposed proactive replacement.

Like-for-Like Renewal Analysis (5.4.5.2.C.b.vi)

XLPE renewal projects will include: the elimination of radial underground feeds; replacement of below grade transformers with padmount transformers; and the introduction of fusing on the underground distribution systems where applicable.

Capital Project Summary

General Information on Project (5.4.5.2.A)

Project Name	2018 St. Catharines XLPE Renewal		
Budget Year	2018		
Investment Category	System Renewal		
Project Summary	Renewal of end-of-life XLPE cable assets in the St. Catharines operating area.		
Capital Investment (5.4.5.2.A.i)	Capital Investment (gross)	$2,835,000	
	Customer Contribution	$0	
	Capital Investment (net)	$2,835,000	
	O&M Expenditure	$0	
Customer Attachments / Load (kVA) (5.4.5.2.A.ii)	The customer and load impacted by this project will vary depending upon the final scope of the project.		
Project Dates (5.4.5.2.A.iii)	Start Date	2018/03/01	
	In Service Date	2018/12.31	

Expenditure Timing

Q1	Q2	Q3	Q4
10%	40%	10%	40%

Schedule Risk and Risk Mitigation (5.4.5.2.A.iv**)**

Please refer to Note I for risk and risk mitigation.

Comparative Information from Equivalent Projects (5.4.5.2.A.v)

There is no direct comparator in scope, size and design characteristics for this project. This project is part of a multi-year investment to renewal XLPE primary cable. The 2018 investment in the XLPE Renewal Program is $9,384,000.

Comparable gross investments for the XLPE Renewal Program for the 2010 to 2013 Historical Years and the 2014 Bridge Year are:

2010 (CGAAP)- $ 0
2011 (CGAAP)- $ 0
2012 (MIFRS) - $ 0
2013 (MIFRS) - $ 1,572,090
2014 (MIFRS) - $ 893,000

Total Capital OM&A Costs Associated with REG Investments (5.4.5.2.A.vi)

This project is not associated with an REG investment and therefore OM&A costs related to REG will not be incurred.

Leave to Construct Approval (5.4.5.2.A.vii)

This project does not require "Leave to Construct" under Section 92 of the *Ontario Energy Board Act* 1998.

Evaluation Criteria and Information (5.4.5.2.B)	**Project Name** 2018 St. Catharines XLPE Renewal Table 2
	Efficiency, Customer Value, Reliability (5.4.5.2.B.1) **Investment Driver (5.4.5.2.B.1.a)** System Renewal (80%) **Secondary Driver (5.4.5.2.B.1.a)** System Service (20%) **Investment Priority (5.4.5.2.B.1.b)** 4 – Required Project
	Analysis of Project and Project Alternatives (5.4.5.2.B.1.c) This project is part of the multi-year XLPE Renewal Program. Horizon Utilities considered the four replacement philosophies for addressing risk inherent in the XLPE asset group: Area; Reactive; Selected; and Refurbishment. The area replacement philosophy will be utilized 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 St. Catharines operating area contains many small pockets of direct buried XLPE primary cable. The XLPE renewal projects in the St. Catharines operating area will involve the full renewal of each pocket of XLPE cable. Project selection will be guided by asset health, operating history, and reliability of each of the underground pockets of XLPE.
	Safety (5.4.5.2.B.2) These projects are not intended to address safety concerns with the distribution system.
	Cyber-Security and Privacy (5.4.5.2.B.3) (where applicable) Cyber-Security and Privacy are not applicable to this project
	Co-ordination and Interoperability (5.4.5.2.B.4) **Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.5.2.B.4.a) (where applicable)** Please refer to Note II for an explanation on co-ordination with utilities, regional planning and/or links with 3rd parties. **Enabling of Future Technology and/or Future Operational Requirements (5.4.5.2.B.4.b)** Please refer to Note IV for an explanation enabling of future technology and future operational requirements.
	Economic Development (5.4.5.2.B.5) **(where applicable)** Horizon Utilities ensures that policies and practices do not unnecessarily create barriers to economic development which are primarily focused within its communities.
	Environmental Benefits (5.4.5.2.B.6) **(where applicable)** n/a

Project Name	2018 St. Catharines XLPE Renewal	Table 3

System Renewal Specific Requirements (5.4.5.2.C.b)

System Renewal Specific Requirements (5.4.5.2.C.b)

Asset Performance Target and Asset Lifecycle Optimization (5.4.5.2.C.b.i.1)

XLPE primary cable is the asset group with the largest investment requirement as identified by the Kinectrics ACA. 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.

Asset Condition Relative to Typical Life Cycle (5.4.5.2.C.b.i.2)

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.

Number of Customers Impacted (5.4.5.2.C.b.i.3)

The number of customers impacted will vary depending upon the area

Quantitative Customer Impact and Risk (5.4.5.2.C.b.i.4)

The quantitative customer impact varies.

Qualitative Customer Impact and Risk (5.4.5.2.C.b.i.5)

This project will address aging assets at risk of failure. Failures of XLPE primary cable result in extended service interruptions; 30% of these outages exceeded four hours in duration, while 5% of these outages exceeded twelve hours in duration.

Value of Customer Impact (5.4.5.2.C.b.i.6)

High

Other Factors Affecting Project Timing (5.4.5.2.C.b.ii)

Proactive replacements are required because, as assets continue to age and degrade, the cable will fail at an exponential rate. In the worst case, it will exceed Horizon Utilities' ability to keep pace with repairs. Reliability will also deteriorate to unacceptable levels. Reactive replacements will be considerably more costly than proactive renewal.

Impact on System O&M Costs (5.4.5.2.C.b.iii)

This project will have no material impact on planned O&M costs. The renewal of the XLPE primary cable, as a whole, will provide a reduction in reactive O&M costs to address service interruptions caused by failed equipment. These reductions will not be material in the 2015 to 2019 Test Years.

Reliability and Safety Factors (5.4.5.2.C.b.iv)

The renewal of the XLPE primary cable system will provide reliability improvements through reduced service interruptions caused by failed equipment.

Analysis of Project Benefits and Timing (5.4.5.2.C.b.v)

Failure to invest in the proactive renewal of XLPE primary cable and associated underground assets would result in unacceptable levels of system failures and outages beyond Horizon Utilities' ability to resolve within a reasonable timeframe as these assets continue to age and degrade. Reactive replacements will also be considerably more costly than the forecast expenditure required to execute the proposed proactive replacement.

Like-for-Like Renewal Analysis (5.4.5.2.C.b.vi)

XLPE renewal projects will include: the elimination of radial underground feeds; the replacement of below grade transformers with padmount transformers; and the introduction of fusing on the underground distribution systems where applicable.

Capital Project Summary

General Information on Project (5.4.5.2.A)

Project Name	WH – F6 Renewal- Whitney Ave			
Budget Year	2018			
Investment Category	System Renewal			
Project Summary	This project involves the renewal of 4kV distribution assets on the Whitney substation as part of the 4kV and 8kV Renewal Program. The assets are located along Whitney Ave in West Hamilton.			
Capital Investment (5.4.5.2.A.i)	Capital Investment (gross)	$2,114,857		
	Customer Contribution	$0		
	Capital Investment (net)	$2,114,857		
	O&M Expenditure	$0		
Customer Attachments / Load (kVA) (5.4.5.2.A.ii)	This project will impact 2,971 customers and 5000 kVA of transformation			
Project Dates (5.4.5.2.A.iii)	Start Date	2018/03/01		
	In Service Date	2018/12/31		
	Expenditure Timing			
	Q1	Q2	Q3	Q4
	10%	40%	40%	10%

Schedule Risk and Risk Mitigation (5.4.5.2.A.iv**)**

Please refer to Note I for risk and risk mitigation.

Comparative Information from Equivalent Projects (5.4.5.2.A.v)

There is no direct comparator in scope, size and design characteristics for this project. This project is one phase of a multi-year investment to renew the area served by Whitney substation as part of the 4kV and 8kV Renewal Program. The 2018 investment for the renewal of Whitney substation is $2,115,000. The 2017 investment in the 4kV and 8kV Renewal Program is $15,684,000.

Comparable gross investments for the 4kV and 8kV Renewal Program for the 2010 to 2013 Historical Year and the 2014 Bridge Year are:
2010 (CGAAP)- $ 2,556,076
2011 (CGAAP)- $ 8,820,000
2012 (MIFRS) - $ 5,268,441
2013 (MIFRS) - $ 5,072,233
2014 (MIFRS) - $ 6,434,000

Total Capital OM&A Costs Associated with REG Investments (5.4.5.2.A.vi)

This project is not associated with an REG investment and therefore OM&A costs related to REG will not be incurred.

Leave to Construct Approval (5.4.5.2.A.vii)

This project does not require "Leave to Construct" under Section 92 of the *Ontario Energy Board Act* 1998.

Evaluation Criteria and Information (5.4.5.2.B)

Project Name	WH – F6 Renewal- Whitney Ave	Table 2

Efficiency, Customer Value, Reliability (5.4.5.2.B.1)

Investment Driver (5.4.5.2.B.1.a)
System Renewal (80%)

Secondary Driver (5.4.5.2.B.1.a)
System Service (20%)

Investment Priority (5.4.5.2.B.1.b)
3 – Required project

Analysis of Project and Project Alternatives (5.4.5.2.B.1.c)

This project is part of the multi-year 4kV and 8kV Renewal Program. Both the 4kV and 8kV distribution system and the Horizon Utilities-owned substations are at the end of their useful life. Horizon Utilities has chosen to renew the 4kV and 8kV distribution systems to a higher voltage to avoid the cost of the investment in the renewal of the substations. The total avoided substation renewal investment over the remaining 35 years of the plan is $70,000,000 for all 28 substations. Therefore, the renewal of these distribution assets at the current 4kV level was not a feasible alternative.

The renewal of the area serviced by the Whitney substation started in 2014 and is scheduled to be completed in 2018. Whitney substation was constructed in 1962. The switchgear at this substation is 46 years old and has a Health Index of 'very poor' as identified in the Substation Asset Condition Assessment ("SACA") and confirmed by the Kinectrics ACA.

Safety (5.4.5.2.B.2)

This project is not intended to address safety concerns with the distribution system.

Cyber-Security and Privacy (5.4.5.2.B.3) (where applicable)

Cyber-Security and Privacy are not applicable to this project.

Co-ordination and Interoperability (5.4.5.2.B.4)

Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.5.2.B.4.a) (where applicable)
Please refer to Note II for an explanation on co-ordination with utilities, regional planning and/or links with 3rd parties.

Enabling of Future Technology and/or Future Operational Requirements (5.4.5.2.B.4.b)

Please refer to Note IV for an explanation enabling of future technology and future operational requirements.

Economic Development (5.4.5.2.B.5) **(where applicable)**

Horizon Utilities ensures that policies and practices do not unnecessarily create barriers to economic development which are primarily focused within its communities.

Environmental Benefits (5.4.5.2.B.6) **(where applicable)**

n/a

System Renewal Specific Requirements (5.4.5.2.C.b)

Project Name	WH – F6 Renewal- Whitney Ave	Table 3

System Renewal Specific Requirements (5.4.5.2.C.b)

Asset Performance Target and Asset Lifecycle Optimization (5.4.5.2.C.b.i.1)

The distribution assets in the Hamilton West operating area are in poor health and the switchgear in both substations servicing this area have switchgear with a 'very poor' Health Index

Asset Condition Relative to Typical Life Cycle (5.4.5.2.C.b.i.2)

Generally the 4kV assets are the oldest vintage in the system. 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.

Number of Customers Impacted (5.4.5.2.C.b.i.3)

This project impacts 2,971 customers.

Quantitative Customer Impact and Risk (5.4.5.2.C.b.i.4)

SAIDI of 0.008

Qualitative Customer Impact and Risk (5.4.5.2.C.b.i.5)

Renewal of assets at 4kV would not allow for the eventual decommissioning of Whitney Substation. Horizon Utilities' Substation assets are being decommissioned over the life of the 4kV and 8kV Renewal Program to avoid capital investment required for the renewal of substation assets that are nearing the end of their useful lives.

Value of Customer Impact (5.4.5.2.C.b.i.6)

High

Qualitative Customer Impact and Risk (5.4.5.2.C.b.i.5)

This project will address aging assets with inadequate backup. Aging assets represent an increased risk of service interruption to customers and inadequate backup would result in long duration service interruptions upon occurrence. These factors would lead to customer dissatisfaction in this area.

Value of Customer Impact (5.4.5.2.C.b.i.6)

High

Other Factors Affecting Project Timing (5.4.5.2.C.b.ii)

The renewal of the area serviced by the Whitney substation is scheduled for 2014 to 2018.

Impact on System O&M Costs (5.4.5.2.C.b.iii)

This project will have no material impact on planned O&M costs. The renewal of the 4kV and 8kV distribution systems, as a whole, will provide a reduction in reactive O&M costs to address service interruptions caused by failed equipment. These reductions will not be material in the 2015 to 2019 Test Years.

Reliability and Safety Factors (5.4.5.2.C.b.iv)

The renewal of the 4kV and 8kV distribution system will provide reliability improvements through reduced service interruptions caused by failed equipment.

Capital Project Summary

General Information on Project (5.4.5.2.A)

Project Name	YK-F1 York Rd Renewal
Budget Year	2018
Investment Category	System Renewal
Project Summary	This project involves the renewal of 4kV distribution assets on the York F1 feeder as part of the 4kV and 8kV Renewal Program.

Capital Investment (5.4.5.2.A.i)		
	Capital Investment (gross)	$1,073,512
	Customer Contribution	$0
	Capital Investment (net)	$1,073,512
	O&M Expenditure	$0

Customer Attachments / Load (kVA) (5.4.5.2.A.ii)

This project will impact approximately 400 customers and 1000kVA of transformation.

Project Dates (5.4.5.2.A.iii)

Start Date	2018/03/01
In Service Date	2018/09/30

Expenditure Timing

Q1	Q2	Q3	Q4
15%	40%	45%	0%

Schedule Risk and Risk Mitigation (5.4.5.2.A.iv**)**

Please refer to Note I for risk and risk mitigation.

Comparative Information from Equivalent Projects (5.4.5.2.A.v)

There is no direct comparator in scope, size and design characteristics for this project. This project is one phase of a multi-year investment to renew the area served by York substation as part of the 4kV and 8kV Renewal Program. The 2018 investment for the renewal of York substation is $1,073,512. The 2018 investment in the 4kV and 8kV Renewal Program is $15,684,000.

Comparable gross investments for the 4kv and 8kV Renewal Program for the 2010 and 2013 Historical Years and the 2014 Bridge Year are:

2010 (CGAAP)- $ 2,556,076
2011 (CGAAP)- $ 8,820,000
2012 (MIFRS) - $ 5,268,441
2013 (MIFRS) - $ 5,072,233
2014 (MIFRS) - $ 6,434,000

Total Capital OM&A Costs Associated with REG Investments (5.4.5.2.A.vi)

This project is not associated with an REG investment and therefore OM&A costs related to REG will not be incurred.

Leave to Construct Approval (5.4.5.2.A.vii)

This project does not require "Leave to Construct" under Section 92 of the *Ontario Energy Board Act* 1998.

Evaluation Criteria and Information (5.4.5.2.B)

Project Name YK-F1 York Rd Renewal Table 2

Efficiency, Customer Value, Reliability (5.4.5.2.B.1)

Investment Driver (5.4.5.2.B.1.a)
System Renewal (80%)

Secondary Driver (5.4.5.2.B.1.a)

System Service (20%)

Investment Priority (5.4.5.2.B.1.b)

3 – Required project

Analysis of Project and Project Alternatives (5.4.5.2.B.1.c)

This project is part of the multi-year 4kV and 8kV Renewal Program. Both the 4kV and 8kV distribution system and the Horizon Utilities-owned substations are at the end of their useful life. Horizon Utilities has chosen to renew the 4kV and 8kV distribution systems to a higher voltage to avoid the cost of the investment in the renewal of the substations. The total avoided substation renewal investment over the remaining 35 years of the plan is $70,000,000 for all 28 substations. Therefore the renewal of this project at the current 4kV level was not a feasible alternative.

Safety (5.4.5.2.B.2)

These projects are not intended to address safety concerns with the distribution system.

Cyber-Security and Privacy (5.4.5.2.B.3) (where applicable)

n/a

Co-ordination and Interoperability (5.4.5.2.B.4)

Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.5.2.B.4.a) (where applicable)
Please refer to Note II for an explanation on co-ordination with utilities, regional planning and/or links with 3rd parties.

Enabling of Future Technology and/or Future Operational Requirements (5.4.5.2.B.4.b)

Please refer to Note IV for an explanation enabling of future technology and future operational requirements.

Economic Development (5.4.5.2.B.5) **(where applicable)**

Horizon Utilities ensures that policies and practices do not unnecessarily create barriers to economic development which are primarily focused within its communities.

Environmental Benefits (5.4.5.2.B.6) **(where applicable)**

n/a

System Renewal Specific Requirements (5.4.5.2.C.b)

Project Name	YK-F1 York Rd Renewal	Table 3

System Renewal Specific Requirements (5.4.5.2.C.b)

Asset Performance Target and Asset Lifecycle Optimization (5.4.5.2.C.b.i.1)

The distribution assets in the Dundas operating area are in poor health and have significant operating constraints. 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'.

Asset Condition Relative to Typical Life Cycle (5.4.5.2.C.b.i.2)

Generally the 4kV assets are the oldest vintage in the system. 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.

Number of Customers Impacted (5.4.5.2.C.b.i.3)

This project impacts 400 customers.

Quantitative Customer Impact and Risk (5.4.5.2.C.b.i.4)

SAIDI of 0.003

Qualitative Customer Impact and Risk (5.4.5.2.C.b.i.5)

This project will address aging assets with inadequate backup. Aging assets represent an increased risk of service interruption to customers and inadequate backup would result in long duration service interruptions upon occurrence. These factors would lead to customer dissatisfaction in this area.

Value of Customer Impact (5.4.5.2.C.b.i.6)

High

Other Factors Affecting Project Timing (5.4.5.2.C.b.ii)

The renewal of the area serviced by York substation is scheduled for renewal in 2018. This project is required to be completed in 2018 to allow for the renewal of the remaining area to complete on schedule.

Reliability and Safety Factors (5.4.5.2.C.b.iv)

The renewal of the 4kV and 8kV distribution system will provide reliability improvements through reduced service interruptions caused by failed equipment.

Analysis of Project Benefits and Timing (5.4.5.2.C.b.v)

The timing of this project, as part of the 4kV and 8kV Renewal Program, is determined through the assessment of the distribution system health and the health of the substation assets servicing the area. Renewal of this area will allow for the decommissioning of the substation assets by 2019 thereby avoiding the need for capital investment into these substations.

Like-for-Like Renewal Analysis (5.4.5.2.C.b.vi)

The like-for-like renewal of these assets (i.e. same system configuration and same distribution voltage) will perpetuate the existing operating constraints and require capital investment to renew substation assets. Renewal of the distribution assets at a higher voltage does not involve any material incremental costs over renewal at the existing voltage. Operating constraints (e.g. undersized conductor, radial feeds) are addressed on a case by case basis where appropriate.

Reliability and Safety Factors (5.4.5.2.C.b.iv)

The renewal of the 4kV and 8kV distribution system will provide reliability improvements through reduced service interruptions caused by failed equipment.

Capital Project Summary

General Information on Project (5.4.5.2.A)

Project Name	East 16th and Mohawk Security Project
Budget Year	2018
Investment Category	System Service
Project Summary	This project will create a loop feed for an islanded 13.8kV radial feed surrounded by 4kV distribution.

Capital Investment (5.4.5.2.A.i)

Capital Investment (gross)	$323,633
Customer Contribution	$0
Capital Investment (net)	$323,633
O&M Expenditure	$0

Customer Attachments / Load (kVA) (5.4.5.2.A.ii)

This project affects 1000 customers and 250kVA of transformation.

Project Dates (5.4.5.2.A.iii)

Start Date	2018/05/01
In Service Date	2018/09/30

Expenditure Timing

Q1	Q2	Q3	Q4
0%	50%	50%	0%

Schedule Risk and Risk Mitigation (5.4.5.2.A.iv**)**

Please refer to Note I for risk and risk mitigation.

Comparative Information from Equivalent Projects (5.4.5.2.A.v)

There is no equivalent project for comparison.

Total Capital OM&A Costs Associated with REG Investments (5.4.5.2.A.vi)

This project is not associated with an REG investment and therefore OM&A costs related to REG will not be incurred.

Leave to Construct Approval (5.4.5.2.A.vii)

This project does not require “Leave to Construct” under Section 92 of the *Ontario Energy Board Act* 1998.

Evaluation Criteria and Information (5.4.5.2.B)	**Project Name** East 16th and Mohawk Security Project Table 2
	Efficiency, Customer Value, Reliability (5.4.5.2.B.1) **Investment Driver (5.4.5.2.B.1.a)** System Service (80%) **Secondary Driver (5.4.5.2.B.1.a)** System Renewal (20%) **Investment Priority (5.4.5.2.B.1.b)** 3 – Required project
	Analysis of Project and Project Alternatives (5.4.5.2.B.1.c) No alternatives exist to provide redundancy to this island of 13.8kV distribution. The alternative would be to continue to serve these customers on a radial feed with no backup.
	Safety (5.4.5.2.B.2) These projects are not intended to address safety concerns with the distribution system.
	Cyber-Security and Privacy (5.4.5.2.B.3) (where applicable) Cyber-Security and Privacy are not applicable to this project.
	Co-ordination and Interoperability (5.4.5.2.B.4) **Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.5.2.B.4.a) (where applicable)** Please refer to Note II for an explanation on co-ordination with utilities, regional planning and/or links with 3rd parties. **Enabling of Future Technology and/or Future Operational Requirements (5.4.5.2.B.4.b)** Please refer to Note IV for an explanation enabling of future technology and future operational requirements.
	Economic Development (5.4.5.2.B.5) **(where applicable)** Horizon Utilities ensures that policies and practices do not unnecessarily create barriers to economic development which are primarily focused within its communities.
	Environmental Benefits (5.4.5.2.B.6) **(where applicable)** n/a

System Service Specific Requirements (5.4.5.2.C.c)

Project Name	East 16th and Mohawk Security Project	Table 3

System Service Specific Requirements (5.4.5.2.C.c)

Benefit to Customers (5.4.5.2.C.c.i)

This project will provide redundancy to the customers serviced by this radial fed section of 13.8kV distribution system. The line directly feeding the school experienced a cable fault in 2011 which caused the school to be closed for two days until repairs were made.

Regional Planning Requirements (5.4.5.2.C.c.i)

N/A

Integration of Advance Technology (5.4.5.2.C.c.iii)

Please refer to Note IV for an explanation enabling of future technology and future operational requirements.

System Benefits to Reliability, Efficiency and Safety (5.4.5.2.C.c.iv)

n/a

Factors Affecting Implementing Timing/Priority (5.4.5.2.C.c.v)

n/a

Summary of Options Analysis (5.4.5.2.C.c.vi)

n/a

Capital Project Summary

General Information on Project (5.4.5.2.A)

Project Name	St. Paul Street Conductor Upgrade
Budget Year	2018
Investment Category	System Service
Project Summary	This project is required to alleviate a bottleneck on the Vansickle M53 feeder along St. Paul Street in St. Catharines by upgrading the conductor from 3/0 ACSR to 556 Aluminum.

Capital Investment (5.4.5.2.A.i)	Capital Investment (gross)	$1,362,121
	Customer Contribution	$0
	Capital Investment (net)	$1,362,121
	O&M Expenditure	$0
Customer Attachments / Load (kVA) (5.4.5.2.A.ii)	n/a	
Project Dates (5.4.5.2.A.iii)	Start Date	2018/03/01
	In Service Date	2018/09/30

Expenditure Timing

Q1	Q2	Q3	Q4
15%	40%	45%	0%

Schedule Risk and Risk Mitigation (5.4.5.2.A.iv**)**

Please refer to Note I for risk and risk mitigation.

Comparative Information from Equivalent Projects (5.4.5.2.A.v)

There is no equivalent project for comparison.

Total Capital OM&A Costs Associated with REG Investments (5.4.5.2.A.vi)

This project is not associated with an REG investment and therefore OM&A costs related to REG will not be incurred.

Leave to Construct Approval (5.4.5.2.A.vii)

This project does not require “Leave to Construct” under Section 92 of the *Ontario Energy Board Act* 1998.

Evaluation Criteria and Information (5.4.5.2.B)

Project Name	St. Paul St Conductor Upgrade	Table 2

Efficiency, Customer Value, Reliability (5.4.5.2.B.1)

Investment Driver (5.4.5.2.B.1.a)

System Service (60%)

Secondary Driver (5.4.5.2.B.1.a)

System Renewal (40%)

Investment Priority (5.4.5.2.B.1.b)

3 – Required project

Analysis of Project and Project Alternatives (5.4.5.2.B.1.c)

Vansickle TS was upgraded in 2010 to provide increased capacity in the west end of St. Catharines and to provide additional backup and load transferring capability to Carlton TS. A number of subsequent upgrades to the distribution system have been performed to improve the interconnection between Carlton TS and Vansickle TS. This project is the final project required to complete the interconnection through the removal of a capacity constraint along St. Paul Street.

Safety (5.4.5.2.B.2)

These projects are not intended to address safety concerns with the distribution system.

Cyber-Security and Privacy (5.4.5.2.B.3) (where applicable)

Cyber-Security and Privacy are not applicable to this project.

Co-ordination and Interoperability (5.4.5.2.B.4)

Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.5.2.B.4.a) (where applicable)

Please refer to Note II for an explanation on co-ordination with utilities, regional planning and/or links with 3rd parties.

Enabling of Future Technology and/or Future Operational Requirements (5.4.5.2.B.4.b)

Please refer to Note IV for an explanation enabling of future technology and future operational requirements.

Economic Development (5.4.5.2.B.5) **(where applicable)**

Horizon Utilities ensures that policies and practices do not unnecessarily create barriers to economic development which are primarily focused within its communities.

Environmental Benefits (5.4.5.2.B.6) **(where applicable)**

n/a

stem Service Specific Requirements (5.4.5.2.C.c)	**Project Name** St. Paul Street Conductor Upgrade Table 3
	System Service Specific Requirements (5.4.5.2.C.c) **Benefit to Customers (5.4.5.2.C.c.i)** This project will improve security by bringing a feeder with capacity to the area and redefining the open points to enhance flexibility during restoration. **Regional Planning Requirements (5.4.5.2.C.c.i)** n/a **Integration of Advance Technology (5.4.5.2.C.c.iii)** Please refer to Note IV for an explanation enabling of future technology and future operational requirements. **System Benefits to Reliability, Efficiency and Safety (5.4.5.2.C.c.iv)** System benefits include: improved operability within the area and improved life expectancy from the assets that are being relieved by the new feeder. **Factors Affecting Implementing Timing/Priority (5.4.5.2.C.c.v)** n/a **Summary of Options Analysis (5.4.5.2.C.c.vi)** n/a

2018 General Plant Investments

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Capital Project Summary

Project Name	2018 Annual Corporate Computer Replacement		
Budget Year	2018		
Investment Category	General Plant		
Project Summary	This project is part of an ongoing business requirement to refresh end user computers. Horizon Utilities utilizes a three-year lifecycle for replacement of end user computers. On an annual basis, approximately one third of all Horizon Utilities computers (~150 PCs/year) are replaced.		
Capital Investment (5.4.5.2.A.i)	Capital Investment (gross)	$361,200	
	Customer Contribution	n/a	
	Capital Investment (net)	n/a	
	O&M Expenditure	n/a	
Customer Attachments / Load (5.4.5.2.A.ii)	n/a		
Project Dates (5.4.5.2.A.iii)	Start Date	Jan. 2018	
	In Service Date	Dec. 2018	

Expenditure Timing

Q1	Q2	Q3	Q4
25%	25%	25%	25%

Schedule Risk and Risk Mitigation (5.4.5.2.A.iv**)**

Schedule - Implementation is phased throughout the year starting in January and ending in December based on age of PCs being replaced.

Risk – The primary risk to this project is product availability from suppliers.
Risk Mitigation – Work closely with suppliers to schedule orders based on required delivery times.

Comparative Information from Equivalent Projects (5.4.5.2.A.v)

Comparable gross investments for the annual corporate computer replacement for the 2010 to 2013 Historical Years and the 2014 Bridge Year are:

2010 (CGAAP)- $ 336,000
2011 (CGAAP)- $ 227,000
2012 (MIFRS) - $ 312,000
2013 (MIFRS) - $ 364,947
2014 (MIFRS) - $ 366,200

Total Capital and OM&A Costs Associated with REG Investments (5.4.5.2.A.vi)
n/a

Leave to Construct Approval (5.4.5.2.A.vii)
n/a

Evaluation Criteria and Information

Project Name	2018 Annual Corporate Computer Replacement	Table 2

Efficiency, Customer Value, Reliability (5.4.5.2.B.1)

Investment Driver (5.4.5.2.B.1.a)
General Plant (100%)

Secondary Driver (5.4.5.2.B.1.a)
n/a

Investment Priority (5.4.5.2.B.1.b)
High Priority – Personal computers are treated as a strategic asset. They are Horizon Utilities' primary staff productivity tool. They are used to: maintain and deliver services to customers; improve staff productivity; cost-effectively manage total cost of PC ownership; and, support investments in new applications, infrastructure and business capabilities

Analysis of Project and Project Alternatives (5.4.5.2.B.1.c)
n/a

Safety (5.4.5.2.B.2)

n/a

Cyber-Security and Privacy (5.4.5.2.B.3) (where applicable)

n/a

Co-ordination and Interoperability (5.4.5.2.B.4)

Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.5.2.B.4.a) (where applicable)
n/a

Enabling of Future Technology and/or Future Operational Requirements (5.4.5.2.B.4.b)

Suppliers of enterprise systems such as, GIS, OMS, SCADA, AMI, and IFS ERP, are constantly upgrading their products to deliver new processes and functionality. As new versions are released up-to-date hardware is required to perform required upgrades to maintain vendor support for the systems.

Economic Development (5.4.5.2.B.5) **(where applicable)**

n/a

Environmental Benefits (5.4.5.2.B.6) **(where applicable)**

n/a

General Plant Specific Requirements	**Project Name** 2018 Annual Corporate Computer Replacement Table 3

General Plant Specific Requirements (5.4.5.2.C.d)

Summary of Qualitative and Quantitative Analysis (5.4.5.2.C.d.i)

n/a

Business Case Justification Documentation (5.4.5.2.C.d.i)

Horizon Utilities' PCs are treated as a strategic asset, because they are the primary staff productivity tool. Horizon Utilities has streamlined its PC lifecycle management processes utilizing a PC refresh cycle of three years, in order to: deliver, maintain and improve services to customers; to improve staff productivity; to cost-effectively manage total cost of PC ownership; and to support investments in new applications, infrastructure and business capabilities.

A three-year PC refresh cycle reduces the total cost of ownership by reducing the number of models of PCs supported, which results in the reduction of the IST service desk effort required to deploy, secure, and manage new systems and applications. The reduction in the number of supported models has allowed Horizon Utilities to introduce mobile computing for remote field workers and to increase the number of supported PCs by over 100 devices since 2011, without an increase in IST service desk support staff.

A refresh lifecycle of three years reduces the likelihood of device failures that lead to a loss of staff productivity and increased IT support effort. Over 50% of Horizon Utilities' staff utilizes a mobile PC (laptop or tablet) in the performance of their daily activities, many in harsh operating environments outside the office, which increases the likelihood of failure due to operating environment and the age of the device.

Horizon Utilities has introduced several new enterprise business and engineering systems to: mitigate business risks related to aging systems (e.g. GIS); improve electricity system operation (i.e. GIS, OMS); and to address end of vendor support for systems (i.e. IFS ERP, Microsoft Windows XP). Maintaining a three-year PC lifecycle refresh program allows Horizon Utilities' to migrate to these applications without a need to make large one-time investments in PCs to meet the minimum operating requirements of new applications.

PCs are the primary productivity tool used by Horizon Utilities' staff. Unreliable and slow PCs impact productivity and customer service.

Minimizing the number of supported models reduces the IST support effort required to manage, order, configure, and deploy PCs and it reduces the total cost of ownership for PCs.

Capital Project Summary

Project Name	2018 IFS ERP Upgrade
Budget Year	2018
Investment Category	General Plant
Project Summary	This is an enterprise-wide project 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 most current version.

Capital Investment (5.4.5.2.A.i)	Capital Investment (gross)	$1,225,000
	Customer Contribution	n/a
	Capital Investment (net)	n/a
	O&M Expenditure	n/a
Customer Attachments / Load (5.4.5.2.A.ii)	n/a	

Project Dates (5.4.5.2.A.iii)

Start Date Jan. 2018

In Service Date Dec 2018

Expenditure Timing

Q1	Q2	Q3	Q4
30%	30%	40%	0%

Schedule Risk and Risk Mitigation (5.4.5.2.A.iv**)**

Schedule - Implementation is being phased throughout the year starting in January and ending in December. The project is being phased based on a combination of the potential benefit of the process improvement and the business unit resource availability to define, configure, and test the process change.

Risk – The primary risk to this project is internal resource availability.

Risk Mitigation – Utilization of Horizon Utilities Project Management Framework to effectively manage project to budget and schedule.

Comparative Information from Equivalent Projects (5.4.5.2.A.v)

Horizon Utilities has no recently completed project which is comparable in scope and scale which can be as a reasonable comparator

Total Capital and OM&A Costs Associated with REG Investments (5.4.5.2.A.vi)

n/a

Leave to Construct Approval (5.4.5.2.A.vii)

n/a

Evaluation Criteria and Information

Project Name	2018 IFS ERP Upgrade	Table 2

Efficiency, Customer Value, Reliability (5.4.5.2.B.1)

Investment Driver (5.4.5.2.B.1.a)
General Plant 100%

Secondary Driver (5.4.5.2.B.1.a)
n/a

Investment Priority (5.4.5.2.B.1.b)

High Priority – The IFS ERP System is an enterprise-wide system used to manage business processes in Finance, Human Resources, Supply Chain, and Engineering Project Management and as such, must be maintained at software vendor supported levels.

Analysis of Project and Project Alternatives (5.4.5.2.B.1.c)

n/a

Safety (5.4.5.2.B.2)

n/a

Cyber-Security and Privacy (5.4.5.2.B.3) (where applicable)

n/a

Co-ordination and Interoperability (5.4.5.2.B.4)

Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.5.2.B.4.a) (where applicable)
n/a

Enabling of Future Technology and/or Future Operational Requirements (5.4.5.2.B.4.b)

n/a

Economic Development (5.4.5.2.B.5) **(where applicable)**

n/a

Environmental Benefits (5.4.5.2.B.6) **(where applicable)**

n/a

General Plant Specific Requirements	**Project Name** 2018 IFS ERP Upgrade Table 3
	General Plant Specific Requirements (5.4.5.2.C.d) **Summary of Qualitative and Quantitative Analysis (5.4.5.2.C.d.i)** n/a **Business Case Justification Documentation (5.4.5.2.C.d.i)** Horizon Utilities uses IFS to manage business critical processes in Finance, Human Resources, Supply Chain Management, Asset Management, and Engineering Project Planning. This project is both a lifecycle upgrade and a risk mitigation project. IFS's software development plans are to release a new major version of the system every 3 years. IFS will only provide support for the two most recent versions. The application must be upgraded in order to maintain IFS support for the system. Horizon Utilities has scheduled this project in 2018 to manage required IT investment and to manage internal resource commitments to minimize impact on customers and business operations. Any delay of this project would conflict with a required major upgrade of Horizon Utilities' CIS system, the development for which begins in 2019.

Capital Project Summary

Project Name	2018 Vehicle Replacement
Budget Year	2018
Investment Category	General Plant

Project Summary;

Horizon Utilities has identified a number of current vehicles that require replacement as they have reached end-of-life as per the criteria within Horizon Utilities' Fleet Replacement Plan.

Other expected objectives and outcomes are to:

- Maintain vehicle reliability and availability;
- Reduce fuel consumption;
- Reduce emissions;
- Reduce down time required to conduct maintenance and repairs; and
- Maintain customer response time.

Capital Investment (5.4.5.2.A.i)	Capital Investment (gross)	$785,000
	Customer Contribution	n/a
	Capital Investment (net)	n/a
	O&M Expenditure	n/a
Customer Attachments / Load (5.4.5.2.A.ii)		

Project Dates (5.4.5.2.A.iii)

Start Date	March 2018
In Service Date	December 2018

Expenditure Timing

Q1	Q2	Q1	Q2
0%	0%	50%	50%

Schedule Risk and Risk Mitigation (5.4.5.2.A.iv**)**

Risk – The primary risk to this project is product availability and adherence to delivery schedules from suppliers.

Risk Mitigation – Work closely with suppliers to schedule orders based on required delivery times.

Comparative Information from Equivalent Projects (5.4.5.2.A.v)

Comparable gross investments for vehicle replacements for the 2010 to 2013 Historical Years and the 2014 Bridge Year are:

2010 (CGAAP)- $ 1,590,516
2011 (CGAAP)- $ 1,033,975
2012 (MIFRS) - $ 1,057,410
2013 (MIFRS) - $ 36,365
2014 (MIFRS) - $ 785,000

Total Capital OM&A Costs Associated with REG Investments (5.4.5.2.A.vi)

N/A

Leave to Construct Approval (5.4.5.2.A.vii)
N/A

Evaluation Criteria and Information

Project Name: 2018 Vehicle Replacement — Table 2

Efficiency, Customer Value, Reliability (5.4.5.2.B.1)

Investment Driver (5.4.5.2.B.1.a)

General Plant – 100%

Secondary Driver (5.4.5.2.B.1.a)
n/a

Investment Priority (5.4.5.2.B.1.b)

High

Analysis of Project and Project Alternatives (5.4.5.2.B.1.c)

n/a

Safety (5.4.5.2.B.2)

n/a

Cyber-Security and Privacy (5.4.5.2.B.3) (where applicable)
n/a

Co-ordination and Interoperability (5.4.5.2.B.4)

Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.5.2.B.4.a) (where applicable)

n/a

Enabling of Future Technology and/or Future Operational Requirements (5.4.5.2.B.4.b)

n/a

Economic Development (5.4.5.2.B.5)

n/a

Environmental Benefits (5.4.5.2.B.6)

n/a

General Plant Specific Requirements

Project Name	2018 Vehicle Replacement	Table 3

General Plant Specific Requirements (5.4.5.2.C.d)

Summary of Qualitative and Quantitative Analysis (5.4.5.2.C.d.i)

Horizon Utilities uses the data collected from electronic fleet and fuel management system, the Global Positional 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 and vehicle maintenance and repairs activities to determine the maintenance scheduling and vehicles replacements.

Business Case Justification Documentation (5.4.5.2.C.d.i)

To maintain the quality, reliability and availability of Horizon Utilities' vehicle fleet to Construction and Maintenance, Metering Services and corporate group activities, vehicles are assessed annually based on a replacement criteria matrix defined within the Fleet Replacement Plan.

Replacement strategies also ensure that Horizon Utilities maintains safe vehicles for employees, while targeting reduced emissions, as well as reduced fuel, operating and maintenance costs. Horizon Utilities will not be procuring any net new vehicles and instead will focus on the replacement of end of life vehicles over the 2015-2019 Test Years.

Due to budget mitigation efforts in 2011, 2012, and 2013, a number of vehicles scheduled for replacement were kept in operation and rescheduled for replacement in 2014. It is now critical that these vehicles be replaced as maintenance and repairs costs have increased and the vehicles no longer operate at full capacity, reducing vehicle availability and impacting service delivery.

Regular vehicle replacement is necessary to avoid undue vehicle down and associated negative impacts to customer response time and employee productivity.

Capital Project Summary

Project Name	2018 Tools, Shop and Garage Equipment
Budget Year	2018
Investment Category	General Plant

Project Summary
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

Capital Investment (5.4.5.2.A.i)	Capital Investment (gross)	$530,600
	Customer Contribution	n/a
	Capital Investment (net)	n/a
	O&M Expenditure	$0

Customer Attachments / Load (5.4.5.2.A.ii)
n/a

Project Dates (5.4.5.2.A.iii)

Start Date	January 2018
In Service Date	December 2018

Expenditure Timing

Q1	Q2	Q3	Q4
25%	25%	25%	25%

Schedule Risk and Risk Mitigation (5.4.5.2.A.iv**)**

Risk – n/a

Risk Mitigation – n/a

Comparative Information from Equivalent Projects (5.4.5.2.A.v)

n/a

Total Capital OM&A Costs Associated with REG Investments (5.4.5.2.A.vi)
n/a

Leave to Construct Approval (5.4.5.2.A.vii)
n/a

Evaluation Criteria and Information	Project Name: 2018 Tools, Shop and Garage Equipment — Table 2
	Efficiency, Customer Value, Reliability (5.4.5.2.B.1) **Investment Driver (5.4.5.2.B.1.a)** General Plant (100%) **Secondary Driver (5.4.5.2.B.1.a)** n/a
	Investment Priority (5.4.5.2.B.1.b) High **Analysis of Project and Project Alternatives (5.4.5.2.B.1.c)** Tools and equipment over $5000 are procured through a competitive process and alternatives are considered at the time of requisition.
	Safety (5.4.5.2.B.2) Tools and equipment meet CSA requirements and are reviewed for conformance to requirements by Horizon Utilities' Tool & Equipment Committee.
	Cyber-Security and Privacy (5.4.5.2.B.3) (where applicable) n/a
	Co-ordination and Interoperability (5.4.5.2.B.4) **Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.5.2.B.4.a) (where applicable)** n/a **Enabling of Future Technology and/or Future Operational Requirements (5.4.5.2.B.4.b)** n/a
	Economic Development (5.4.5.2.B.5) **(where applicable)** n/a
	Environmental Benefits (5.4.5.2.B.6) **(where applicable)** n/a

General Plant Specific Requirements

Project Name	2018 Tools, Shop and Garage Equipment	Table 3

General Plant Specific Requirements (5.4.5.2.C.d)

Su**mmary of Qualitative and Quantitative Analysis (5.4.5.2.C.d.i)**

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.

Business Case Justification Documentation (5.4.5.2.C.d.i)

n/a

Capital Project Summary

Project Name	2018 Building Renovation – John St
Budget Year	2018
Investment Category	General Plant

Project Summary:

The objectives of this project planned for 2018 is to replace end-of-life facilities in the John St basement washroom/shower/lockers area to support the current and planned work force and to improve the lobby space to better service Horizon Utilities' customers [redacted] This project will enhance the quality of the workplace for employees; reduce safety risks; remove hazards materials; and improve the use of existing space.

Other expected objectives and outcomes include:

.

- Improved energy performance of buildings including systems and infrastructure;
- Replacement of end of life equipment;
- Increased washroom facilities to support current requirements; mad
- Compliance of facilities to support wheel chair access and meet *Accessibility for Ontarians with Disabilities Act* requirements

Capital Investment (5.4.5.2.A.i)	Capital Investment (gross)	$1,200,000
	Customer Contribution	n/a
	Capital Investment (net)	n/a
	O&M Expenditure	n/a
Customer Attachments / Load (5.4.5.2.A.ii)		

Project Dates (5.4.5.2.A.iii)

Start Date March 2018

In Service Date December 2018

Expenditure Timing			
Q1	Q2	Q1	Q2
10%	30%	30%	30%

Schedule Risk and Risk Mitigation (5.4.5.2.A.iv**)**

Project timelines and costs exceeding the budget are risks. The project manager will report regularly on project timelines and adherence to budget and escalates issues for resolution.

Comparative Information from Equivalent Projects (5.4.5.2.A.v)

Comparable gross investments for building renovations for the 2010 to 2013 Historical Years and the 2014 Bridge Year are:

2010 (CGAAP)- $ 0
2011 (CGAAP)- $ 0
2012 (MIFRS) - $ 1,767,000
2013 (MIFRS) - $ 5,490,000
2014 (MIFRS) - $ 3,700,000

Total Capital OM&A Costs Associated with REG Investments (5.4.5.2.A.vi)

n/a

Leave to Construct Approval (5.4.5.2.A.vii)

n/a

Evaluation Criteria and Information

Project Name: 2018 Building Renovation – John St — Table 2

Efficiency, Customer Value, Reliability (5.4.5.2.B.1)

Investment Driver (5.4.5.2.B.1.a)

General Plant – 100%

Secondary Driver (5.4.5.2.B.1.a)
n/a

Investment Priority (5.4.5.2.B.1.b)

High

Analysis of Project and Project Alternatives (5.4.5.2.B.1.c)

Horizon Utilities' building renovation plans were developed through a facilities planning process that utilized the outputs of a space planning study and multiple building assessments.

Safety (5.4.5.2.B.2)

n/a

Cyber-Security and Privacy (5.4.5.2.B.3) (where applicable)

n/a

Co-ordination and Interoperability (5.4.5.2.B.4)

Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.5.2.B.4.a) (where applicable)

n/a

Enabling of Future Technology and/or Future Operational Requirements (5.4.5.2.B.4.b)

n/a

Economic Development (5.4.5.2.B.5) **(where applicable)**

n/a

Environmental Benefits (5.4.5.2.B.6) **(where applicable)**

n/a

General Plant Specific Requirements

Project Name	2018 Building Renovation – John St	Table 3

General Plant Specific Requirements (5.4.5.2.C.d)

Summary of Qualitative and Quantitative Analysis (5.4.5.2.C.d.i)

n/a

Business Case Justification Documentation (5.4.5.2.C.d.i)

The project's primary focus is to address employee and public safety concerns in the basement and lobby of the John Street building, which is largely original to the 1950s building.

The project will include the following:

- Renovation of the locker, washroom, and shower space which is original to the 1950's building. The facilities have leaking plumbing and is 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 entrances to improve the utilization of space and to address concerns regarding [redacted]

Capital Project Summary

General Information on Project (5.4.5.2.A)

Project Name	2019 Meters				
Budget Year	2019				
Investment Category	System Access				
Capital Investment (5.4.5.2.A.i)	Capital Investment	$ 2,063,000			
	Total	$ 2,063,000			
	O&M Expenditure	$0			
Customer Attachments / Load (kVA) (5.4.5.2.A.ii)	n/a.				
Project Dates (5.4.5.2.A.iii)	Start Date	2019/01/01			
	In Service Date	2019/12/31			
	Expenditure Timing				
	Q1	Q2	Q3	Q4	
	25%	25%	25%	25%	

Schedule Risk and Risk Mitigation (5.4.5.2.A.iv**)**

Please refer to Note I for risk and risk mitigation.

Comparative Information from Equivalent Projects (5.4.5.2.A.v)

Metering investments for the 2010 to 2013 Historical Years and the 2014 Bridge Year are:

2010 (CGAAP) - $1,715,716
2011 (CGAAP)- $3,467,413
2012 (MIFRS) - $25,168,043
2013 (MIFRS) - $1,658,707
2014 (MIFRS) - $2,499,104

The increased investment in 2012 was due to the implementation of Smart Meters at a cumulative capital cost of $23,277,588. 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.

Total Capital OM&A Costs Associated with REG Investments (5.4.5.2.A.vi)

This project is not associated with an REG investment and as such no associated OM&A costs related to REG will be incurred.

Leave to Construct Approval (5.4.5.2.A.vii)

This project does not require “Leave to Construct” under Section 92 of the *Ontario Energy Board Act* 1998.

Evaluation Criteria and Information (5.4.5.2.B)	**Project Name** 2019 Meters	Table 2
	Efficiency, Customer Value, Reliability (5.4.5.2.B.1) **Investment Driver (5.4.5.2.B.1.a)** System Access (80%) **Secondary Driver (5.4.5.2.B.1.a)** System Renewal (20%) Replacement of commercial meters with Smart Meters. **Investment Priority (5.4.5.2.B.1.b)** 5 – Mandatory Project	
	Analysis of Project and Project Alternatives (5.4.5.2.B.1.c) Metering asset management is governed by Measurement Canada regulation and customer requirements for new and upgraded services.	
	Safety (5.4.5.2.B.2) This project is not intended to address safety concerns with the distribution system.	
	Cyber-Security and Privacy (5.4.5.2.B.3) (where applicable) Horizon Utilities' Smart Meter and related AMI network have been procured through Elster. Elster's system supports a multi-layered security approach including: access control, authorization, authentication and data integrity protocols. As part of its continuous improvement model, Horizon Utilities performs periodic security assessments to identify opportunities for enhanced system hardening.	
	Co-ordination and Interoperability (5.4.5.2.B.4) **Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.5.2.B.4.a) (where applicable)** Please refer to Note II for an explanation on co-ordination with utilities, regional planning and/or links with 3rd parties. **Enabling of Future Technology and/or Future Operational Requirements (5.4.5.2.B.4.b)** Please refer to Note IV for an explanation enabling of future technology and future operational requirements.	
	Economic Development (5.4.5.2.B.5) **(where applicable)** Horizon Utilities ensures that policies and practices do not unnecessarily create barriers to economic development which are primarily focused within its communities.	
	Environmental Benefits (5.4.5.2.B.6) **(where applicable)** The smart meter infrastructure supports the province's conservation culture. Smart Metering also provides environmental benefits through reduction in field visits associated with manual meter reading.	

System Access Specific Requirements (5.4.5.2.C.a)

Project Name 2019 Metering Table 3

System Access Specific Requirements (5.4.5.2.C.a)

Factors Affecting Implementing Project Timing/Priority (5.4.5.2.C.a.i)

Compliance sampling work completed to comply with Measurement Canada regulations. The schedule is created to smooth the annual sampling requirements from the original Smart Meter mass deployments.

New and replacement metering is provided on demand to address new load growth and meter failures.

Factors Related to Customer Preference or 3rd Party Input (5.4.5.2.C.a.ii)

Metering for new and upgraded connection projects are customer initiated and are designed to meet customer identified requirements.

Factors Affecting Final Project Cost (5.4.5.2.C.a.iii)

Please refer to Note I for an explanation on the factors affecting the final project cost.

Controllable Cost Minimization (5.4.5.2.C.a.iv)

Please refer to Note I for an explanation regarding controllable cost minimization.

Other Planning Objectives (5.4.5.2.C.a.v)

Horizon Utilities combines work from multiple work groups to reduce costs and increase efficiency. The line work and meter work is combined when connecting new customers to allow the work to be completed by a single work group.

Assessment of Technical or Implementation Options (5.4.5.2.C.a.vi)

Metering work is Measurement Canada and customer driven and the technology is primarily based on the metering products available from a sole source supplier.

Summary of Options Analysis (5.4.5.2.C.a.vii)

Metering supplier selected as part of the smart meter implementation program.

Final Economic Evaluation Results (5.4.5.2.C.a.viii)

n/a

Identification of System Impacts (5.4.5.2.C.a.ix)

System expansion, if required, to connect customers within this category are governed by Horizon Utilities' Conditions of Service Section 2.1.2.1.

Capital Project Summary

General Information on Project (5.4.5.2.A)

Project Name	2019 Road Relocations
Budget Year	2019
Investment Category	System Access
Project Description	Projects in this category include all projects required for the relocation of system plant for roadway reconstruction work. Horizon Utilities follows the *Public Service Works on Highway Act,* 1990 and associated regulations governing the recovery of costs related to road reconstruction work by collecting contributed capital for 50% of labour and labour saving devices.

Capital Investment (5.4.5.2.A.i)	Capital Investment (gross)	$2,749,687
	Customer Contribution	$904,360
	Capital Investment (net)	$1,845,327
	O&M Expenditure	$0
Customer Attachments / Load (kVA) (5.4.5.2.A.ii)	n/a.	

Project Dates (5.4.5.2.A.iii)	Start Date	Various – driven by road authority schedules		
	In Service Date	Various – driven by road authority schedules		
	Expenditure Timing			
	Q1	Q2	Q3	Q4
	25%	25%	25%	25%

Schedule Risk and Risk Mitigation (5.4.5.2.A.iv**)**

Please refer to Note I for risk and risk mitigation.

Comparative Information from Equivalent Projects (5.4.5.2.A.v)

Road relocations for the 2010 to 2013 Historical Years and the 2014 Bridge Year are:

2010 (CGAAP) - $ 2,889,575
2011 (CGAAP)- $ 895,524
2012 (MIFRS) - $ 3,151,887
2013 (MIFRS) - $ 340,491
2014 (MIFRS) - $ 977,024

Total Capital OM&A Costs Associated with REG Investments (5.4.5.2.A.vi)

This project is not associated with an REG investment and therefore OM&A costs related to REG will not be incurred.

Leave to Construct Approval (5.4.5.2.A.vii)

This project does not require “Leave to Construct” under Section 92 of the *Ontario Energy Board Act* 1998.

Evaluation Criteria and Information (5.4.5.2.B)

Project Name	2019 Road Relocations	Table 2

Efficiency, Customer Value, Reliability (5.4.5.2.B.1)

Investment Driver (5.4.5.2.B.1.a)

System Access (100%)

Secondary Driver (5.4.5.2.B.1.a) System Service (10%)

N/A

Investment Priority (5.4.5.2.B.1.b)
5 – Mandatory Project

Analysis of Project and Project Alternatives (5.4.5.2.B.1.c)

Horizon Utilities co-ordinates project design and discusses design alternatives for each project with the organization (City, Municipality, Ministry of Transportation) originating the request to relocate distribution assets.

Safety (5.4.5.2.B.2)

This project is not intended to address safety concerns with the distribution system.

Cyber-Security and Privacy (5.4.5.2.B.3) (where applicable)

Cyber-Security and Privacy are not applicable to this project

Co-ordination and Interoperability (5.4.5.2.B.4)

Cyber-Security and Privacy (5.4.5.2.B.3) (where applicable)Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.5.2.B.4.a) (where applicable)

Please refer to Note II for an explanation on co-ordination with utilities, regional planning and/or links with 3rd parties.

Enabling of Future Technology and/or Future Operational Requirements (5.4.5.2.B.4.b)

Please refer to Note IV for an explanation enabling of future technology and future operational requirements.

Economic Development (5.4.5.2.B.5) **(where applicable)**

Horizon Utilities ensures that policies and practices do not unnecessarily create barriers to economic development which are primarily focused within its communities.

	Environmental Benefits (5.4.5.2.B.6) **(where applicable)** n/a

System Access Specific Requirements (5.4.5.2.C.a)	**Project Name** 2019 Road Relocations Table 3
	System Access Specific Requirements (5.4.5.2.C.a) **Factors Affecting Implementing Project Timing/Priority (5.4.5.2.C.a.i)** The road authority's schedule and timing of the road project will affect Horizon Utilities' project implementation and timing. **Factors Related to Customer Preference or 3rd Party Input (5.4.5.2.C.a.ii)** Road relocation projects involve a co-ordinated design process and the initiating organization (City, Municipality, or Ministry of Transportation) has input into the design of the project. The designs for all projects within the public right-of-way are reviewed with the City as Municipal Consents are required prior to construction. Consideration is given by the road authority to coordinate all utilities within the right-of-way in the least disruptive manner. **Factors Affecting Final Project Cost (5.4.5.2.C.a.iii)** Please refer to Note I for an explanation on the factors that can affect the final project cost. **Controllable Cost Minimization (5.4.5.2.C.a.iv)** 50% of Labour, Labour saving devices and Equipment rentals are recovered from the road authority. Please refer to Note I for an explanation on controllable cost minimization. **Other Planning Objectives (5.4.5.2.C.a.v)** Horizon Utilities combines work to reduce overall costs and increase efficiency. The most common opportunity is during city road relocation projects where a new water main is being installed. Horizon Utilities may be able to take advantage of the fact that installing duct structure is less costly since the road is already excavated. Horizon Utilities may also be able to change the schedule of a renewal project to align with the road authority's work to maximize these benefits. The cost of the additional work is allocated either to system service or system renewal where applicable. Horizon Utilities can maximize the amount of work that can be completed at the lowest cost to benefit ratepayers in these cases. **Assessment of Technical or Implementation Options (5.4.5.2.C.a.vi)** Horizon Utilities co-ordinates project design and discusses design alternatives for each project with the road authority (City, Municipality, Ministry of Transportation) originating the request to relocate distribution assets. **Summary of Options Analysis (5.4.5.2.C.a.vii)** Horizon Utilities reviews proposed design with municipalities and the Ministry of Transportation, as applicable, in an effort to determine the most cost effective solution.

Final Economic Evaluation Results (5.4.5.2.C.a.viii)

This is not applicable to road relocations.

Identification of System Impacts (5.4.5.2.C.a.ix)

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.

Capital Project Summary

General Information on Project (5.4.5.2.A)

Project Name	2019 Customer Connections
Budget Year	2019
Investment Category	System Access
Project Summary	Projects in this category include multiple projects required to connect, upgrade, or disconnect customers to the distribution system. Horizon Utilities' obligation to connect new customers is governed by the *Electricity Act, 1998, Schedule 28.*

Capital Investment (5.4.5.2.A.i)

Capital Investment (gross)	$5,185,023
Customer Contribution	$820,186
Capital Investment (net)	$4,364,835
O&M Expenditure	$0

Customer Attachments / Load (kVA) (5.4.5.2.A.ii): n/a

Project Dates (5.4.5.2.A.iii)

Start Date	Various – as driven by the customer
In Service Date	Various – as driven by the customer

Expenditure Timing

Q1	Q2	Q3	Q4
25%	25%	25%	25%

Schedule Risk and Risk Mitigation (5.4.5.2.A.iv**)**

Please refer to Note I for risk and risk mitigation.

Comparative Information from Equivalent Projects (5.4.5.2.A.v)

Comparable investments, net of capital contributions, for the 2010 and 2013 Historical Years and the 2014 Bridge Year are:

2010 (CGAAP)- $ 1,023,336
2011 (CGAAP)- $ 2,030,541
2012 (MIFRS) - $ 1,652,000
2013 (MIFRS) - $ 3,541,455
2014 (MIFRS) - $ 4,063,471

Total Capital OM&A Costs Associated with REG Investments (5.4.5.2.A.vi)

This project is not associated with an REG investment and therefore OM&A costs related to REG will not be incurred.

Leave to Construct Approval (5.4.5.2.A.vii)

This project does not require "Leave to Construct" under Section 92 of the *Ontario Energy Board Act* 1998.

Evaluation Criteria and Information (5.4.5.2.B)	**Project Name** 2019 Customer Connections Table 2
	Efficiency, Customer Value, Reliability (5.4.5.2.B.1) **Investment Driver (5.4.5.2.B.1.a)** System Access (100%) **Secondary Driver (5.4.5.2.B.1.a)** N/A **Investment Priority (5.4.5.2.B.1.b)** 5 – Mandatory Project **Analysis of Project and Project Alternatives (5.4.5.2.B.1.c)** Please refer to Note III for information on analysis of the project and project alternatives.
	Safety (5.4.5.2.B.2) This project is not intended to address safety concerns with the distribution system.
	Cyber-Security and Privacy (5.4.5.2.B.3) (where applicable) Cyber-Security and Privacy are not applicable to this project
	Co-ordination and Interoperability (5.4.5.2.B.4) **Cyber-Security and Privacy (5.4.5.2.B.3) (where applicable)Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.5.2.B.4.a) (where applicable)** Please refer to Note II for an explanation on co-ordination with utilities, regional planning and/or links with 3rd parties. **Enabling of Future Technology and/or Future Operational Requirements (5.4.5.2.B.4.b)** This is not applicable for these projects.
	Economic Development (5.4.5.2.B.5) **(where applicable)** Horizon Utilities ensures that policies and practices do not unnecessarily create barriers to economic development which are primarily focused within its communities.
	Environmental Benefits (5.4.5.2.B.6) **(where applicable)** n/a

System Access Specific Requirements (5.4.5.2.C.a)

Project Name	2019 Customer Connections	Table 3

System Access Specific Requirements (5.4.5.2.C.a)

Factors Affecting Implementing Project Timing/Priority (5.4.5.2.C.a.i)

Schedule of work based on customer expectations; customer request may not be standard design.

Factors Related to Customer Preference or 3rd Party Input (5.4.5.2.C.a.ii)

There projects are customer initiated and are designed to meet customer identified requirements.

Factors Affecting Final Project Cost (5.4.5.2.C.a.iii)

Please refer to Note I for an explanation on the factors affecting final project cost.

Controllable Cost Minimization (5.4.5.2.C.a.iv)

Please refer to Note I for an explanation on the factors affecting controllable cost.

Other Planning Objectives (5.4.5.2.C.a.v)

n/a

Assessment of Technical or Implementation Options (5.4.5.2.C.a.vi)

Please refer to Note III for information on the technical and implementation options.

Summary of Options Analysis (5.4.5.2.C.a.vii)

Please refer to Note III for information on results of options analysis.

Final Economic Evaluation Results (5.4.5.2.C.a.viii)

Horizon Utilities completes the economic evaluation for any customer system access project which requires the construction of new facilities to the main distribution system or an increase in the existing capacity of distribution facilities. For further details please see Appendix E of Horizon Utilities' Conditions of Service. The economic evaluation is completed in accordance with section 3.2 of the Distribution System Code ("DSC"). For the 2015-2019 Test Years, Horizon Utilities has no known projects for which to provide the final economic evaluation. When a road authority requests a relocation of Horizon Utilities' plant located on the public road allowance, the costs shall be shared, as outlined in the Ontario *Public Service Works on Highways Act*. Other projects within this category will have an economic evaluation completed where applicable in accordance with both the DSC and Appendix E of Horizon Utilities' Conditions of Service.

Identification of System Impacts (5.4.5.2.C.a.ix)

System expansion, if required, to connect customers within this category are governed by Horizon Utilities' Conditions of Service Section 2.1.2.1.

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Capital Project Summary

General Information on Project (5.4.5.2.A)

Project Name	AB-F2 Renewal - Bold St
Budget Year	2019
Investment Category	System Renewal
Project Summary	This project involves the renewal of 4kV distribution assets on the Aberdeen F2 feeder as part of the 4kV and 8kV Renewal Plan. The assets are located along Bold St in central Hamilton.
Capital Investment (5.4.5.2.A.i)	Capital Investment (gross): $2,900,412 Customer Contribution: $0 Capital Investment (net): $2,900,412 O&M Expenditure: $0
Customer Attachments / Load (kVA) (5.4.5.2.A.ii)	This project will impact 1,295 customers and 2000kVA of transformation
Project Dates (5.4.5.2.A.iii)	Start Date 2019/03/01 In Service Date 2019/09/30

Expenditure Timing

Q1	Q2	Q3	Q4
20%	60%	20%	0%

Schedule Risk and Risk Mitigation (5.4.5.2.A.iv**)**

Please refer to Note I for risk and risk mitigation.

Comparative Information from Equivalent Projects (5.4.5.2.A.v)

There is no direct comparator in scope, size and design characteristics for this project. This project is one phase of a multi-year investment to renew the area served by Aberdeen substation as part of the 4kV and 8kV Renewal Plan. The 2019 investment for the renewal of Aberdeen substation is $2,900,000. The 2019 investment in the 4kV and 8kV Renewal Program is $16,846,000.

Comparable gross investments for the 4kv and 8kV Renewal Program for the 2010 and 2013 Historical Years and the 2014 Bridge Year are:

2010 (CGAAP)- $ 2,556,076
2011 (CGAAP)- $ 8,820,000
2012 (MIFRS) - $ 5,268,441
2013 (MIFRS) - $ 5,072,233
2014 (MIFRS) - $ 6,434,000

Total Capital OM&A Costs Associated with REG Investments (5.4.5.2.A.vi)

This project is not associated with an REG investment and therefore OM&A costs related to REG will not be incurred.

Leave to Construct Approval (5.4.5.2.A.vii)

This project does not require "Leave to Construct" under Section 92 of the *Ontario Energy Board Act* 1998.

Evaluation Criteria and Information (5.4.5.2.B)

Project Name	AB-F2 Renewal - Bold St	Table 2

Efficiency, Customer Value, Reliability (5.4.5.2.B.1)

Investment Driver (5.4.5.2.B.1.a)
System Renewal (80%)

Secondary Driver (5.4.5.2.B.1.a)
System Service (20%)

Investment Priority (5.4.5.2.B.1.b)
3 – Required project

Analysis of Project and Project Alternatives (5.4.5.2.B.1.c)

This project is part of the multi-year 4kV and 8kV Renewal Program. It is necessary to renew both the 4kV and 8kV distribution system and the Horizon Utilities-owned substations. Horizon Utilities has chosen to renew the 4kV and 8kV distribution systems to a higher voltage to avoid the cost of the investment in the renewal of the substations. The total avoided substation renewal investment over the remaining 35 years of the plan is $70,000,000 for all 28 substations. Therefore the renewal of these distribution assets at the current 4kV level was not a feasible alternative

The renewal of the area serviced by Aberdeen substation started in 2017 and is scheduled to be completed in 2021.

Safety (5.4.5.2.B.2)

This project is not intended to address safety concerns with the distribution system.

Cyber-Security and Privacy (5.4.5.2.B.3) (where applicable)

Cyber-Security and Privacy are not applicable to this project.

Co-ordination and Interoperability (5.4.5.2.B.4)

Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.5.2.B.4.a) (where applicable)
Please refer to Note II for an explanation on co-ordination with utilities, regional planning and/or links with 3rd parties.

Enabling of Future Technology and/or Future Operational Requirements (5.4.5.2.B.4.b)

Please refer to Note IV for an explanation enabling of future technology and future operational requirements.

Economic Development (5.4.5.2.B.5) **(where applicable)**

Horizon Utilities ensures that policies and practices do not unnecessarily create barriers to economic development which are primarily focused within its communities.

Environmental Benefits (5.4.5.2.B.6) **(where applicable)**

n/a

System Renewal Specific Requirements (5.4.5.2.C.b)

Project Name	AB-F2 Renewal - Bold St	Table 3

System Renewal Specific Requirements (5.4.5.2.C.b)

Asset Performance Target and Asset Lifecycle Optimization (5.4.5.2.C.b.i.1)

The two substations servicing the downtown Hamilton operating area service a total of 7,400 customers and were constructed in 1950 and 1960. The overall Station Health Index for Aberdeen and Central substations is 53% and 56% respectively. 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.

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Asset Condition Relative to Typical Life Cycle (5.4.5.2.C.b.i.2)

Generally the 4kV assets are the oldest vintage in the system. 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.

Number of Customers Impacted (5.4.5.2.C.b.i.3)

This project impacts approximately 1,295 customers.

Quantitative Customer Impact and Risk (5.4.5.2.C.b.i.4)

SAIDI of 0.137

Qualitative Customer Impact and Risk (5.4.5.2.C.b.i.5)

This project will address aging assets with inadequate backup. Aging assets represent an increased risk of service interruption to customers and inadequate backup would result in long duration service interruptions upon occurrence. These factors would lead to customer dissatisfaction in this area.

Value of Customer Impact (5.4.5.2.C.b.i.6)

High

Other Factors Affecting Project Timing (5.4.5.2.C.b.ii)

The renewal of the area serviced by Aberdeen substation is scheduled for 2017 to 2021. This project is required to be completed in 2019 to allow for the renewal of the remaining area to be completed on schedule.

Impact on System O&M Costs (5.4.5.2.C.b.iii)

This project will have no material impact on planned O&M costs. The renewal of the 4kV and 8kV distribution systems, as a whole, will provide a reduction in reactive O&M costs to address service interruptions caused by failed equipment. These reductions will not be material in the 2015 to 2019 Test Years.

Reliability and Safety Factors (5.4.5.2.C.b.iv)

The renewal of the 4kV and 8kV distribution system will provide reliability improvements through reduced service interruptions caused by failed equipment.

Analysis of Project Benefits and Timing (5.4.5.2.C.b.v)

The timing of this project, as part of the 4kV and 8kV Renewal Program, is determined through the assessment of the distribution system health and the health of the substation assets servicing the area. Renewal of this area will allow for the decommissioning of the substation assets by 2021 thereby avoiding the need for capital investment into these substations.

Like-for-Like Renewal Analysis (5.4.5.2.C.b.vi)

The like-for-like renewal of these assets (i.e. same system configuration and same distribution voltage) will perpetuate the existing operating constraints and require capital investment to renew substation assets. Renewal of the distribution assets at a higher voltage does not involve any material incremental costs over renewal at the existing voltage. Operating constraints (e.g. undersized conductor, radial feeds) are addressed on a case by case basis where appropriate.

Capital Project Summary

General Information on Project (5.4.5.2.A)

Project Name	BD-F1 Renewal - Alma St
Budget Year	2019
Investment Category	System Renewal
Project Summary	This project involves the renewal of 4kV distribution assets on the Baldwin F1 feeder as part of the 4kV and 8kV Renewal Program. The assets are located along Alma St in Dundas.

Capital Investment (5.4.5.2.A.i)	Capital Investment (gross)	$1,943,487
	Customer Contribution	$0
	Capital Investment (net)	$1,943,487
	O&M Expenditure	$0

Customer Attachments / Load (kVA) (5.4.5.2.A.ii)	This project will impact 862 customers and 4000KVA of transformation

Project Dates (5.4.5.2.A.iii)

Start Date	2019/03/01
In Service Date	2019/10/01

Expenditure Timing

Q1	Q2	Q3	Q4
15%	40%	45%	0%

Schedule Risk and Risk Mitigation (5.4.5.2.A.iv**)**

Please refer to Note I for risk and risk mitigation.

Comparative Information from Equivalent Projects (5.4.5.2.A.v)

There is no direct comparator in scope, size and design characteristics for this project. This project is one phase of a multi-year investment to renew the area served by Baldwin substation as part of the 4kV and 8kV Renewal Program. The 2019 investment for the renewal of Baldwin substation is $4,403,000. The 2019 investment in the 4kV and 8kV Renewal Program is $16,846,000.

Comparable gross investments for the 4kv and 8kV Renewal Program for the 2010 to 2013 Historical Years and the 2014 Bridge Year are:

2010 (CGAAP)- $ 2,556,076
2011 (CGAAP)- $ 8,820,000
2012 (MIFRS) - $ 5,268,441
2013 (MIFRS) - $ 5,072,233
2014 (MIFRS) - $ 6,434,000

Total Capital OM&A Costs Associated with REG Investments (5.4.5.2.A.vi)

This project is not associated with an REG investment and therefore OM&A costs related to REG will not be incurred.

Leave to Construct Approval (5.4.5.2.A.vii)

This project does not require "Leave to Construct" under Section 92 of the *Ontario Energy Board Act* 1998.

Evaluation Criteria and Information (5.4.5.2.B)

Project Name BD-F1 Renewal - Alma St Table 2

Efficiency, Customer Value, Reliability (5.4.5.2.B.1)

Investment Driver (5.4.5.2.B.1.a)
System Renewal (80%)

Secondary Driver (5.4.5.2.B.1.a)
System Service (20%)

Investment Priority (5.4.5.2.B.1.b)

3 – Required project

Analysis of Project and Project Alternatives (5.4.5.2.B.1.c)

This project is part of the multi-year 4kV and 8kV Renewal Program. Both the 4kV and 8kV distribution system and the Horizon Utilities-owned substations are at the end of their useful life. Horizon Utilities has chosen to renew the 4kV and 8kV distribution systems to a higher voltage to avoid the cost of the investment in the renewal of the substations. The total avoided substation renewal investment over the remaining 35 years of the plan is $70,000,000 for all 28 substations. Therefore the renewal of these distribution assets at the current 4kV level was not a feasible alternative.

Safety (5.4.5.2.B.2)

This project is not intended to address safety concerns with the distribution system.

Cyber-Security and Privacy (5.4.5.2.B.3) (where applicable)

Cyber-Security and Privacy are not applicable to this project.

Co-ordination and Interoperability (5.4.5.2.B.4)

Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.5.2.B.4.a) (where applicable)
Please refer to Note II for an explanation on co-ordination with utilities, regional planning and/or links with 3rd parties.

Enabling of Future Technology and/or Future Operational Requirements (5.4.5.2.B.4.b)

Please refer to Note IV for an explanation enabling of future technology and future operational requirements.

	Economic Development (5.4.5.2.B.5) **(where applicable)** Horizon Utilities ensures that policies and practices do not unnecessarily create barriers to economic development which are primarily focused within its communities.
	Environmental Benefits (5.4.5.2.B.6) **(where applicable)** n/a

System Renewal Specific Requirements (5.4.5.2.C.b)

Project Name BD-F1 Renewal - Alma St Table 3

System Renewal Specific Requirements (5.4.5.2.C.b)

Asset Performance Target and Asset Lifecycle Optimization (5.4.5.2.C.b.i.1)

The distribution assets in the Dundas operating area are in poor health and have significant operating constraints. 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'.

Asset Condition Relative to Typical Life Cycle (5.4.5.2.C.b.i.2)

Generally the 4kV assets are the oldest vintage in the system. 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.

Number of Customers Impacted (5.4.5.2.C.b.i.3)

This project impacts 862 customers.

Quantitative Customer Impact and Risk (5.4.5.2.C.b.i.4)

SAIDI of 0.029

Qualitative Customer Impact and Risk (5.4.5.2.C.b.i.5)

This project will address aging assets with inadequate backup. Aging assets represent an increased risk of service interruption to customers and inadequate backup would result in long duration service interruptions upon occurrence. These factors would lead to customer dissatisfaction in this area.

Value of Customer Impact (5.4.5.2.C.b.i.6)

High

Other Factors Affecting Project Timing (5.4.5.2.C.b.ii)

The renewal of the area serviced by Baldwin substation is scheduled for renewal in 2018 and 2019.

Impact on System O&M Costs (5.4.5.2.C.b.iii)

This project will have no material impact on planned O&M costs. The renewal of the 4kV and 8kV distribution systems, as a whole, will provide a reduction in reactive O&M costs to address service interruptions caused by failed equipment. These reductions will not be material in the 2015 to 2019 Test Years.

Reliability and Safety Factors (5.4.5.2.C.b.iv)

The renewal of the 4kV and 8kV distribution system will provide reliability improvements through reduced service interruptions caused by failed equipment.

Analysis of Project Benefits and Timing (5.4.5.2.C.b.v)

The timing of this project, as part of the 4kV and 8kV Renewal Program, is determined through the assessment of the distribution system health and the health of the substation assets servicing the area.

Like-for-Like Renewal Analysis (5.4.5.2.C.b.vi)

The like-for-like renewal of these assets (i.e. same system configuration and same distribution voltage) will perpetuate the existing operating constraints and require capital investment to renew substation assets. Renewal of the distribution assets at a higher voltage does not involve any material incremental costs over renewal at the existing voltage. Operating constraints (e.g. undersized conductor, radial feeds) are addressed on a case by case basis where appropriate.

Capital Project Summary

General Information on Project (5.4.5.2.A)

Project Name	BD-F2 Renewal
Budget Year	2019
Investment Category	System Renewal
Project Summary	This project involves the renewal of 4kV distribution assets on the Baldwin F2 feeder as part of the 4kV and 8kV Renewal Program.

Capital Investment (5.4.5.2.A.i)

Capital Investment (gross)	$2,336,349
Customer Contribution	$0
Capital Investment (net)	$2,336,349
O&M Expenditure	$0

Customer Attachments / Load (kVA) (5.4.5.2.A.ii)

This project will impact 862 customers and 4000kVA of transformation

Project Dates (5.4.5.2.A.iii)

Start Date	2019/03/01
In Service Date	2019/09/30

Expenditure Timing

Q1	Q2	Q3	Q4
15%	40%	45%	0%

Schedule Risk and Risk Mitigation (5.4.5.2.A.iv**)**

Please refer to Note I for risk and risk mitigation.

Comparative Information from Equivalent Projects (5.4.5.2.A.v)

There is no direct comparator in scope, size and design characteristics for this project. This project is one phase of a multi-year investment to renew the area served by Baldwin substation as part of the 4kV and 8kV Renewal Program. The 2019 investment for the renewal of Baldwin substation is $4,403,000. The 2019 investment in the 4kV and 8kV Renewal Program is $16,846,000.

Comparable gross investments for the 4kV and 8kV Renewal Program for the 2010 to 2013 Historical Years and the 2014 Bridge Year are:

2010 (CGAAP)- $ 2,556,076
2011 (CGAAP)- $ 8,820,000
2012 (MIFRS) - $ 5,268,441
2013 (MIFRS) - $ 5,072,233
2014 (MIFRS) - $ 6,434,000

Total Capital OM&A Costs Associated with REG Investments (5.4.5.2.A.vi)

This project is not associated with an REG investment and therefore OM&A costs related to REG will not be incurred.

Leave to Construct Approval (5.4.5.2.A.vii)

This project does not require "Leave to Construct" under Section 92 of the *Ontario Energy Board Act* 1998.

Evaluation Criteria and Information (5.4.5.2.B)	**Project Name** BD-F2 Renewal Table 2
	Efficiency, Customer Value, Reliability (5.4.5.2.B.1) **Investment Driver (5.4.5.2.B.1.a)** System Renewal (80%) **Secondary Driver (5.4.5.2.B.1.a)** System Service (20%) **Investment Priority (5.4.5.2.B.1.b)** 3 – Required project
	Analysis of Project and Project Alternatives (5.4.5.2.B.1.c) This project is part of the multi-year 4kV and 8kV Renewal Program. Both the 4kV and 8kV distribution system and the Horizon Utilities-owned substations are at the end of their useful life. Horizon Utilities has chosen to renew the 4kV and 8kV distribution systems to a higher voltage to avoid the cost of the investment in the renewal of the substations. The total avoided substation renewal investment over the remaining 35 years of the plan is $70,000,000 for all 28 substations. Therefore the renewal of these distribution assets at the current 4kV level was not a feasible alternative.
	Safety (5.4.5.2.B.2) This project is not intended to address safety concerns with the distribution system.
	Cyber-Security and Privacy (5.4.5.2.B.3) (where applicable) Cyber-Security and Privacy are not applicable to this project.
	Co-ordination and Interoperability (5.4.5.2.B.4) **Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.5.2.B.4.a) (where applicable)** Please refer to Note II for an explanation on co-ordination with utilities, regional planning and/or links with 3rd parties. **Enabling of Future Technology and/or Future Operational Requirements (5.4.5.2.B.4.b)** Please refer to Note IV for an explanation enabling of future technology and future operational requirements.
	Economic Development (5.4.5.2.B.5) **(where applicable)** Horizon Utilities ensures that policies and practices do not unnecessarily create barriers to economic development which are primarily focused within its communities.
	Environmental Benefits (5.4.5.2.B.6) **(where applicable)** n/a

Project Name	BD-F2 Renewal	Table 3

System Renewal Specific Requirements (5.4.5.2.C.b)

System Renewal Specific Requirements (5.4.5.2.C.b)

Asset Performance Target and Asset Lifecycle Optimization (5.4.5.2.C.b.i.1)

The distribution assets in the Dundas operating area are in poor health and have significant operating constraints. 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'.

Asset Condition Relative to Typical Life Cycle (5.4.5.2.C.b.i.2)

Generally the 4kV assets are the oldest vintage in the system. 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.

Number of Customers Impacted (5.4.5.2.C.b.i.3)

This project impacts 862 customers

Quantitative Customer Impact and Risk (5.4.5.2.C.b.i.4)

SAIDI of 0.029

Qualitative Customer Impact and Risk (5.4.5.2.C.b.i.5)

This project will address aging assets with inadequate backup. Aging assets represent an increased risk of service interruption to customers and inadequate backup would result in long duration service interruptions upon occurrence. These factors would lead to customer dissatisfaction in this area.

Value of Customer Impact (5.4.5.2.C.b.i.6)

High

Other Factors Affecting Project Timing (5.4.5.2.C.b.ii)

The renewal of the area serviced by Baldwin substation is scheduled for renewal in 2018 and 2019.

Impact on System O&M Costs (5.4.5.2.C.b.iii)

This project will have no material impact on planned O&M costs. The renewal of the 4kV and 8kV distribution systems, as a whole, will provide a reduction in reactive O&M costs to address service interruptions caused by failed equipment. These reductions will not be material in the 2015 to 2019 Test Years.

Reliability and Safety Factors (5.4.5.2.C.b.iv)

The renewal of the 4kV and 8kV distribution system will provide reliability improvements through reduced service interruptions caused by failed equipment.

Analysis of Project Benefits and Timing (5.4.5.2.C.b.v)

The timing of this project, as part of the 4kV and 8kV Renewal Program, is determined through the assessment of the distribution system health and the health of the substation assets servicing the area.

Like-for-Like Renewal Analysis (5.4.5.2.C.b.vi)

The like-for-like renewal of these assets (i.e. same system configuration and same distribution voltage) will perpetuate the existing operating constraints and require capital investment to renew substation assets. Renewal of the distribution assets at a higher voltage does not involve any material incremental costs over renewal at the existing voltage. Operating constraints (e.g. undersized conductor, radial feeds) are addressed on a case by case basis where appropriate.

Capital Project Summary

General Information on Project (5.4.5.2.A)

Project Name	CE-F4 Renewal – Freeman Place
Budget Year	2019
Investment Category	System Renewal
Project Summary	This project involves the renewal of 4kV distribution assets on the Central F4 feeder as part of the 4kV and 8kV Renewal Program. The assets are located along Freeman Place in central Hamilton.

Capital Investment (5.4.5.2.A.i)		
	Capital Investment (gross)	$647,524
	Customer Contribution	$0
	Capital Investment (net)	$647,524
	O&M Expenditure	$0

Customer Attachments / Load (kVA) (5.4.5.2.A.ii)	This project will impact 750 customers and 2500kVA of transformation
Project Dates (5.4.5.2.A.iii)	Start Date 2019/09/01 In Service Date 2019/12/31

Expenditure Timing

Q1	Q2	Q3	Q4
0%	0%	25%	75%

Schedule Risk and Risk Mitigation (5.4.5.2.A.iv**)**

Please refer to Note I for risk and risk mitigation.

Comparative Information from Equivalent Projects (5.4.5.2.A.v)

There is no direct comparator in scope, size and design characteristics for this project. This project is one phase of a multi-year investment to renew the area served by Central substation as part of the 4kV and 8kV Renewal Program. The 2019 investment for the renewal of Central substation is $648,000. The 2019 investment in the 4kV and 8kV Renewal Program is $16,846,000.

Comparable gross investments for the 4kv and 8kV Renewal Program for the 2010 and 2013 Historical Years and the 2014 Bridge Year are:

2010 (CGAAP)- $ 2,556,076
2011 (CGAAP)- $ 8,820,000
2012 (MIFRS) - $ 5,268,441
2013 (MIFRS) - $ 5,072,233
2014 (MIFRS) - $ 6,434,000

Total Capital OM&A Costs Associated with REG Investments (5.4.5.2.A.vi)

This project is not associated with an REG investment and therefore OM&A costs related to REG will not be incurred.

Leave to Construct Approval (5.4.5.2.A.vii)

This project does not require "Leave to Construct" under Section 92 of the *Ontario Energy Board Act* 1998.

Evaluation Criteria and Information (5.4.5.2.B)

Project Name	CE-F4 Renewal – Freeman Place	Table 2

Efficiency, Customer Value, Reliability (5.4.5.2.B.1)

Investment Driver (5.4.5.2.B.1.a)
System Renewal (80%)

Secondary Driver (5.4.5.2.B.1.a)
System Service (20%)

Investment Priority (5.4.5.2.B.1.b)
3 – Required project

Analysis of Project and Project Alternatives (5.4.5.2.B.1.c)

This project is part of the multi-year 4kV and 8kV Renewal Program. It is necessary to renew both the 4kV and 8kV distribution system and the Horizon Utilities-owned substations. Horizon Utilities has chosen to renew the 4kV and 8kV distribution systems to a higher voltage to avoid the cost of the investment in the renewal of the substations. The total avoided substation renewal investment over the remaining 35 years of the plan is $70,000,000 for all 28 substations. Therefore the renewal of these distribution assets at the current 4kV level was not a feasible alternative.

The renewal of the area serviced by Central substation started in 2016 and is scheduled to be completed in 2022.

Safety (5.4.5.2.B.2)

This project is not intended to address safety concerns with the distribution system.

Cyber-Security and Privacy (5.4.5.2.B.3) (where applicable)

Cyber-Security and Privacy are not applicable to this project.

Co-ordination and Interoperability (5.4.5.2.B.4)

Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.5.2.B.4.a) (where applicable)

Please refer to Note II for an explanation on co-ordination with utilities, regional planning and/or links with 3rd parties.

Enabling of Future Technology and/or Future Operational Requirements (5.4.5.2.B.4.b)

Please refer to Note IV for an explanation enabling of future technology and future operational requirements.

Economic Development (5.4.5.2.B.5) **(where applicable)**

Horizon Utilities ensures that policies and practices do not unnecessarily create barriers to economic development which are primarily focused within its communities.

Environmental Benefits (5.4.5.2.B.6) **(where applicable)**

n/a

System Renewal Specific Requirements (5.4.5.2.C.b)

Project Name CE-F4 Renewal – Freeman Place Table 3

System Renewal Specific Requirements (5.4.5.2.C.b)

Asset Performance Target and Asset Lifecycle Optimization (5.4.5.2.C.b.i.1)

The two substations servicing the downtown Hamilton operating area service a total of 7,400 customers and were constructed in 1950 and 1960. The overall Station Health Index for Aberdeen and Central substations is 53% and 56% respectively. 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 identified that this switchgear has a high risk of failure within three years. Central substation has limited interconnection with other substations. The loss of the entire substation would affect all 3100 customers who would be out of power until the substation assets were repaired.

Asset Condition Relative to Typical Life Cycle (5.4.5.2.C.b.i.2)

Generally the 4kV assets are of the oldest vintage in the system. 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.

Number of Customers Impacted (5.4.5.2.C.b.i.3)
This project impacts approximately 750 customers.

Quantitative Customer Impact and Risk (5.4.5.2.C.b.i.4)

SAIDI of 0.242

Qualitative Customer Impact and Risk (5.4.5.2.C.b.i.5)

This project will address aging assets with inadequate backup. Aging assets represent an increased risk of service interruption to customers and inadequate backup would result in long duration service interruptions upon occurrence. These factors would lead to customer dissatisfaction in this area.

Value of Customer Impact (5.4.5.2.C.b.i.6)

High

Other Factors Affecting Project Timing (5.4.5.2.C.b.ii)

The renewal of the area serviced by Central substation is schedule for 2016 to 2022. This project is required to be completed in 2016 to allow for the renewal of the remaining area to completed on schedule

Impact on System O&M Costs (5.4.5.2.C.b.iii)

This project will have no material impact on planned O&M costs. The renewal of the 4kV and 8kV distribution systems, as a whole, will provide a reduction in reactive O&M costs to address service interruptions caused by failed equipment. These reductions will not be material in the 2015 to 2019 Test Years

Reliability and Safety Factors (5.4.5.2.C.b.iv)

The renewal of the 4kV and 8kV distribution system will provide reliability improvements through reduced service interruptions caused by failed equipment.

Analysis of Project Benefits and Timing (5.4.5.2.C.b.v)

The timing of this project, as part of the 4kV and 8kV Renewal Program, is determined through the assessment of the distribution system health and the health of the substation assets servicing the area. Renewal of this area will allow for the decommissioning of the substation assets by 2022 thereby avoiding the need for capital investment into these substations.

Like-for-Like Renewal Analysis (5.4.5.2.C.b.vi)

The like-for-like renewal of these assets (i.e. same system configuration and same distribution voltage) will perpetuate the existing operating constraints and require capital investment to renew substation assets. Renewal of the distribution assets at a higher voltage does not involve any material incremental costs over renewal at the existing voltage. Operating constraints (e.g. undersized conductor, radial feeds) are addressed on a case by case basis where appropriate.

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Capital Project Summary

General Information on Project (5.4.5.2.A)

Project Name	2019 Load Break Disconnect Switch ("LBDS") Replacement
Budget Year	2019
Investment Category	System Renewal
Project Summary	This project involves the replacement of LBDS found to be either inoperable or beyond economic repair (where the cost of maintenance is not warranted) as found through Horizon Utilities' maintenance and inspection programs. Such switches will be replaced with automated switches where an operational benefit can be realized. This is a multi-year program based on 16 replacements per year.

Capital Investment (5.4.5.2.A.i)	Capital Investment (gross)	$368,000
	Customer Contribution	$0
	Capital Investment (net)	$368,000
	O&M Expenditure	$0
Customer Attachments / Load (kVA) (5.4.5.2.A.ii)	n/a	

Project Dates (5.4.5.2.A.iii)

Start Date	2019/06/01
In Service Date	2019/12/31

Expenditure Timing

Q1	Q2	Q3	Q4
0%	0%	50%	50%

Schedule Risk and Risk Mitigation (5.4.5.2.A.iv**)**

Please refer to Note I for risk and risk mitigation.

Comparative Information from Equivalent Projects (5.4.5.2.A.v)

Comparable gross investments for the 2010 to 2013 Historical Years and the 2014 Bridge Year are:

2010 (CGAAP)- $ 0
2011 (CGAAP)- $ 0
2012 (MIFRS) - $ 0
2013 (MIFRS) - $ 212,000
2014 (MIFRS) - $ 312,000

Total Capital OM&A Costs Associated with REG Investments (5.4.5.2.A.vi)
This project is not associated with an REG investment and therefore OM&A costs related to REG will not be incurred.

Leave to Construct Approval (5.4.5.2.A.vii)

This project does not require “Leave to Construct” under Section 92 of the *Ontario Energy Board Act* 1998.

Evaluation Criteria and Information (5.4.5.2.B)

Project Name	2019 LBDS Replacement	Table 2

Efficiency, Customer Value, Reliability (5.4.5.2.B.1)

Investment Driver (5.4.5.2.B.1.a)
System Renewal (80%)

Secondary Driver (5.4.5.2.B.1.a)
System Service (20%)

Investment Priority (5.4.5.2.B.1.b)
3 – Required project

Analysis of Project and Project Alternatives (5.4.5.2.B.1.c)

This project involves the replacement of LBDS identified as requiring replacement through Horizon Utilities’ maintenance and inspection programs. When feasible, the switches are refurbished rather than replaced. Where refurbishment is not possible, the switches will be replaced with an automated switch where an operational benefit can be realized.

Safety (5.4.5.2.B.2)

This project is not intended to address safety concerns with the distribution system.

Cyber-Security and Privacy (5.4.5.2.B.3) (where applicable)

Horizon Utilities utilizes the Smart Meter communication infrastructure when communicating with automated switches. Horizon Utilities’ Smart Meter and related AMI network have been procured through Elster. Elster’s system supports a multi-layered security approach including: access control, authorization, authentication and data integrity protocols. As part of its continuous improvement model, Horizon Utilities performs periodic security assessments to identify opportunities for enhanced system hardening.

Co-ordination and Interoperability (5.4.5.2.B.4)

Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.5.2.B.4.a) (where applicable)

Please refer to Note II for an explanation on co-ordination with utilities, regional planning and/or links with 3rd parties.

Enabling of Future Technology and/or Future Operational Requirements (5.4.5.2.B.4.b)

This is not applicable to this project.

Economic Development (5.4.5.2.B.5) **(where applicable)**

Horizon Utilities ensures that policies and practices do not unnecessarily create barriers to economic development which are primarily focused within its communities.

Environmental Benefits (5.4.5.2.B.6) **(where applicable)**

n/a

System Renewal Specific Requirements (5.4.5.2.C.b)

Project Name	2019 LBDS Replacement	Table 3

System Renewal Specific Requirements (5.4.5.2.C.b)

Asset Performance Target and Asset Lifecycle Optimization (5.4.5.2.C.b.i.1)

LBDS are critical devices for the operation of the distribution system and are installed at key operating points (e.g. feeder tie points, feeder sectionalizing). Unplanned failures of these devices would impact Horizon Utilities' ability to restore power, resulting in extended outages.

Asset Condition Relative to Typical Life Cycle (5.4.5.2.C.b.i.2)

The asset condition of load break switches relative to their typical lifecycle varies from switch to switch depending upon the operational stresses experienced by the switch. LBDS that are identified for replacement are replaced because they would not operate properly when required and are beyond economical repair.

Number of Customers Impacted (5.4.5.2.C.b.i.3)

None if the project is planned.

Quantitative Customer Impact and Risk (5.4.5.2.C.b.i.4)

n/a

Qualitative Customer Impact and Risk (5.4.5.2.C.b.i.5)

Failure of a LBDS to operate when required can impact Horizon Utilities' operational ability which can adversely affect the service experienced by customers.

Value of Customer Impact (5.4.5.2.C.b.i.6)

The value of the customer impact varies in each instance.

Other Factors Affecting Project Timing (5.4.5.2.C.b.ii)

The timing of this project is dependent upon the timing of Horizon Utilities' LBDS maintenance program.

Impact on System O&M Costs (5.4.5.2.C.b.iii)

These projects do not materially impact system O&M costs.

Reliability and Safety Factors (5.4.5.2.C.b.iv)

Reliability can be adversely affected when a LBDS fails to operate when required as part of switching to restore service.

Analysis of Project Benefits and Timing (5.4.5.2.C.b.v)

n/a

	Like-for-Like Renewal Analysis (5.4.5.2.C.b.vi) LDBS are replaced with an automated switch where an operational benefit can be realized. Otherwise they are replaced on a like-for-like basis.

Capital Project Summary

General Information on Project (5.4.5.2.A)

Project Name	2019 Proactive Transformer Replacement
Budget Year	2019
Investment Category	System Renewal
Project Summary	This project was established to proactively replace distribution transformers as required. Renewal of distribution transformers in the past has either been reactive upon failure or proactive when included in the 4kV & 8KV Renewal or XLPE Primary Cable Renewal Programs. There are instances where proactive replacement of transformers is required even when the replacement is outside of the scope of the programs mentioned above. This is a multi-year project, based on 25 replacements per year.

Capital Investment (5.4.5.2.A.i)	Capital Investment (gross)	$395,000
	Customer Contribution	$0
	Capital Investment (net)	$395,000
	O&M Expenditure	$0
Customer Attachments / Load (kVA) (5.4.5.2.A.ii)	n/a	
Project Dates (5.4.5.2.A.iii)	Start Date	2019/06/01
	In Service Date	2019/12/31

Expenditure Timing

Q1	Q2	Q3	Q4
0%	0%	50%	50%

Schedule Risk and Risk Mitigation (5.4.5.2.A.iv**)**

Please refer to Note I for risk and risk mitigation.

Comparative Information from Equivalent Projects (5.4.5.2.A.v)

Comparable gross investments for the 2010 to 2013 Historical Years and the 2014 Bridge Year are:

2010 (CGAAP)- $ 0
2011 (CGAAP)- $ 104,447
2012 (MIFRS) - $ 185,523
2013 (MIFRS) - $ 276,978
2014 (MIFRS) - $ 339,000

Total Capital OM&A Costs Associated with REG Investments (5.4.5.2.A.vi)
This project is not associated with an REG investment and therefore OM&A costs related to REG will not be incurred.

Leave to Construct Approval (5.4.5.2.A.vii)

This project does not require “Leave to Construct” under Section 92 of the *Ontario Energy Board Act* 1998.

Evaluation Criteria and Information (5.4.5.2.B)

Project Name 2019 Proactive Transformer Replacement Table 2

Efficiency, Customer Value, Reliability (5.4.5.2.B.1)

Investment Driver (5.4.5.2.B.1.a)
System Renewal (100%)

Secondary Driver (5.4.5.2.B.1.a)
n/a

Investment Priority (5.4.5.2.B.1.b)
3 – Required project

Analysis of Project and Project Alternatives (5.4.5.2.B.1.c)

Proactive transformer replacements are identified through Horizon Utilities’ visual inspection programs and 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, in a reactive replacement scenario, the customer(s) may be subject to an extended outage duration;
- Transformers that have visible oil leaks; and
- Transformers that have been identified through testing as containing PCBs.

These criteria were selected due to the level of associated risk. Transformers with visible oil leaks or containing PCBs represent a significant environmental risk. All oil spills must be tracked, reported, and the oil reclaimed where possible. Obsolete transformers, where a replacement is not available in inventory, represent a risk of prolonged service interruption upon failure and are replaced to reduce the risk of outage to the customer.

Safety (5.4.5.2.B.2)

This project is not intended to address safety concerns with the distribution system.

Cyber-Security and Privacy (5.4.5.2.B.3) (where applicable)

Cyber-Security and Privacy are not applicable to this project

Co-ordination and Interoperability (5.4.5.2.B.4)

Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.5.2.B.4.a) (where applicable)

Please refer to Note II for an explanation on co-ordination with utilities, regional planning and/or links with 3rd parties.

Enabling of Future Technology and/or Future Operational Requirements (5.4.5.2.B.4.b)

This is not applicable to this project.

Economic Development (5.4.5.2.B.5) **(where applicable)**

Horizon Utilities ensures that policies and practices do not unnecessarily create barriers to economic development which are primarily focused within its communities.

Environmental Benefits (5.4.5.2.B.6) **(where applicable)**

n/a

System Renewal Specific Requirements (5.4.5.2.C.b)

Project Name	2019 Proactive Transformer Replacement	Table 3

System Renewal Specific Requirements (5.4.5.2.C.b)

Asset Performance Target and Asset Lifecycle Optimization (5.4.5.2.C.b.i.1)

The transformers selected for proactive replacement represent a level of risk to Horizon Utilities and this project provides risk mitigation consistent with Horizon Utilities asset management objectives.

Asset Condition Relative to Typical Life Cycle (5.4.5.2.C.b.i.2)

The asset condition of these transformers relative to their typical lifecycle varies from transformer to transformer. Transformers selected for replacement present a level of risk to Horizon Utilities either through imminent failure of the transformer or through the need to address environmental risk associated with PCBs; or through the risks associated with transformers that have visible oil leaks.

Number of Customers Impacted (5.4.5.2.C.b.i.3)

n/a

Quantitative Customer Impact and Risk (5.4.5.2.C.b.i.4)

n/a

Qualitative Customer Impact and Risk (5.4.5.2.C.b.i.5)

These criteria were selected due to the level of associated risk. Transformers with visible oil leaks or containing PCBs represent a significant environmental risk. All oil spills must be tracked, reported, and the oil reclaimed where possible. Obsolete transformers, where a replacement is not available in inventory, represent a risk of prolonged service interruption upon failure and are replaced to reduce the risk of outage to the customer.

Value of Customer Impact (5.4.5.2.C.b.i.6)

The value of the customer impact varies in each instance.

Other Factors Affecting Project Timing (5.4.5.2.C.b.ii)

n/a

Impact on System O&M Costs (5.4.5.2.C.b.iii)

These projects do not materially impact system O&M costs.

Reliability and Safety Factors (5.4.5.2.C.b.iv)

n/a.

Analysis of Project Benefits and Timing (5.4.5.2.C.b.v)

n/a

Like-for-Like Renewal Analysis (5.4.5.2.C.b.vi)

n/a.

Capital Project Summary

General Information on Project (5.4.5.2.A)

Project Name	2019 Substation Infrastructure Renewal			
Budget Year	2019			
Investment Category	System Renewal			
Project Summary	This program involves the renewal of substation infrastructure throughout Horizon Utilities' service territory. Substation maintenance and inspection programs annually identify a number of required investments for the continued safe and reliable operation of Horizon Utilities' substations. Investments under this program include: battery replacements; SCADA and communication upgrades; and grounding improvements			
Capital Investment (5.4.5.2.A.i)	Capital Investment (gross)	$500,000		
	Customer Contribution	$0		
	Capital Investment (net)	$500,000		
	O&M Expenditure	$0		
Customer Attachments / Load (kVA) (5.4.5.2.A.ii)	n/a			
Project Dates (5.4.5.2.A.iii)	Start Date	2019/01/01		
	In Service Date	2019/12/31		
	Expenditure Timing			
	Q1	Q2	Q3	Q4
	25%	25%	25%	25%

Schedule Risk and Risk Mitigation (5.4.5.2.A.iv**)**

Please refer to Note I for risk and risk mitigation.

Comparative Information from Equivalent Projects (5.4.5.2.A.v)

Comparable gross investments for the 2010 to 2013 Historical Years and the 2014 Bridge Year are:

2010 (CGAAP)- $ 146,477
2011 (CGAAP)- $ 326,000
2012 (MIFRS) - $ 305,000
2013 (MIFRS) - $ 168,507
2014 (MIFRS) - $ 455,503

Total Capital OM&A Costs Associated with REG Investments (5.4.5.2.A.vi)

This project is not associated with an REG investment and therefore OM&A costs related to REG will not be incurred.

Leave to Construct Approval (5.4.5.2.A.vii)

This project does not require "Leave to Construct" under Section 92 of the *Ontario Energy Board Act* 1998.

Evaluation Criteria and Information (5.4.5.2.B)

Project Name 2019 Substation Infrastructure Renewal Table 2

Efficiency, Customer Value, Reliability (5.4.5.2.B.1)

Investment Driver (5.4.5.2.B.1.a)
System Renewal (80%)

Secondary Driver (5.4.5.2.B.1.a)
System Service (20%)

Investment Priority (5.4.5.2.B.1.b)
3 – Required project

Analysis of Project and Project Alternatives (5.4.5.2.B.1.c)

This program is required for the ongoing safe and reliable operation of Horizon Utilities' municipal substations. The 4kV and 8kV Renewal Program is structured to decommission Horizon Utilities' 28 substations over the next 34 years. There is no investment in the renewal of the major electrical assets (power transformers, switchgear and breakers) forecasted for the 2015 to 2019 Test Years. The investments provided above are required to maintain the ancillary substation assets in safe working order. Substation investment requirements are identified though preventative maintenance programs performed on both routine maintenance cycles and monthly inspections. 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. Investments are required to address both electrical assets within the substation (e.g. replacement of switchgear components and instrument transformers), and ancillary equipment (e.g. SCADA, communication equipment, or backup batteries). All of these components are critical to the continued safe and reliable operation of the substation. A failure to undertake these required investments could lead to premature failure of substation components that would result in a service interruption and increased operating or reactive capital expenditure.

Safety (5.4.5.2.B.2)

This project is not intended to address safety concerns with the distribution system.

Cyber-Security and Privacy (5.4.5.2.B.3) (where applicable)

Cyber-Security and Privacy are not applicable to this project.

Co-ordination and Interoperability (5.4.5.2.B.4)

Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.5.2.B.4.a) (where applicable)
Please refer to Note II for an explanation on co-ordination with utilities, regional planning and/or links with 3rd parties.

Enabling of Future Technology and/or Future Operational Requirements (5.4.5.2.B.4.b)

Please refer to Note IV for an explanation enabling of future technology and future operational requirements.

Economic Development (5.4.5.2.B.5) **(where applicable)**

	Horizon Utilities ensures that policies and practices do not unnecessarily create barriers to economic development which are primarily focused within its communities.
	Environmental Benefits (5.4.5.2.B.6) **(where applicable)** n/a.

System Renewal Specific Requirements (5.4.5.2.C.b)	**Project Name** 2019 Substation Infrastructure Renewal Table 3
	System Renewal Specific Requirements (5.4.5.2.C.b) **Asset Performance Target and Asset Lifecycle Optimization (5.4.5.2.C.b.i.1)** This project involves investment to replace substation infrastructure required for the continued safe and reliable operation of Horizon Utilities' substations. **Asset Condition Relative to Typical Life Cycle (5.4.5.2.C.b.i.2)** n/a **Number of Customers Impacted (5.4.5.2.C.b.i.3)** n/a. **Quantitative Customer Impact and Risk (5.4.5.2.C.b.i.4)** **Qualitative Customer Impact and Risk (5.4.5.2.C.b.i.5)** n/a **Value of Customer Impact (5.4.5.2.C.b.i.6)** Medium **Other Factors Affecting Project Timing (5.4.5.2.C.b.ii)** The timing of investments in this project is dependent upon the timing of substation maintenance programs and the infrastructure requiring renewal identified while performing maintenance. **Impact on System O&M Costs (5.4.5.2.C.b.iii)** This project will have no material impact on O&M expenditures. **Reliability and Safety Factors (5.4.5.2.C.b.iv)** n/a

Analysis of Project Benefits and Timing (5.4.5.2.C.b.v)

n/a

Like-for-Like Renewal Analysis (5.4.5.2.C.b.vi)

The assets renewed in this program are replaced on a like-for-like basis.

Capital Project Summary

General Information on Project (5.4.5.2.A)

Project Name	2019 Reactive Renewal
Budget Year	2019
Investment Category	System Renewal
Project Summary	This category includes all projects required for the reactive renewal or repairs driven by emergency equipment failures and associated corrective action. Projects arise from trouble calls or inspection programs identifying an urgent need to replace system assets and the scope of the equipment replacement requires engineering. Also included in this category are projects to address customer power quality issues and Electrical Safety Authority ("ESA") due diligence inspection outcomes.

Capital Investment (5.4.5.2.A.i)		
	Capital Investment (gross)	$4,608,000
	Customer Contribution	n/a
	Capital Investment (net)	n/a
	O&M Expenditure	n/a

Customer Attachments / Load (kVA) (5.4.5.2.A.ii): n/a

Project Dates (5.4.5.2.A.iii)

Start Date January 1, 2019

In Service Date December 31, 2019

Expenditure Timing

Q1	Q2	Q3	Q4
25%	25%	25%	25%

Schedule Risk and Risk Mitigation (5.4.5.2.A.iv**)**

Please refer to Note I for risk and risk mitigation.

Comparative Information from Equivalent Projects (5.4.5.2.A.v)

Comparable investments for the 2010 and 2013 Historical Years and the 2014 Bridge Year are:

2010 (CGAAP)- $ 8,745,125
2011 (CGAAP)- $ 8,230,970
2012 (MIFRS) - $ 4,032,000
2013 (MIFRS) - $ 6.069,566
2014 (MIFRS) - $ 4,840,000

Total Capital OM&A Costs Associated with REG Investments (5.4.5.2.A.vi)
This project is not associated with an REG investment and therefore OM&A costs related to REG will not be incurred.

Leave to Construct Approval (5.4.5.2.A.vii)

This project does not require "Leave to Construct" under Section 92 of the *Ontario Energy Board Act* 1998.

Evaluation Criteria and Information (5.4.5.2.B)

Project Name 2019 Reactive Renewal Table 2

Efficiency, Customer Value, Reliability (5.4.5.2.B.1)

Investment Driver (5.4.5.2.B.1.a)
System Renewal (80%)

Secondary Driver (5.4.5.2.B.1.a)
System Service (20%)

Investment Priority (5.4.5.2.B.1.b)
3 – Required project

Analysis of Project and Project Alternatives (5.4.5.2.B.1.c)

No alternatives are considered for these projects as they involve the emergency replacement of failed equipment required to restore service.

Safety (5.4.5.2.B.2)

These projects are intended to primarily address failed assets however investments required to address immediate safety issues, including issues presenting a potential risk to public safety identified by the ESA, are included in this project.

Cyber-Security and Privacy (5.4.5.2.B.3) (where applicable)

Cyber-Security and Privacy are not applicable to this project.

Co-ordination and Interoperability (5.4.5.2.B.4)

Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.5.2.B.4.a) (where applicable)

Please refer to Note II for an explanation on co-ordination with utilities, regional planning and/or links with 3rd parties.

Enabling of Future Technology and/or Future Operational Requirements (5.4.5.2.B.4.b)

Please refer to Note IV for an explanation enabling of future technology and future operational requirements.

Economic Development (5.4.5.2.B.5) **(where applicable)**

Horizon Utilities ensures that policies and practices do not unnecessarily create barriers to economic development which are primarily focused within its communities.

Environmental Benefits (5.4.5.2.B.6) **(where applicable)**

n/a

Project Name	2019 Reactive Renewal	Table 3

System Renewal Specific Requirements (5.4.5.2.C.b)

System Renewal Specific Requirements (5.4.5.2.C.b)

Asset Performance Target and Asset Lifecycle Optimization (5.4.5.2.C.b.i.1)

These projects are reactive in nature and are initiated from equipment that has failed or with a high risk of failure resulting in a service interruption. These projects have a very high probability of impacting Horizon Utilities' reliability targets.

Asset Condition Relative to Typical Life Cycle (5.4.5.2.C.b.i.2)

These projects address failed assets or assets with a high risk of imminent failure and as such, these assets are at the end of their useful life. The asset condition relative to their typical life cycle varies in each incident or outage.

Number of Customers Impacted (5.4.5.2.C.b.i.3)

The number of customers impacted varies in each incident or outage.

Quantitative Customer Impact and Risk (5.4.5.2.C.b.i.4)

The quantitative customer impact varies in each incident or outage.

Qualitative Customer Impact and Risk (5.4.5.2.C.b.i.5)

These projects address customer satisfaction as they are required to address failed assets that have either caused a system interruption, or have a high probability of causing a service interruption.

Value of Customer Impact (5.4.5.2.C.b.i.6)

The value of the customer impact varies in each incident or outage.

Other Factors Affecting Project Timing (5.4.5.2.C.b.ii)

These projects are reactive in nature and address failed assets, or assets at risk of imminent failure. Investments must be performed when identified.

Impact on System O&M Costs (5.4.5.2.C.b.iii)

These projects do not materially impact system O&M costs.

Reliability and Safety Factors (5.4.5.2.C.b.iv)

Improvements to reliability and security are expected as secondary benefits to this project.

Analysis of Project Benefits and Timing (5.4.5.2.C.b.v)

Investment for this project addresses failed assets, or assets at risk of imminent failure. Investments are not subject to project prioritization as they are reactive and non-discretionary.

Like-for-Like Renewal Analysis (5.4.5.2.C.b.vi)

Assets replaced reactively to replace failed assets, or assets at risk of imminent failure are performed on a like-for-like basis. No extra costs to address other distributor planning objectives are incurred with these projects.

Capital Project Summary

General Information on Project (5.4.5.2.A)

Project Name	2019 Hamilton Mountain XLPE Renewal
Budget Year	2019
Investment Category	System Renewal
Project Summary	Renewal of end-of-life XLPE cable assets in the Hamilton Mountain area.

Capital Investment (5.4.5.2.A.i)	Capital Investment (gross)	$3,473,233
	Customer Contribution	$0
	Capital Investment (net)	$3,473,233
	O&M Expenditure	$0

Customer Attachments / Load (kVA) (5.4.5.2.A.ii)	The customer and load impacted by this project will vary depending upon the final scope of the project

Project Dates (5.4.5.2.A.iii)

Start Date	2019/01/01
In Service Date	2019/12/31

Expenditure Timing

Q1	Q2	Q3	Q4
25%	25%	25%	25%

Schedule Risk and Risk Mitigation (5.4.5.2.A.iv**)**

Please refer to Note I for risk and risk mitigation.

Comparative Information from Equivalent Projects (5.4.5.2.A.v)

There is no direct comparator in scope, size and design characteristics for this project. This project is part of a multi-year investment to renewal XLPE primary cable. The 2019 investment in the XLPE Renewal Program is $10,271,000.

Comparable gross investments for the XLPE Renewal Program for the 2010 to 2013 Historical Years and the 2014 Bridge Year are:

2010 (CGAAP)- $ 0
2011 (CGAAP)- $ 0
2012 (MIFRS) - $ 0
2013 (MIFRS) - $ 1,572,090
2014 (MIFRS) - $ 893,000

Total Capital OM&A Costs Associated with REG Investments (5.4.5.2.A.vi)

This project is not associated with an REG investment and therefore OM&A costs related to REG will not be incurred.

Leave to Construct Approval (5.4.5.2.A.vii)

This project does not require "Leave to Construct" under Section 92 of the *Ontario Energy Board Act* 1998.

Evaluation Criteria and Information (5.4.5.2.B)	**Project Name** 2019 Hamilton Mountain XLPE Renewal Table 2
	Efficiency, Customer Value, Reliability (5.4.5.2.B.1) **Investment Driver (5.4.5.2.B.1.a)** System Renewal (80%) **Secondary Driver (5.4.5.2.B.1.a)** System Service (20%) **Investment Priority (5.4.5.2.B.1.b)** 5 – Mandatory Project
	Analysis of Project and Project Alternatives (5.4.5.2.B.1.c) This project is part of the multi-year XLPE Renewal Program. Horizon Utilities considered the four replacement philosophies for addressing risk inherent in the XLPE asset group: Area; Reactive; Selected; and Refurbishment. The area replacement philosophy will be utilized for selected areas of the service territory where the asset health analysis and the failure history indicate a substantial risk of continued failures. A reactive replacement philosophy will continued to be used for the remaining areas of the service territory. The area replacement philosophy will be employed for the Hamilton Mountain operating area due to the high volume of XLPE primary cable. 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.
	Safety (5.4.5.2.B.2) These projects are not intended to address safety concerns with the distribution system.
	Cyber-Security and Privacy (5.4.5.2.B.3) (where applicable) n/a
	Co-ordination and Interoperability (5.4.5.2.B.4) **Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.5.2.B.4.a) (where applicable)** Please refer to Note II for an explanation on co-ordination with utilities, regional planning and/or links with 3rd parties. **Enabling of Future Technology and/or Future Operational Requirements (5.4.5.2.B.4.b)** Please refer to Note IV for an explanation enabling of future technology and future operational requirements.
	Economic Development (5.4.5.2.B.5) Horizon Utilities ensures that policies and practices do not unnecessarily create barriers to economic development which are primarily focused within its communities.
	Environmental Benefits (5.4.5.2.B.6) n/a

System Renewal Specific Requirements (5.4.5.2.C.b)

Project Name	2019 Hamilton Mountain XLPE Renewal	Table 3

System Renewal Specific Requirements (5.4.5.2.C.b)

Asset Performance Target and Asset Lifecycle Optimization (5.4.5.2.C.b.i.1)

XLPE primary cable is the asset group with the largest investment requirement as identified by the Kinectrics ACA. 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.

The Hamilton Mountain operating area has 225km of XLPE primary cable with a Health Index of either "very poor" or "poor". 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

Asset Condition Relative to Typical Life Cycle (5.4.5.2.C.b.i.2)

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.

Number of Customers Impacted (5.4.5.2.C.b.i.3)

The customer and load impacted by this project will vary depending upon the final scope of the project.

Quantitative Customer Impact and Risk (5.4.5.2.C.b.i.4)

The qualitative customer varies for customers affected by this project.

Qualitative Customer Impact and Risk (5.4.5.2.C.b.i.5)

This project will address aging assets at risk of failure. Failures of XLPE primary cable result in extended service interruptions; 30% of these outages exceeded four hours in duration, while 5% of these outages exceeded twelve hours in duration.

Value of Customer Impact (5.4.5.2.C.b.i.6)

High

Other Factors Affecting Project Timing (5.4.5.2.C.b.ii)

Proactive replacements are required because, 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 proactive renewal.

Impact on System O&M Costs (5.4.5.2.C.b.iii)

This project will have no material impact on planned O&M costs. The renewal of the XLPE primary cable, as a whole, will provide a reduction in reactive O&M costs to address service interruptions caused by failed equipment. These reductions will not be material in the 2015 to 2019 Test Years.

Reliability and Safety Factors (5.4.5.2.C.b.iv)

The renewal of the XLPE primary cable system will provide reliability improvements through reduced service interruptions caused by failed equipment.

Analysis of Project Benefits and Timing (5.4.5.2.C.b.v)

Failure to invest in the proactive renewal of XLPE primary cable and associated underground assets would result in unacceptable levels of system failures and outages beyond Horizon Utilities' ability to resolve within a reasonable timeframe as these assets continue to age and degrade. Reactive replacements will also be considerably more costly than the forecast expenditure required to execute the proposed proactive replacement.

Like-for-Like Renewal Analysis (5.4.5.2.C.b.vi)

XLPE renewal projects will include: the elimination of radial underground feeds; replacement of below grade transformers with padmount transformers; and the introduction of fusing on the underground distribution systems where applicable.

Capital Project Summary

General Information on Project (5.4.5.2.A)

Project Name	JN-F1 Renewal
Budget Year	2019
Investment Category	System Renewal
Project Summary	This project involves the renewal of 4kV distribution assets on the John F1 feeder as part of the 4kV and 8kV Renewal Program. The assets are located along Hatt St in Dundas.

Capital Investment (5.4.5.2.A.i)		
	Capital Investment (gross)	$5,927,519
	Customer Contribution	$0
	Capital Investment (net)	$5,927,519
	O&M Expenditure	$0

Customer Attachments / Load (kVA) (5.4.5.2.A.ii)

This project will impact 1048 customers and 5000kVA

Project Dates (5.4.5.2.A.iii)

Start Date	2019/02/01
In Service Date	2019/09/30

Expenditure Timing

Q1	Q2	Q3	Q4
15%	40%	45%	0%

Schedule Risk and Risk Mitigation (5.4.5.2.A.iv**)**

Please refer to Note I for risk and risk mitigation.

Comparative Information from Equivalent Projects (5.4.5.2.A.v)

There is no direct comparator in scope, size and design characteristics for this project. This project is one phase of a multi-year investment to renew the area served by John substation as part of the 4kV and 8kV Renewal Program. The 2019 investment for the renewal of John substation is $8,259,000. The 2019 investment in the 4kV and 8kV Renewal Program is $18,846,000.

Comparable gross investments for the 4kV and 8kV Renewal Program for the 2010 and 2013 Historical Years and the 2014 Bridge Year are:

2010 (CGAAP)- $ 2,556,076
2011 (CGAAP)- $ 8,820,000
2012 (MIFRS) - $ 5,268,441
2013 (MIFRS) - $ 5,072,233
2014 (MIFRS) - $ 6,434,000

	Total Capital OM&A Costs Associated with REG Investments (5.4.5.2.A.vi) This project is not associated with an REG investment and therefore OM&A costs related to REG will not be incurred. **Leave to Construct Approval** (5.4.5.2.A.vii) This project does not require "Leave to Construct" under Section 92 of the *Ontario Energy Board Act* 1998.

Evaluation Criteria and Information (5.4.5.2.B)	
	Project Name JN-F1 Renewal Table 2
	Efficiency, Customer Value, Reliability (5.4.5.2.B.1) **Investment Driver (5.4.5.2.B.1.a)** System Renewal (60%) **Secondary Driver (5.4.5.2.B.1.a)** System Service (40%) **Investment Priority (5.4.5.2.B.1.b)** 3 – Required project
	Analysis of Project and Project Alternatives (5.4.5.2.B.1.c) Renewal of assets at 4kV would not allow for the eventual decommissioning of John substation. Horizon Utilities' substation assets are being decommissioned over the life of the 4kV and 8kV Renewal Program to avoid capital investment required for the renewal of substation assets that are nearing the end of their useful lives.
	Safety (5.4.5.2.B.2) This project is not intended to address safety concerns with the distribution system.
	Cyber-Security and Privacy (5.4.5.2.B.3) (where applicable) Cyber-Security and Privacy are not applicable to this project.
	Co-ordination and Interoperability (5.4.5.2.B.4) **Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.5.2.B.4.a) (where applicable)** Please refer to Note II for an explanation on co-ordination with utilities, regional planning and/or links with 3rd parties. **Enabling of Future Technology and/or Future Operational Requirements (5.4.5.2.B.4.b)** Please refer to Note IV for an explanation enabling of future technology and future operational requirements.
	Economic Development (5.4.5.2.B.5) **(where applicable)** Horizon Utilities ensures that policies and practices do not unnecessarily create barriers to economic development which are primarily focused within its communities.

	Environmental Benefits (5.4.5.2.B.6) **(where applicable)** n/a

System Renewal Specific Requirements (5.4.5.2.C.b)	**Project Name**	JN-F1 Renewal	Table 3

System Renewal Specific Requirements (5.4.5.2.C.b)

Asset Performance Target and Asset Lifecycle Optimization (5.4.5.2.C.b.i.1)

The distribution assets in the Dundas operating area are in poor health and have significant operating constraints. 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'.

Asset Condition Relative to Typical Life Cycle (5.4.5.2.C.b.i.2)

Generally the 4kV assets are the oldest vintage in the system. 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.

Number of Customers Impacted (5.4.5.2.C.b.i.3)

This project impacts 745 customers.

Quantitative Customer Impact and Risk (5.4.5.2.C.b.i.4)

SAIDI of 0.025

Qualitative Customer Impact and Risk (5.4.5.2.C.b.i.5)

This project will address aging assets with inadequate backup. Aging assets represent an increased risk of service interruption to customers and inadequate backup would result in long duration service interruptions upon occurrence. These factors would lead to customer dissatisfaction in this area.

Value of Customer Impact (5.4.5.2.C.b.i.6)

High

Other Factors Affecting Project Timing (5.4.5.2.C.b.ii)

The timing of this project is required to co-ordinate with the 4kV and 8kV Renewal Program as involves both the renewal of XLPE primary cable the renewal of the underground section of the John substation F1 feeder. Renewal of this area will allow for the decommissioning of the substation assets by 2019 thereby avoiding the need for capital investment into these substations.

	Impact on System O&M Costs (5.4.5.2.C.b.iii) This project will have no material impact on planned O&M costs. The renewal of the 4kV and 8kV distribution systems, as a whole, will provide a reduction in reactive O&M costs to address service interruptions caused by failed equipment. These reductions will not be material in the 2015 to 2019 Test Years. **Reliability and Safety Factors (5.4.5.2.C.b.iv)** The renewal of the 4kV and 8kV distribution system will provide reliability improvements through reduced service interruptions caused by failed equipment. **Analysis of Project Benefits and Timing (5.4.5.2.C.b.v)** The timing of this project, as part of the 4kV and 8kV Renewal Program, is determined through the assessment of the distribution system health and the health of the substation assets servicing the area. **Like-for-Like Renewal Analysis (5.4.5.2.C.b.vi)** The like-for-like renewal of these assets (i.e. same system configuration and same distribution voltage) will perpetuate the existing operating constraints and require capital investment to renew substation assets. Renewal of the distribution assets at a higher voltage does not involve any material incremental costs over renewal at the existing voltage. Operating constraints (e.g. undersized conductor, radial feeds) are addressed on a case by case basis where appropriate.

Capital Project Summary

General Information on Project (5.4.5.2.A)

Project Name	JN-F2 Renewal
Budget Year	2019
Investment Category	System Renewal
Project Summary	This project involves the renewal of 4kV distribution assets on the John F2 feeder in Dundas as part of the 4kV and 8kV Renewal Plan.

Capital Investment (5.4.5.2.A.i)	Capital Investment (gross)	$2,331,019
	Customer Contribution	$0
	Capital Investment (net)	$2,331,019
	O&M Expenditure	$0

Customer Attachments / Load (kVA) (5.4.5.2.A.ii)	This project will impact approximately 1,048 customers and 5000kVA of transformation

Project Dates (5.4.5.2.A.iii)

Start Date	2019/03/01
In Service Date	2019/09/30

Expenditure Timing

Q1	Q2	Q3	Q4
15%	40%	45%	0%

Schedule Risk and Risk Mitigation (5.4.5.2.A.iv**)**

Please refer to Note I for risk and risk mitigation.

Comparative Information from Equivalent Projects (5.4.5.2.A.v)

There is no direct comparator in scope, size and design characteristics for this project. This project is one phase of a multi-year investment to renew the area served by John substation as part of the 4kV and 8kV Renewal Program. The 2019 investment for the renewal of John substation is $8,259,000. The 2019 investment in the 4kV and 8kV Renewal Program is $18,846,000.

Comparable gross investments for the 4kv and 8kV Renewal Program for the 2010 and 2013 Historical Years and the 2014 Bridge Year are:

2010 (CGAAP)- $ 2,556,076
2011 (CGAAP)- $ 8,820,000
2012 (MIFRS) - $ 5,268,441
2013 (MIFRS) - $ 5,072,233
2014 (MIFRS) - $ 6,434,000

Total Capital OM&A Costs Associated with REG Investments (5.4.5.2.A.vi)

This project is not associated with an REG investment and therefore OM&A costs related to REG will not be incurred.

	Leave to Construct Approval (5.4.5.2.A.vii) This project does not require "Leave to Construct" under Section 92 of the *Ontario Energy Board Act* 1998.

Evaluation Criteria and Information (5.4.5.2.B)			
	Project Name	JN-F2 Renewal	Table 2
	Efficiency, Customer Value, Reliability (5.4.5.2.B.1) **Investment Driver (5.4.5.2.B.1.a)** System Renewal (60%) **Secondary Driver (5.4.5.2.B.1.a)** System Service (40%) **Investment Priority (5.4.5.2.B.1.b)** 3 – Required project		
	Analysis of Project and Project Alternatives (5.4.5.2.B.1.c) Renewal of assets at 4kV would not allow for the eventual decommissioning of John substation. Horizon Utilities' substation assets are being decommissioned over the life of the 4kV and 8kV Renewal Plan to avoid capital investment required for the renewal of substation assets that are nearing the end of their useful lives.		
	Safety (5.4.5.2.B.2) This project is not intended to address safety concerns with the distribution system.		
	Cyber-Security and Privacy (5.4.5.2.B.3) (where applicable) Cyber-Security and Privacy are not applicable to this project.		
	Co-ordination and Interoperability (5.4.5.2.B.4) **Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.5.2.B.4.a) (where applicable)** Please refer to Note II for an explanation on co-ordination with utilities, regional planning and/or links with 3rd parties. **Enabling of Future Technology and/or Future Operational Requirements (5.4.5.2.B.4.b)** Please refer to Note IV for an explanation enabling of future technology and future operational requirements.		
	Economic Development (5.4.5.2.B.5) **(where applicable)** Horizon Utilities ensures that policies and practices do not unnecessarily create barriers to economic development which are primarily focused within its communities.		
	Environmental Benefits (5.4.5.2.B.6) **(where applicable)** n/a		

System Renewal Specific Requirements (5.4.5.2.C.b)

Project Name	JN-F2 Renewal	Table 3

System Renewal Specific Requirements (5.4.5.2.C.b)

Asset Performance Target and Asset Lifecycle Optimization (5.4.5.2.C.b.i.1)

The distribution assets in the Dundas operating area are in poor health and have significant operating constraints. 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’.

Asset Condition Relative to Typical Life Cycle (5.4.5.2.C.b.i.2)

Generally the 4kV assets are the oldest vintage in the system. 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.

Number of Customers Impacted (5.4.5.2.C.b.i.3)

This project impacts approximately 1,048 customers.

Quantitative Customer Impact and Risk (5.4.5.2.C.b.i.4)

SAIDI of 0.036

Qualitative Customer Impact and Risk (5.4.5.2.C.b.i.5)

This project will address aging assets with inadequate backup. Aging assets represent an increased risk of service interruption to customers and inadequate backup would result in long duration service interruptions upon occurrence. These factors would lead to customer dissatisfaction in this area.

Value of Customer Impact (5.4.5.2.C.b.i.6)

High

Other Factors Affecting Project Timing (5.4.5.2.C.b.ii)

The timing of this project is required to co-ordinate with the 4kV and 8kV Renewal Program as involves both the renewal of XLPE primary cable the renewal of the underground section of the John substation F2 feeder. Renewal of this area will allow for the decommissioning of the substation assets by 2019 thereby avoiding the need for capital investment into these substations.

Impact on System O&M Costs (5.4.5.2.C.b.iii)

This project will have no material impact on planned O&M costs. The renewal of the 4kV and 8kV distribution systems, as a whole, will provide a reduction in reactive O&M costs to address service interruptions caused by failed equipment. These reductions will not be material in the 2015 to 2019 Test Years.

Reliability and Safety Factors (5.4.5.2.C.b.iv)

The renewal of the 4kV and 8kV distribution system will provide reliability improvements through reduced service interruptions caused by failed equipment.

Analysis of Project Benefits and Timing (5.4.5.2.C.b.v)

The timing of this project, as part of the 4kV and 8kV Renewal Program, is determined through the assessment of the distribution system health and the health of the substation assets servicing the area.

Like-for-Like Renewal Analysis (5.4.5.2.C.b.vi)

The like-for-like renewal of these assets (i.e. same system configuration and same distribution voltage) will perpetuate the existing operating constraints and require capital investment to renew substation assets. Renewal of the distribution assets at a higher voltage does not involve any material incremental costs over renewal at the existing voltage. Operating constraints (e.g. undersized conductor, radial feeds) are addressed on a case by case basis where appropriate.

Capital Project Summary

General Information on Project (5.4.5.2.A)

Project Name	2019 Pole Residual Replacements
Budget Year	2019
Investment Category	System Renewal
Project Summary	This project involves the replacement of wood poles identified by pole residual testing as having a high risk of failure.

Capital Investment (5.4.5.2.A.i)		
	Capital Investment (gross)	$1,368,894
	Customer Contribution	$0
	Capital Investment (net)	$1,368,894
	O&M Expenditure	$0

Customer Attachments / Load (kVA) (5.4.5.2.A.ii)	n/a
Project Dates (5.4.5.2.A.iii)	Start Date 2019/01/01 In Service Date 2019/06/30

Expenditure Timing

Q1	Q2	Q3	Q4
50%	50%	0%	0%

Schedule Risk and Risk Mitigation (5.4.5.2.A.iv**)**

Please refer to Note I for risk and risk mitigation.

Comparative Information from Equivalent Projects (5.4.5.2.A.v)

Comparable gross investments for the 2010 to 2013 Historical Years and the 2014 Bridge Year are:

2010 (CGAAP)- $ 1,326,407
2011 (CGAAP)- $ 895,000
2012 (MIFRS) - $ 930,000
2013 (MIFRS) - $ 718,074
2014 (MIFRS) - $ 1,190,000

Total Capital OM&A Costs Associated with REG Investments (5.4.5.2.A.vi)

This project is not associated with an REG investment and therefore OM&A costs related to REG will not be incurred.

Leave to Construct Approval (5.4.5.2.A.vii)

This project does not require “Leave to Construct” under Section 92 of the *Ontario Energy Board Act* 1998.

Evaluation Criteria and Information (5.4.5.2.B)

Project Name 2019 Pole Residual Replacements Table 2

Efficiency, Customer Value, Reliability (5.4.5.2.B.1)

Investment Driver (5.4.5.2.B.1.a)
System Renewal (100%)

Secondary Driver (5.4.5.2.B.1.a)
N/A

Investment Priority (5.4.5.2.B.1.b)

5 – Mandatory Project

Analysis of Project and Project Alternatives (5.4.5.2.B.1.c)

The replacement of wood poles in this project is identified through Horizon Utilities' pole testing maintenance program. The pole testing categorized the poles requiring replacement into two categories: 1) requiring immediate replacement; and 2) requiring replacement within five years.

Horizon Utilities replaces poles requiring immediate replacement as soon as possible to mitigate the risk of service interruptions and the risk to public safety resulting from a failure of the pole.

Horizon Utilities replaces poles requiring replacement within five years in the following year. Failure to replace in the following year compounds the volume of work in subsequent years resulting in cascading delays and compounded volumes in subsequent years.

Poles replaced in this project are replaced on a like-for-like basis where possible.

Safety (5.4.5.2.B.2)

This project will address wood poles requiring replacement as identified through testing. Renewal of these assets prior to failure avoids the potential risk to public safety that would result from a failure of a wood pole.

Cyber-Security and Privacy (5.4.5.2.B.3) (where applicable)

Cyber-Security and Privacy are not applicable to this project

Co-ordination and Interoperability (5.4.5.2.B.4)

Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.5.2.B.4.a) (where applicable)

Please refer to Note II for an explanation on co-ordination with utilities, regional planning and/or links with 3rd parties.

Enabling of Future Technology and/or Future Operational Requirements (5.4.5.2.B.4.b)

This is not applicable to this project.

Economic Development (5.4.5.2.B.5) **(where applicable)**

Horizon Utilities ensures that policies and practices do not unnecessarily create barriers to economic development which are primarily focused within its communities.

	Environmental Benefits (5.4.5.2.B.6) **(where applicable)** n/a

System Renewal Specific Requirements (5.4.5.2.C.b)	**Project Name** 2019 Pole Residual Replacements Table 3

System Renewal Specific Requirements (5.4.5.2.C.b)

Asset Performance Target and Asset Lifecycle Optimization (5.4.5.2.C.b.i.1)

This project is reactive in nature the work required is initiated through Horizon Utilities maintenance and inspection programs. This project has a very high probability of impacting Horizon Utilities' reliability targets if the poles are not replaced.

Asset Condition Relative to Typical Life Cycle (5.4.5.2.C.b.i.2)

This project addresses wood poles that have been identified as having a high risk of failure and as such, these assets are at the end of their useful life. The asset condition relative to their typical life cycle varies in case.

Number of Customers Impacted (5.4.5.2.C.b.i.3)

The number of customers impacted varies in each incident or outage.

Quantitative Customer Impact and Risk (5.4.5.2.C.b.i.4)

The quantitative customer impact varies in each incident or outage.

Qualitative Customer Impact and Risk (5.4.5.2.C.b.i.5)

These projects address customer satisfaction as they are required to address assets at risk of failure which would result in a service interruption.

Value of Customer Impact (5.4.5.2.C.b.i.6)

The value of the customer impact varies in each incident or outage.

Other Factors Affecting Project Timing (5.4.5.2.C.b.ii)

These projects are reactive in nature and address assets at risk of failure. Horizon Utilities replaces poles requiring immediate replacement as soon as possible to mitigate the risk of service interruptions and the risk to public safety resulting from a failure of the pole.

Horizon Utilities replaces poles requiring replacement within five years in the following year. Failure to replace in the following year compounds the volume of work in subsequent years resulting in cascading delays and compounded volumes in subsequent years.

Impact on System O&M Costs (5.4.5.2.C.b.iii)

These projects do not materially impact system O&M costs.

Reliability and Safety Factors (5.4.5.2.C.b.iv)

This project will provide reliability and safety benefits as the project involves the replacement of wood poles that are at risk of failure. Failure of the asset would result in a service interruption and a potential risk to public safety.

Analysis of Project Benefits and Timing (5.4.5.2.C.b.v)

n/a

Like-for-Like Renewal Analysis (5.4.5.2.C.b.vi)

Poles replaced in this project are replaced on a like-for-like basis where possible as this presents the lowest cost option. No additional costs are incurred to address other distributor planning objectives.

Capital Project Summary

General Information on Project (5.4.5.2.A)

Project Name	YK-F2 Watsons Lane XLPE Renewal
Budget Year	2019
Investment Category	System Renewal
Project Summary	This project involves the renewal of 4kV XLPE distribution assets on the York F2 feeder as part of the 4kV and 8kV Renewal Program.

Capital Investment (5.4.5.2.A.i)		
	Capital Investment (gross)	$2,216,862
	Customer Contribution	$0
	Capital Investment (net)	$2,216,862
	O&M Expenditure	$0

Customer Attachments / Load (kVA) (5.4.5.2.A.ii)	This project will impact approximately 400 customers and 1000kVA of transformation

Project Dates (5.4.5.2.A.iii)

Start Date	2019/07/01
In Service Date	2019/12/31

Expenditure Timing

Q1	Q2	Q3	Q4
0%	0%	50%	50%

Schedule Risk and Risk Mitigation (5.4.5.2.A.iv**)**

Please refer to Note I for risk and risk mitigation.

Comparative Information from Equivalent Projects (5.4.5.2.A.v)

There is no direct comparator in scope, size and design characteristics for this project. This project supports both the 4kV and 8kV Renewal Program and the XLPE Renewal Program.

Total Capital OM&A Costs Associated with REG Investments (5.4.5.2.A.vi)

This project is not associated with an REG investment and therefore OM&A costs related to REG will not be incurred.

Leave to Construct Approval (5.4.5.2.A.vii)

This project does not require “Leave to Construct” under Section 92 of the *Ontario Energy Board Act* 1998.

Evaluation Criteria and Information (5.4.5.2.B)	**Project Name** YK-F2 Watsons Lane XLPE Renewal Table 2
	Efficiency, Customer Value, Reliability (5.4.5.2.B.1) **Investment Driver (5.4.5.2.B.1.a)** System Renewal (80%) **Secondary Driver (5.4.5.2.B.1.a)** System Service (20%) **Investment Priority (5.4.5.2.B.1.b)** 3 – Required project
	Analysis of Project and Project Alternatives (5.4.5.2.B.1.c) Renewal of assets at 4kV would not allow for the eventual decommissioning of York Substation. Horizon Utilities' substation assets are being decommissioned over the life of the 4kV and 8kV Renewal Program to avoid capital investment required for the renewal of substation assets that are nearing the end of their useful lives.
	Safety (5.4.5.2.B.2) This project is not intended to address safety concerns with the distribution system.
	Cyber-Security and Privacy (5.4.5.2.B.3) (where applicable) Cyber-Security and Privacy are not applicable to this project.
	Co-ordination and Interoperability (5.4.5.2.B.4) **Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.5.2.B.4.a) (where applicable)** Please refer to Note II for an explanation on co-ordination with utilities, regional planning and/or links with 3rd parties. **Enabling of Future Technology and/or Future Operational Requirements (5.4.5.2.B.4.b)** Please refer to Note IV for an explanation enabling of future technology and future operational requirements.
	Economic Development (5.4.5.2.B.5) **(where applicable)** Horizon Utilities ensures that policies and practices do not unnecessarily create barriers to economic development which are primarily focused within its communities.
	Environmental Benefits (5.4.5.2.B.6) **(where applicable)** n/a

Project Name	YK-F2 Watsons Lane XLPE Renewal	Table 3

System Renewal Specific Requirements (5.4.5.2.C.b)

System Renewal Specific Requirements (5.4.5.2.C.b)

Asset Performance Target and Asset Lifecycle Optimization (5.4.5.2.C.b.i.1)

XLPE primary cable is the asset group with the largest investment requirement as identified by the Kinectrics ACA. 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.

The Dundas operating area has 13.5km of XLPE cable with a Health Index of either "very poor" or "poor".

Asset Condition Relative to Typical Life Cycle (5.4.5.2.C.b.i.2)

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. Generally the 4kV assets are of the oldest vintage in the system.

Number of Customers Impacted (5.4.5.2.C.b.i.3)

This project impacts approximately 400 customers.

Quantitative Customer Impact and Risk (5.4.5.2.C.b.i.4)

SAIDI of 0.014

Qualitative Customer Impact and Risk (5.4.5.2.C.b.i.5)

This project will address aging assets with inadequate backup. Aging assets represent an increased risk of service interruption to customers and inadequate backup would result in long duration service interruptions upon occurrence. These factors would lead to customer dissatisfaction in this area.

Value of Customer Impact (5.4.5.2.C.b.i.6)

High

Other Factors Affecting Project Timing (5.4.5.2.C.b.ii)

The timing of this project is required to co-ordinate with the 4kV and 8kV Renewal Program as involves both the renewal of XLPE primary cable the renewal of the underground section of the York substation F2 feeder. Renewal of this area will allow for the decommissioning of the substation assets by 2019 thereby avoiding the need for capital investment into these substations.

Impact on System O&M Costs (5.4.5.2.C.b.iii)

This project will have no material impact on planned O&M costs. The renewal of the 4kV and 8kV distribution systems, as a whole, will provide a reduction in reactive O&M costs to address service interruptions caused by failed equipment. These reductions will not be material in the 2015 to 2019 Test Years.

Reliability and Safety Factors (5.4.5.2.C.b.iv)

The renewal of XLPE primary cable will provide reliability improvements through reduced service interruptions caused by failed equipment. The cable renewed by this project is direct buried and therefore subject to extended outages, requiring multiple hours to repair, upon failure.

Analysis of Project Benefits and Timing (5.4.5.2.C.b.v)

The timing of this project is required to co-ordinate with the 4kV and 8kV Renewal Program as involves both the renewal of XLPE primary cable the renewal of the underground section of the York substation F2 feeder.

Like-for-Like Renewal Analysis (5.4.5.2.C.b.vi)

The like-for-like renewal of these assets (i.e. same system configuration and same distribution voltage) will perpetuate the existing operating constraints and require capital investment to renew substation assets. Renewal of the distribution assets at a higher voltage does not involve any material incremental costs over renewal at the existing voltage. Operating constraints (e.g. undersized conductor, radial feeds) are addressed on a case by case basis where appropriate.

Capital Project Summary

General Information on Project (5.4.5.2.A)

Project Name	2019 St. Catharines XLPE Renewal
Budget Year	2019
Investment Category	System Renewal
Project Summary	This project involves the renewal of direct buried XLPE primary cable in the St. Catharines service territory.

Capital Investment (5.4.5.2.A.i)	Capital Investment (gross)	$4,096,184
	Customer Contribution	$0
	Capital Investment (net)	$4,096,184
	O&M Expenditure	$0

Customer Attachments / Load (kVA) (5.4.5.2.A.ii)	The customer and load impacted by this project will vary depending upon the final scope of the project.

Project Dates (5.4.5.2.A.iii)

Start Date	2019/01/01
In Service Date	2019/12/31

Expenditure Timing

Q1	Q2	Q3	Q4
20%	30%	30%	0%

Schedule Risk and Risk Mitigation (5.4.5.2.A.iv**)**

Please refer to Note I for risk and risk mitigation.

Comparative Information from Equivalent Projects (5.4.5.2.A.v)

There is no direct comparator in scope, size and design characteristics for this project. This project is part of a multi-year investment to renewal XLPE primary cable. The 2019 investment in the XLPE Renewal Program is $10,271,000.

Comparable gross investments for the XLPE Renewal Program for the 2010 to 2013 Historical Year and the 2014 Bridge Year are:

2010 (CGAAP)- $ 0
2011 (CGAAP)- $ 0
2012 (MIFRS) - $ 0
2013 (MIFRS) - $ 1,572,090
2014 (MIFRS) - $ 893,000

Total Capital OM&A Costs Associated with REG Investments (5.4.5.2.A.vi)

This project is not associated with an REG investment and therefore OM&A costs related to REG will not be incurred.

Leave to Construct Approval (5.4.5.2.A.vii)

This project does not require “Leave to Construct” under Section 92 of the *Ontario Energy Board Act* 1998.

Evaluation Criteria and Information (5.4.5.2.B)

Project Name 2019 St. Catharines XLPE Renewal Table 2

Efficiency, Customer Value, Reliability (5.4.5.2.B.1)

Investment Driver (5.4.5.2.B.1.a)
System Renewal (80%)

Secondary Driver (5.4.5.2.B.1.a)
System Service (20%)

Investment Priority (5.4.5.2.B.1.b)
3 – Required project

Analysis of Project and Project Alternatives (5.4.5.2.B.1.c)

This project is part of the multi-year XLPE Renewal Program. Horizon Utilities considered the four replacement philosophies for addressing risk inherent in the XLPE asset group: Area; Reactive; Selected; and Refurbishment. The area replacement philosophy will be utilized for selected areas of the service territory where the asset health analysis and the failure history indicate a substantial risk of continued failures. A reactive replacement philosophy will continued to be used for the remaining areas of the service territory. The St. Catharines operating area contains many small pockets of direct buried XLPE primary cable. The XLPE renewal projects in the St. Catharines operating area will involve the full renewal of each pocket of XLPE cable. Project selection will be guided by asset health, operating history, and reliability of each of the underground pockets of XLPE.

Safety (5.4.5.2.B.2)

These projects are not intended to address safety concerns with the distribution system.

Cyber-Security and Privacy (5.4.5.2.B.3) (where applicable)

Cyber-Security and Privacy are not applicable to this project.

Co-ordination and Interoperability (5.4.5.2.B.4)

Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.5.2.B.4.a) (where applicable)

Please refer to Note II for an explanation on co-ordination with utilities, regional planning and/or links with 3rd parties.

Enabling of Future Technology and/or Future Operational Requirements (5.4.5.2.B.4.b)

Please refer to Note IV for an explanation enabling of future technology and future operational requirements.

Economic Development (5.4.5.2.B.5) **(where applicable)**

Horizon Utilities ensure all policies and practices don’t unnecessarily create barriers to economic development which are primarily focused within our communities.

Environmental Benefits (5.4.5.2.B.6) **(where applicable)**

n/a.

Project Name	2019 St. Catharines XLPE Renewal	Table 3

System Renewal Specific Requirements (5.4.5.2.C.b)

System Renewal Specific Requirements (5.4.5.2.C.b)

Asset Performance Target and Asset Lifecycle Optimization (5.4.5.2.C.b.i.1)

XLPE primary cable is the asset group with the largest investment requirement as identified by the Kinectrics ACA. 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.

Asset Condition Relative to Typical Life Cycle (5.4.5.2.C.b.i.2)

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.

Number of Customers Impacted (5.4.5.2.C.b.i.3)

The number of customers impacted will vary depending upon the area.

Quantitative Customer Impact and Risk (5.4.5.2.C.b.i.4)

The quantitative customer impact varies.

Qualitative Customer Impact and Risk (5.4.5.2.C.b.i.5)

This project will address aging assets at risk of failure. Failures of XLPE primary cable result in extended service interruptions with 30% of these outages exceeded four hours in duration, while 5% of these outages exceeded twelve hours in duration

Value of Customer Impact (5.4.5.2.C.b.i.6)

High

Other Factors Affecting Project Timing (5.4.5.2.C.b.ii)

Proactive replacements are required because, as assets continue to age and degrade, the cable will fail at an exponential rate. In the worst case scenario, it will exceed Horizon Utilities' ability to keep pace with repairs. Reliability will also deteriorate to unacceptable levels. Reactive replacements will be considerably more costly than proactive renewal.

Impact on System O&M Costs (5.4.5.2.C.b.iii)

This project will have no material impact on planned O&M costs. The renewal of the XLPE primary cable, as a whole, will provide a reduction in reactive O&M costs to address service interruptions caused by failed equipment. These reductions will not be material in the 2015 to 2019 Test Years

Reliability and Safety Factors (5.4.5.2.C.b.iv)

The renewal of the XLPE primary cable system will provide reliability improvements through reduced service interruptions caused by failed equipment.

Analysis of Project Benefits and Timing (5.4.5.2.C.b.v)

Failure to invest in the proactive renewal of XLPE primary cable and associated underground assets would result in unacceptable levels of system failures and outages beyond Horizon Utilities' ability to resolve within a reasonable timeframe as these assets continue to age and degrade. Reactive replacements will also be considerably more costly than the forecast expenditure required to execute the proposed proactive replacement.

Like-for-Like Renewal Analysis (5.4.5.2.C.b.vi)

XLPE renewal projects will include: the elimination of radial underground feeds; replacement of below grade transformers with padmount transformers; and the introduction of fusing on the underground distribution systems where applicable.

Capital Project Summary

General Information on Project (5.4.5.2.A)

Project Name	Security – Lake 141X Grays Road			
Budget Year	2019			
Investment Category	System Service			
Project Summary	This project involves upgrading the conductor size of the main trunk line to accommodate a full capacity tie with an adjacent feeder.			
Capital Investment (5.4.5.2.A.i)	Capital Investment (gross)	$412,551		
	Customer Contribution	$0		
	Capital Investment (net)	$412,551		
	O&M Expenditure	$0		
Customer Attachments / Load (kVA) (5.4.5.2.A.ii)	n/a			
Project Dates (5.4.5.2.A.iii)	Start Date	2019/01/01		
	In Service Date	2019/05/01		
	Expenditure Timing			
	Q1	Q2	Q3	Q4
	75%	25%	0%	0%

Schedule Risk and Risk Mitigation (5.4.5.2.A.iv**)**

Please refer to Note I for risk and risk mitigation.

Comparative Information from Equivalent Projects (5.4.5.2.A.v)

There are no equivalent projects for comparison.

Total Capital OM&A Costs Associated with REG Investments (5.4.5.2.A.vi)

This project is not associated with an REG investment and therefore OM&A costs related to REG will not be incurred.

Leave to Construct Approval (5.4.5.2.A.vii)

This project does not require “Leave to Construct” under Section 92 of the *Ontario Energy Board Act* 1998.

Evaluation Criteria and Information (5.4.5.2.B)	**Project Name** Security – Lake 141X Grays Road Table 2
	Efficiency, Customer Value, Reliability (5.4.5.2.B.1) **Investment Driver (5.4.5.2.B.1.a)** System Service (80%) **Secondary Driver (5.4.5.2.B.1.a)** System Renewal (20%) **Investment Priority (5.4.5.2.B.1.b)** 3 – Required project
	Analysis of Project and Project Alternatives (5.4.5.2.B.1.c) No alternatives exist to provide redundancy to this area of Grays Road.
	Safety (5.4.5.2.B.2) These projects are not intended to address safety concerns with the distribution system.
	Cyber-Security and Privacy (5.4.5.2.B.3) (where applicable) Cyber-Security and Privacy are not applicable to this project.
	Co-ordination and Interoperability (5.4.5.2.B.4) **Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.5.2.B.4.a) (where applicable)** Please refer to Note II for an explanation on co-ordination with utilities, regional planning and/or links with 3rd parties. **Enabling of Future Technology and/or Future Operational Requirements (5.4.5.2.B.4.b)** Please refer to Note IV for an explanation enabling of future technology and future operational requirements.
	Economic Development (5.4.5.2.B.5) **(where applicable)** Horizon Utilities ensures that policies and practices do not unnecessarily create barriers to economic development which are primarily focused within its communities.
	Environmental Benefits (5.4.5.2.B.6) **(where applicable)** n/a

System Service Specific Requirements (5.4.5.2.C.c)

Project Name	Security – Lake 141X Grays Road	Table 3

System Service Specific Requirements (5.4.5.2.C.c)

Benefit to Customers (5.4.5.2.C.c.i)

This project will provide redundancy to the customers serviced by this radial fed section of 13.8kV distribution system.

Regional Planning Requirements (5.4.5.2.C.c.i)

n/a

Integration of Advance Technology (5.4.5.2.C.c.iii)

Please refer to Note IV for an explanation enabling of future technology and future operational requirements.

System Benefits to Reliability, Efficiency and Safety (5.4.5.2.C.c.iv)

n/a

Factors Affecting Implementing Timing/Priority (5.4.5.2.C.c.v)

n/a

Summary of Options Analysis (5.4.5.2.C.c.vi)

n/a

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Capital Project Summary

General Information on Project (5.4.5.2.A)

Project Name	Mohawk/Nebo TS Upgrade
Budget Year	2019
Investment Category	System Service
Project Summary	Payment planned for Hydro One to upgrade the capacity at either Mohawk TS or Nebo TS (13.8kV bus) as load forecasts project the loading to encroach on the 10-day LTR rating at these stations in the medium term.

Capital Investment (5.4.5.2.A.i)		
	Capital Investment (gross)	$1,000,000
	Customer Contribution	$0
	Capital Investment (net)	$1,000,000
	O&M Expenditure	$0

Customer Attachments / Load (kVA) (5.4.5.2.A.ii)	n/a

Project Dates (5.4.5.2.A.iii)

Start Date 2019/07/01

In Service Date 2019/08/01

Expenditure Timing			
Q1	Q2	Q3	Q4
0%	0%	100%	0%

Schedule Risk and Risk Mitigation (5.4.5.2.A.iv**)**

Please refer to Note I for risk and risk mitigation.

Comparative Information from Equivalent Projects (5.4.5.2.A.v)

The Nebo TS upgrade was the only comparable project in the 2010 to 2013 Historical Years and the 2014 Bridge Year. The Nebo TS expenditures were:

2010 (CGAAP)- $ 0
2011 (CGAAP)- $ 0
2012 (MIFRS) - $ 970,000
2013 (MIFRS) - $ 1,450,000
2014 (MIFRS) - $ 1,708,000

Total Capital OM&A Costs Associated with REG Investments (5.4.5.2.A.vi)

This project is not associated with an REG investment and therefore OM&A costs related to REG will not be incurred.

Leave to Construct Approval (5.4.5.2.A.vii)

This project does not require “Leave to Construct” under Section 92 of the *Ontario Energy Board Act* 1998.

Evaluation Criteria and Information (5.4.5.2.B)	**Project Name** Mohawk/Nebo TS Upgrade Table 2
	Investment Driver (5.4.5.2.B.1.a) System Service (100%) **Secondary Driver (5.4.5.2.B.1.a)** N/A **Investment Priority (5.4.5.2.B.1.b)** 3 – Required project
	Analysis of Project and Project Alternatives (5.4.5.2.B.1.c) This project is required to address capacity issues in the Hamilton Mountain operating area. There are three Hydro One transformer stations that supply this area and Horizon Utilities will co-ordinate with Hydro One to determine the most appropriate station to upgrade. The loading of each of the existing transformer stations; the area where the load growth is occurring; and the investment required to upgrade each station will be leveraged to determine the best option.
	Safety (5.4.5.2.B.2) This project is not intended to address safety concerns with the distribution system.
	Cyber-Security and Privacy (5.4.5.2.B.3) (where applicable) Cyber-Security and Privacy are not applicable to this project.
	Co-ordination and Interoperability (5.4.5.2.B.4) **Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.5.2.B.4.a) (where applicable)** Please refer to Note II for an explanation on co-ordination with utilities, regional planning and/or links with 3rd parties. **Enabling of Future Technology and/or Future Operational Requirements (5.4.5.2.B.4.b)** Please refer to Note IV for an explanation enabling of future technology and future operational requirements.
	Economic Development (5.4.5.2.B.5) **(where applicable)** Horizon Utilities ensures that policies and practices do not unnecessarily create barriers to economic development which are primarily focused within its communities.
	Environmental Benefits (5.4.5.2.B.6) **(where applicable)** n/a

System Service Specific Requirements (5.4.5.2.C.c)

Project Name	Mohawk/Nebo TS Upgrade	Table 3

System Service Specific Requirements (5.4.5.2.C.c)

Benefit to Customers (5.4.5.2.C.c.i)

This project will allow for continued load growth.

Regional Planning Requirements (5.4.5.2.C.c.i)

This project involves the upgrade of a Hydro One owned TS. Horizon Utilities will co-ordinate the investment requirements with Hydro One.

Integration of Advance Technology (5.4.5.2.C.c.iii)

Please refer to Note IV for an explanation enabling of future technology and future operational requirements.

System Benefits to Reliability, Efficiency and Safety (5.4.5.2.C.c.iv)

n/a

Factors Affecting Implementing Timing/Priority (5.4.5.2.C.c.v)

The timing for this investment will depend upon the timing of Hydro One's upgrade of the station.

Summary of Options Analysis (5.4.5.2.C.c.vi)

n/a

2019 General Plant Investments

Capital Project Summary

Project Name	Annual Corporate Computer Replacement
Budget Year	2019
Investment Category	General Plant
Project Summary	This project is part of an ongoing business requirement to refresh end user computers. Horizon Utilities utilizes a three-year lifecycle for replacement of end user computers. On an annual basis, approximately one third of all Horizon Utilities computers (~150 PCs/year) are replaced.

Capital Investment (5.4.5.2.A.i)	Capital Investment (gross)	$361,200
	Customer Contribution	n/a
	Capital Investment (net)	n/a
	O&M Expenditure	n/a
Customer Attachments / Load (5.4.5.2.A.ii)	n/a	

Project Dates (5.4.5.2.A.iii)

Start Date Jan. 2019

In Service Date Dec. 2019

Expenditure Timing			
Q1	Q2	Q3	Q4
25%	25%	25%	25%

Schedule Risk and Risk Mitigation (5.4.5.2.A.iv)

Schedule - Implementation is phased throughout the year starting in January and ending in December based on age of PCs being replaced.

Risk – The primary risk to this project is product availability from suppliers.
Risk Mitigation – Work closely with suppliers to schedule orders based on required delivery times.

Comparative Information from Equivalent Projects (5.4.5.2.A.v)

Comparable gross investments for the annual corporate computer replacement for the 2010 to 2013 Historical Years and the 2014 Bridge Year are:

2010 (CGAAP)- $ 336,000
2011 (CGAAP)- $ 227,000
2012 (MIFRS) - $ 312,000
2013 (MIFRS) - $ 364,947
2014 (MIFRS) - $ 366,200

Total Capital and OM&A Costs Associated with REG Investments (5.4.5.2.A.vi)
n/a

Leave to Construct Approval (5.4.5.2.A.vii)
n/a

Project Name	2019 Annual Corporate Computer Replacement	Table 2

Evaluation Criteria and Information

Efficiency, Customer Value, Reliability (5.4.5.2.B.1)

Investment Driver (5.4.5.2.B.1.a)
General Plant (100%)

Secondary Driver (5.4.5.2.B.1.a)
n/a

Investment Priority (5.4.5.2.B.1.b)
High Priority – Personal computers are treated as a strategic asset. They are Horizon Utilities' primary staff productivity tool. They are used to: maintain and deliver services to customers; improve staff productivity; cost-effectively manage total cost of PC ownership; and, support investments in new applications, infrastructure and business capabilities

Analysis of Project and Project Alternatives (5.4.5.2.B.1.c)
n/a

Safety (5.4.5.2.B.2)

n/a

Cyber-Security and Privacy (5.4.5.2.B.3) (where applicable)

n/a

Co-ordination and Interoperability (5.4.5.2.B.4)

Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.5.2.B.4.a) (where applicable)
n/a

Enabling of Future Technology and/or Future Operational Requirements (5.4.5.2.B.4.b)

Suppliers of enterprise systems such as, GIS, OMS, SCADA, AMI, and IFS ERP, are constantly upgrading their products to deliver new processes and functionality. As new versions are released up-to-date hardware is required to perform required upgrades to maintain vendor support for the systems.

Economic Development (5.4.5.2.B.5) **(where applicable)**

n/a

Environmental Benefits (5.4.5.2.B.6) **(where applicable)**

n/a

General Plant Specific Requirements	**Project Name** 2019 Annual Corporate Computer Replacement Table 3

General Plant Specific Requirements (5.4.5.2.C.d)

Summary of Qualitative and Quantitative Analysis (5.4.5.2.C.d.i)

n/a

Business Case Justification Documentation (5.4.5.2.C.d.i)

Horizon Utilities' PCs are treated as a strategic asset, because they are the primary staff productivity tool. Horizon Utilities has streamlined its PC lifecycle management processes utilizing a PC refresh cycle of three years, in order to: deliver, maintain and improve services to customers; to improve staff productivity; to cost-effectively manage total cost of PC ownership; and to support investments in new applications, infrastructure and business capabilities.

A three-year PC refresh cycle reduces the total cost of ownership by reducing the number of models of PCs supported, which results in the reduction of the IST service desk effort required to deploy, secure, and manage new systems and applications. The reduction in the number of supported models has allowed Horizon Utilities to introduce mobile computing for remote field workers and to increase the number of supported PCs by over 100 devices since 2011, without an increase in IST service desk support staff.

A refresh lifecycle of three years reduces the likelihood of device failures that lead to a loss of staff productivity and increased IT support effort. Over 50% of Horizon Utilities' staff utilizes a mobile PC (laptop or tablet) in the performance of their daily activities, many in harsh operating environments outside the office, which increases the likelihood of failure due to operating environment and the age of the device.

Horizon Utilities has introduced several new enterprise business and engineering systems to: mitigate business risks related to aging systems (e.g. GIS); improve electricity system operation (i.e. GIS, OMS); and to address end of vendor support for systems (i.e. IFS ERP, Microsoft Windows XP). Maintaining a three-year PC lifecycle refresh program allows Horizon Utilities' to migrate to these applications without a need to make large one-time investments in PCs to meet the minimum operating requirements of new applications.

PCs are the primary productivity tool used by Horizon Utilities' staff. Unreliable and slow PCs impact productivity and customer service.

Minimizing the number of supported models reduces the IST support effort required to manage, order, configure, and deploy PCs and it reduces the total cost of ownership for PCs.

Capital Project Summary

Project Name	Storage Area Network ("SAN") Expansion
Budget Year	2019
Investment Category	General Plant
Project Summary	This is a risk management and sustainment project to ensure adequate data storage capacity for Horizon Utilities at the production data centre in Hamilton and the disaster recovery data centre in St. Catharines. The project involves the expansion of the existing SAN in both the production and disaster recovery data centres.

Capital Investment (5.4.5.2.A.i)		
	Capital Investment (gross)	$300,000
	Customer Contribution	n/a
	Capital Investment (net)	n/a
	O&M Expenditure	n/a

Customer Attachments / Load (5.4.5.2.A.ii)	N/A

Project Dates (5.4.5.2.A.iii)

Start Date	May 2019
In Service Date	June 2019

Expenditure Timing

Q1	Q2	Q3	Q4
0%	100%	0%	0%

Schedule Risk and Risk Mitigation (5.4.5.2.A.iv**)**

Schedule - Implementation June 2019

Risk – The primary risk to this project is product availability from suppliers.

Risk Mitigation – Work closely with suppliers to schedule orders based on required delivery times.

Comparative Information from Equivalent Projects (5.4.5.2.A.v)

There are no comparable projects in scope and nature for comparison.

Total Capital and OM&A Costs Associated with REG Investments (5.4.5.2.A.vi)
n/a

Leave to Construct Approval (5.4.5.2.A.vii)
n/a

Evaluation Criteria and Information	Project Name	Storage Area Network (“SAN”) Expansion	Table 2
	Efficiency, Customer Value, Reliability (5.4.5.2.B.1) **Investment Driver (5.4.5.2.B.1.a)** General Plant (100%) **Secondary Driver (5.4.5.2.B.1.a)** n/a **Investment Priority (5.4.5.2.B.1.b)** High Priority – This is a risk mitigation project to ensure adequate disk storage capacity.		
	Analysis of Project and Project Alternatives (5.4.5.2.B.1.c) n/a		
	Safety (5.4.5.2.B.2) n/a		
	Cyber-Security and Privacy (5.4.5.2.B.3) (where applicable) n/a		
	Co-ordination and Interoperability (5.4.5.2.B.4) **Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.5.2.B.4.a) (where applicable)** n/a **Enabling of Future Technology and/or Future Operational Requirements (5.4.5.2.B.4.b)**		
	Suppliers of enterprise systems such as, GIS, OMS, SCADA, AMI, and IFS ERP, are constantly upgrading their products to deliver new processes and functionality. As new versions are released up-to-date hardware is required to perform required upgrades to maintain vendor support for the systems. **Economic Development** (5.4.5.2.B.5) **(where applicable)**		
	n/a **Environmental Benefits** (5.4.5.2.B.6) **(where applicable)**		

General Plant Specific Requirements

Project Name Storage Area Network ("SAN") Expansion Table 3

General Plant Specific Requirements (5.4.5.2.C.d)

Summary of Qualitative and Quantitative Analysis (5.4.5.2.C.d.i)

N/A

Business Case Justification Documentation (5.4.5.2.C.d.i)

This project is required to support Horizon Utilities' annual data growth rate which, based on historical experience, exceeds 30% per annum. The data growth rate is expected to increase during the 2015-2019 Test Years as new applications such as, GIS and OMS are implemented and operationalized.

This investment in SAN expansion will eliminate risk related to insufficient storage capacity to support day-to-day business operations.

The risk of not proceeding with this project is that Horizon Utilities will not have enough disk storage capacity to sustain its systems environment to meet business requirements.

Capital Project Summary

Project Name	2019 Capital Lease – IBM
Budget Year	2019
Investment Category	General Plant
Project Summary	This project is the end of lease replacement of the IBM iSeries server hardware environment used to run the Daffron Customer Information System (“CIS”) which supports Horizon Utilities’ customer management and meter-to-cash processes. The hardware is a three-year lease with planned renewals in 2016 and 2019. The environment includes a production IBM iSeries server in Hamilton and an identical IBM iSeries server at the Disaster Recovery Data Centre in St. Catharines.

Capital Investment (5.4.5.2.A.i)		
	Capital Investment (gross)	$900,000
	Customer Contribution	n/a
	Capital Investment (net)	n/a
	O&M Expenditure	n/a

Customer Attachments / Load (5.4.5.2.A.ii)	n/a

Project Dates (5.4.5.2.A.iii)

Start Date	January 2019
In Service Date	January 2019

Expenditure Timing			
Q1	Q2	Q3	Q4
100%	0%	0%	0%

Schedule Risk and Risk Mitigation (5.4.5.2.A.iv**)**

Schedule - Implementation January 2019

Risk – The primary risk to this project is product availability from suppliers.

Risk Mitigation – Work closely with suppliers to schedule orders based on required delivery times.

Comparative Information from Equivalent Projects (5.4.5.2.A.v)

There are no comparable projects in scope and nature for comparison.

Total Capital and OM&A Costs Associated with REG Investments (5.4.5.2.A.vi)
n/a

Leave to Construct Approval (5.4.5.2.A.vii)
n/a

Evaluation Criteria and Information	**Project Name** 2019 Capital Lease – IBM Table 2
	Efficiency, Customer Value, Reliability (5.4.5.2.B.1) **Investment Driver (5.4.5.2.B.1.a)** General Plant (100%) **Secondary Driver (5.4.5.2.B.1.a)** n/a **Investment Priority (5.4.5.2.B.1.b)** High Priority – This project is required for the continued operation of Horizon Utilities' CIS system.
	Analysis of Project and Project Alternatives (5.4.5.2.B.1.c) n/a
	Safety (5.4.5.2.B.2) n/a
	Cyber-Security and Privacy (5.4.5.2.B.3) (where applicable) n/a
	Co-ordination and Interoperability (5.4.5.2.B.4) **Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.5.2.B.4.a) (where applicable)** n/a **Enabling of Future Technology and/or Future Operational Requirements (5.4.5.2.B.4.b)**
	n/a **Economic Development** (5.4.5.2.B.5) **(where applicable)**
	n/a **Environmental Benefits** (5.4.5.2.B.6) **(where applicable)** n/a

General Plant Specific Requirements	**Project Name** 2019 Capital Lease – IBM Table 3
	General Plant Specific Requirements (5.4.5.2.C.d) **Summary of Qualitative and Quantitative Analysis (5.4.5.2.C.d.i)** N/A **Business Case Justification Documentation (5.4.5.2.C.d.i)** The IBM iSeries hardware lease will expire December 31, 2015 and December 31, 2018. This environment is required to maintain the continued operation of Horizon Utilities' Daffron CIS system to ensure appropriate technology for the customer management and meter-to-cash processes. Replacement of the IBM iSeries hardware at end-of-life reduces the likelihood of hardware failures that could disrupt normal business operations, impacting Horizon Utilities' ability to: read Smart Meters; bill customers; apply customer payments; manage customer interactions; and, manage customer work orders.

Capital Project Summary

Project Name	2019 Vehicle Replacement
Budget Year	2019
Investment Category	General Plant

Project Summary;

Horizon Utilities has identified a number of current vehicles that required replacement as they have reached end-of-life as per the criteria within Horizon Utilities' Fleet Replacement Plan.

Other expected objectives and outcomes are to:

- Maintain vehicle reliability and availability;
- Reduce fuel consumption;
- Reduce emissions;
- Reduce down time required to conduct maintenance and repairs; and
- Maintain customer response time.

Capital Investment (5.4.5.2.A.i)	Capital Investment (gross)	$785,000
	Customer Contribution	n/a
	Capital Investment (net)	n/a
	O&M Expenditure	n/a
Customer Attachments / Load (5.4.5.2.A.ii)		

Project Dates (5.4.5.2.A.iii)

Start Date	March 2019
In Service Date	December 2019

Expenditure Timing

Q1	Q2	Q1	Q2
0%	0%	50%	50%

Schedule Risk and Risk Mitigation (5.4.5.2.A.iv**)**

Risk – The primary risk to this project is product availability and adherence to delivery schedules from suppliers.

Risk Mitigation – Work closely with suppliers to schedule orders based on required delivery times.

Comparative Information from Equivalent Projects (5.4.5.2.A.v)

Comparable gross investments for vehicle replacements for the 2010 to 2013 Historical Years and the 2014 Bridge Year are:

2010 (CGAAP)- $ 1,590,516
2011 (CGAAP)- $ 1,033,975
2012 (MIFRS) - $ 1,057,410
2013 (MIFRS) - $ 36,365
2014 (MIFRS) - $ 785,000

Total Capital OM&A Costs Associated with REG Investments (5.4.5.2.A.vi)

n/a

Leave to Construct Approval (5.4.5.2.A.vii)
n/a

Evaluation Criteria and Information

Project Name: 2019 Vehicle Replacement — Table 2

Efficiency, Customer Value, Reliability (5.4.5.2.B.1)

Investment Driver (5.4.5.2.B.1.a)

General Plant – 100%

Secondary Driver (5.4.5.2.B.1.a)
n/a

Investment Priority (5.4.5.2.B.1.b)

High

Analysis of Project and Project Alternatives (5.4.5.2.B.1.c)

n/a

Safety (5.4.5.2.B.2)

n/a

Cyber-Security and Privacy (5.4.5.2.B.3) (where applicable)
n/a

Co-ordination and Interoperability (5.4.5.2.B.4)

Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.5.2.B.4.a) (where applicable)

n/a

	Enabling of Future Technology and/or Future Operational Requirements (5.4.5.2.B.4.b) n/a
	Economic Development (5.4.5.2.B.5) (where applicable) n/a **Environmental Benefits (5.4.5.2.B.6) (where applicable)** n/a

General Plant Specific Requirements			
	Project Name	2019 Vehicle Replacement	Table 3
	General Plant Specific Requirements (5.4.5.2.C.d) **Summary of Qualitative and Quantitative Analysis** (5.4.5.2.C.d.i) Horizon Utilities uses the data collected from electronic fleet and fuel management system, the Global Positional 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 and vehicle maintenance and repairs activities to determine the maintenance scheduling and vehicles replacements.		
	Business Case Justification Documentation (5.4.5.2.C.d.i) To maintain the quality, reliability and availability of Horizon Utilities' vehicle fleet to Construction and Maintenance, Metering Services and corporate group activities, vehicles are assessed annually based on a replacement criteria matrix defined within the Fleet Replacement Plan. Replacement strategies also ensure that Horizon Utilities maintains safe vehicles for employees, while targeting reduced emissions, as well as reduced fuel, operating and maintenance costs. During the next six years, Horizon Utilities will not be procuring any net new vehicles and instead will focus on the replacement of end of life vehicles. Due to budget mitigation efforts in 2011, 2012, and 2013 a number of vehicles scheduled for replacement were kept in operation and rescheduled for replacement in 2014. It is now critical that these vehicles be replaced as maintenance and repairs costs have increased and the vehicles no longer operate at full capacity, reducing vehicle availability and impacting service delivery. Regular vehicle replacement is necessary to avoid undue vehicle downtime and associated negative impacts to customer response time and employee productivity.		

Capital Project Summary

Project Name	2019 Tools, Shop and Garage Equipment
Budget Year	2019
Investment Category	General Plant

Project Summary
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 where the continued use of such creates health and safety risk.

Capital Investment (5.4.5.2.A.i)	Capital Investment (gross)	$580,600
	Customer Contribution	n/a
	Capital Investment (net)	n/a
	O&M Expenditure	n/a

Customer Attachments / Load (5.4.5.2.A.ii)	n/a
Project Dates (5.4.5.2.A.iii)	Start Date: January 2019 In Service Date: December 2019

Expenditure Timing

Q1	Q2	Q3	Q4
25%	25%	25%	25%

Schedule Risk and Risk Mitigation (5.4.5.2.A.iv**)**

Risk – n/a

Risk Mitigation – n/a

Comparative Information from Equivalent Projects (5.4.5.2.A.v)

n/a

Total Capital OM&A Costs Associated with REG Investments (5.4.5.2.A.vi)
n/a

Leave to Construct Approval (5.4.5.2.A.vii)
n/a

Evaluation Criteria and Information	**Project Name:** 2019 Tools, Shop and Garage Equipment — Table 2
	Efficiency, Customer Value, Reliability (5.4.5.2.B.1) **Investment Driver (5.4.5.2.B.1.a)** General Plant (100%) **Secondary Driver (5.4.5.2.B.1.a)** n/a
	Investment Priority (5.4.5.2.B.1.b) High **Analysis of Project and Project Alternatives (5.4.5.2.B.1.c)** Tools and equipment over $5000 are procured through a competitive process and alternatives are considered at the time of requisition.
	Safety (5.4.5.2.B.2) Tools and equipment meet CSA requirements and are reviewed for conformance to requirements by Horizon Utilities' Tool & Equipment Committee.
	Cyber-Security and Privacy (5.4.5.2.B.3) (where applicable) n/a
	Co-ordination and Interoperability (5.4.5.2.B.4) **Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.5.2.B.4.a) (where applicable)** n/a **Enabling of Future Technology and/or Future Operational Requirements (5.4.5.2.B.4.b)** n/a
	Economic Development (5.4.5.2.B.5) **(where applicable)** n/a
	Environmental Benefits (5.4.5.2.B.6) **(where applicable)** n/a

General Plant Specific Requirements

Project Name	2019 Tools, Shop and Garage Equipment	Table 3

General Plant Specific Requirements (5.4.5.2.C.d)

Su**mmary of Qualitative and Quantitative Analysis (5.4.5.2.C.d.i)**

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

Business Case Justification Documentation (5.4.5.2.C.d.i)

n/a

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Capital Project Summary

Project Name	2019 Facility Renovations – Stoney Creek
Budget Year	2019
Investment Category	General Plant

Project Summary;

The objectives of this project planned for 2019 is to replace end-of-life facilities in the Stoney Creek Service Centre and to support current and planned work force. This project will: enhance the quality of workplaces for employees; reduce safety risks; remove hazardous materials; and improve the use of existing space.

Capital Investment (5.4.5.2.A.i)	Capital Investment (gross)	$1,200,000
	Customer Contribution	n/a
	Capital Investment (net)	n/a
	O&M Expenditure	n/a
Customer Attachments / Load (5.4.5.2.A.ii)	n/a	

Project Dates (5.4.5.2.A.iii)

Start Date	March 2019
In Service Date	December 2019

Expenditure Timing

Q1	Q2	Q1	Q2
10%	30%	30%	30%

Schedule Risk and Risk Mitigation (5.4.5.2.A.iv**)**

Project timelines and costs exceeding the budget are risks. The project manager will report regularly on project timelines and adherence to budget and escalates issues for resolution.

Comparative Information from Equivalent Projects (5.4.5.2.A.v)

Comparable gross investments for building renovations for the 2010 to 2013 Historical Years and the 2014 Bridge Year are:

2010 (CGAAP)- $ 0
2011 (CGAAP)- $ 0
2012 (MIFRS) - $ 1,767,000
2013 (MIFRS) - $ 5,490,000
2014 (MIFRS) - $ 3,700,000

Total Capital OM&A Costs Associated with REG Investments (5.4.5.2.A.vi)

n/a

	Leave to Construct Approval (5.4.5.2.A.vii) n/a

Evaluation Criteria and Information	**Project Name:**	2019 Facility Renovations – Stoney Creek	Table 2
	Efficiency, Customer Value, Reliability (5.4.5.2.B.1) **Investment Driver (5.4.5.2.B.1.a)** General Plant – 100% **Secondary Driver (5.4.5.2.B.1.a)** n/a **Investment Priority (5.4.5.2.B.1.b)** High		
	Analysis of Project and Project Alternatives (5.4.5.2.B.1.c) Horizon Utilities' building renovation plans were developed through a facilities planning process that utilized the outputs of a space planning study and multiple building assessments. **Safety** (5.4.5.2.B.2)		
	n/a **Cyber-Security and Privacy (5.4.5.2.B.3) (where applicable)**		
	n/a **Co-ordination and Interoperability** (5.4.5.2.B.4)		
	Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.5.2.B.4.a) (where applicable) n/a **Enabling of Future Technology and/or Future Operational Requirements (5.4.5.2.B.4.b)** n/a **Economic Development** (5.4.5.2.B.5)		
	n/a **Environmental Benefits** (5.4.5.2.B.6)		
	n/a		

General Plant Specific Requirements

Project Name	2019 Facility Renovations – Stoney Creek	Table 3

General Plant Specific Requirements (5.4.5.2.C.d)

Summary of Qualitative and Quantitative Analysis (5.4.5.2.C.d.i)

Space Study and the Building Conditioning Assessment

Business Case Justification Documentation (5.4.5.2.C.d.i)

The Stoney Creek Service Centre is a centralized trades training location for Horizon Utilities and a satellite office for Utility Operations. The project will include the renovation of the locker, washroom, and shower space, and it will replace end-of-life plumbing, lighting, HVAC, and fire and life support systems. These renovations will support the needs of the current and future workforces, and improve employee safety.

Material Investments- Notes Referenced in Project Summary Sheets

Horizon Utilities references each requirement listed in the Material Investments section (5.4.5.2) of the Chapter Five Requirements in the Capital Project Summary sheets. Each Project Summary Sheet is organized to follow the structure set out in that section.

In order to organize information into the Capital Project Summary Sheets, without unnecessary duplication, the following summaries have been included and are referenced in the Project Summary Sheets. These summaries should be read in conjunction with each Project Summary Sheet.

I. Schedule Risk and Risk Mitigation (5.4.5.2.A.iv, 5.4.5.2.C.a.iii, 5.4.5.2.C.a.iv)

Horizon Utilities considers the following as general risks to project schedule and cost:

a. Customer delays or restricted access to work sites
b. Inclement weather, either in the form of extreme temperatures or due to restoration activities following major storms.
c. Delays to material shipment from vendors
d. General unforeseen delays such as striking rock when digging, tree conservation, municipal/regional consent forms.

Horizon Utilities has utilized coordination with 3rd parties to mitigate some of the issues where possible, with municipalities/region/suppliers/customers. Horizon Utilities has implemented a Planning and Scheduling solution (refer to DSP section 1.3, Planning and Implementation) to track projects and resources. The Planning and Scheduling process allows Horizon Utilities to manage schedule and cost risks and improve the overall efficiency of implementation. Horizon Utilities is able to reduce controllable cost impacts on the project due to these risk mitigation strategies.

II. Coordination, Interoperability (5.4.5.2.B.4.a)

Horizon Utilities constructs all new projects using approved construction standards complying with ESA Regulation 22/04. Horizon Utilities participates in regional planning, both at an infrastructure level with local municipalities and regions, as well as at an electrical infrastructure level with Hydro One and other participants in the Regional Planning Process. Horizon Utilities has also been active with neighbouring utilities in trying to resolve Long-Term Load Transfers (“LTLT”). Horizon Utilities also attends Public Utility Coordinating Committee (“PUCC”) meetings which allows for the coordination and planning of investments with other utilities who provide: cable TV; internet; telephone; and natural gas services.

III. Efficiency, Customer Value, and Reliability (5.4.5.2.B.1.c), and Analysis of Project and Project Alternatives for Customer Connections Projects (5.4.5.2.C.c.vi and vii)

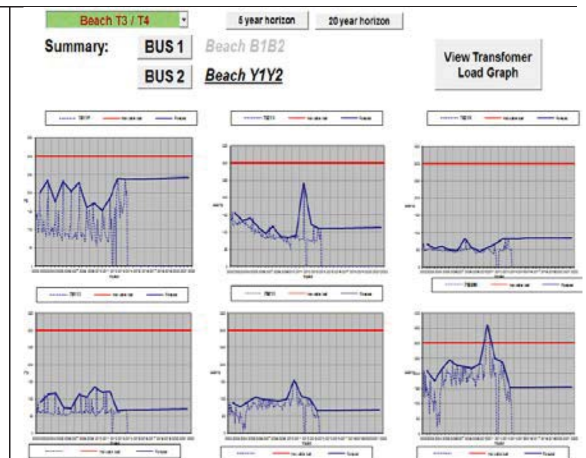
Customer connection projects are driven by customer requests and the customer's specific technical requirements. Horizon Utilities utilizes a set of design standards that have been engineered and approved in order to build efficiencies into the process. Customer connections requests are fulfilled consistent with Horizon Utilities' Conditions of Service. The projects are designed to meet the customer requirements and maintain system reliability.

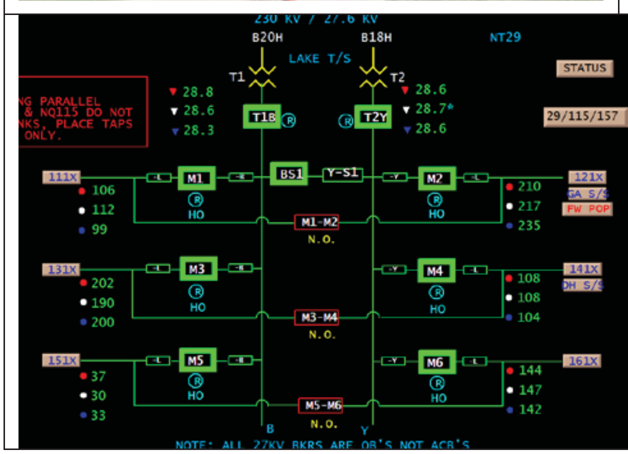
IV. Enabling of future technology and future operational requirements (5.4.5.2.B.4.b, 5.4.5.2.C.c.iii)

Horizon Utilities designs projects according to the life expectancy of the assets being installed. The use of new technology for immediate system benefit, or enabling the future use of new technology is factored into the project design. Marginal additional costs are considered against the benefit, and the additional investment will be made where appropriate.

Appendix H – 2013 Long Term Load Forecast Report

2013 Long Term Load Forecast Report





Prepared By: Networks

Date: Nov 12, 2013

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Executive Summary

This report is a summary of distribution forecast planning performed by Horizon Utilities staff to date. The report includes an enhanced long term load forecast generated at the feeder level. Future capacity requirements are based on customer information and a new growth rate determination of 0.25%, unless otherwise specified.

The data is used to perform the capacity analysis at all voltage levels of the Horizon distribution system. It breaks down the analysis at a station and feeder level. At a station level it highlights such issues as Carlton, Horning, Mohawk and Nebo TS running near Limited Time Rating (LTR), which have action plans to resolve the issues.

As listed in the feeder analysis section, feeders that have exceeded 85% loading are identified so that new loads planned for these feeders can be flagged for more intensive investigation.

A summary of constraints on the system, either Bus or Feeder related, is compiled in section 4.0 for quick reference. As well, a listing of underutilized feeders has been added this year, in section 4.1.

Contents

Introduction:

This report is provided to outline Horizon Utilities Corporation's Long Term Load Forecast, and station and feeder capacity analysis. The load forecast is based on over ten years of reliable data gathered by the Networks department. The load forecast is used to determine station and feeder capacity and security needs in both the short and long term.

Issues arising from the station and feeder analysis are highlighted for information purposes. The severity of the issues varies, and thus, subsequent examination is necessary to determine appropriate solutions.

The report is broken down into four sections, the first being the load forecast, the second station analysis, followed by the feeder analysis and lastly a summary of the load forecast spreadsheets.

1.0 Load Forecast (13-27kV):

The long term load forecast is based on six years of reliable data and projected capacity requirements from customers and community growth. In the following two subsections all assumptions used in forecasting demand are listed along with explanation. Included in the report is a:

- 15 year load forecast summary at the bus level for all stations with voltage levels above 4kV (see *Appendix 1*)
- A 5 year and 25 year load forecast at the feeder level and a 34 year bus level forecast can be found on the Horizon corporate server under: V:\Planning\Planning_Forecasts\

Municipal substations are not detailed in this forecast as they are all supplied from either the 13.8kV or 27.6kV Transformer Station feeders, and therefore contribute to the load forecast at that level.

1.1 Assumptions:

- *A general load growth of 0.25% was assumed across all feeders*

  A conservative 0.25% growth factor was applied to all feeders, as the general trend across the system was a gradual decline in loading over the last couple of years. Likely some of the Conservation and Demand Management (CDM) effects are beginning to be realized across the service territory. There has also been some recovery on feeders serving mainly industrial loads back to pre-2009 recession levels.

  It is unclear what the ultimate saturation point for CDM effects will be. As such, the growth rate should be reviewed again in 2 years to determine if this downward trend in loading continues.

- *The load forecast is not weather corrected/normalized*

  It is unclear if Horizon has all the information necessary to generate a weather corrected trend as it has never been performed by the Networks group in previous years. If a normalizing process can be developed then further enhancement would be required to allow the load forecast to utilize this tool.

- *All previously existing feeder demand projects have been accounted for*

  Any project listed since the completion of the previous Load Forecast Report in 2011 was assumed completed unless specifically informed otherwise.

- *The load forecast is based on feeder level growth*

  The load forecast is prepared at a feeder level (based on monthly peak loads) and totalized at the bus level in the 15 year summary in this report. As listed in the introduction, feeder level forecasts are located in the planning folder on Horizon's network

- *Customer-driven projects and projected community growth were added to specific feeders based on information provided to Horizon for forecasted spot load growth*

A list of known customer projects were accounted for, the list includes;

[redacted]

- Caroline/George St developments

[redacted]

- Various Customer Connections' department projects that exceed 1MVA

In addition, information provided to Horizon from the City of Hamilton regarding residential and commercial growth in certain areas was included in the forecast. Those areas include:

- Ancillary commercial development around the Niagara Regional Hospital
- Summit Park Subdivision
- Upper Centennial area development
- Rymal area bounded by Upper Paradise and Garth
- Isaac Brock and Highbury area
- Waterdown east area, south of Highway #5
- Waterdown west Parkside Drive area
- Rymal and Stonechurch area bounded by West 5th and Garth streets
- Glen Morris Rd area

Residential subdivision developments are accounted in the load forecast by including the planned load and applying a diversity factor of 50%. This diversity factor is derived based on typical loading on transformers in existing comparable subdivisions.

Large generation projects that have a confirmed in-service date are included in the forecast. No new generation projects have been confirmed as of the writing of this report, although several sites are being considered in Horizon's service territory.

- *Existing Generating stations have been removed from the load forecast*

Customer Information System data was used to determine the generation capacity and remove the effects of generation from the load forecast to give an accurate value of the actual load on the feeders. The generating stations include:

[redacted]

2.0 Station Level Capacity Analysis

The charts included in *Appendix 1* provide the station bus level loading forecasts and compare it the 10-day station Limited Time Rating (LTR) stipulated by Hydro One. This value represents the maximum capacity of the station in an (N-1) contingency situation (loss of a single station transformer) and is the indicator of station-level security. A brief explanation for each station is discussed in section 2.1.

Examination has not been performed with regard to the ability of all loads from each transformer station to be transferred to another station at peak load conditions in the event of loss of the complete station (N-2 contingency).

Section 2.2 lists 4 and 8kV Municipal substations with analysis on the capacity at each, corresponding to the charts provided in *Appendix 2*. Stations which have security concerns in the event of loss of the station transformer are explained in further detail in this section.

2.1 Station Capacity Analysis – 27.6kV & 13.8kV

The following section highlights the stations loading, with further explanation on those that are running above the Hydro One provided LTR.

Beach TS:
Beach TS serves mainly industrial customers, typically with direct feeds from the breakers. Generally the capacity is sufficient on the B1B2, Q1Q2, and J1J2 busses. Beach Y1Y2 bus exceeded the LTR in 2010 but has dropped back below the threshold in 2011 and dropped even further in 2012.

Birmingham TS:
Birmingham TS serves mainly industrial customers [redacted], typically with direct feeds from the breakers. Generally the capacity is sufficient on all busses at Birmingham, and actually the load has been decreasing over the last couple of years, largely in part due to the economic downturn.

Dundas TS:
Dundas TS serves primarily residential customers in the Dundas, Ancaster, Flamborough, and Waterdown areas. There aren't any bus level capacity issues at Dundas TS, nor are any expected as this TS saw capacity upgrades in 2002.

Elgin TS:
Elgin TS serves mainly commercial/residential customers in the Hamilton Downtown area as well as some critical large customers, [redacted]. Hydro One has approached Horizon to plan asset renewal at Elgin TS in the near future.

Gage TS:

Gage TS serves mainly industrial customers [redacted] There is capacity available on Gage TS as the economic downturn has reduced the load consumption at these industrial customers. Gage TS is in the midst of a renewal project by Hydro One to replace aging assets and consolidate busses to reflect the diminished loading and to achieve better utilization of assets.

Horning TS:

Horning TS serves mainly residential customers in the West Mountain area in Hamilton. There are also some large loads planned for this station in the near term, including the new Center for Mountain Health. The B1B2 bus was loaded to the 10-day LTR rating in 2011, with further capacity issues anticipated in the short term. The Q1Q2 bus has excess capacity available, so the loading issues on the B1B2 bus can be resolved by transferring load from B1B2 to the Q1Q2 bus.

It is important to note that a portion of the excess capacity at Horning TS on the Q1Q2 bus is to be utilized to address capacity issues at both Mohawk TS and Nebo TS (approximately 6MVA from each TS). As such, it will be important to monitor all large projects to be connected at Horning TS in the future to ensure that reserve capacity does not get used up elsewhere. A long term plan is to re-align the boundaries of the 3 territories served by the TS's on the Hamilton mountain to balance the loading issues.

Kenilworth TS:

Kenilworth TS serves mainly industrial customers [redacted] on the DK and B1Y1 busses, and is split residential/industrial on the EJ bus [redacted]orizon Utilities municipal substations). There are no capacity issues at Kenilworth TS.

Lake TS:

Lake TS serves mainly residential/commercial customers [redacted] in the Stoney Creek area. There are no capacity issues at Lake TS expected in the near term.

Mohawk TS:

Mohawk TS serves mainly residential/commercial customers [redacted]orizon Utilities municipal substations) in the Central Mountain area in Hamilton. Mohawk TS has been identified in past reports as having capacity issues and they still persist, but load has gradually decreased over the last few years. The option to upgrade at Mohawk TS is a difficult proposition due to the configuration of the station, so the only way to increase capacity in the short term is to transfer load to adjacent stations.

As mentioned in the Horning TS section, the Planning department is investigating options to transfer approximately 6 MVA of load from Mohawk TS to Horning TS. There is some urgency to address this transfer in the short term as the Mohawk Y1Y2 bus has been operating above the LTR rating in three of the last five years. Accomplishing this transfer would defer the need to address capacity issues at Mohawk TS for the foreseeable future.

Nebo TS:
Nebo TS serves mainly residential/commercial customers (Horizon Utiltiies municipal substations, [redacted]) in the East Mountain area of Hamilton and the Stoney Creek Mountain. Nebo TS has been identified in past reports as having capacity issues and they still persist on the QJ bus. The Nebo BY bus serves the Stoney Creek Mountain at 27kV, and shares the station with Hydro One Distribution. This area is the primary region experiencing growth in Horizon's service territory. As of the writing of this report, the upgrades to the Nebo BY bus are virtually complete with Horizon gaining ~17 MVA of capacity and 2 new breaker positions.

The Nebo QJ bus (13kV) is also forecast to encroach on the 10-day LTR limit in the short term and as mentioned in the Horning TS section, the Planning department is investigating options to transfer approximately 6 MVA of load from the Nebo QJ bus to Horning TS. Accomplishing this transfer would defer the need to address capacity issues at Nebo TS on the QJ bus for the foreseeable future.

Newton TS:
Newton TS serves mainly residential/commercial customers (Horizon Utilities municipal [redacted]) in the West Hamilton area. No capacity issues are forecasted at Newton TS in the near term.

Stirton TS:
Stirton TS serves mainly residential/industrial customers (Horizon Utilities municipal substations [redacted]) in the Central Hamilton area. There are no capacity issues at Stirton TS.

Winona TS:
Winona TS serves mainly residential/commercial customers at 27kV in the Stoney Creek area below the escarpment. Winona TS came into service in 2002 and has not seen the amount of growth anticipated when the TS was planned. The capacity issue at Winona TS is to transfer load *to* the station. One plan being investigated is to transfer the rural load on the Stoney Creek mountain from the constrained Nebo BY bus to Winona TS, which could benefit both stations.

Bunting TS:
Bunting TS serves mainly residential/commercial customers ([redacted] Horizon Utilities municipal substation) in the Northeast quadrant [redacted] some generation connected (Rankin Weir 1, Rankin Weir 2). According to the load forecast, the busses are nearing capacity and should be monitored, however the effects of generation will offset some of that load in reality.

Carlton TS:
Carlton TS serves a mix of all customer types (St.Catharines Downtown network, Horizon Utilities municipal substations, [redacted]) in the Northwest quadrant of St.Catharines and also has some generation connected (Heywood generating station).

Carlton QE bus is virtually unused. Carlton HK bus is encroaching on its 10-day LTR rating, and actually exceeded this rating in 2011 and 2012. As outlined in the last Load Forecast, the Carlton BY bus has been operating well above its 10-day LTR rating since 2006, were it not for Heywood G.S. offsetting about 5-6 MVA of load. With Vansickle JQ bus coming online in 2011, plans to transfer load from Carlton TS to Vansickle TS to alleviate some of this capacity constraint have been under construction. Furthermore, significant capital expenditure has been planned to increase the number of ties to feeders on the Carlton BY bus with other stations to further improve the ability to shed load from this bus.

Glendale TS:

Glendale TS serves a mix of all customer types ([redacted]) in the Southeast quadrant of St.Catharines, and also has some generation connected [redacted]). Glendale TS was scheduled for upgrades by Hydro One in late-2013, (revised to 2015 per most recent discussions with Hydro One), to undergo replacement of the existing transformers with larger sized transformers as part of Hydro One's asset renewal program.

Vansickle TS:

Vansickle TS serves mainly residential/commercial customers ([redacted]) in the Southwest quadrant of St.Catharines. The Vansickle JQ bus was placed into service in 2011 to address the capacity constraints at Vansickle TS. Projects are underway to utilize this new capacity to shift loads from the heavily loaded Vansickle BY bus, as well as from Carlton TS. At the time of this report, Hydro One had not yet provided a revised value for the 10-day LTR at Vansickle TS post-upgrade.

2.2 Station Capacity Analysis – 4.16 & 8.32 kV

The following section highlights stations capacity availability when operating at full transformer rating, as well as detailing which stations that would be in jeopardy during a transformer (N-1) contingency situation. Refer to *Appendix 2* for a detailed table indicating the loading of each station. *Note*: the amount of load required to be shed in an (N-1) situation does not take into account feeder security ties with other stations.

Aberdeen MS – 13.3 MVA capacity
Aberdeen MS is a 4kV dual-transformer station. Should one of the transformers fail under peak conditions, no load would need to be shed from the station.

Baldwin MS – 7.5 MVA capacity
Baldwin MS is a 4kV single transformer station. If the station were to lose the transformer under peak conditions, 2.2 MVA would need to be shed from the station.

Bartonville MS – 13.3 MVA capacity
Bartonville MS is a 4kV single transformer station, with the space available to maintain a deployable spare. If the station were to lose the transformer under peak conditions, 4.9 MVA would need to be shed from the station. It is recommended that the existing scrap transformer occupying the spare pad be removed and replaced with a deployable spare kept on-potential at Bartonville MS.

Caroline MS – 10 MVA capacity
Caroline MS is a 4kV dual-transformer station. If the station were to lose the transformer under peak conditions, no load would need to be shed from the station. Caroline MS is planned to be decommissioned in 2014, therefore no further investment need be considered.

Central MS – 26.7 MVA capacity
Central MS is a 4kV dual-transformer station. If the station were to lose a transformer under peak conditions, no load would need to be shed from the station.

Cope MS – 20.0 MVA capacity
Cope MS is a 4kV three-transformer station. If the station were to lose a transformer under peak conditions, no load would need to be shed from the station.

Deerhurst MS – 7.5 MVA capacity
Deerhurst MS is an 8kV single transformer station. If the station were to lose the transformer under peak conditions, 0.8 MVA would need to be shed from the station.

Dewitt MS – 5.0 MVA capacity
Dewitt MS is an 8kV single transformer station. If the station were to lose the transformer under peak conditions, 0.8 MVA would need to be shed from the station.

Eastmount MS – 26.7 MVA capacity
Eastmount MS is a 4kV four-transformer station. If the station were to lose another transformer under peak conditions, no load would need to be shed from the station.

Elmwood MS – 20.0 MVA capacity
Elmwood MS is a 4kV three-transformer station. If the station were to lose a transformer under peak conditions, no load would need to be shed from the station.

Galbraith MS – 5.6 MVA capacity
Galbraith MS is an 8kV single transformer station. If the station were to lose the transformer under peak conditions, 0.8 MVA would need to be shed from the station.

Highland MS – 6.7 MVA capacity
Highland MS is a 4kV single transformer station. If the station were to lose the transformer under peak conditions, 2.3 MVA would need to be shed from the station.

Hughson MS – 20.0 MVA capacity
Hughson MS is a 4kV four-transformer station, operating in an (N-1) situation at present. If the station were to lose another transformer under peak conditions, no load would need to be shed from the station. Hughson MS is planned to be decommissioned in early 2014.

John MS – 6.7 MVA capacity
John MS is a 4kV single transformer station. If the station were to lose the transformer under peak conditions, 2.4 MVA would need to be shed from the station.

Kenilworth MS – 13.3 MVA capacity
Kenilworth MS is a 4kV dual-transformer station. If the station were to lose a transformer under peak conditions, no load would need to be shed from the station.

Mohawk MS – 26.7 MVA capacity
Mohawk MS is a 4kV three-transformer station, with one transformer serving as an on-potential deployable spare. If the station were to lose a transformer under peak conditions, no load would need to be shed from the station.

Mountain MS – 26.7 MVA capacity
Mountain MS is a 4kV three-transformer station, with one transformer serving as an on-potential deployable spare. If the station were to lose a transformer under peak conditions, no load would need to be shed from the station.

Ottawa MS – 20.0 MVA capacity
Ottawa MS is a 4kV three-transformer station. If the station were to lose a transformer under peak conditions, no load would need to be shed from the station.

Parkdale MS – 26.7 MVA capacity
Parkdale MS is a 4kV dual-transformer station, with an off-potential spare stored on one of the pads. If the station were to lose a transformer under peak conditions, no load would need to be shed from the station.

Spadina MS – 13.3 MVA capacity
Spadina MS is now a 4kV dual-transformer station. If the station were to lose a transformer under peak conditions, 0.9 MVA would need to be shed from the station. There is a possibility that a deployable spare could be placed at Spadina MS on-potential in the future, but this would require further investigation into the logistics required to facilitate the spare transformer.

Stroud's Lane MS – 13.3 MVA capacity
Stroud's Lane MS is a 4kV dual-transformer station. If the station were to lose a transformer under peak conditions, no load would need to be shed from the station. However, Stroud's Lane MS is slated to begin conversion in 2014 which will reduce the loading on the station.

Webster MS – Decommissioned
Webster MS conversion was completed in 2010.

Wellington MS – 26.7 MVA capacity
Wellington MS is a 4kV four-transformer station. If the station were to lose a transformer under peak conditions, no load would need to be shed from the station.

Wentworth MS – 20.0 MVA capacity
Wentworth MS is a 4kV four-transformer station, operating in an (N-1) situation at present. If the station were to lose a transformer under peak conditions, no load would need to be shed from the station. Furthermore, two of the three remaining transformers are operating at above 75% loading, with the third transformer loaded to only 33%. Restoring the station back to 4 fully operational transformers is planned for the near term.

Whitney MS – 13.3 MVA capacity
Whitney MS is a 4kV dual-transformer station. If the station were to lose a transformer under peak conditions, no load would need to be shed from the station. However, Whitney MS is slated to begin conversion in 2014 which will reduce the loading on the station.

York MS – 4.0 MVA capacity
York MS is a 4kV single transformer station. There is an on-site spare that is ready for service, but would require approximately 8 hours to connect and energize if the station were to lose the main transformer. York MS has no other ties to other stations.

Grantham MS – 11.0 MVA capacity
Grantham MS is a 4kV dual-transformer station in St.Catharines, which is operating in an (N-1) situation at present as there is no way to operate the tie-breaker without dumping all of the customers on the station first. There is also an issue with the cable feeding the T2 transformer, as the cable is undersized for the load. Under peak conditions, 3.3 MVA would need to be shed from the station. Grantham MS is planned to begin conversion in 2015.

Taylor MS – Decommissioned
Taylor MS conversion was completed in 2013.

Vine MS – 14.2 MVA capacity
Vine MS is a 4kV dual-transformer station in St.Catharines. If the station were to lose a transformer under peak conditions, no load would need to be shed from the station. Vine MS is planned to begin conversion in 2014.

Welland MS – 9.6 MVA capacity
Welland MS is a 4kV three-transformer station in St.Catharines. If the station were to lose the transformer under peak conditions, no load would need to be shed from the station. Welland MS is currently in the process of being converted, with a planned completion date of 2015.

3.0 Feeder Level Capacity Analysis

In 2009 after a preliminary review by Network staff a set of new operating ampacities was assigned to more accurately reflect the de-rating required due to cable heating in duct banks.

These assigned ampacities are based on three factors: the cable specifications and termination, the general infrastructure conditions, and the load on the feeders. An average collection of feeder egress scenarios were used to assume an average system condition. This average system condition was then reviewed in various engineering contexts to determine a new standard operating ampacity. This level would apply for all feeders in the Horizon distribution system based on the type of cable being used.

As indicated previously, the load forecast is prepared on a feeder-by-feeder basis which is then totalized to create the station-by-station forecast discussed earlier. Analysis of capacity and security has also been undertaken at the individual feeder level.

Included below is a summary of ampacity ratings for primary cable (underground) and also conductor (overhead) for reference.

Cable	Ampacity	MVA (4.16kV)	MVA (13.8kV)	MVA (27.6kV)
350 MCM PILC	250A	1.8 MVA	6.0 MVA	N/A
4/0 CU PILC	280*A	2.0 MVA	6.7 MVA	N/A
500 MCM PILC / EPR	300A	2.2 MVA	7.2 MVA	N/A
750 MCM CU XLPE	525A	3.8 MVA	12.5 MVA	N/A
1000 MCM AL XLPE	566**A	N/A	13.5 MVA	27.0 MVA
1500 MCM CU XLPE	800***A	5.8 MVA	19.1 MVA	N/A
Conductor	**Ampacity**	**MVA (4.16kV)**	**MVA (13.8kV)**	**MVA (27.6kV)**
#2 AL ACSR	185A	1.3 MVA	4.4 MVA	8.8 MVA
4/0 CU Aerial	480A	3.5 MVA	11.4 MVA	N/A
336 AL ACSR	530A	3.8 MVA	12.6 MVA	25.3 MVA
556 AL ACSR	730A	5.3 MVA	17.4 MVA	34.9 MVA

** - Note that 4/0 CU does not get used as an egress feeder and therefore is not subject to the same de-rating factors applied to 350 MCM cable.*
*** - Note that the ampacity derived for 1000 MCM 15kV XLPE is only applicable when ‘floating the neutral’ (i.e. grounding the neutral at one end, but not the other). If the neutral is grounded at both ends the ampacity is reduced to 500A.*
**** - Based on the Okonite catalog value for parallel circuits (6 single cables) installed in individual ducts.*

3.1 Constrained Feeder Capacity Analysis

The following section highlights all feeders that have repeatedly experienced a *peak* loading above 85% of their engineering-assigned cable ampacities. These feeders should be highlighted to Planning so as to ensure that further investigation is performed for any new loads proposed on these feeders, and that any required capital work to free up capacity on the feeders is accounted for in the Planning phase.

13.8kV AND 27.6kV TRANSFORMER STATIONS

Beach TS

Q1Q2 Bus:
7311B – 2013 Peak 262A (87% of cable rating)
This feeder serves the Bartonville substation. This circuit likely encroached on the cable ampacity limit due to the various long-term transfers that occurred due to the substation upgrades at neighbouring stations. Loading is likely to reduce in 2014, but this circuit should be reviewed at that time to ensure this expectation holds.

7411X – 2013 Peak 272A (91% of cable rating)
This feeder serves residential customers that have been captured as part of the voltage conversion in the Bartonville/Kenilworth service territory. This circuit is consistently operating with peak loading encroaching on the cable ampacity limits. This circuit may need to be reconfigured in order to be utilized when Bartonville MS undergoes further voltage conversion in the near future in this area.

7441X – 2013 Peak 318A (106% of cable rating)
This feeder serves residential/commercial customers along Parkdale Ave. This circuit should be monitored in 2014 to determine if the peak load continues to encroach on the cable ampacity limits.

J1J2 Bus:
7722X – 2013 Peak 266A (89% of cable rating)
This feeder serves as the primary supply to several industrial customers. This circuit should be monitored in 2014 to determine if the peak load continues to encroach on the cable ampacity limits. It is possible to alleviate the loading problem by switching some of the customers to the alternate supply, which is the Beach 7821X, as this feeder has more capacity available at present. It should also be noted that [redacted] is served on this feeder and are proposing a significant Co-generation facility to displace their load in the near future.

7731X – 2013 Peak 262A (87% of cable rating)
This feeder serves residential and industrial customers along the Eastport Blvd and Beach Blvd areas. This circuit should be monitored in 2014 to determine if the peak load continues to encroach on the cable ampacity limits. The Eastport Blvd industrial park is expected to see some growth over the next few years.

Dundas TS:

JQ Bus:
2D13X – 2013 Peak 481A (85% of cable rating)
This feeder serves residential customers in the Waterdown service territory. This circuit should be monitored in 2014 to determine if the peak load continues to encroach on the cable ampacity limits. It is possible to alleviate the loading problem by transferring some customers to the Dundas 2D12X, which also serves customers in this territory. However, long term plans are to bring another feeder to the area to improve security for the region.

Elgin TS:

QJ Bus:
5231X – 2013 Peak 326A (131% of cable rating)
This feeder serves commercial customers in the Hamilton downtown core. It also functions as the alternate supply to many other customers. This circuit leaves the station as 500 MCM PILC, but transitions to 350 MCM PILC before picking up its load. As a result, the feeder has continually seen overloading. It is recommended that this section of cable be converted to 500 MCM EPR as it presents a major bottleneck in the system for security.

5301X – 2013 Peak 280A (94% of cable rating)
This feeder serves commercial customers in the Hamilton downtown core. It also serves as the alternate supply to many other customers. This circuit should be monitored in 2014 to determine if the peak load continues to encroach on the cable ampacity limits.

Horning TS:

B1B2 Bus:
441X – 2013 Peak 265A (88% of cable rating)
This feeder serves some residential/commercial customers in the West Hamilton Mountain area. This circuit has seen steady growth in loading and has been identified as the supply for a new subdivision, which will push the loading on the feeder even further above the rated ampacity. The Planning group will need to investigate any Capital upgrades required to transfer loads from this feeder to Horning Q1Q2 bus.

491X – 2013 Peak 296A (99% of cable rating)
This feeder serves some residential/commercial customers in the West Hamilton Mountain area. This circuit is being targeted for several large Customer Connection projects at [redacted], which will push the loading on the feeder well above the rated ampacity. The Planning group will need to investigate any Capital upgrades required to transfer loads from this feeder to Horning Q1Q2 bus, if necessary.

4111X – 2013 Peak 272A (91% of cable rating)
This feeder serves some residential/commercial customers in the West Hamilton Mountain area. This circuit should be monitored in 2014 to determine if the peak load continues to approach the cable ampacity limits. The Planning group will need to investigate any Capital upgrades required to transfer loads from this feeder to Horning Q1Q2 bus, if necessary.

Q1Q2 Bus:
4451X – 2013 Peak 289A (96% of cable rating)
This feeder serves some residential/commercial customers in the West Hamilton Mountain area. This circuit has seen steady growth in loading and has been identified as the supply for a new subdivision, which will push the loading on the feeder even further above the rated ampacity. The Planning group will need to investigate any Capital upgrades required to transfer loads from this feeder to other feeders on the Horning Q1Q2 bus.

Lake TS

J1J2 Bus:
1411X – 2013 Peak 295A (98% of cable rating)
This feeder serves commercial customers along Kenora Ave in the East Hamilton area. This circuit should be monitored in 2014 to determine if the peak load continues to encroach on the cable ampacity limits.

1431X – 2013 Peak 285A (95% of cable rating)
This feeder serves residential/commercial customers around Greenhill Ave in the East Hamilton area. This circuit should be monitored in 2014 to determine if the peak load continues to encroach on the cable ampacity limits.

Q1Q2 Bus:
1811X – 2013 Peak 294A (98% of cable rating)
This feeder serves residential/commercial customers around Barton St in Stoney Creek. This circuit should be monitored in 2014 to determine if the peak load continues to encroach on the cable ampacity limits.

1831X – 2013 Peak 284A (95% of cable rating)
This feeder serves residential/commercial customers in along Queenston St in the East Hamilton area. This circuit should be monitored in 2014 to determine if the peak load continues to encroach on the cable ampacity limits.

Mohawk TS

B1B2 Bus:
0611X - 2013 Peak 263A (88% of cable rating)
This feeder serves Mountain Substation. This peak may be a result of the substation upgrades that occurred in 2013, therefore this circuit should be monitored in 2014 to determine if the peak load continues to encroach on the cable ampacity limits.

Y1Y2 Bus:
0731X - 2013 Peak 261A (87% of cable rating)
This feeder serves residential/commercial customers in the Hamilton Central Mountain area and is also the back-up feeder for [redacted]. Plans are underway to alleviate the loading on this feeder by transferring some load to adjacent feeders. This circuit should be monitored in 2014 to determine if the peak load continues to encroach on the cable ampacity limits.

Nebo TS

QJ Bus:
3521X - 2013 Peak 265A (88% of cable rating)
This feeder serves residential/commercial customers in the Hamilton East/Stoney Creek Mountain areas. This circuit should be monitored in 2014 to determine if the peak load continues to encroach on the cable ampacity limits. The Planning group should investigate transferring some loading from the Nebo QJ bus feeders to Horning TS to alleviate the capacity constraints on these feeders.

3621X - 2013 Peak 267A (89% of cable rating)
This feeder serves residential/commercial customers in the Hamilton East/Stoney Creek Mountain areas. This circuit should be monitored in 2014 to determine if the peak load continues to exceed the cable ampacity limits. The Planning group should investigate transferring some loading from the Nebo QJ bus feeders to Horning TS to alleviate the capacity constraints on these feeders.

Newton TS

B Bus:
282X - 2013 Peak 328A (109% of cable rating)
This feeder serves residential/commercial customers in the West Hamilton area. This circuit should be monitored in 2014 to determine if the peak load continues to exceed the cable ampacity limits. The Planning group should investigate the feasibility to transfer some load to the Newton Y bus feeders.

Stirton TS

BY Bus:
8721X - 2013 Peak 285A (114% of cable rating)
This feeder serves residential/commercial customers in the Central Hamilton area. This station has several feeders that egress with 350 MCM PILC cable, including this feeder, which results in a bottleneck in the system. This feeder should be monitored in 2014 to determine if the peak load continues to exceed the cable ampacity limits. The Planning group should investigate the feasibility to remove these bottlenecks in the system to improve security. However, with 8721X the Planning group should also investigate the possibility to transfer part of the load to other feeders.

8831W - 2013 Peak 265A (88% of cable rating)
This feeder serves Wentworth Substation. With the WT-T2 offline, this feeder is carrying more load than originally planned. The Planning group is investigating restoring the WT-T2 to service to alleviate some loading issues in this area at the 4kV level, which would mitigate the loading issue on this feeder as well.

8852X - 2013 Peak 243A (97% of cable rating)
This feeder serves residential/commercial customers in the Central Hamilton area. This station has several feeders that egress with 350 MCM PILC cable, including this feeder, which results in a bottleneck in the system. This feeder should be monitored in 2014 to determine if the peak load continues to exceed the cable ampacity limits. The Planning group should investigate the feasibility to remove these bottlenecks in the system to improve security.

QZ Bus:
8611S - 2013 Peak 262A (87% of cable rating)
This feeder serves residential/commercial customers in the Central Hamilton area. This station has several feeders that egress with 350 MCM PILC cable, this feeder was converted in 2011 to 500 MCM Concentric Neutral cable. This feeder should be monitored in 2012 to determine if the peak load continues to exceed the cable ampacity limits. The Planning group should also investigate the possibility to transfer part of the load from this feeder to other feeders.

8621X - 2013 Peak 220A (88% of cable rating)
This feeder serves [redacted] in the Central Hamilton mountain area. This station has several feeders that egress with 350 MCM PILC cable, including this feeder, which results in a bottleneck in the system. This feeder should be monitored in 2014 to determine if the peak load continues to exceed the cable ampacity limits. The Planning group should investigate the feasibility to remove these bottlenecks in the system to improve security. The Planning group should also investigate the possibility to transfer part of the load from this feeder to other feeders.

Bunting TS

Q1Q2 Bus:
BUM77 - 2013 Peak 495A (87% of cable rating)
This feeder serves residential/commercial customers in the Northeast quadrant of St.Catharines along Vine St. This circuit should be monitored in 2014 to determine if the peak load continues to encroach on the cable ampacity limits.

Carlton TS

BY Bus:
CTM10 - 2013 Peak 679A (129% of cable rating)
This feeder serves residential/commercial customers in the Northwest quadrant of St.Catharines along Ontario St and Lakeshore, and also serves as the primary connection to [redacted]. typically displaces about 250A of load from this feeder, but even taking this amount into account, the feeder is running close to 100% loading under peak conditions. There have been several Capital projects implemented to transfer load from Carlton TS to Vansickle TS in order to alleviate this overload condition. This circuit has seen some reduction in loading since 2011, but should be monitored closely in 2014 to determine if the peak load continues to encroach on the cable ampacity limits. Further planning may be required to shed more load from this feeder as the failure of Heywood G.S. to displace load would severely stress this feeder under peak conditions.

CTM11 - 2013 Peak 553A (105% of cable rating)
This feeder serves residential/commercial customers in the Northwest quadrant of St.Catharines along Geneva St. This circuit should be monitored in 2014 to determine if the peak load continues to exceed the cable ampacity limits.

CTM12 - 2013 Peak 0A (0% of cable rating)
This feeder position is available at Carlton TS on the BY bus, however in addition to the constraints on all of the feeders off the BY bus, there is also bus constraints as the station has exceeded the 10-day LTR rating for the last 8 years. Therefore, before this feeder can be utilized, a significant load will have to be transferred from Carlton TS to an adjoining station, as confirmed in discussions with Hydro One.

CTM21 - 2013 Peak 565A (108% of cable rating)
This feeder serves residential/commercial customers in the Northwest quadrant of St.Catharines along Linwell Rd. This circuit should be monitored in 2014 to determine if the peak load continues to encroach on the cable ampacity limits.

HK Bus:
CTM18 - 2013 Peak 598A (114% of cable rating)
This feeder serves residential/commercial customers in the Northwest quadrant of St.Catharines along Carlton St and Vine Substation. This circuit should be monitored in 2014 to determine if the peak load continues to exceed the cable ampacity limits.

Vansickle TS

BY Bus:
VSM51- 2013 Peak 564A (107% of cable rating)
This feeder serves residential/commercial customers in the Southwest quadrant of St.Catharines along Rykert St. This circuit is undergoing reconfiguration to accept the transfer of significant load from Carlton TS. Once the loading levels are established, the Planning group will have to monitor this situation to make any further changes to re-balance the feeders in the area.

As there are several Capital projects ongoing at Vansickle TS, the Planning group will continue to monitor the Vansickle feeders in 2014 to ensure that the new bus is utilized effectively to distribute the load.

4.16kV AND 8.32kV MUNICIPAL SUBSTATIONS

Aberdeen MS:

AB-2- 2011 Peak 346A (117% of cable rating)

This feeder has peaks above its cable ampacity in July only. However, a monthly peak investigation reveals that this is not an issue that requires a solution as transfer options are available if this feeder requires temporary relief.

Caroline MS:

CA-4- 2011 Peak 293A (98% of cable rating)

This feeder has peaks nearing its cable ampacity in July only. However, a monthly peak investigation reveals that this is not an issue that requires a solution as transfer options are available if this feeder requires temporary relief. Furthermore, Caroline SS is nearing completion of its Voltage Conversion, with an anticipated completion date in early 2014.

Hughson MS:

HU-6- 2011 Peak 313A (104% of cable rating)

This feeder has peaks above its cable ampacity in July only. However, a monthly peak investigation reveals that this is not an issue that requires a solution as transfer options are available if this feeder requires temporary relief. Furthermore, Hughson SS is nearing completion of its Voltage Conversion, with an anticipated completion date in early 2014.

Stroud's Lane MS:

ST-3- 2011 Peak 27A (92% of cable rating)

This feeder has peaks near its cable ampacity in July only. Monthly peak investigation reveals that this is not an issue that requires a solution as transfer options are available if this feeder requires temporary relief, but it should be noted that the transfer options are also constrained feeders. Stroud's Lane MS is scheduled to begin Voltage Conversion in 2013, with loading on this feeder being a priority for the initial stages of conversion.

Wentworth MS:

WT-2- 2011 Peak 264A (88% of cable rating)

This feeder has peaks above its cable ampacity in July only. However, a monthly peak investigation reveals that this is not an issue that requires a solution as transfer options are available if this feeder requires temporary relief.

WT-5- 2011 Peak 272A (91% of cable rating)

This feeder has peaks above its cable ampacity in July only. However, a monthly peak investigation reveals that this is not an issue that requires a solution as transfer options are available if this feeder requires temporary relief.

*4.0 Summa*ry of Constraints on Horizon Distribution System

The following is a list of areas that should be reviewed with Planning due to system capacity constraints (Busses exceeding 85% of LTR, feeders exceeding 85% of feeder ampacity rating).

TS Bus Constraints

Horning B1B2	Mohawk Y1Y2	Carlton BY
Kenilworth EJ	Nebo QJ	Carlton HK

TS Feeder Constraints

Beach 7311B	Horning 4451X	Stirton 8831W
Beach 7411X	Lake 1411X	Stirton 8852X
Beach 7441X	Lake 1431X	Stirton 8611S
Beach 7722X	Lake 1811X	Stirton 8621X
Beach 7731X	Lake 1831X	
Dundas 2D13X	Mohawk 0611X	Bunting BUM77
Elgin 5231X	Mohawk 0731X*(Reserved*)*	Carlton CTM18
Elgin 5301X	Nebo 3521X	Carlton CTM10
Horning 441X	Nebo 3621X	Carlton CTM11
Horning 491X	Newton 282X	Carlton CTM21
Horning 4111X	Stirton 8721X	Vansickle VSM51

**Under current configuration, Mohawk 0731X would not adequately provide reserve capacity without shedding load.*

MS Feeder Constraints

Aberdeen AB-2	Hughson HU-6	Wentworth WT-2
Caroline CA-4	Stroud’s Lane ST-3	Wentworth WT-5

4.1 Summary of Capacity available on Horizon Distribution System

The following is a list of areas with excess capacity available (Busses being under 50% of LTR, feeders being under-utilized at 25% rated ampacity of cable or less)

TS Bus Capacity*

Beach B1B2	Gage KE	Winona JQ
Birmingham EZ	Horning Q1Q2	
Dundas BY	Kenilworth DK	Carlton QE
Elgin EZ	Stirton BY	Vansickle JQ
Gage DJ	Stirton QZ	

**does not apply to Distributed Generation*

TS Feeder Capacity Available

Beach 7111SC	Elgin 5251X	Stirton 8712W
Beach 7121SC	Elgin 5281X	Stirton 8751WC
Beach 7141F	Elgin 5512HG *(Reserved)*	Stirton 8762G
Beach 7142F	Elgin 5612X	Stirton 8811X
Beach 7211F	Elgin 5632X	Stirton 8821DG
Beach 7212F	Gage M13,M15,M20	Stirton 8832X
Beach 7231SC	Gage M24,M27	Stirton 8842X
Beach 7241SC	Gage M31,M33,M35,M37	Stirton 8862X
Beach 7611X	Gage M34,M36,M38,M40	Stirton 8541X
Beach 7621X	Horning 492X *	Stirton 8542X
Beach 7631X	Horning 4102X *	Stirton 8641S
Beach 7341X	Kenilworth 9361X	Stirton 8642WC
Beach 7711DF	Kenilworth 9281X *	Stirton 8632X
Beach 7712DF	Kenilworth M51	Winona W15X
Beach 7742X	Kenilworth M54	Winona W16X
Beach 7811DF	Kenilworth M61	
Beach 7812X	Kenilworth M64	Bunting BUM57
Beach 7832X	Lake 111X	Bunting BUM81
Birmingham 50L21	Lake 151X	Bunting BUM82
Birmingham 50L22	Lake 1721X	Carlton CTM13
Birmingham 50PG11	Lake 1832X	Carlton CTM14
Birmingham 50PG21	Mohawk 0531X	Carlton CTM15
Birmingham 50X41	Mohawk 0532X	Carlton CTM16
Birmingham 50X42	Mohawk 0641X	Carlton CTMA3 *
Birmingham 50X52	Mohawk 0642X	Carlton CTM12 *
Birmingham 50DC101	Nebo 3531X *	Glendale GLM24
Dundas 2D11X	Newton 231X	Vansickle VSM71 *(Reserved)*
Elgin 5421X	Newton 262X	Vansickle VSM73
Elgin 5422X	Newton 281X	Vansickle VSM82
Elgin 5441X	Newton 242X	Vansickle VSM83
Elgin 5471X *(Reserved)*	Stirton 8711X	

**Capacity available on feeder however bus is constrained*

MS Feeder Capacity Available

Bartonville BA-3	Parkdale PA-8	York YK-2
Central CE-5	Stroud's Lane ST-4	Deerhurst DH-1
Central CE-6	Wellington WL-6	Deerhurst DH-2
Central CE-9	Wentworth WT-8	Deerhurst DH-3
Kenilworth KE-5	Wentworth WT-11	Galbraith GA-1
Mohawk MK-5	Wentworth WT-12	Galbraith GA-3
Mountain MT-11	Whitney WH-4	Dewitt DW-1
Ottawa OT-6	John JN-2	Dewitt DW-2
Parkdale PA-7	York YK-1	Dewitt DW-3

5.0 Attached Appendices

See attached

HORIZON UTILITIES 25 YEAR LOAD FORECAST SUMMARY

Hydro One Supply Bus		Actual										Forecast																		
		2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Beach B1B2	MVA	48.9	28.0	28.4	18.6	17.4	19.2	18.6	16.7	18.7	10.6	10.7	10.7	10.7	10.7	10.8	10.8	10.8	10.9	10.9	10.9	10.9	11.0	11.0	11.0	11.0	11.1	11.1	11.1	11.2
	10 day LTR	38.5	38.5	38.5	38.5	38.5	38.5	38.5	38.5	38.5	38.5	38.5	38.5	38.5	38.5	38.5	38.5	38.5	38.5	38.5	38.5	38.5	38.5	38.5	38.5	38.5	38.5	38.5	38.5	38.5
	Ratio of 10 day LTR	1.27	0.73	0.74	0.48	0.45	0.50	0.48	0.43	0.49	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.29	0.29	0.29	0.29	0.29	0.29	0.29
	MVA LAR	10.4																												
Beach Y1Y2	MVA	24.8	27.5	33.5	35.2	30.3	28.0	43.4	35.1	27.8	27.5	27.5	27.6	27.7	27.7	27.8	27.9	28.0	28.0	28.1	28.2	28.2	28.3	28.4	28.5	28.5	28.6	28.7	28.7	28.8
	10 day LTR	38.5	38.5	38.5	38.5	38.5	38.5	38.5	38.5	38.5	38.5	38.5	38.5	38.5	38.5	38.5	38.5	38.5	38.5	38.5	38.5	38.5	38.5	38.5	38.5	38.5	38.5	38.5	38.5	38.5
	Ratio of 10 day LTR	0.64	0.71	0.87	0.91	0.79	0.73	1.13	0.91	0.72	0.71	0.72	0.72	0.72	0.72	0.72	0.72	0.73	0.73	0.73	0.73	0.73	0.74	0.74	0.74	0.74	0.74	0.74	0.75	0.75
	MVA LAR							4.9																						
Beach Q1Q2	MVA	32.7	34.5	32.8	32.9	34.7	27.3	36.8	33.0	37.9	38.3	38.4	38.5	38.6	38.7	38.8	38.9	39.0	39.1	39.2	39.3	39.4	39.5	39.6	39.7	39.8	39.9	40.0	40.1	40.2
	10 day LTR	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0
	Ratio of 10 day LTR	0.64	0.68	0.64	0.65	0.68	0.54	0.72	0.65	0.74	0.75	0.75	0.76	0.76	0.76	0.76	0.76	0.77	0.77	0.77	0.77	0.77	0.77	0.78	0.78	0.78	0.78	0.78	0.79	0.79
	MVA LAR																													
Beach J1J2	MVA	23.5	24.8	27.6	29.1	29.5	28.5	43.8	30.6	29.4	34.1	34.2	34.3	34.4	34.5	34.6	34.7	34.7	34.8	34.9	35.0	35.1	35.2	35.3	35.4	35.4	35.5	35.6	35.7	35.8
	10 day LTR	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0
	Ratio of 10 day LTR	0.46	0.49	0.54	0.57	0.58	0.56	0.86	0.60	0.58	0.67	0.67	0.67	0.67	0.68	0.68	0.68	0.68	0.68	0.68	0.69	0.69	0.69	0.69	0.69	0.70	0.70	0.70	0.70	0.70
	MVA LAR																													
Birmingham BY	MVA	38.1	38.1	33.7	35.6	35.9	13.7	14.0	13.2	14.0	32.4	32.5	32.6	32.7	32.8	32.8	32.9	33.0	33.1	33.2	33.2	33.3	33.4	33.5	33.6	33.7	33.7	33.8	33.9	34.0
	10 day LTR	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0
	Ratio of 10 day LTR	0.91	0.91	0.80	0.85	0.85	0.33	0.33	0.31	0.33	0.77	0.77	0.78	0.78	0.78	0.78	0.78	0.79	0.79	0.79	0.79	0.79	0.80	0.80	0.80	0.80	0.80	0.81	0.81	0.81
	MVA LAR																													
Birmingham QJ	MVA	25.5	24.1	23.0	22.5	21.8	20.8	26.0	23.4	21.3	21.8	21.9	22.0	22.0	22.1	22.1	22.2	22.2	22.3	22.3	22.4	22.5	22.5	22.6	22.6	22.7	22.7	22.8	22.8	22.9
	10 day LTR	40.9	40.9	40.9	40.9	40.9	40.9	40.9	40.9	40.9	40.9	40.9	40.9	40.9	40.9	40.9	40.9	40.9	40.9	40.9	40.9	40.9	40.9	40.9	40.9	40.9	40.9	40.9	40.9	40.9
	Ratio of 10 day LTR	0.62	0.59	0.56	0.55	0.53	0.51	0.63	0.57	0.52	0.53	0.54	0.54	0.54	0.54	0.54	0.54	0.54	0.54	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.56	0.56	0.56	0.56
	MVA LAR																													
Birmingham EZ	MVA	28.6	28.6	27.5	28.6	26.7	26.5	33.5	24.9	26.9	20.7	20.7	20.8	20.8	20.9	20.9	21.0	21.0	21.1	21.1	21.2	21.2	21.3	21.3	21.4	21.5	21.5	21.6	21.6	21.7
	10 day LTR	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0
	Ratio of 10 day LTR	0.68	0.68	0.65	0.68	0.64	0.63	0.80	0.59	0.64	0.49	0.49	0.49	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.51	0.51	0.51	0.51	0.51	0.51	0.51	0.51	0.52
	MVA LAR																													
Birmingham DK	MVA	31.9	31.7	32.3	33.8	33.7	34.3	32.9	28.0	32.1	31.9	31.9	32.0	32.1	32.2	32.3	32.4	32.4	32.5	32.6	32.7	32.8	32.8	32.9	33.0	33.1	33.2	33.3	33.3	33.4
	10 day LTR	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0
	Ratio of 10 day LTR	0.71	0.70	0.72	0.75	0.75	0.76	0.73	0.62	0.71	0.71	0.71	0.71	0.71	0.72	0.72	0.72	0.72	0.72	0.72	0.73	0.73	0.73	0.73	0.73	0.74	0.74	0.74	0.74	0.74
	MVA LAR																													
Dundas BY	MVA	32.9	33.9	36.1	33.2	31.8	35.1	39.2	44.0	34.4	34.3	34.4	34.5	34.6	34.7	34.8	34.9	34.9	35.0	35.1	35.2	35.3	35.4	35.5	35.6	35.6	35.7	35.8	35.9	36.0
	10 day LTR	96.0	96.0	96.0	96.0	96.0	96.0	96.0	96.0	96.0	96.0	96.0	96.0	96.0	96.0	96.0	96.0	96.0	96.0	96.0	96.0	96.0	96.0	96.0	96.0	96.0	96.0	96.0	96.0	96.0
	Ratio of 10 day LTR	0.34	0.35	0.38	0.35	0.33	0.37	0.41	0.46	0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.37	0.37	0.37	0.37	0.37	0.37	0.37	0.37	0.37	0.37	0.38
	MVA LAR																													
Dundas JQ	MVA	34.1	38.5	46.0	43.3	42.4	39.4	46.2	49.3	51.5	53.3	54.3	55.3	56.3	57.4	58.4	58.9	59.0	59.2	59.3	59.5	59.6	59.8	59.9	60.1	60.2	60.4	60.5	60.7	60.8
	10 day LTR	96.0	96.0	96.0	96.0	96.0	96.0	96.0	96.0	96.0	96.0	96.0	96.0	96.0	96.0	96.0	96.0	96.0	96.0	96.0	96.0	96.0	96.0	96.0	96.0	96.0	96.0	96.0	96.0	96.0
	Ratio of 10 day LTR	0.36	0.40	0.48	0.45	0.44	0.41	0.48	0.51	0.54	0.56	0.57	0.58	0.59	0.60	0.61	0.61	0.61	0.62	0.62	0.62	0.62	0.62	0.62	0.63	0.63	0.63	0.63	0.63	0.63
	MVA LAR																													
Elgin DK	MVA	30.0	30.4	30.8	29.1	28.4	32.6	43.0	43.1	40.3	34.5	34.6	34.7	34.8	34.9	34.9	35.0	35.1	35.2	35.3	35.4	35.5	35.6	35.6	35.7	35.8	35.9	36.0	36.1	36.2
	10 day LTR	45.8	45.8	45.8	45.8	45.8	45.8	45.8	45.8	45.8	45.8	45.8	45.8	45.8	45.8	45.8	45.8	45.8	45.8	45.8	45.8	45.8	45.8	45.8	45.8	45.8	45.8	45.8	45.8	45.8
	Ratio of 10 day LTR	0.66	0.66	0.67	0.63	0.62	0.71	0.94	0.94	0.88	0.75	0.76	0.76	0.76	0.76	0.76	0.76	0.77	0.77	0.77	0.77	0.77	0.78	0.78	0.78	0.78	0.78	0.79	0.79	0.79
	MVA LAR																													
Elgin QJ	MVA	30.7	31.7	33.3	32.7	32.0	34.3	40.0	39.8	36.5	33.5	35.3	37.1	37.2	37.3	37.4	37.5	37.6	37.7	37.8	37.9	38.0	38.1	38.2	38.3	38.4	38.5	38.6	38.7	38.8
	10 day LTR	45.8	45.8	45.8	45.8	45.8	45.8	45.8	45.8	45.8	45.8	45.8	45.8	45.8	45.8	45.8	45.8	45.8	45.8	45.8	45.8	45.8	45.8	45.8	45.8	45.8	45.8	45.8	45.8	45.8
	Ratio of 10 day LTR	0.67	0.69	0.73	0.71	0.70	0.75	0.87	0.87	0.80	0.73	0.77	0.81	0.81	0.82	0.82	0.82	0.82	0.82	0.83	0.83	0.83	0.83	0.83	0.84	0.84	0.84	0.84	0.84	0.85
	MVA LAR																													
Elgin EZ	MVA	23.5	25.0	23.3	26.0	25.1	28.2	27.8	23.1	20.5	20.6	20.6	20.7	20.7	20.8	20.8	20.9	20.9	21.0	21.0	21.1	21.1	21.2	21.2	21.3	21.3	21.4	21.4	21.5	21.5
	10 day LTR	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0
	Ratio of 10 day LTR	0.56	0.60	0.56	0.62	0.60	0.67	0.66	0.55	0.49	0.49	0.49	0.49	0.49	0.49	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.51	0.51	0.51	0.51	0.51	0.51	0.51
	MVA LAR																													
Gage ZY	MVA	40.8	47.8	41.4	54.4	41.1	26.0	32.6	6.8	34.6	34.7	34.8	34.8	34.9	35.0	35.1	35.2	35.3	35.4	35.5	35.6	35.6	35.7	35.8	35.9	36.0	36.1	36.2	36.3	36.4
	10 day LTR	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0
	Ratio of 10 day LTR	0.64	0.75	0.65	0.85	0.64	0.41	0.51	0.11	0.54	0.54	0.54	0.54	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.56	0.56	0.56	0.56	0.56	0.56	0.56	0.57	0.57	0.57
	MVA LAR																													
Gage DJ	MVA	19.4	19.1	16.6	16.4	14.4	18.0	18.3	17.9	13.6	17.2	17.2	17.2	17.3	17.3	17.4	17.4	17.5	17.5	17.5	17.6	17.6	17.7	17.7	17.8	17.8	17.9	17.9	17.9	18.0
	10 day LTR	73.0	73.0	73.0	73.0	73.0	73.0	73.0	73.0	73.0	73.0	73.0	73.0	73.0	73.0	73.0	73.0	73.0	73.0	73.0	73.0	73.0	73.0	73.0	73.0	73.0	73.0	73.0	73.0	73.0
	Ratio of 10 day LTR	0.27	0.26	0.23	0.23	0.20	0.25	0.25	0.24	0.19	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.25	0.25	0.25
	MVA LAR																													
Gage KE	MVA	82.8	89.0	78.4	78.2	79.0	48.4	60.9	23.8	20.7	18.0	18.0	18.1	18.1	18.2	18.2	18.3	18.3	18.4	18.4	18.4	18.5	18.5	18.6	18.6	18.7	18.7	18.8	18.8	18.9
	10 day LTR	124.0	124.0	124.0	124.0	124.0	124.0	124.0	124.0	124.0	124.0	124.0	124.0	124.0	124.0	124.0	124.0	124.0	124.0	124.0	124.0	124.0	124.0	124.0	124.0	124.0	124.0	124.0	124.0	124.0
	Ratio of 10 day LTR	0.67	0.72	0.63	0.63	0.64	0.39	0.49	0.19	0.17	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15
	MVA LAR																													
Gage QB	MVA	25.9	23.2	22.5	22.1	0.2	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	10 day LTR	73.0	73.0	73.0	73.0	73.0	73.0	73.0	73.0	73.0	73.0	73.0	73.0	73.0	73.0	73.0	73.0	73.0	73.0	73.0	73.0	73.0	73.0	73.0	73.0	73.0	73.0	73.0	73.0	73.0
	Ratio of 10 day LTR	0.36	0.32	0.31	0.30	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	MVA LAR																													

HORIZON UTILITIES 25 YEAR LOAD FORECAST SUMMARY

Hydro One Supply Bus		Actual										Forecast																		
		2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Horning B1B2	MVA	46.7	55.2	52.7	49.6	45.4	46.2	53.4	53.6	56.3	49.8	50.4	50.5	50.6	50.7	50.9	51.0	51.1	51.3	51.4	51.5	51.6	51.8	51.9	52.0	52.2	52.3	52.4	52.6	52.7
	10 day LTR	56.8	56.8	56.8	56.8	56.8	56.8	56.8	56.8	56.8	56.8	56.8	56.8	56.8	56.8	56.8	56.8	56.8	56.8	56.8	56.8	56.8	56.8	56.8	56.8	56.8	56.8	56.8	56.8	56.8
	Ratio of 10 day LTR	0.82	0.97	0.93	0.87	0.80	0.81	0.94	0.94	0.99	0.88	0.89	0.89	0.89	0.89	0.90	0.90	0.90	0.90	0.90	0.91	0.91	0.91	0.91	0.92	0.92	0.92	0.92	0.93	0.93
	MVA LAR																													
Horning Q1Q2	MVA	8.5	8.7	13.6	13.0	10.4	9.4	19.1	21.6	22.2	23.9	27.8	29.5	32.4	33.1	33.9	33.9	34.0	34.1	34.2	34.3	34.4	34.5	34.5	34.6	34.7	34.8	34.9	35.0	35.1
	10 day LTR	56.8	56.8	56.8	56.8	56.8	56.8	56.8	56.8	56.8	56.8	56.8	56.8	56.8	56.8	56.8	56.8	56.8	56.8	56.8	56.8	56.8	56.8	56.8	56.8	56.8	56.8	56.8	56.8	56.8
	Ratio of 10 day LTR	0.15	0.15	0.24	0.23	0.18	0.17	0.34	0.38	0.39	0.42	0.49	0.52	0.57	0.58	0.60	0.60	0.60	0.60	0.60	0.60	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.62	0.62
	MVA LAR																													
Kenilworth DK	MVA	1.4	2.8	2.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	10 day LTR	44.1	44.1	44.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Ratio of 10 day LTR	0.03	0.06	0.06	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	MVA LAR																													
Kenilworth EJ	MVA	26.2	30.0	28.1	24.8	26.2	21.1	34.4	32.2	33.8	31.7	31.8	31.9	32.0	32.1	32.1	32.2	32.3	32.4	32.5	32.5	32.6	32.7	32.8	32.9	33.0	33.0	33.1	33.2	33.3
	10 day LTR	37.8	37.8	37.8	37.8	37.8	37.8	37.8	37.8	37.8	37.8	37.8	37.8	37.8	37.8	37.8	37.8	37.8	37.8	37.8	37.8	37.8	37.8	37.8	37.8	37.8	37.8	37.8	37.8	37.8
	Ratio of 10 day LTR	0.69	0.79	0.74	0.65	0.69	0.56	0.91	0.85	0.89	0.84	0.84	0.84	0.85	0.85	0.85	0.85	0.85	0.86	0.86	0.86	0.86	0.87	0.87	0.87	0.87	0.87	0.88	0.88	0.88
	MVA LAR																													
Kenilworth B1Y1	MVA	54.7	57.9	59.4	45.4	34.0	32.1	32.3	36.2	32.3	32.8	32.9	33.0	33.1	33.2	33.3	33.3	33.4	33.5	33.6	33.7	33.8	33.8	33.9	34.0	34.1	34.2	34.3	34.4	34.4
	10 day LTR	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0
	Ratio of 10 day LTR	0.86	0.90	0.93	0.71	0.53	0.50	0.50	0.57	0.50	0.51	0.51	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.53	0.53	0.53	0.53	0.53	0.53	0.53	0.54	0.54	0.54
	MVA LAR																													
Lake BY (27kV)	MVA	68.3	63.4	65.3	64.0	73.2	82.9	70.8	60.1	66.5	65.5	65.7	65.9	66.0	66.2	66.4	66.5	66.7	66.9	67.0	67.2	67.4	67.5	67.7	67.9	68.0	68.2	68.4	68.5	68.7
	10 day LTR	106.0	106.0	106.0	106.0	106.0	106.0	106.0	106.0	106.0	106.0	106.0	106.0	106.0	106.0	106.0	106.0	106.0	106.0	106.0	106.0	106.0	106.0	106.0	106.0	106.0	106.0	106.0	106.0	106.0
	Ratio of 10 day LTR	0.64	0.60	0.62	0.60	0.69	0.78	0.67	0.57	0.63	0.62	0.62	0.62	0.62	0.62	0.63	0.63	0.63	0.63	0.63	0.63	0.64	0.64	0.64	0.64	0.64	0.64	0.65	0.65	0.65
	MVA LAR																													
Lake J1J2	MVA	26.1	29.3	30.1	27.5	26.4	26.4	28.2	37.2	29.1	36.6	36.7	36.8	36.9	37.0	37.1	37.1	37.2	37.3	37.4	37.5	37.6	37.7	37.8	37.9	38.0	38.1	38.2	38.3	38.4
	10 day LTR	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0
	Ratio of 10 day LTR	0.51	0.57	0.59	0.54	0.52	0.52	0.55	0.73	0.57	0.72	0.72	0.72	0.72	0.72	0.73	0.73	0.73	0.73	0.73	0.74	0.74	0.74	0.74	0.74	0.74	0.75	0.75	0.75	0.75
	MVA LAR																													
Lake Q1Q2	MVA	36.6	40.6	41.0	37.6	34.5	32.9	42.6	41.6	36.0	33.6	35.2	36.8	36.9	37.0	37.1	37.2	37.3	37.4	37.5	37.6	37.7	37.8	37.9	38.0	38.1	38.2	38.2	38.3	38.4
	10 day LTR	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0
	Ratio of 10 day LTR	0.72	0.80	0.80	0.74	0.68	0.65	0.84	0.82	0.71	0.66	0.69	0.72	0.72	0.73	0.73	0.73	0.73	0.73	0.74	0.74	0.74	0.74	0.74	0.74	0.75	0.75	0.75	0.75	0.75
	MVA LAR																													
Mohawk B1B2	MVA	36.9	49.3	45.6	42.0	38.6	36.6	37.2	37.0	35.3	32.4	32.9	33.4	33.9	34.4	34.9	35.4	35.5	35.6	35.6	35.7	35.8	35.9	36.0	36.1	36.2	36.3	36.4	36.5	36.6
	10 day LTR	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0
	Ratio of 10 day LTR	0.88	1.17	1.09	1.00	0.92	0.87	0.89	0.88	0.84	0.77	0.78	0.80	0.81	0.82	0.83	0.84	0.84	0.85	0.85	0.85	0.85	0.86	0.86	0.86	0.86	0.86	0.87	0.87	0.87
	MVA LAR		**7.3**	**3.6**	**0.0**																									
Mohawk Y1Y2	MVA	37.9	43.4	45.2	42.8	38.7	39.1	46.5	43.6	43.0	38.4	38.5	38.6	38.7	38.8	38.9	39.0	39.1	39.2	39.3	39.4	39.5	39.6	39.7	39.8	39.9	40.0	40.1	40.2	40.3
	10 day LTR	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0
	Ratio of 10 day LTR	0.90	1.03	1.08	1.02	0.92	0.93	1.11	1.04	1.02	0.92	0.92	0.92	0.92	0.92	0.93	0.93	0.93	0.93	0.94	0.94	0.94	0.94	0.95	0.95	0.95	0.95	0.95	0.96	0.96
	MVA LAR		**1.4**	**3.2**	**0.8**			**4.5**	**1.6**	**1.0**																				
Nebo BY	MVA	23.5	28.6	31.1	32.5	28.4	27.0	31.0	35.1	33.8	34.5	37.4	39.4	41.5	43.6	44.7	45.5	45.6	45.7	45.9	46.0	46.1	46.2	46.3	46.4	46.6	46.7	46.8	46.9	47.0
	10 day LTR	33.5	33.5	33.5	33.5	33.5	33.5	33.5	33.5	33.5	33.5	50.8	50.8	50.8	50.8	50.8	50.8	50.8	50.8	50.8	50.8	50.8	50.8	50.8	50.8	50.8	50.8	50.8	50.8	50.8
	Ratio of 10 day LTR	0.70	0.85	0.93	0.97	0.85	0.81	0.93	1.05	1.01	1.03	0.74	0.78	0.82	0.86	0.88	0.90	0.90	0.90	0.90	0.91	0.91	0.91	0.91	0.91	0.92	0.92	0.92	0.92	0.93
	MVA LAR								**1.6**	**0.3**	**1.0**																			
Nebo QJ	MVA	42.1	49.8	61.4	59.9	54.6	52.8	61.0	57.5	56.0	56.6	56.8	56.9	57.1	57.2	57.4	57.5	57.6	57.8	57.9	58.1	58.2	58.4	58.5	58.7	58.8	59.0	59.1	59.3	59.4
	10 day LTR	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0
	Ratio of 10 day LTR	0.73	0.86	1.06	1.03	0.94	0.91	1.05	0.99	0.97	0.98	0.98	0.98	0.98	0.99	0.99	0.99	0.99	1.00	1.00	1.00	1.00	1.01	1.01	1.01	1.01	1.02	1.02	1.02	1.02
	MVA LAR			**3.4**	**1.9**			**3.0**													**0.1**	**0.2**	**0.4**	**0.5**	**0.7**	**0.8**	**1.0**	**1.1**	**1.3**	**1.4**
Newton B	MVA	23.8	24.6	23.7	22.8	21.5	19.9	20.8	25.2	24.3	21.6	21.6	23.4	24.1	25.2	25.3	25.4	25.4	25.5	25.5	25.6	25.7	25.7	25.8	25.9	25.9	26.0	26.1	26.1	26.2
	10 day LTR	36.2	36.2	36.2	36.2	36.2	36.2	36.2	36.2	36.2	36.2	36.2	36.2	36.2	36.2	36.2	36.2	36.2	36.2	36.2	36.2	36.2	36.2	36.2	36.2	36.2	36.2	36.2	36.2	36.2
	Ratio of 10 day LTR	0.66	0.68	0.65	0.63	0.59	0.55	0.57	0.70	0.67	0.60	0.60	0.65	0.67	0.70	0.70	0.70	0.70	0.70	0.71	0.71	0.71	0.71	0.71	0.71	0.72	0.72	0.72	0.72	0.72
	MVA LAR																													
Newton Y	MVA	20.8	23.6	24.5	21.8	19.2	19.3	20.9	23.2	20.7	20.3	20.3	20.4	20.4	20.5	20.5	20.6	20.7	20.7	20.8	20.8	20.9	20.9	21.0	21.0	21.1	21.1	21.2	21.2	21.3
	10 day LTR	36.2	36.2	36.2	36.2	36.2	36.2	36.2	36.2	36.2	36.2	36.2	36.2	36.2	36.2	36.2	36.2	36.2	36.2	36.2	36.2	36.2	36.2	36.2	36.2	36.2	36.2	36.2	36.2	36.2
	Ratio of 10 day LTR	0.58	0.65	0.68	0.60	0.53	0.53	0.58	0.64	0.57	0.56	0.56	0.56	0.56	0.57	0.57	0.57	0.57	0.57	0.57	0.57	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.59	0.59
	MVA LAR																													
Stirton BY	MVA	25.5	30.2	28.0	37.8	27.9	35.3	31.5	24.7	22.2	21.9	22.0	22.0	22.1	22.2	22.2	22.3	22.3	22.4	22.4	22.5	22.5	22.6	22.7	22.7	22.8	22.8	22.9	22.9	23.0
	10 day LTR	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0
	Ratio of 10 day LTR	0.50	0.59	0.55	0.74	0.55	0.69	0.62	0.48	0.44	0.43	0.43	0.43	0.43	0.43	0.44	0.44	0.44	0.44	0.44	0.44	0.44	0.44	0.44	0.45	0.45	0.45	0.45	0.45	0.45
	MVA LAR																													
Stirton QZ	MVA	26.1	31.3	30.7	35.2	25.7	26.7	29.0	29.6	25.7	25.0	25.1	25.1	25.2	25.3	25.3	25.4	25.5	25.5	25.6	25.7	25.7	25.8	25.8	25.9	26.0	26.0	26.1	26.2	26.2
	10 day LTR	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0
	Ratio of 10 day LTR	0.51	0.61	0.60	0.69	0.50	0.52	0.57	0.58	0.50	0.49	0.49	0.49	0.49	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.51	0.51	0.51	0.51	0.51	0.51	0.51	0.51
	MVA LAR																													
Winona JQ	MVA	47.4	47.7	51.9	51.1	49.7	40.6	50.7	52.2	52.1	54.3	57.0	59.7	59.8	60.0	60.1	60.3	60.4	60.6	60.7	60.9	61.0	61.2	61.3	61.5	61.6	61.8	61.9	62.1	62.2
	10 day LTR	106.0	106.0	106.0	106.0	106.0	106.0	106.0	106.0	106.0	106.0	106.0	106.0	106.0	106.0	106.0	106.0	106.0	106.0	106.0	106.0	106.0	106.0	106.0	106.0	106.0	106.0	106.0	106.0	106.0
	Ratio of 10 day LTR	0.45	0.45	0.49	0.48	0.47	0.38	0.48	0.49	0.49	0.51	0.54	0.56	0.56	0.57	0.57	0.57	0.57	0.57	0.57	0.57	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.59	0.59
	MVA LAR																													

HORIZON UTILITIES 25 YEAR LOAD FORECAST SUMMARY

Hydro One Supply Bus		Actual 2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Bunting J1J2	MVA	0.0	40.5	35.2	33.4	29.9	24.1	36.5	35.4	35.5	31.7
	10 day LTR	42.1	42.1	42.1	42.1	42.1	42.1	42.1	42.1	42.1	42.1
	Ratio of 10 day LTR	0.00	0.96	0.84	0.79	0.71	0.57	0.87	0.84	0.84	0.75
	MVA LAR										
Bunting Q1Q2	MVA	0.0	45.4	39.2	36.1	34.6	32.5	37.5	33.7	33.0	34.2
	10 day LTR	42.1	42.1	42.1	42.1	42.1	42.1	42.1	42.1	42.1	42.1
	Ratio of 10 day LTR	0.00	1.08	0.93	0.86	0.82	0.77	0.89	0.80	0.78	0.81
	MVA LAR		**3.3**								
Carlton QE	MVA	0.0	48.1	38.9	20.7	19.2	15.5	19.1	7.9	4.1	3.8
	10 day LTR	43.0	43.0	43.0	43.0	43.0	43.0	43.0	43.0	43.0	43.0
	Ratio of 10 day LTR	0.00	1.12	0.90	0.48	0.45	0.36	0.44	0.18	0.10	0.09
	MVA LAR		**5.1**								
Carlton HK	MVA	0.0	71.0	50.9	50.8	45.7	46.2	47.7	56.6	55.5	50.8
	10 day LTR	53.0	53.0	53.0	53.0	53.0	53.0	53.0	53.0	53.0	53.0
	Ratio of 10 day LTR	0.00	1.34	0.96	0.96	0.86	0.87	0.90	1.07	1.05	0.96
	MVA LAR		**18.0**						**3.6**	**2.5**	
Carlton BY	MVA	0.0	29.8	62.0	64.6	61.1	68.0	59.5	73.0	60.4	60.4
	10 day LTR	55.5	55.5	55.5	55.5	55.5	55.5	55.5	55.5	55.5	55.5
	Ratio of 10 day LTR	0.00	0.54	1.12	1.16	1.10	1.23	1.07	1.32	1.09	1.09
	MVA LAR			**6.5**	**9.1**	**5.6**	**12.5**	**4.0**	**17.5**	**4.9**	**4.9**
Glendale BJ	MVA	0.0	35.6	27.3	28.7	28.9	25.7	27.4	26.0	27.6	26.6
	10 day LTR	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0
	Ratio of 10 day LTR	0.00	0.77	0.59	0.62	0.63	0.56	0.59	0.57	0.60	0.58
	MVA LAR										
Glendale DQ	MVA	0.0	35.6	26.7	27.7	33.0	29.9	30.7	26.9	25.2	27.1
	10 day LTR	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0
	Ratio of 10 day LTR	0.00	0.77	0.58	0.60	0.72	0.65	0.67	0.58	0.55	0.59
	MVA LAR										
Glendale EY	MVA	0.0	13.3	18.0	18.3	15.7	15.6	17.6	16.0	15.5	12.0
	10 day LTR	19.8	19.8	19.8	19.8	19.8	19.8	19.8	19.8	19.8	19.8
	Ratio of 10 day LTR	0.00	0.67	0.91	0.92	0.79	0.79	0.89	0.81	0.78	0.61
	MVA LAR										
Vansickle BY	MVA	0.0	45.8	38.0	42.4	40.5	44.3	44.2	38.3	38.4	33.0
	10 day LTR	54.0	54.0	54.0	54.0	54.0	54.0	54.0	54.0	54.0	54.0
	Ratio of 10 day LTR	0.00	0.85	0.70	0.78	0.75	0.82	0.82	0.71	0.71	0.61
	MVA LAR										
Vansickle JQ	MVA	0.0	0.0	0.0	0.0	0.0	0.0	0.0	11.8	13.0	26.2
	10 day LTR	54.0	54.0	54.0	54.0	54.0	54.0	54.0	54.0	54.0	54.0
	Ratio of 10 day LTR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.22	0.24	0.49
	MVA LAR										

Hydro One Supply Bus		Forecast 2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Bunting J1J2	MVA	31.7	31.8	31.9	32.0	32.1	32.1	32.2	32.3	32.4	32.5	32.6	32.6	32.7	32.8	32.9	33.0	33.0	33.1	33.2
	10 day LTR	42.1	42.1	42.1	42.1	42.1	42.1	42.1	42.1	42.1	42.1	42.1	42.1	42.1	42.1	42.1	42.1	42.1	42.1	42.1
	Ratio of 10 day LTR	0.75	0.76	0.76	0.76	0.76	0.76	0.77	0.77	0.77	0.77	0.77	0.78	0.78	0.78	0.78	0.78	0.78	0.79	0.79
	MVA LAR																			
Bunting Q1Q2	MVA	34.3	34.4	34.4	34.5	34.6	34.7	34.8	34.9	35.0	35.0	35.1	35.2	35.3	35.4	35.5	35.6	35.7	35.8	35.8
	10 day LTR	42.1	42.1	42.1	42.1	42.1	42.1	42.1	42.1	42.1	42.1	42.1	42.1	42.1	42.1	42.1	42.1	42.1	42.1	42.1
	Ratio of 10 day LTR	0.81	0.82	0.82	0.82	0.82	0.82	0.83	0.83	0.83	0.83	0.83	0.84	0.84	0.84	0.84	0.85	0.85	0.85	0.85
	MVA LAR																			
Carlton QE	MVA	3.8	3.8	3.8	3.8	3.8	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	4.0	4.0	4.0	4.0
	10 day LTR	43.0	43.0	43.0	43.0	43.0	43.0	43.0	43.0	43.0	43.0	43.0	43.0	43.0	43.0	43.0	43.0	43.0	43.0	43.0
	Ratio of 10 day LTR	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09
	MVA LAR																			
Carlton HK	MVA	52.6	53.8	55.1	55.2	55.3	55.5	55.6	55.7	55.9	56.0	56.2	56.3	56.5	56.6	56.7	56.9	57.0	57.2	57.3
	10 day LTR	53.0	53.0	53.0	53.0	53.0	53.0	53.0	53.0	53.0	53.0	53.0	53.0	53.0	53.0	53.0	53.0	53.0	53.0	53.0
	Ratio of 10 day LTR	0.99	1.02	1.04	1.04	1.04	1.05	1.05	1.05	1.05	1.06	1.06	1.06	1.07	1.07	1.07	1.07	1.08	1.08	1.08
	MVA LAR		**0.8**	**2.1**	**2.2**	**2.3**	**2.5**	**2.6**	**2.7**	**2.9**	**3.0**	**3.2**	**3.3**	**3.5**	**3.6**	**3.7**	**3.9**	**4.0**	**4.2**	**4.3**
Carlton BY	MVA	60.6	60.7	60.9	61.0	61.2	61.3	61.5	61.6	61.8	61.9	62.1	62.2	62.4	62.6	62.7	62.9	63.0	63.2	63.3
	10 day LTR	55.5	55.5	55.5	55.5	55.5	55.5	55.5	55.5	55.5	55.5	55.5	55.5	55.5	55.5	55.5	55.5	55.5	55.5	55.5
	Ratio of 10 day LTR	1.09	1.09	1.10	1.10	1.10	1.10	1.11	1.11	1.11	1.12	1.12	1.12	1.12	1.13	1.13	1.13	1.14	1.14	1.14
	MVA LAR	**5.1**	**5.2**	**5.4**	**5.5**	**5.7**	**5.8**	**6.0**	**6.1**	**6.3**	**6.4**	**6.6**	**6.7**	**6.9**	**7.1**	**7.2**	**7.4**	**7.5**	**7.7**	**7.8**
Glendale BJ	MVA	26.6	26.7	26.8	26.8	26.9	27.0	27.0	27.1	27.2	27.2	27.3	27.4	27.5	27.5	27.6	27.7	27.7	27.8	27.9
	10 day LTR	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0
	Ratio of 10 day LTR	0.58	0.58	0.58	0.58	0.58	0.59	0.59	0.59	0.59	0.59	0.59	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.61
	MVA LAR																			
Glendale DQ	MVA	27.1	27.2	27.3	27.3	27.4	27.5	27.6	27.6	27.7	27.8	27.8	27.9	28.0	28.0	28.1	28.2	28.3	28.3	28.4
	10 day LTR	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0
	Ratio of 10 day LTR	0.59	0.59	0.59	0.59	0.60	0.60	0.60	0.60	0.60	0.60	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.62	0.62
	MVA LAR																			
Glendale EY	MVA	12.1	12.1	12.1	12.2	12.2	12.2	12.3	12.3	12.3	12.3	12.4	12.4	12.4	12.5	12.5	12.5	12.6	12.6	12.6
	10 day LTR	19.8	19.8	19.8	19.8	19.8	19.8	19.8	19.8	19.8	19.8	19.8	19.8	19.8	19.8	19.8	19.8	19.8	19.8	19.8
	Ratio of 10 day LTR	0.61	0.61	0.61	0.61	0.62	0.62	0.62	0.62	0.62	0.62	0.63	0.63	0.63	0.63	0.63	0.63	0.63	0.64	0.64
	MVA LAR																			
Vansickle BY	MVA	34.0	34.0	34.1	34.2	34.3	34.4	34.5	34.6	34.6	34.7	34.8	34.9	35.0	35.1	35.2	35.3	35.3	35.4	35.5
	10 day LTR	54.0	54.0	54.0	54.0	54.0	54.0	54.0	54.0	54.0	54.0	54.0	54.0	54.0	54.0	54.0	54.0	54.0	54.0	54.0
	Ratio of 10 day LTR	0.63	0.63	0.63	0.63	0.64	0.64	0.64	0.64	0.64	0.64	0.64	0.65	0.65	0.65	0.65	0.65	0.65	0.66	0.66
	MVA LAR																			
Vansickle JQ	MVA	26.6	27.0	27.4	27.4	27.5	27.6	27.6	27.7	27.8	27.8	27.9	28.0	28.1	28.1	28.2	28.3	28.3	28.4	28.5
	10 day LTR	54.0	54.0	54.0	54.0	54.0	54.0	54.0	54.0	54.0	54.0	54.0	54.0	54.0	54.0	54.0	54.0	54.0	54.0	54.0
	Ratio of 10 day LTR	0.49	0.50	0.51	0.51	0.51	0.51	0.51	0.51	0.51	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.53	0.53
	MVA LAR																			

LTR = Limited Time Rating
LAR = Load at Risk

Notes:
2013 feeder peaks used to forecast 2014 onwards
Generation has been removed from feeders
Expected load growth has been accounted for based on information as of Nov 1, 2013
0.25% growth per year unless otherwise specified

Generators	
Bunting J1J2	Rankin Weir 1 & Weir 2 Generators Approx 3 MW combined
Carlton BY	Heywood Generating Station Approx 5.2 MW
Glendale EY	St.Lawrence Seaway Generator Approx 3.5 MW

Substation Transformer Lookup Table For Previous Year

Station	Peak Tx Current (A)				Tx Load Calculated (kVA)				TX Ratings				% Loaded				Loss of 1 Tx Excess (kVA)	Max Limit	Single Bus (No tie s/w)	Total # of Circuits	Circuits Feed by (per Tx)			
	TX1	TX2	TX3	TX4	TX1	TX2	TX3	TX4	TX1	TX2	TX3	TX4	TX1	TX2	TX3	TX4					TX1	TX2	TX3	TX4
Aberdeen	394	336	0	0	2838	2424	0	0	6667	6667			43%	36%				13334	N	4	2	2		
Baldwin	306	0	0	0	2204	0	0	0	7500				29%				2204	7500	Y	2	2			
Bartonville	677	0	0	0	4881	0	0	0	13333				37%				4881	13333	Y	5	5			
Caroline	360	49	0	0	2594	353	0	0	5000	5000			52%	7%				10000	N	3	2	1		
Central	586	410	0	0	4222	2958	0	0	13333	13333			32%	22%				26666	N	10	6	4		
Cope	439	298	481	0	3160	2148	3465	0	6667	6667	6667		47%	32%	52%			20001	N	9	3	3	3	
Deerhurst	118	0	0	0	849	0	0	0	7500				11%				849	7500	Y	3	3			
Dewitt	109	0	0	0	787	0	0	0	5000				16%				787	5000	Y	3	3			
Eastmount	570	205	433	261	4108	1479	3119	1879	6667	6667	6667	6667	62%	22%	47%	28%		26668	N	10	3	2	3	2
Elmwood	344	123	400	0	2476	885	2885	0	6667	6667	6667		37%	13%	43%			20001	N	7	3	1	3	
Galbraith	114	0	0	0	821	0	0	0	5600				15%				821	5600	Y	3	3			
Highland	319	0	0	0	2300	0	0	0	6667				34%				2300	6667	Y	3	3			
Hughson	271	0	0	199	1951	0	0	1431	6667	0	6667	6667	29%			21%		20001	N	3	1	1	0	1
John	331	0	0	0	2382	0	0	0	6667				36%				2382	6667	Y	2	2			
Kenilworth	469	338	0	0	3381	2437	0	0	6667	6667			51%	37%				13334	N	6	3	3		
Mohawk	668	481	0	0	4812	3464	0	0	13333	6667	6667		36%	52%				26667	N	8	5	3	0	
Mountain	842	370	0	0	6065	2663	0	0	13333	6667	6667		45%	40%				26667	N	8	5	3	0	
Ottawa	397	366	246	0	2861	2635	1773	0	6667	6667	6667		43%	40%	27%			20001	N	7	3	2	2	
Parkdale	624	359	0	0	4496	2586	0	0	13333	13333			34%	19%				26666	N	7	4	3		
Spadina	519	538	0	0	3737	3874	0	0	6667	6667	0		56%	58%			945	13334	N	6	3	3		
Strouds	408	320	0	0	2942	2303	0	0	6667	6667			44%	35%				13334	N	5	3	2		
~~Webster~~	0	0	0	0	0	0	0	0	0								0	0	Y	0	0			
Wellington	400	304	291	212	2882	2190	2094	1526	6667	6667	6667	6667	43%	33%	31%	23%		26668	N	10	3	3	2	2
Wentworth	631	0	728	275	4545	0	5243	1978	6667	0	6667	6667	68%		79%	30%		20001	N	11	3	3	2	3
Whitney	474	255	0	0	3419	1838	0	0	6667	6667			51%	28%				13334	N	6	3	3		
York	107	0	0	0	773	0	0	0	4000	5000			19%					9000	Y	2	2			
Vine	622	0	0	0	4484	0	0	0	7500	6667			60%					14167	Y	4	4			
Taylor	0	0	0	0	0	0	0	0	2499	2000	3000							7499	N	3	1	1	1	
Grantham	457	0	0	0	3292	0	0	0	6000	0			55%				3292	6000	N	3	3	0		
Welland	152	0	0	0	1095	0	0		3000	3000	3600		37%					9600	Y	3	1			

Note: Stations highlighted in Yellow are 8kV, all others are 4kV.

Appendix I – Hydro One Regional Planning Status Letter

Hydro One Network Inc.
483 Bay Street
15th Floor, South Tower
Toronto, ON M5G 2P5
www.HydroOne.com

Tel: (416) 345-5420
Fax: (416) 345-4141
ajay.garg@HydroOne.com

February 12, 2014

R. Bassindale
Supervisor, Engineering and Asset Management
Horizon Utilities Corporation Inc.
55 John Street North
Hamilton, Ontario, L8R 3M8

Dear Mr. Bassindale:

Subject: Regional Planning Status

In reference to your request for a regional planning status letter, please note that your Local Distribution Company (LDC) belongs to a) Burlington to Nanticoke Region in Group 1 and b) Niagara Region in Group 3. A map showing details with respect to the 21 Regions/Groups and list of LDCs in each Region is attached in Appendix A and B respectively.

This letter is to confirm that the regional planning process for Burlington to Nanticoke Region in Group 1 was initiated in January 2014 and the Needs Screening report is expected to be completed in the 2nd quarter of 2014. The regional planning process for Niagara Region in Group 3 has not been initiated nor has a Regional Infrastructure Plan (RIP) been developed for the sub-region within the Niagara Region affecting the Horizon Utilities. I am expecting that the regional planning process for the Niagara Region will be initiated in 4th quarter of 2016. Hydro One will formally notify your organization in advance, along with other stakeholders, prior to launching the regional planning process.

The new planning process provides flexibility, during the transition period to the new process, and will ensure that both distribution and transmission planning continue to address any short-term needs. Hydro One looks forward to working with Horizon Utilities Corporation Inc. in executing the new regional planning process.

If you have any further questions, please feel free to contact me.

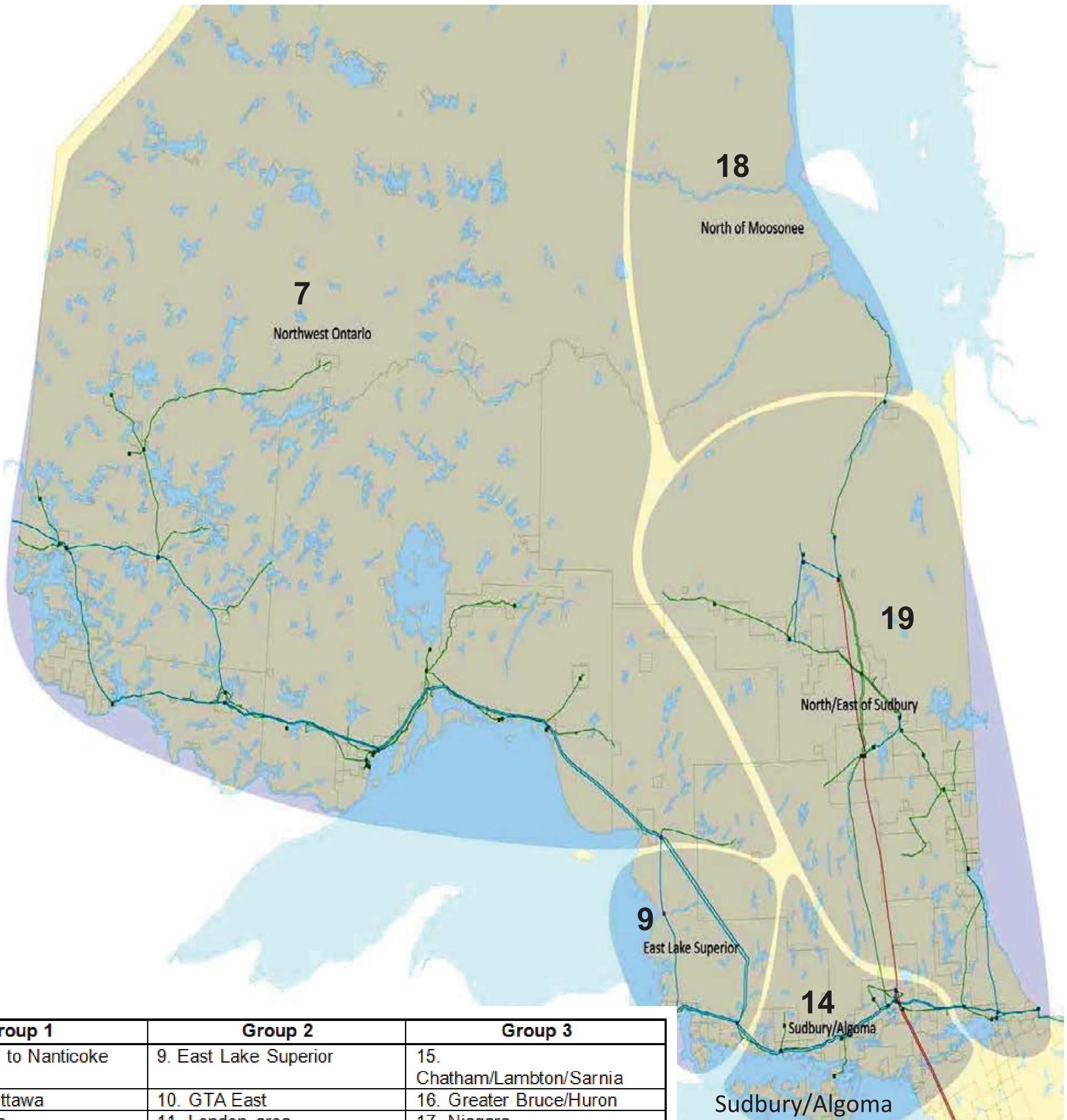
Sincerely,

Ajay Garg
Manager - Regional Planning and Transmission Load Connections
Hydro One Networks Inc.

Cc:
Brad Colden, Manager – Customer Business Relations

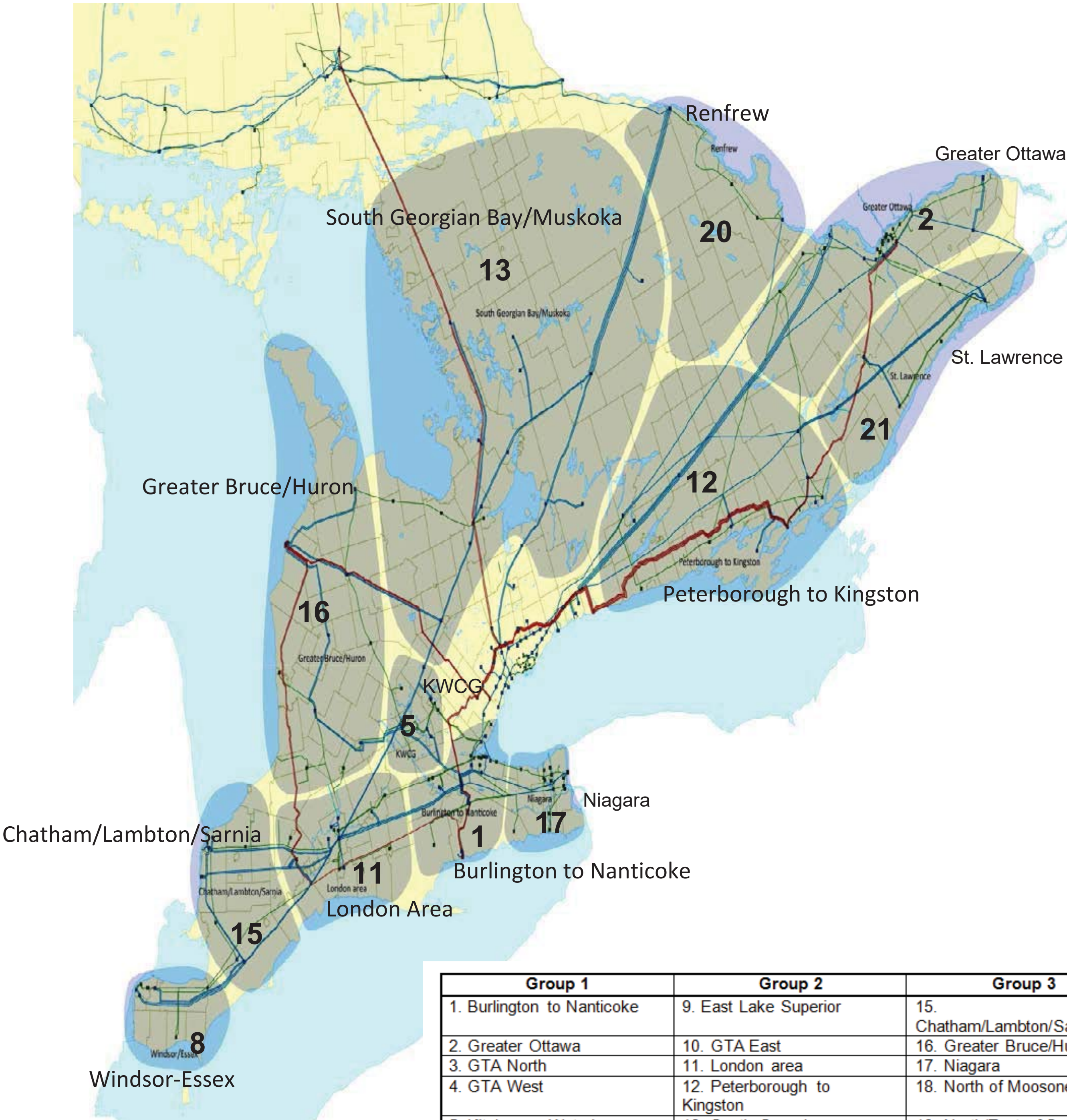
<u>Appendix A: Map of Ontario's Planning Regions</u>

Northern Ontario



Group 1	Group 2	Group 3
1. Burlington to Nanticoke	9. East Lake Superior	15. Chatham/Lambton/Sarnia
2. Greater Ottawa	10. GTA East	16. Greater Bruce/Huron
3. GTA North	11. London area	17. Niagara
4. GTA West	12. Peterborough to Kingston	18. North of Moosonee
5. Kitchener- Waterloo-Cambridge-Guelph ("KWCG")	13. South Georgian Bay/Muskoka	19. North/East of Sudbury
6. Metro Toronto	14. Sudbury/Algoma	20. Renfrew
7. Northwest Ontario		21. St. Lawrence
8. Windsor-Essex		

Southern Ontario



Group 1	Group 2	Group 3
1. Burlington to Nanticoke	9. East Lake Superior	15. Chatham/Lambton/Sarnia
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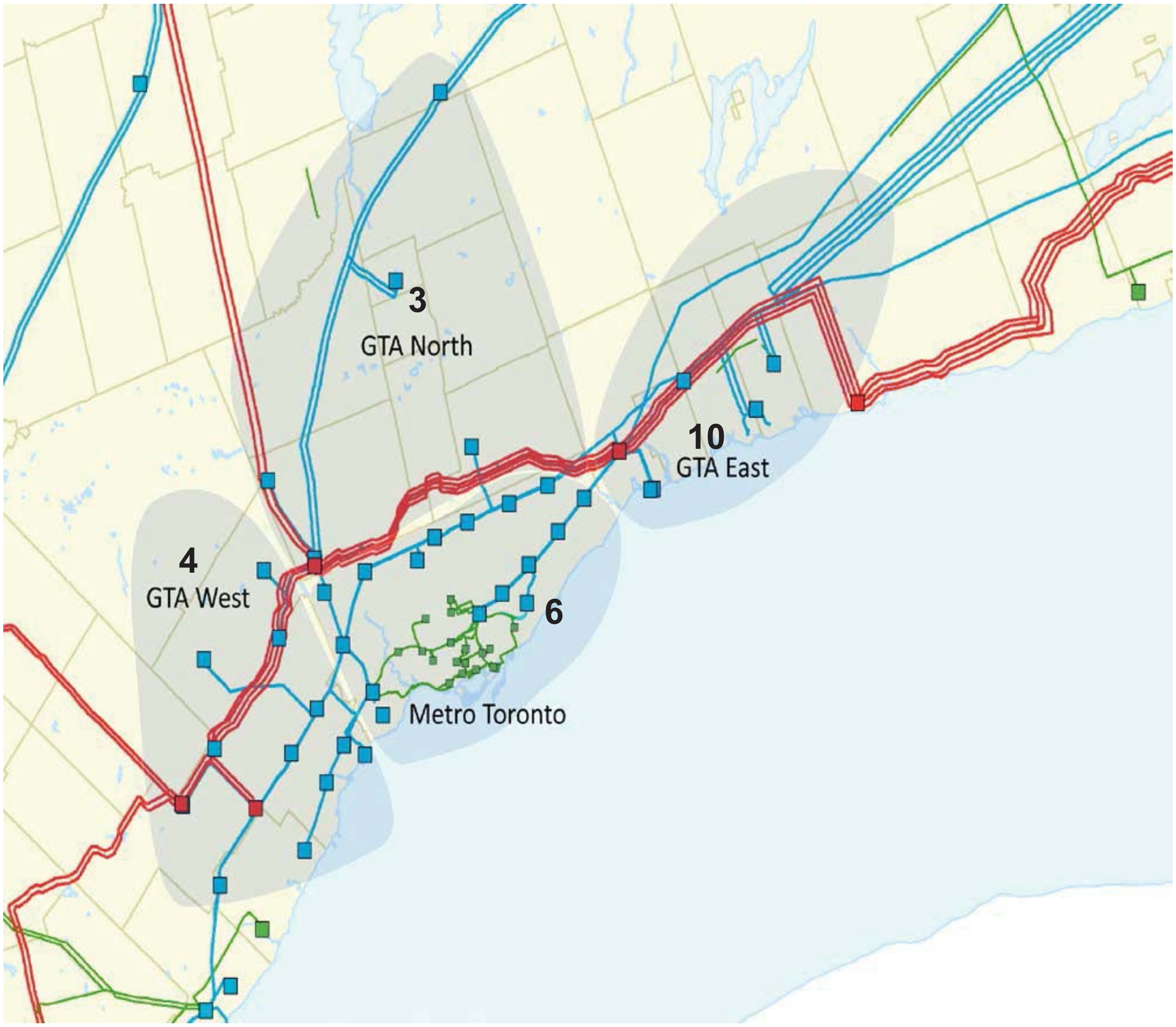
7. Northwest Ontario		21. St. Lawrence
8. Windsor-Essex		

Greater Toronto Area (GTA)



Group 1	Group 2	Group 3
1. Burlington to Nanticoke	9. East Lake Superior	15. Chatham/Lambton/Sarnia
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6. Metro Toronto	14. Sudbury/Algoma	20. Renfrew
7. Northwest Ontario		21. St. Lawrence
8. Windsor-Essex		

<u>Appendix B</u>: List of LDCs for Each Region

[Hydro One as Upstream Transmitter]

Region	LDCs
1. Burlington to Nanticoke	• Brant County Power Inc. • Brantford Power Inc. • Burlington Hydro Inc. • Haldimand County Hydro Inc. • Horizon Utilities Corporation • Hydro One Networks Inc. • Norfolk Power Distribution Inc. • Oakville Hydro Electricity Distribution Inc.
2. Greater Ottawa	• Hydro 2000 Inc. • Hydro Hawkesbury Inc. • Hydro One Networks Inc. • Hydro Ottawa Limited • Ottawa River Power Corporation • Renfrew Hydro Inc.
3. GTA North	• Enersource Hydro Mississauga Inc. • Hydro One Brampton Networks Inc. • Hydro One Networks Inc. • Newmarket-Tay Power Distribution Ltd. • PowerStream Inc. • PowerStream Inc. [Barrie] • Toronto Hydro Electric System Limited • Veridian Connections Inc.
4. GTA West	• Burlington Hydro Inc. • Enersource Hydro Mississauga Inc. • Halton Hills Hydro Inc. • Hydro One Brampton Networks Inc. • Hydro One Networks Inc. • Milton Hydro Distribution Inc. • Oakville Hydro Electricity Distribution Inc.

5. Kitchener- Waterloo-Cambridge-Guelph ("KWCG")	• Cambridge and North Dumfries Hydro Inc. • Centre Wellington Hydro Ltd. • Guelph Hydro Electric System - Rockwood Division • Guelph Hydro Electric Systems Inc. • Halton Hills Hydro Inc. • Hydro One Networks Inc. • Kitchener-Wilmot Hydro Inc. • Milton Hydro Distribution Inc. • Waterloo North Hydro Inc. • Wellington North Power Inc.
6. Metro Toronto	• Enersource Hydro Mississauga Inc. • Hydro One Networks Inc. • PowerStream Inc. • Toronto Hydro Electric System Limited • Veridian Connections Inc.
7. Northwest Ontario	• Atikokan Hydro Inc. • Chapleau Public Utilities Corporation • Fort Frances Power Corporation • Hydro One Networks Inc. • Kenora Hydro Electric Corporation Ltd. • Sioux Lookout Hydro Inc. • Thunder Bay Hydro Electricity Distribution Inc.
8. Windsor-Essex	• E.L.K. Energy Inc. • Entegrus Power Lines Inc. [Chatham-Kent] • EnWin Utilities Ltd. • Essex Powerlines Corporation • Hydro One Networks Inc.
9. East Lake Superior	N/A →This region is not within Hydro One's territory

10. GTA East	• Hydro One Networks Inc. • Oshawa PUC Networks Inc. • Veridian Connections Inc. • Whitby Hydro Electric Corporation
11. London area	• Entegrus Power Lines Inc. [Middlesex] • Erie Thames Power Lines Corporation • Hydro One Networks Inc. • London Hydro Inc. • Norfolk Power Distribution Inc. • St. Thomas Energy Inc. • Tillsonburg Hydro Inc. • Woodstock Hydro Services Inc.
12. Peterborough to Kingston	• Eastern Ontario Power Inc. • Hydro One Networks Inc. • Kingston Hydro Corporation • Lakefront Utilities Inc. • Peterborough Distribution Inc. • Veridian Connections Inc.
13. South Georgian Bay/Muskoka	• Collingwood PowerStream Utility Services Corp. (COLLUS PowerStream Corp.) • Hydro One Networks Inc. • Innisfil Hydro Distribution Systems Limited • Lakeland Power Distribution Ltd. • Midland Power Utility Corporation • Orangeville Hydro Limited • Orillia Power Distribution Corporation • Parry Sound Power Corp. • Powerstream Inc. [Barrie] • Tay Power • Veridian Connections Inc. • Veridian-Gravenhurst Hydro Electric Inc. • Wasaga Distribution Inc.

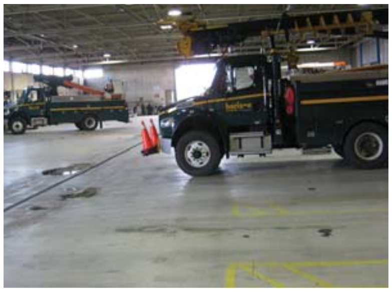
14. Sudbury/Algoma	• Espanola Regional Hydro Distribution Corp. • Greater Sudbury Hydro Inc. • Hydro One Networks Inc.
15. Chatham/Lambton/Sarnia	• Bluewater Power Distribution Corporation • Entegrus Power Lines Inc. [Chatham-Kent] • Hydro One Networks Inc.
16. Greater Bruce/Huron	• Entegrus Power Lines Inc. [Middlesex] • Erie Thames Power Lines Corporation • Festival Hydro Inc. • Hydro One Networks Inc. • Wellington North Power Inc. • West Coast Huron Energy Inc. • Westario Power Inc.
17. Niagara	• Canadian Niagara Power Inc. [Port Colborne] • Grimsby Power Inc. • Haldimand County Hydro Inc*. • Horizon Utilities Corporation • Hydro One Networks Inc. • Niagara Peninsula Energy Inc. • Niagara-On-The-Lake Hydro Inc. • Welland Hydro-Electric System Corp. *Changes to the May 17, 2013 OEB Planning Process Working Group Report.
18. North of Moosonee	N/A →This region is not within Hydro One's territory
19. North/East of Sudbury	• Greater Sudbury Hydro Inc. • Hearst Power Distribution Company Limited • Hydro One Networks Inc. • North Bay Hydro Distribution Ltd. • Northern Ontario Wires Inc.

20. Renfrew	• Hydro One Networks Inc. • Ottawa River Power Corporation • Renfrew Hydro Inc.
21. St. Lawrence	• Cooperative Hydro Embrun Inc. • Hydro One Networks Inc. • Rideau St. Lawrence Distribution Inc.

Appendix J – Resource and Office Space Utilization Study Report

Resource and Office Space Utilization Study



PRISM Partners Inc

In collaboration with:

Garwood-Jones and Hanham Architects
IRC Group
BnZ Engineering

August 3, 2010

TABLE OF CONTENTS

TABLE OF CONTENTS

1 PURPOSE

Horizon Utilities Corporation is one of the largest municipally owned electricity distribution companies in Ontario providing electrical and utility services to commercial and residential customers in the Hamilton, Stoney Creek and St. Catharines areas. Horizon is committed to providing safe, reliable electricity, customer value and creating a culture of energy conservation. The company employs over 400 employees that currently work out of Horizon-owned facilities located in Hamilton, Stoney Creek and St. Catharines.

Horizon is projecting a multi-business growth strategy through potential mergers and acquisitions and organic growth over the next five to ten year period. Potential growth areas include movement further into the Niagara region and northwest along the Highway 403 and 401 corridors to Cambridge. Horizon senior management predicts that with additional merger and acquisition activity, the staff complement could continue to increase to approximately 600 employees over the next five years and up to 900 employees in the next ten years. Without merger or acquisition growth, the organic staff complement is expected grow to 500 employees in the next five years.

In order to plan for this projected growth, Horizon management realizes the need to review its current real estate assets and facilities to ensure that future capacity for increased resources and equipment could be supported. At this time, some Horizon facilities are experiencing under-utilization of space, while other facilities are overcrowded and/or lacking in amenities or spaces to assist staff to work effectively.

Horizon has contracted PRISM Partners Inc (PRISM) to perform a Resource and Space Utilization Study to audit its existing buildings and facilities and to provide investment recommendations for the next five to ten years. The process included a staff engagement to determine departmental needs, interviews with key stakeholders and a review of current planning documents and site plans as well as site tours of all facilities. This report will outline challenges with existing facilities and space, and opportunities and efficiencies for Horizon Utilities staff to work and communicate more effectively, as well as identify opportunities for expansion potential at the sites.

1.1 Approach and Methodology

The Space Utilization Study investigated the current Horizon facilities (approximately 300,000 square feet), located on John Street and Nebo Road in Hamilton, Highway 8 in Stoney Creek and Vansickle Road in St. Catharines. The information found in this report was compiled based on information gleaned from the following activities:

- Site visits and photographic recording of all Horizon sites;
- Review of Horizon existing as-built drawings and building assessment reports;
- Visioning sessions with the CEO and Executives;

- Development of a needs assessment staff questionnaire and analysis of findings;
- Departmental user group interviews focusing on growth, adjacencies and clarification of questionnaire submissions; and
- Summary of user group information for updating CEO and Executives to highlight findings and obtaining further direction.

2 CURRENT STATE

2.1 Overview

Horizon Utilities Corporation currently owns four properties accommodating approximately 400 staff and 94 fleet vehicles. Properties include:

55 John Street, Hamilton – Head Office and Substation
450 Nebo Road, Hamilton – Service Centre and Main Stores
703 Highway 8, Stoney Creek – Overhead Lines, Stores and Training Centre
340 Vansickle Road, St. Catharines – Customer Service Centre, Service Centre and Stores

Within each of these facilities, there is potential area for growth; most notably at St. Catharines and Stoney Creek. In general, the facilities are in good shape and have been well maintained. Detailed architectural and engineering reports for all sites are included in Appendix A. Detailed information for each site will be discussed in the sections that follow.

2.2 John Street

The John Street facility primarily houses administrative offices and is considered the corporation's head office. There is a strong commitment to keep this location as the head office over the next ten years. The building is in good shape with all but the fourth floor having been recently renovated. The sixth floor is currently partially tenanted. Reorganization of the floors, reduction of onsite record storage, closure of the various lunch rooms and the upcoming departure of the tenant on the sixth floor will create potential to create the functions desired and allow for future growth.

2.2.1 Architectural Summary

The building was constructed in 1949. It is a steel framed structure with limestone facades on the north, east and west sides and brick on the south side. The building footprint is 41,000 square feet (including the Man building and substation). There is no construction record for the Man building. It appears to be a reinforced concrete structure. Gross floor areas are as follows:

Basement	36,000 square feet
Ground Floor	30,300 square feet (not including substation)
Levels 2-6	13,000 square feet
Second Floor Man	2,400 square feet

Most of the main tower has been renovated. Insulation has not been added to the perimeter walls to enhance its thermo performance. Man building exterior walls are original double-wythe brick with no insulation. Most of the exterior windows in the main tower were replaced in the early 1990's. There are still a few original single-glazed windows in the main tower, mainly exit stairs and service rooms. The Man building windows are the original single-glazed steel.

2.2.2 Building Envelope Assessment

Component	Composition	Observations/Recommendations
Exterior Wall 55 John Street	• Perimeter foundation walls are of cast-in-place concrete. • Upper level walls consist of limestone exterior veneer, clay tile back up and plaster interior. • Limestone veneer in 4" or 8" thicknesses depending on locations. Clay tile backup is in 4" or 8" thickness depending on locations. The clay tile backup is load-bearing as indicated on record drawings. • There is no thermal insulation in original exterior walls. There is no evidence that any exterior insulation was added in later dates.	• Adding insulation to exterior walls will reduce the heating/cooling load for this building and increase comfort for perimeter offices. • The recommended method of insulating the exterior walls is to: 1. Remove the existing plaster 2. Apply 2/12" of high performance sprayed polyurethane insulation to the existing clay tile (approx R13) 3. Line walls with 2/12" metal studs at 24" on centre 4. Apply 5/8" gypsum wallboard • Removal of existing plaster will ensure that there is no unvented cavity in the wall system which might cause deterioration of the stone and clay tile back up and will save space. • Electrical boxes along perimeter walls can be installed within the 2/12" stud space, perimeter heaters have to be moved inwards, and new window sills will be required. • It will be a difficult task for areas with heritage significance. The marble wall finishes and wood panels have to be carefully removed and reinstalled to suit the increased wall thickness. It is our understanding that this building is not officially designated, which makes the permit process relatively easier. It is possible to do this upgrade on a floor by floor basis.
Perimeter Windows 55 John Street	Majority of windows are double-glazed, operable aluminum windows similar in style to the original design. They were installed in the early 1990's. Some original single-glazed steel windows remain in service areas.	• Seals around the aluminum windows have deteriorated, causing drafty conditions and the windows are nearly twenty years old. It is recommended that they be replaced at the same time of exterior wall upgrades.
Exterior Wall Man Building	Double-wythe brick, no insulation, no cavity	• Insulating the existing perimeter walls will reduce energy bills and increase comfort for office space in this building. • The recommended method is to: 1. Apply 2/12" of high performance sprayed polyurethane insulation to the existing clay tile (approx R13) 2. Line walls with 2/12" metal studs at 24" on centre 3. Apply 5/8" gypsum wallboard
Perimeter Windows Man Building	Original single-glazed steel windows	• Replace with aluminum windows with sealed double-glazing units by Kawneer or Alumicor

2.2.3 Structural Summary

There are no obvious structural deficiencies with the building. The main building was originally designed to support an addition which was added to increase the main building height to 6 storeys. The structural design of the garage/receiving area is designed significantly different and does not appear to have included the capacity for additional floors. Buildings of this vintage are generally not designed to meet the requirements of present building codes particularly from a seismic perspective. Any plans that would significantly impact the structural systems should consider the structural modifications that might be imposed on the existing six storey structure to meet the new code requirements.

2.2.4 Mechanical and Electrical Summary

2.2.4.1 HVAC

Main Vehicle Area
The existing HVAC system in this portion of the facility consists mainly of infrared tube heaters mounted at the underside of the roof deck in the main vehicle area. There is a roof mounted exhaust fan on the first level (ground level) however it is believed that this fan is timer controlled.

First Floor Metering Department (Existing) - Proposed Command Centre
The existing HVAC system in this portion of the facility is serviced by AHU-6 which is located on the first floor adjacent to the paring area and this department. AHU-6 moves 7000 cfm of air throughout this space. AHU-6 was installed in 1997 and is in relatively good condition. Cooling capacities are sufficient and heating capacities should be sufficient for the current use.

First Floor Lobby/Second/Third Floor
These areas are served by AHU-2 & AHU-3 located in the basement mechanical room. These units were installed in 1995 and are in relatively good condition. The HVAC ductwork and terminal reheat/cooling coils in the lobby and second floor were redone in 2001/2002.

Fourth Floor
This area is served by AHU-4 located in the penthouse mechanical room. This unit was installed in 1995 and is in relatively good condition. The fourth floor is serviced by a pressurized supply air plenum and is neither particularly efficient nor effective. The HVAC ductwork and terminal reheat/cooling coils on the fourth floor have not been recently upgraded and will need to be addressed as part of any redevelopment of the fourth floor.

Fifth Floor
This area is served by AHU-4 and AHU-5 located in the penthouse mechanical room. AHU-4 was installed in 1995 and is in relatively good condition. AHU-5 is older and needs to be replaced in the near future. The HVAC ductwork and terminal reheat/cooling coils on the fifth floor has been recently upgraded (2004) and will not require any major work as a result of the proposed fifth floor redevelopment.

Sixth Floor
This area is served by HVAC-3, HVAC-4, HVAC-5, HVAC-6 and HVAC-7. These units are approximately ten years old and are still less than 50% of the way through their useful life. The sixth floor was renovated in 1998 and it appears that the ductwork and controls are in relatively good condition.

Man Building (2-storey)
This area is served by HVAC-1 (first floor) and HVAC-2 (second floor). HVAC-1 is approximately 17 years old and HVAC-2 is approximately 27 years old.

2.2.4.2 Plumbing

Domestic Cold and Hot Water
Domestic cold and hot water piping system, fixtures and tanks appear to be in good repair.

Sanitary Piping System
The sanitary piping system appears to be in good repair.

2.2.4.3 Fire Protection

The standpipe system in the facility appears to be in relatively good condition and receiving regular inspections and maintenance.

2.2.4.4 Lighting

The lighting system in the facility appears to be in relatively good condition. The majority of the office tower has been renovated and the lighting is relatively new. The emergency and exit lighting system in the facility appears to be in relatively good condition. The majority of the office tower has been renovated and this system is relatively new.

2.2.4.5 Power and Distribution

Electrical Distribution System
The electrical distribution system consisting of 13.8kV 600A load break switches, 2000 kVA 13.8 kV-347/600V substation and 500 kVA 600-120/208V transformation feeding a main 1200A 347/600V switchboard. Various feeds are then distributed throughout the

building including the basement mechanical room and the penthouse mechanical room. Some of the main equipment appears to be original and might be nearing its anticipated end of life.

Emergency power for critical loads is through a permanent emergency generator system tied with automatic transfer capability. Upon failure of the normal power system, all critical loads are transferred to the emergency generator system until such time as the normal power is restored.

2.2.4.6 Communications and Data

Telephone/Voice
This system was not reviewed at the time of the visit. Since this is primarily an operational system, it is anticipated that any maintenance, operational shortcomings or inadequacies are addressed by the appropriate division of the client.

Data/Network
This system was not reviewed at the time of the visit. Since this is primarily an operational system, it is anticipated that any maintenance, operational shortcomings or inadequacies are addressed by the appropriate division of the client.

2.2.4.7 Fire Alarm

Fire Alarm System
There is an existing Notifier 5000 series Fire alarm system in the facility. The fire alarm system in the facility appears to be in relatively good condition, receiving regular inspections and maintenance.

2.3 Nebo Road

Built in 1981, the Nebo Road facility was originally constructed as a service centre to house fleet parking, a mechanic garage, stores and support services such as lunch room and locker rooms for the service staff. Over time offices and other workspaces have been constructed to accommodate growth. There are a number of issues associated with the HVAC systems and the ability to exhaust fumes. With the number of staff at the location increasing, PRISM recommends that Horizon look to redevelop the space to improve its utilization, but more importantly, to upgrade mechanical systems to improve the airflow within the building.

The Stores department has an excellent plan to reduce stock and move towards more just-in-time inventory management. Implementation of this plan will provide Horizon the opportunity to construct properly built and ventilated workspaces on the south mezzanine. Other opportunities include: more support space for the service staff such as larger locker spaces and hotelling spaces for the staff to work from at the start and end of their shifts; improved indoor fleet parking (larger and more spaces); upgraded security and pedestrian safety for exterior parking and storage spaces; and improved external traffic and staff flows to ensure a safe environment.

The Nebo facility is in a good location to service the Hamilton customers and as such, is a good candidate for upgrades and expansion.

2.3.1 Architectural Summary

The Nebo facility is a pre-engineered steel main frame structure, steel framed mezzanine structure, 6' and 9' mezzanine floor slab. The building is one-storey, plus mezzanines on the north and south sides. The building footprint is 72,900 square feet. Gross floor areas are as follows:

Ground floor	72,900 square feet
Mezzanines	35,300 square feet

2.3.2 Building Envelope Assessment

Component	Composition	Observations/Recommendations
Exterior Walls (all areas except offices)	Prefinished steel panels with 3" insulation, 26 GA prefinished steel interior liner panel	• Rated approximately R10 when new. ASHRAE 90.1-2004 requires R13.
Exterior Walls (at perimeter office spaces)	Prefinished steel panels, painted drywall interior	• Uncertain if 3" insulation exists behind drywall finish. • Upgrading necessary if office spaces are to remain.
Perimeter Office Windows	Original sliding aluminum windows	• Past life expectancy and should be replaced
Perimeter Man Doors	Hollow metal doors and frames	• Doors may have been replaced/added in the past. Unknown if insulated • If original, should be replaced with insulated metal doors and all frames complete with proper weather stripping.
Perimeter Overhead Doors		• If original, should be replaced with insulated sectional doors with new weather seal around perimeter of the door opening.
Roof	Aluminized steel panel 3" vinyl covered insulation	• No evidence of leaks. • Rated approximately R10 when new. ASHRAE 90.1-2004 requires R13

2.3.3 Structural Summary

There are no obvious structural deficiencies with the building. From a structural perspective building can be enlarged and/or reconfigured. Mezzanine areas could be removed and/or reworked as required to accommodate an architectural redesign. A separate office building is an option, but redevelopment is more driven by zoning and architectural requirements rather than structural inadequacies.

2.3.4 Mechanical and Electrical Summary

2.3.4.1 HVAC

<u>Main Vehicle Area</u>
The exhaust rate is code compliant, however it is designed at the low end of the acceptable limits. It was not likely intended to serve as more than vehicle use. Current use of this space includes occupied offices and in its current capacity, the emission exhaust system does not provide acceptable performance. Continued and future use of this building for office areas will necessitate improving the performance of the emission exhaust system along with other good engineering measures to ensure a comfortable and safe working environment for the employees at this site.

The existing HVAC system in this portion of the facility consists mainly of infrared tube heaters mounted at the underside of the roof deck in the main vehicle and storage areas and exhaust fans and intake louvers with motorized dampers for CO and NOX from vehicles. The emissions exhaust system is controlled via CO sensors, NOX sensors (for diesel) and timers.

The rollup doors are not interlocked with heating system. The motorized damper at A7/8 is not operational.

<u>Maintenance Shop</u>
There is no fresh air intake louver in the maintenance shop. There is a roof mounted extraction fan and a wall mounted extraction fan leaving the room in significant negative pressure and the fans cavitating when the doors are closed. The fans were disconnected several years ago from the control system. The system is currently operated via manual switches mounted on the walls of the maintenance shop. Heating is provided by means of electric unit heaters mounted along the walls. There is a welding exhaust system at the welding station which seems to function adequately.

<u>Offices 129, 130, 131 and 132</u>
The HVAC system serving this space consists of an old Lennox horizontal natural gas fired furnace with duct mounted air conditioning coil. There is no fresh air for this system, thus it is not possible to pressurize these offices to eliminate exhaust odours. The system is old, does not have sufficient fan capacity for the spaces served and does not do an adequate job of maintaining comfort for the occupied spaces.

<u>Offices 133, 134, 135 and 136</u>
The HVAC system serving this space consists of a newer horizontal natural gas fired furnace with duct mounted air conditioning coil. There is no fresh air for this system, thus it is not possible to pressurize these offices to eliminate exhaust odours. The system does not have sufficient fan capacity for the spaces served and does not do an adequate job of maintaining comfort for the occupied spaces.

Mezzanine Offices
The portable structures mounted on the mezzanine are ducted from a system mounted on the roof of the portable structures. Fresh air is from a common plenum ducted through the roof. All of the ducting consists of flexible insulated ductwork loosely installed along the top of the structures. These offices are extremely dirty from airborne particulate and it appears that they are very poorly sealed and not properly pressurized. The existing system is inadequate and poorly installed. The air quality is continuously monitored to ensure limits are not exceeded.

Lunch Room, Washrooms, Showers
These areas are served by roof mounted gas fired packaged HVAC units which have replaced the original heat pumps with electric duct heaters. Exhaust is mainly through the side walls. Ducting travels vertically through the ceiling, up through the mezzanine and to the roof mounted equipment. Two units are utilized to service all the noted areas. The main challenge within these spaces is that there are different heating/cooling requirements and comfort/air balance is severely compromised.

2.3.4.2 Plumbing

Domestic Cold and Hot Water
Domestic cold and hot water piping systems, fixtures and tanks appear to be in good repair.

Sanitary Piping System
Sanitary piping system appears to be in good repair. Trench drains in the vehicle area appear to be in good working condition and in fair repair.

2.3.4.3 Process Piping

Shop Air Compressor Piping
The maintenance garage air compressor system and piping appears to be in good condition.

2.3.4.4 Fire Protection

The standpipe system in the facility appears to be in relatively good condition and receiving regular inspections and maintenance.

2.3.4.5 Lighting

The lighting system in the facility appears to be in relatively good condition. The vehicle/storage area consists of high pressure sodium high bay lighting. Office areas are fluorescent. Emergency and exit lighting units appear to be in relatively good condition, receiving regular inspections and maintenance.

2.3.4.6 Power and Distribution

The electrical distribution system consisting of 1200A 347/60 0V switchboard, transformation and various distribution panels in the facility appears to be in relatively good condition and receiving regular inspections and maintenance.

2.3.4.7 Communications and Data

Telephone/Voice
This system was not reviewed at the time of the visit. Since this is primarily an operational system, it is anticipated that any maintenance, operational shortcomings or inadequacies are addressed by the appropriate division of the client.

Data/Network
This system was not reviewed at the time of the visit. Since this is primarily an operational system, it is anticipated that any maintenance, operational shortcomings or inadequacies are addressed by the appropriate division of the client.

2.3.4.8 Fire Alarm

The fire alarm system in the facility appears to be in relatively good condition, and receiving regular inspections and maintenance.

2.4 Stoney Creek

Built in 1985, the Stoney Creek site was obtained through a merger and is primarily used as a service centre with a stores department and fleet parking. This site consists of 10 acres of land of which the building and operations currently use one quarter of the space. The majority of the space is vacant or is used as an ad hoc training facility. The building is in excellent condition and has potential to be better utilized. Its location, ideal as it is centrally located between the Hamilton and St. Catharines facilities, sits in a rural area just outside of residential neighbourhoods. As Stoney Creek develops, especially with residential growth, there may be an opportunity for Horizon to divest this property and relocate to another location within Stoney Creek that is more conducive to light industrial use. For the short term, PRISM recommends that this facility is retained. Issues with the current site include vandalism of fleet vehicles and theft of outdoor stock. Upgraded security measures are recommended.

2.4.1 Architectural Summary

The facility's administrative area is load bearing masonry and steel structure. The shop area is a pre-engineered steel main frame structure. The building is one-storey, with a footprint of 30,900 square feet. The gross floor areas are as follows:

- Administrative area 11,300 square feet
- Shop area 19,600 square feet

2.4.2 Building Envelope Assessment

Component	Composition	Observations/Recommendations
Exterior Walls Administrative	3 ½" brick veneer, 3/8" air space, 2" rigid insulation, 7 ½" concrete block, interior	• In excellent condition. • No upgrades necessary.
Exterior Walls Administrative area above windows	3 ½" brick veneer, 3 ½" concrete block, soffit cavity +/- 24", 2 ½" rigid insulation, 2x4 wood studs	• In excellent condition. • No upgrades necessary.
Perimeter Windows Administrative	Aluminum windows with sealed double glazing units, non-operable	• In good condition. No visible seal deterioration or condensation. • Owner may consider installing operable units at certain areas to allow natural ventilation.
Perimeter Doors Administrative	Original double-glazed aluminum entrances	• In good condition. No visible seal deterioration or condensation. • No upgrading necessary.
Roof Administrative	Gravel, single ply roofing, 4" rigid insulation, vapour barrier, galvanized metal deck	• No evidence of leaks observed. • No upgrading necessary.
Roof Shop Area	Prefinished standing seam metal roof, R20 batt insulation, prefinished metal liner panels	• No evidence of leaks observed. • No upgrading necessary.

2.4.3 Structural Summary

There are no obvious structural deficiencies with the building. From a structural perspective, the building can be enlarged and/or reconfigured as required to accommodate an architectural redesign.

2.4.4 Mechanical and Electrical Summary

2.4.4.1 HVAC

<u>Main Vehicle Area</u>
The existing HVAC system in this portion of the facility consists mainly of infrared tube heaters mounted around the perimeter on the underside of the roof deck in the main vehicle and storage areas. These are supplemented by electric unit heaters mounted in the interior of the space. Exhaust fans and intake louvers with motorized dampers for carbon monoxide and nitrogen oxide from vehicles are installed. The emissions exhaust system is manually controlled. The rollup doors are not interlocked with the heating system.

<u>Stores/Storage</u>
The existing HVAC system in this portion of the facility consists mainly of infrared tube heaters mounted around the perimeter on the underside of the roof deck and supplemented by electric unit heaters in the interior area. There is an exhaust fan in the space which is anticipated for general use only. Vehicles are not operated inside this space with the exception of a small propane powered fork lift. The rollup receiving door is not interlocked with the heating system.

Office Area
These areas are served by four roof mounted heat packaged heat pump units with electric heating.

2.4.4.2 Plumbing

Domestic Water
Domestic cold and hot water piping systems, tanks and fixtures appear to be in good repair.

Sanitary Piping System
The sanitary piping system appears to be in good repair.

2.4.4.3 Fire Protection

Fire Standpipe System
The office and operations areas have a standpipe system. There are two main fire pumps, one for standpipe and one for sprinkler system. The standpipe system in the facility appears to be in relatively good condition and receiving regular inspections and maintenance.

Fire Sprinkler System
Both areas have a zoned sprinkler system. There are two main fire pumps, one for standpipe and one for the sprinkler system. The sprinkler system in the facility appears to be in relatively good condition, having been modified over the years to suit various renovations and receiving regular inspections and maintenance.

2.4.4.4 Lighting

The lighting system in the facility appears to be in relatively good condition. Typically, lighting is serviced by the 347V panels. The vehicle/storage area consists of metal halide high bay lighting. The stores and office areas utilize T-12 fluorescent lighting.

Emergency and Exit Lighting
Despite their age, the units appear to be in relatively good condition, receiving regular inspections and maintenance.

2.4.4.5 Electrical Distribution System

The electrical distribution system consists of a 750 kVA pad mounted utility transformer feeding a main 1200A 347/600V switchboard. The transformation and distribution panels in the facility appear to be in relatively good condition and receiving regular inspections and maintenance.

2.4.4.6 Communications and Data

Telephone/Voice
This system was not reviewed at the time of the visit. Since this is primarily an operational system, it is anticipated that any maintenance, operational shortcomings or inadequacies are addressed by the appropriate division of the client.

Data/Network
This system was not reviewed at the time of the visit. Since this is primarily an operational system, it is anticipated that any maintenance, operational shortcomings or inadequacies are addressed by the appropriate division of the client.

2.4.4.7 Fire Alarm

There is an existing Mircom fire alarm system in the facility. The system appears to be in relatively good condition and receiving regular inspections and maintenance.

2.4.4.8 Exterior Security System

There is an issue with theft at this location.

2.5 St. Catharines

The original facility (north building) was built in 1977 to serve as an office and service centre. An addition (south building) was constructed in 2002 to provide additional administrative office space. Horizon obtained the St. Catharines facility through a merger, and primarily uses it as the main customer call centre supporting all Horizon customers and a full operations service centre including fleet parking, mechanic garage and stores. Customer service, Lines and Metering departments that support St. Catharines are located at this site.

Horizon senior management has made a commitment to keep a presence in St. Catharines to support its customers in the area. There is logic in this decision, whereas customer response times from Horizon's Hamilton facilities would be unreasonable, in consideration of the 54 km distance between communities. Further the situation of the company Call Centre in St. Catharines has proven strategic. There are multiple privately owned call centres in the area that provide a qualified feed-in pool for new hires. The buildings are in good condition and the second floor of the north building is vacant. The site's floor area is adequate to support the departments and staff activities, however it is poorly configured and utilized, thus efficient use of space to support productive work by the staff is compromised. A number of issues are present:

- The Overhead Lines area is not large enough to support the staff. A larger area to meet as a team and more hotelling stations for the service staff are required.
- The Customer Service area requires more room to support the staff and allow for more space to help with noise issues.

- The indoor fleet parking area does not support the number of vehicles as they have grown in size and quantity over time. There is some concern with leaving the vehicles outdoors as they have been vandalized and exposure to the elements shortens the vehicle usable lifespan.
- Ongoing issues with vandalism and theft of outdoor stock. A security system has recently been installed.

2.5.1 Architectural Summary

The north building office/shop is a steel framed structure. The south building addition is load bearing masonry with supporting steel beams and OWSJ roof joists. The north building has two storeys and the south building has one storey. The two buildings have a total of 55,500 square feet. The gross floor areas are as follows:

- South building (admin) 28,800 square feet
- North building (office/garage/storage) 36,800 square feet

2.5.2 Building Envelope Assessment

Component	Composition	Observations/Recommendations
Exterior Walls North Building	4" architectural concrete block, 2" rigid insulation, 6" concrete block	• Exterior block is in good condition • Non-cavity wall contains asbestos in wall insulation. Avoid disturbing this wall type if possible.
Exterior Walls South Building	8" load bearing concrete block, Tyvec membrane, 1" air space, 3-5/8" stud wall batt insulation, 6 mil poly vapour barrier, 5/8" drywall	• In good condition. • No upgrades necessary.
Perimeter Windows North Building	Original single-glazed aluminum windows	• Past their life expectancy, do not meet current thermal performance standard and should be replaced.
Perimeter Doors South Building	Original double-glazed aluminum windows, non operable	• In good condition. • Owner may consider replacing them with new sealed double-glazed windows with an operable section to allow some natural ventilation in shoulder seasons.
Perimeter Overhead Doors		• If original, should be replaced with insulated sectional doors with new weather seal around perimeter of the opening.
Roof North Building	Built up roofing, 2 ½" rigid insulation, vapour barrier, 1 ½ " metal deck	• No evidence of leaks observed • Less than R10 when new. ASHRAE 90.1-2004 requires R19. Upgrading recommended.
Roof South Building	Information not available	• Considering the building is less than 10 years old, roof construction and insulation level should meet current standards.

2.5.3 Structural Summary

There are no obvious structural deficiencies with the building. From a structural perspective the building can be enlarged and/or reconfigured as required to accommodate architectural redesign. An elevator can be installed within, or as an addition to the existing structure.

2.5.4 Mechanical and Electrical Summary

2.5.4.1 HVAC

Main Vehicle Area, North Building
The existing HVAC system in this portion of the facility consists mainly of infrared tube heaters mounted around the perimeter on the underside of the roof deck in the main vehicle and storage areas. These are supplemented by electric unit heaters mounted in the interior of the space. Exhaust fans and intake louvers with motorized dampers for carbon monoxide and nitrogen oxide from vehicles are installed. The emissions exhaust system is manually controlled. The rollup doors are not interlocked with the heating system.

Garage, North Building
There is no fresh air intake louver in the garage. There is a roof mounted extraction fan leaving the room in significant negative pressure and the fans cavitating when the doors are closed. There is a small source capture vehicle exhaust system on a swivel assembly as well. Heating is provided by means of electric unit heaters mounted along the walls.

Stores/Storage, North Building
Heating is provided by an overhead ducted system. The stores storage area uses natural gas fired infrared tube heaters along the perimeter of the space. Access to the roof was not permitted, and the documentation does not show this system, however it is anticipated that there is a roof mounted HVAC unit above the stores office which feeds the stores office and the stores area.

First Floor, Meter Shop and Office, North Building
These areas are served by eight air handling units with electric duct heaters and a roof mounted condenser. Exhaust is handled mainly through the roof.

Second Floor, North Building
These areas are served by seven air handling units with electric duct heaters and a roof mounted condenser. Exhaust is handled mainly through roof.

Existing Call Centre, South Building
This area is serviced by five roof mounted natural gas units.

2.5.4.2 Plumbing

Domestic Water
Domestic cold and hot water piping systems, tanks and fixtures appear to be in good repair.

Sanitary Piping System

The sanitary piping system appears to be in good repair. Trench drains in the vehicle appear to be in good working condition and fair repair.

2.5.4.3 Fire Protection

The sprinkler system in the facility appears to be in relatively good condition, having been inspected and maintained regularly. The system consists of an excess pressure pump, and an all annunciators tie to the fire alarm system. There are two sprinkler trees, one in the office area and one in the stores area of the north building. The south building is sprinkled, however it is not certain where it connects to the sprinkler system from the north building.

2.5.4.4 Lighting

The lighting system in the facility appears to be in relatively good condition. The vehicle/garage area consists of metal halide high bay lighting. Office areas are fluorescent.

Despite their age, the emergency and exit lighting units appear to be in relatively good condition, receiving regular inspections and maintenance.

2.5.4.5 Electrical Distribution System

The electrical distribution system consisting of 1000A 347/600V switchboard, transformation and various distribution panels in the facility. There are multiple transformers for various parts of the system. Generally, the system appears to be in relatively good condition, receiving regular inspections and maintenance.

Emergency Power System
The emergency power system in the building is provided by means of a 350kW 347/600V emergency generator (natural gas) and various transfer switches/interlocks in the facility. This system has its own transformation and panel boards and appears to be in relatively good condition, receiving regular inspections and maintenance.

2.5.4.6 Communications and Data

<u>Telephone/Voice</u>
This system was not reviewed at the time of the visit. Since this is primarily an operational system, it is anticipated that any maintenance, operational shortcomings or inadequacies are addressed by the appropriate division of the client.

<u>Data/Network</u>
This system was not reviewed at the time of the visit. Since this is primarily an operational system, it is anticipated that any maintenance, operational shortcomings or inadequacies are addressed by the appropriate division of the client.

2.5.4.7 Fire Alarm

The fire alarm system in the north building is a Simplex 4010 control panel with all appropriate detection, monitoring and annunciation devices and appears to be in relatively good condition, receiving regular inspections and maintenance. It appears that this system has been extended into the south building and zones added to accommodate this expansion.

2.5.4.8 Exterior Security System

There is an issue with theft at this location.

3 COMMON THEMES SURVEY

The following summarizes common themes from the staff surveys and interviews***, have not been substantiated through this report and do not necessarily form the recommendations in this report.*** More details can be found in Appendix B.

3.1 General

- Main environmental concerns were related to HVAC, lighting and access to natural light.
- There is a desire to have more indoor fleet parking at Nebo, Stoney Creek and St. Catharines.
- Hotelling space is required at each site for staff who work out of multiple sites or their vehicles and students. Although less so at the John Street and Stoney Creek Facility.
- More meeting rooms are required at all sites, including small rooms where staff without offices can meet one-on-one or make personal calls. All meeting rooms should be equipped with appropriate telephones and AV equipment.
- Some feel it is unfair that the satellite sites have free parking for the staff, while John Street does not. Improved bicycle parking and some designated spots to encourage car pooling at John Street may help.
- Most departments have projected staffing growth plans. The addition of more apprentices is the main reason. Some departments feel they will grow if Horizon has more acquisitions over time. Some flexibility must be planned for this in the space projections for each site.
- Document storage is not managed well and taking up valuable real estate. Purging of records should be considered.
- Most feel communication is working well. Would like to see more use of teleconferencing and video conferencing to reduce travel time.
- Amenities such as lunch room/cafeteria, quiet space and exercise space is important to the staff. John Street would like to see the elimination of the small lunch rooms and the creation of a communal area to encourage staff interaction. Ideally some food service would be provided. Improved locker facilities, especially at Nebo, should be considered. Most departments indicated the desire to have exercise facilities at each site.
- Security is a concern after hours at John Street. Theft and vehicle damage is a concern at Nebo, Stoney Creek and St. Catharines.

3.2 Site Specific Themes

3.2.1 John Street

- Network Operating would like to relocate the Control Centre from the fourth floor to the first floor Customer Connections area. The area has the required HVAC and is safer so that staff do not feel isolated as they work 24/7.
- Consolidate the executive team on the sixth floor with a new boardroom.
- Renovate the fourth floor as it is the only floor not redeveloped.

- There is a desire to better consolidate some departments to be more effective.
- Create a centralized lunch room, preferably with some food service provisions on one of the upper floors.
- Improved locker facilities that are fully accessible and barrier-free.
- Improve use of lobby to make it more welcoming and to provide space for educational and archival material.

3.2.2 Nebo Road

- It is felt that more indoor parking for large trucks is required. Vandalism is an issue with outdoor fleet parking.
- Office areas are small, dirty and noisy due to proximity of vehicles in building. The building's HVAC system is ineffective, so diesel fumes are circulating throughout the building.
- Office areas are not adequate for team meetings.
- There are not enough hotelling spaces for staff who are visiting or who work from their vehicles, and staff growth is anticipated.
- Potential staff safety issues exist with external parking and storage areas.
- Locker rooms are not large enough to accommodate all of the staff and their belongings.
- Stores are working on a plan to reduce stock over time creating the potential for more useable space at this site.

3.2.3 Stoney Creek

- Customer Connections would like to consolidate the John Street and St. Catharines groups to this site to improve efficiencies in staffing, coverage and communication.
- There is a desire to extend the garage and indoor parking area to accommodate the increase in vehicles and vehicle size.
- The large training centre is in a convenient location between Hamilton and St. Catharines.

3.2.4 St. Catharines

- There is a desire to extend the garage and indoor parking area at St. Catharines to accommodate the increase in the number of vehicles and vehicle size.
- An elevator is required to utilize the second floor.
- Overhead Lines require more space to meet as a team and hotelling spaces for the service staff to work from when on site.
- Customer service area is crowded and noise in an issue, there is also no male washroom in the south building.

4 SPACE TABLES

JOHN STREET LEVEL 6

Room/Space	Department	QTY	NSF	Total	Comments
Executive Suite					
Office, CEO	Executive	1	240	240	
Workstation, Executive Assistant	Executive	3	100	300	
Office, VP	Executive	1	160	160	
Office, VP	Executive	1	160	160	
Office, VP	Executive	1	160	160	
Office, VP	Executive	1	160	160	
File Storage	Executive	1	50	50	
Boardroom	Executive	1	850	850	Seats 30 with AV and teleconferencing
Waiting/Coat Closet	Executive	1	20	20	near boardroom
Network Printer/Fax	Executive	1	50	50	
Washroom	Executive	1	50	50	
	TOTAL EXECUTIVE			**2,200**	
Office, VP, Regulatory	Regulatory Services	1	160	160	
Office, Director	Regulatory Services	1	140	140	
Office, Manager, Rates and Reporting	Rates and PBR	1	120	120	
Workstation, Rates Analyst	Rates and PBR	2	64	128	File Cabinets
Workstation, Regulatory Coordinator	Rates and PBR	1	64	64	
Office, Manager, Regulatory Compliance	Regulatory Services	1	120	120	
File Storage		1	100	100	
	TOTAL REGULATORY			**832**	
Office, VP Finance	Finance	1	160	160	
Workstation, Executive Assistant, Finance	Finance	1	100	100	
Workstation, Accountant	Accounting	3	80	240	
Workstation, Accounting Analyst Red Circled	Accounting	1	64	64	
Workstation, Accounting Clerk	Accounting	2	64	128	
Office, Manager, Treasury & Taxation	Finance	1	120	120	
Office, Manager, Accounting	Accounting	1	120	120	
Workstation, Student, Finance	Accounting	2	64	128	
Workstation, Supervisor, Accounting	Accounting	1	80	80	
Workstation, Accounting Analyst	Business Analysis	1	64	64	
Office, Director, Budgeting & Business Analysis	Business Analysis	1	140	140	
Workstation, Lead Budgeting & ABC	Business Analysis	1	64	64	
Office, Manager, Business Analysis	Business Analysis	1	120	120	
File Storage	Finance	1	150	150	
	TOTAL FINANCE			**1,678**	

JOHN STREET LEVEL 6

Room/Space	Department	QTY	NSF	Total	Comments
Office, Director, Corporate Communications	Corporate Communications	1	140	140	
Office, Manager, Corporate Communications	Corporate Communications	1	120	120	
Workstation, Public Relations Clerk	Corporate Communications	1	64	64	
Workstation, Specialist, Communications	Corporate Communications	1	64	64	
Workstation, Advisor, Human Resources	Human Resources	1	64	64	
Workstation, Coordinator, Human Resources	Human Resources	1	64	64	
Workstation, Coordinator, Training	Human Resources	1	64	64	
Office, Director, Human Resources	Human Resources	1	140	140	
Workstation, Lead, Training & Development	Human Resources	1	64	64	
Office, Manager, Employee Relations	Human Resources	1	120	120	
Workstation, Advisor, Human Resources	Human Resources	1	64	64	
Workstation, Specialist, Payroll	Human Resources	1	64	64	
Workstation, Specialist, Process & Change Mgmt	Human Resources	1	80	80	
Workstation, Computer Testing Carrel	Human Resources	2	30	60	
Reference Library, Lockable Storage	Human Resources	1	70	70	Near Reception
File Storage	Human Resources	1	120	120	
Interview Room, Enclosed	Human Resources	1	120	120	Near Reception
Change Management Team Workroom	Human Resources	1	180	180	
	TOTAL CORPORATE SERVICES			**1,662**	
Reception for Floor		1	144	144	small area to wait
Central Printer, Fax and Storage Area		1	150	150	Partially enclosed
Washroom, Male, Barrier-free		1	170	170	Multi-stall, existing good
Washroom, Female, Barrier-free		1	170	170	Multi-stall, existing good
Servery		1	80	80	With counter, sink, coffee/tea/microwave, full size fridge
Coat Closet		1	50	50	For staff with workstations
Housekeeping Closet		1	70	70	With sink
	TOTAL SHARED			**834**	

Total Net Square Feet (NSF)	**7,544**
NSF : GSF Grossing Factor	1.42
Total Gross Square Feet (GSF)	**10,712**
Available	**10,795**
Difference	**83**

JOHN STREET LEVEL 5

Room/Space	Department	QTY	NSF	Total	Comments
Office, Chief Conservation Officer	CDM	1	140	140	
Workstation, Conservation Clerk	CDM	3	64	192	Including 1 workstation for temp conservation clerk
Workstation, Events Team Specialist, Temp	CDM	1	64	64	
Office, Manager, Commercial Programs	CDM	1	120	120	
Office, Manager, Marketing	CDM	1	120	120	
Workstation, Specialist, Conservation	CDM	1	80	80	
Display Trade Show Storage, Level 1 at Dock	CDM	1	0	0	
File Cabinets for File Storage	CDM	1	100	100	
Workstation, Student	CDM	1	64	64	
Workstation, Residential Specialist	CDM	1	64	64	**FUTURE**
Workstation, Communications Specialist	CDM	1	64	64	**FUTURE**
Workstation, Smart Grid Student	CDM	1	64	64	**FUTURE**
Workstation, Smart Grid Supervisor	CDM	1	64	64	**FUTURE**
Workstation, Energy Advisor	CDM	1	64	64	**FUTURE**
Project Workroom and Meeting Table	CDM	1	200	200	Seats 8 with AV, smartboard, whiteboards
	TOTAL CDM			**1,400**	
Workstation, Analyst, Report Data	Business Applications	1	64	64	
Workstation, Console Operator	Business Applications	1	64	64	
Workstation, Database Administrator	Business Applications	1	64	64	
Office, Director, Info Systems & Technology	Business Applications	1	140	140	
Officer, Manager, Business Applications	Business Applications	1	120	120	
Office, Manager, Business Projects	Business Applications	1	120	120	
Workstation, Senior Programmer Analyst	Business Applications	3	80	240	
Workstation, Specialist, Business and Project	Business Applications	1	80	80	
Workstation, Systems Administrator	Business Applications	1	64	64	
Office, Manager, Technical Services	Technical Services	1	120	120	
Workstation, Network Administrator	Technical Services	1	64	64	
Workstation, PC Technician	Technical Services	3	64	192	
Workstation, Web Developer	Technical Services	1	64	64	
Workstation	Technical Services	2	64	128	**FUTURE 2010**
Workstation	Technical Services	4	64	256	**FUTURE 2011**
Locked Room, Equipment Staging/Testing Area	Technical Services	1	300	300	
Locked Room, Record Storage	IT	1	200	200	
Data Centre/SCADA & UPS Rooms	IT	1	917	917	
	TOTAL IT			**3,197**	
Training Room		1	2,230	2,230	Seats 60 - 70, AV, chair storage, servery
Meeting Room, Large		1	330	330	Seats 10-12 people with AV, teleconferencing equipment, whiteboards
Central Printer, Fax and Storage Area		1	140	140	Partially enclosed
Washroom, Male, Barrier-free		1	170	170	
Washroom, Female, Barrier-free		1	250	250	
Quiet Room		1	80	80	Small table, seats 4, with telephone
Servery		1	100	100	Counter, sink, coffee/tea/microwave, full size fridge
Coat Closet, enclosed		1	50	50	For staff with workstations
Hotelling Stations		4	30	120	
Housekeeping Closet		1	70	70	With sink
	TOTAL SHARED			**3,540**	
		Total Net Square Feet (NSF)		**8,137**	
		NSF : GSF Grossing Factor		1.35	
		Total Gross Square Feet (GSF)		**10,985**	
		Available		**11,065**	
		Difference		**80**	

JOHN STREET LEVEL 4

Room/Space	Department	QTY	NSF	Total	Comments
Team Room, Facilities	Facilities	6	30	180	For 6 staff, including **1 FUTURE staff**
Workstation, Lead Hand, Facilities	Facilities	1	64	64	
Office, Manager, Facilities	Facilities	1	120	120	
Workstation, Student, Facilities	Facilities	2	30	60	
Workstation, Supervisor	Facilities	1	80	80	**FUTURE**
Record Storage		1	80	80	
	TOTAL FACILITIES			**584**	
Office, Manager, Healthy Workplace and Safety	Healthy Workplace and Safety	1	120	120	
Workstation, Specialist Health and Safety	Healthy Workplace and Safety	1	80	80	
Workstation, Student, Health and Safety	Healthy Workplace and Safety	1	64	64	
Locked, File Storage	Healthy Workplace and Safety	1	80	80	
	TOTAL WORKPLACE & SAFETY			**344**	
Workstation, Assistant, Purchasing	Procurement	1	64	64	
Workstation, Manager, Procurement	Procurement	1	120	120	
Workstation, Specialist, Commodity Management	Procurement	1	80	80	
Workstation, Specialist, Projects	Procurement	1	80	80	
Workstation, Student, Procurement	Procurement	1	64	64	
Workstation, Procurement	Procurement	2	64	128	**FUTURE**
Interview/Meeting Team Room	Procurement	1	180	180	
Filing	Procurement	1	250	250	
Reference Library	Procurement	1	60	60	
Workstation, Storekeeper	Logistics	1	64	64	
Office, Director, Supply Chain	Supply Chain	1	140	140	
Workstation, Environmental Mgmt & Sustainable Dev Specialist	Supply Chain	1	64	64	
Workstation, Specialist, Master Data & Document	Supply Chain	1	80	80	
Workstation, Student, Supply Chain	Supply Chain	1	64	64	
	TOTAL SUPPLY CHAIN			**1,438**	
Corporate Lunch Room		1	3,030	3,030	With food service?
Meeting Room, Medium		1	280	280	Seats 12 people with AV, teleconferencing equipment, whiteboards
Central Printer/Fax Storage Area		1	170	170	Partially enclosed
Washroom, at Cafeteria		1	140	140	
Washroom, Male, Barrier-free		1	180	180	Multi-stall, new
Washroom, Female, Barrier-free		1	160	160	Multi-stall, new
Quiet Room		1	80	80	Small table, seats 4, with telephone
Multifaith Prayer Room		1	180	180	
First Aid/Rest Room		1	120	120	Recliner, sink, visitor chair
Servery		1	100	100	Counter, sink, coffee/tea, microwave, full size fridge
Coat Closet		1	50	50	For staff with workstations
Hotelling Stations		3	30	90	
Housekeeping Closet		1	70	70	With sink
	TOTAL SHARED			**4,650**	
	Total Net Square Feet (NSF)			**7,016**	
	NSF : GSF Grossing Factor			1.35	
	Total Gross Square Feet (GSF)			**9,472**	
	Available			**10,955**	DGSF confirmed
	Difference			**1,483**	

JOHN STREET LEVEL 3

Room/Space	Department	QTY	NSF	Total	Comments
Office, VP, Utility Operations	Utility Operations	1	160	160	
Workstation, Engineering Technician	Capital Projects	9	80	720	
Office, Manager	Capital Projects	1	120	120	
Workstation, Student	Capital Projects	1	80	80	
Workstation, Supervisor, Engineering Design	Capital Projects	2	80	160	
Workstation, for expansion	Capital Projects	5	80	400	**FUTURE**
Workstation, Distribution Engineer	Network Assets	1	80	80	
Workstation, Engineer in Training, Project	Network Assets	2	80	160	
Workstation, Engineering Intern	Network Assets	1	80	80	
Office, Manager, Network	Network Assets	1	120	120	
Workstation, for expansion	Network Assets	5	80	400	
Workstation, AM/FM Technician	Network Records	2	64	128	
Workstation, Co-op Student, Network Records	Network Records	2	64	128	
Workstation, Draftsperson	Network Records	4	80	320	
Workstation, Network Records Clerk	Network Records	1	80	80	
Workstation, Records Coordinator	Network Records	2	80	160	
Workstation, Supervisor, Network Records	Network Records	1	80	80	
Office, Manager, Operational	Operational Improvement	1	120	120	
Workstation, Project Specialist	Operational Improvement	1	80	80	
Office, Director, Engineering	Eng, Op & Op Imp	1	140	140	
TOTAL ENGINEERING & OPERATIONAL IMPROVEMENT				**3,716**	
Reference Library/Drawing Storage		1	200	200	
Plotter, Light Table, Large Table to Review		1	260	260	
Project Team Workroom		1	310	310	Seats 8 people
Meeting Room, Large		1	500	500	Seats 20 people with AV, teleconferencing equipment, whiteboards
Meeting Room, Medium		1	290	290	Seats 10-12 people with AV, teleconferencing equipment, whiteboards
Central Printer/Fax Storage Area		1	120	120	Partially enclosed
Washroom, Male, Barrier-free		1	170	170	Multi-stall, existing good
Washroom, Female, Barrier-free		1	245	245	Multi-stall, existing good, includes 1 enclosed barrier-free washroom
Quiet Room		1	80	80	Small table seats 4, with telephone
Servery		1	100	100	Counter, sink, coffee/tea/microwave, full size fridge
Coat Closet		1	50	50	For staff with workstations
Hotelling Stations		6	30	180	
Data Centre Phone Room		1	270	270	Existing
Housekeeping Closet		1	70	70	With sink
TOTAL SHARED				**2,845**	

Total Net Square Feet (NSF)	**6,561**
NSF : GSF Grossing Factor	1.53
Total Gross Square Feet (GSF)	**10,038**
Available	**10,948**
Difference	**910**

JOHN STREET LEVEL 2

Room/Space	Department	QTY	NSF	Total	Comments
Office, VP, Customer Services	Customer Service & Connections	1	180	180	
Workstation, Student	Collections	1	30	30	Swing Space
Office, Manager	Billing	1	120	120	
Workstation, Billing Clerk	Billing	11	64	704	
Workstation, Key Clerk	Billing	1	64	64	
Workstation, Mail Clerk	Billing	3	64	192	
Workstation, Student	Billing	1	64	64	
Workstation Supervisor	Billing	1	80	80	
Workstations	Daffron	5	64	320	
Office, Acting Director	Customer Service	1	140	140	
Workstation, Cashier	Customer Service	1	64	64	from Lobby
Workstation, Creditron Operator	Customer Service	1	64	64	from Lobby
Workstation, Customer Service Coordinator	Customer Service	1	64	64	from Lobby
Workstation, Cashier Student	Customer Service	1	30	30	from Lobby
Workstation, CIS Analyst	Customer Service	1	64	64	
Worstation, CS AMI Operator	Customer Service	1	64	64	
Workstation, General Clerk	Customer Service	5	64	320	
Workstation, Senior Cashier	Customer Service	1	80	80	
Workstation, Senior Customer Service Clerk	Customer Service	1	64	64	
Workstation, Student	Customer Service	5	30	150	
Workstation, Collections Clerk	Credits and Collections	5	64	320	
Workstation, Head Billing Clerk	Credits and Collections	2	80	160	
Workstation, Pre-Authorized Clerk	Credits and Collections	1	64	64	
Workstation, Collections Supervisor	Credits and Collections	1	80	80	
Vault	Customer Service	1	100	100	
File Storage	Customer Service	1	300	300	
	TOTAL CUSTOMER SERVICE			**3,702**	
Office, VP, Business Development	Business Development	1	160	160	
Workstation, Financial Analyst	Business Development	1	64	64	
Workstation, Policy Advisor	Business Development	1	64	64	
Storage, Pamphlets/Brochures	Business Development	1	50	50	
	TOTAL BUSINESS DEVELOPMENT			**338**	
Meeting Room, Large		1	440	440	With AV, teleconferencing equipment, whiteboards
Central Printer/Fax Storage Area		1	150	150	Partially enclosed
Washroom, Male, Barrier-free		1	170	170	Multi-stall, existing stalls aren't barrier-free
Washroom, Female, Barrier-free		1	230	230	Multi-stall, existing stalls aren't barrier-free
Quiet Room		2	80	160	Small table seats 4, with telephone
Servery		1	100	100	Counter, sink, coffee/tea/microwave, full size fridge
Coat Closet		1	50	50	For staff with workstations
Hotelling Stations		4	30	120	
Housekeeping Closet		1	40	40	With sink
	TOTAL SHARED			**1,460**	
	Total Net Square Feet (NSF)			**5,500**	
	NSF : GSF Grossing Factor			1.53	
	Total Gross Square Feet (GSF)			**8,415**	
	Available			**12,635**	
	Difference			**4,220**	

JOHN STREET LEVEL 1

Room/Space	Department	QTY	NSF	Total	Comments
Workstation, Security Officer	Corporate	2	64	128	Open desk welcoming
Workstation, Customer Service Desk	Customer Service	1	80	80	Panels for privacy seating for 2
Open Area, Visitor Waiting/Reception		1	120	120	Seating for 8, located near Security Desk
Open Area, Customer PC and Drop Box	Corporate	1	60	60	Open area
Open Area, Brochure Racks/Educational Info	Corporate	1	250	250	Open area
Open Area, Display	CDM	1	250	250	Open Area
Open Area, Archival Display	Corporate	1	250	250	Old meters/photos, etc
Public Washroom		1	70	70	Barrier-free
	TOTAL JOHN ST ENTRANCE			**1,208**	
	Total Net Square Feet (NSF)			**1,208**	
	NSF : GSF Grossing Factor			1.71	
	Total Gross Square Feet (GSF)			**2,066**	
	Available			**2,885**	
	Difference			**819**	
John Street Current Metering/Loading Dock					
Office, Manager Network Operating	Network Operating	1	120	120	**Moved from Level 3**
Workstation, Operating Group	Network Operating	5	100	500	Multi-screened consoles (replacing 16, as shiftwork)
Workstation, Operating Group	Network Operating	3	100	300	Multi-screened consoles **FUTURE**
Enclosed, Servery	Network Operating	1	80	80	In Control Centre
Meeting Room for 20	Network Operating	1	350	350	Can be emergency command centre. Requires phones, PCs, large table
Storage Area	Network Operating	1	100	100	Locked, in Control Centre
Washroom, Barrier-free	Network Operating	1	65	65	In Control Centre **NEW CONSTRUCTION**
Lockers	Network Operating	1	150	150	Qty 20, In Control Centre
Alcove with Mobile Filing Pedestal Units	Network Operating	1	80	80	20 mobile filing units for staff to pull to desk
	TOTAL NETWORK OPERATING			**1,745**	
Storage Area for Display/Trade Materials	CDM	1	500	500	
Housekeeping Closet		1	70	70	With sink
Loading Dock		1	650	650	
Gym/Exersize Room		1	700	700	
Bicycle Parking		1	400	400	
Lockers and Showers, Male		1	1,100	1,100	Barrier-free
Lockers and Showers, Female		1	1,000	1,000	Barrier-free
	TOTAL SHARED			**4,420**	
	Total Net Square Feet (NSF)			**6,165**	
	NSF : GSF Grossing Factor			1.35	
	Total Gross Square Feet (GSF)			**8,323**	**DGSF confirmed**
	Available			**8,350**	
	Difference			**27**	
Does note include water rates offices	**1,548 sf**				
Does not include Man building	**1,935 sf**				
Does not include substation	**7,545 sf**				
Does not include parking garage					

JOHN STREET BASEMENT LEVEL

Room/Space	Department	QTY	NSF	Total	Comments
Locker Room, Male	Corporate	1	960	960	Could convert use in future
Locker Room, Female	Corporate	1	500	500	Could convert use in future
Mail Room	Customer Service	1	420	420	Includes mailing machine, sorting area, ventilation
Billing Machine	Customer Service	1	200	200	in same area as mailroom
Billing & Mail Supplies	Customer Service	1	150	150	
Storage	Corporate	1	480	480	
Housekeeping Closet		1	70	70	With sink
	TOTAL			**2,780**	

Total Net Square Feet (NSF)	**2,780**
NSF : GSF Grossing Factor	1.40
Total Gross Square Feet (GSF)	**3,892**
Available	**3,906**
Difference	**14**

NEBO SERVICE CENTRE

Room/Space	Department	QTY	NSF	Total	Comments
Office, Manager Substations	Substations	1	120	120	
Team Room, Substation Maintainers & Apprentices	Substations	3	30	90	Accommodates 3 stations **NEW**
Test Lab	Substations	1	80	80	
Storage, Technical Info and Archives	Substations	1	120	120	
Hotelling Station, Troublemen	Capital Projects	3	30	90	
	TOTAL SUBSTATIONS			**500**	
Workstation, Maintenance Clerk	Facilities	1	64	64	
Workstation, Lineman/Clerk	Overhead	2	64	128	
Office, Manager, Lines - Overhead	Overhead	1	120	120	
Workstation, Overhead Clerk	Overhead	1	100	100	
Office, Supervisor, OH	Overhead	4	80	320	
Team Room, OH Groups, Apprentices		28	30	840	Accommodates 28 stations **NEW**
Record Storage, Filing		1	80	80	Files
	TOTAL OVERHEAD			**1,652**	
Workstation, Clerk	Underground	1	100	100	
Office, Supervisor, Duct Crew	Underground	1	80	80	
Office, Supervisor, Pulling Crew	Underground	1	80	80	
Office, Supervisor, Underground	Underground	2	80	160	
Office, Supervisor	Outside Contractors	1	80	80	
Workstation, Contractor Inspector	Outside Contractors	3	64	192	
Team Room, Duct Crew, Operators, UG Groups, Apprentices		18	30	540	Accommodates 18 stations **NEW**
Record Storage, Filing		1	80	80	Files
	TOTAL UNDERGROUND			**1,312**	
Workstation, Fleet Clerk	Fleet	1	100	100	
Workstation, Fleet Coordinator	Fleet	1	100	100	
Workstation, Lead Hand Mechanic	Fleet	1	64	64	
Office, Manager, Fleet	Fleet	1	120	120	
Hotelling Station, Mechanic	Fleet	3		0	In Garage
Workstation, Inventory Control Clerk	Logistics	1	64	64	
Office, Manager, Logistics	Logistics	1	120	120	
Workstation, Specialist, Material Planner & Expediter	Logistics	1	64	64	
Hotelling Station, Storekeeper	Logistics	6	0	0	In Stores
Hotelling Station, Student	Logistics	1	0	0	In Stores
Office, Supervisor, Warehouse	Logistics	1	80	80	
Hotelling Station, Transformer Maintainer	Logistics	1	30	30	
Hotelling Station		1	30	30	Accommodates 1 station **NEW**
Hotelling Station in Stores		4	0	0	Accommodates 4 stations **NEW** in stores
	TOTAL SUPPLY CHAIN			**772**	

NEBO SERVICE CENTRE

Room/Space	Department	QTY	NSF	Total	Comments
Workstation, Reception/Waiting		1	120	120	New
Locked Room, Data Centre	Network Operating	1	200	200	
Locker Room, Male		1	2,500	2,500	
Locker Room, Female		1	925	925	Could be upgraded
Drying Room		1	200	200	
Hotelling Stations for Staff	Corporate	6	30	180	For offsite staff
Office, HR Interview Room	Human Resources	1	120	120	Seats 4, locked, with PC and phone
Large Meeting Room		1	470	470	Seats 24 people, with AV, teleconferencing equipment, whiteboards
Central Printer, Fax, Storage Area		1	150	150	Partially enclosed
Washroom, Male, Barrier-free		1	180	180	
Washroom, Female, Barrier-free		1	180	180	
Quiet Room		1	90	90	Small table seats 4, with telephone
Multifaith Prayer Room		1	215	215	
First Aid Room		1	215	215	Recliner, sink, storage
Lunchroom		1	1,700	1,700	
	TOTAL SHARED			**7,445**	
	Total Net Square Feet (NSF)			**11,681**	
	NSF : GSF Grossing Factor			1.35	
	Total Gross Square Feet (GSF)			**15,769**	
Mechanic, Garage	Fleet	1	5,800	5,800	
Storage, North Mezzanine	Logistics	1	10,400	10,400	
Stores, Main Level	Logistics	1	5,000	5,000	
Stores, Mezzanine	Logistics	1	3,700	3,700	
Transformer Testing	Logistics	1	1,530	1,530	
	TOTAL			**26,430**	
	Total Area Required			**42,199**	
	Area Available			**53,111**	**Note: Does not include indoor fleet parking (50,900 GSF)**
	Difference			**10,912**	**Note: Additional areas not on chart: 2 new stairs and elevator**

STONEY CREEK

Room/Space	Department	QTY	NSF	Total	Comments
Office, Director, Customer Connections	Customer Connections	1	140	140	
Workstation, Lead Hand, Quality Mgmt, System Metering	Meter Assets and Inside Service	1	64	64	
Office, Manager, Meter Assets & Inside Services	Meter Assets and Inside Service	1	120	120	
Workstation, Meter Support Clerk - Meter Assets	Meter Assets and Inside Service	1	100	100	
Workstation, Specialist, Revenue Protection	Meter Assets and Inside Service	1	64	64	
Workstation, Student, Meter Assets & Inside Services	Meter Assets and Inside Service	1	30	30	
Workstation, Engineering Technician	Customer Connections	4	64	256	
Office, Manager, Customer Connections	Customer Connections	1	120	120	
Workstation, Meter Support Clerk	Customer Connections	3	100	300	
Workstation, Meterperson, Lead Hand	Customer Connections	1	64	64	
Workstation, Student, Customer Connections	Customer Connections	1	30	30	
Workstation, Supervisor, Customer Connections	Customer Connections	1	80	80	
Workstation, Time of Use Street Team Lead	Smart Metering	1	64	64	
Workstation, CIS Analyst	AMI/MDMR	1	64	64	
Office, Manager, Meter Comm & Tech	AMI/MDMR	1	120	120	
Workstation, Student, Meter Comm & Tech	AMI/MDMR	1	30	30	
Workstation, Supervisor, Meter Comm & Tech	AMI/MDMR	1	80	80	
	TOTAL JOHN ST STAFF			**1,726**	
Workstation, Engineering Technician	Customer Connections	2	80	160	
Workstation, Meter Support Clerk	Customer Connections	1	100	100	
Workstation, General Clerk, St. Catharines	Smart Metering	4	64	256	
	TOTAL ST. CATHARINES STAFF			**516**	
Team Room, Hotelling Stations for Staff	Customer Connections	12	30	360	For 22 staff
Stores	Customer Connections	1	0	0	Use part of existing Stores
Secure Tool Storage	Customer Connections	1	100	100	
Workshop Area	Customer Connections	1	200	200	
Testing Board Area	Customer Connections	1	500	500	
	TOTAL SHARED			**1,160**	
Network Closet	Network Operating	1	150	150	
Locker Room, Male		1	675	675	
Locker Room, Female		1	100	100	
Corporate Training Centre		1	1,600	1,600	With AV and chair storage
Hotelling Stations for Staff		6	30	180	For offsite staff
HR Office/Interview Room	Corporate	1	100	100	Seats 4, Locked with PC and telephone
Meeting Room	Human Resources	1	270	270	Seats 10-12 with AV, teleconferencing equipment, whiteboards
Central Printer, Fax, Storage Area		1	150	150	Partially enclosed
Washroom, Male, Barrier-free		1	170	170	
Washroom, Female, Barrier-free		1	170	170	
Quiet Room		1	80	80	
Multifaith Prayer Room		1	80	80	Seats 4, small table, with telephone
First Aid Room		1	80	80	
Lunchroom		1	320	320	
Housekeeping Closet		1	70	70	
	TOTAL OTHER RESOURCES FOR FACILITY			**4,195**	
	Total Net Square Feet (NSF)			**7,597**	
	NSF : GSF Grossing Factor			1.35	
	Total Gross Square Feet (GSF)			**10,256**	
		Stores		**7,300**	
	Area Available			**17,855**	**Not including parking garage**
	Difference			**299**	

ST CATHARINES LEVEL 1 NORTH BUILDING

Room/Space	Department	QTY	NSF	Total	Comments
Workstation, Lines Clerk	595 - Lines	1	100	100	
Office, Manager, Lines	595 - Lines	1	120	120	
Hotelling Station, Student, Overhead	595 - Lines	2	30	60	
Office, Supervisor, Lines	595 - Lines	3	80	240	
Hotelling Station, Engineering, Capital Projects	Engineering	3	30	90	For when on site
Hotelling Station, Underground	Underground	2	30	60	
Workroom, Lead Hands		5	30	150	
Team Room, All Lines Groups and Apprentices		1	600	600	Gathering area for shift start/end for 35 staff, with PCs and telephones
TOTAL OVERHEAD AND UNDERGROUND LINES				**1,420**	
Reception Area	Customer Service	1	360	360	At entrance with desk, waiting and storage
Locker Room, Male		1	1,940	1,940	Current
Locker Room, Female		1	270	270	New on 1st Floor
Janitor Closet		1	63	63	Current
Copy Room		1	65	65	Current
Washroom, Male, Barrier-free		1	135	135	
Washroom, Female, Barrier-free		1	135	135	
First Aid Room		1	125	125	With recliner, sink and storage
Quiet Room		1	125	125	Small table, seats 4, with telephone
Lunchroom		1	1,300	1,300	Current, could be upgraded
TOTAL SHARED				**4,158**	
Total Net Square Feet (NSF)				**5,578**	
NSF : GSF Grossing Factor				1.35	
Total Gross Square Feet (GSF)				**7,530**	
Admin Area Available				**9,160**	
Difference				**1,630**	

ST. CATHARINES LEVEL 1 GARAGE/STORES

Room/Space	Department	QTY	NSF	Total	Comments
Office, Manager, Supply Chain	Stores	1	0	0	Work 1 day/week from Nebo, In Stores
Workstation, Storekeeper	Logistics	1	0	0	In Stores area
Workstation, Storekeeper	Logistics	1	0	0	In Stores area
Hotelling Station, Student, Stores	Logistics	1	0	0	In Stores area
Stores	Logistics	1	15,980	15,980	More room than req'd
Loading Dock		1	0	0	SF Included In Stores
Indoor Parking		1	15,900	15,900	
Mezzanine	Lines	1	410	410	Current
Mechanic Garage	Lines	1	2,800	2,800	Current
Hotelling Station, Lead Hand Mechanic	Supply Chain Management	1	0	0	In Garage
TOTAL				**35,090**	
Total Net Square Feet (NSF)				**35,090**	
NSF : GSF Grossing Factor				0.00	
Total Gross Square Feet (GSF)				**35,090**	**Includes indoor parking and mechanic garage**
Area Available				**35,680**	
Difference				**590**	

ST. CATHARINES LEVEL 2 NORTH BUILDING

Room/Space	Department	QTY	NSF	Total	Comments
Workstation, Call Centre Coordinator	Customer Service	1	64	64	
Workstation, Customer Service Representative	Customer Service	21	64	1,344	
Workstation, General Clerk	Customer Service	2	64	128	
Office, Supervisor, Customer Service, John St	Customer Service	1	80	80	
Office, Supervisor, Customer Service, St. Catharines	Customer Service	1	80	80	
Workstation, Operating Group	Network Operating	1	64	64	
Locked Room, Data Centre	Network Operating	1	150	150	
Record Storage	Customer Service	1	200	200	
Quiet Room	Customer Service	1	80	80	Small table seating for 2, with telephone
	TOTAL CUSTOMER SERVICE			**2,190**	
Coat Storage		1	75	75	For staff with workstations
Housekeeping Closet		1	70	70	New
Meeting Room, Medium		1	240	240	Seats 10-12 people, with AV, teleconferencing equipment,
Large Training Room		1	1015	1015	Servery / Chair A/V Storage CURRENT
Hotelling Stations for Staff	Corporate	6	30	180	
HR Office/Interview Room	Human Resources	1	110	110	Seats 4, locked, PC and phone
Copy, Printer, Storage Room		1	130	130	New
Washroom, Male, Barrier-free		1	180	180	
Washroom, Female, Barrier-free		1	270	270	New
File Storage		1	250	250	
Servery		1	85	85	Existing
	TOTAL SHARED			**2,605**	
	Total Net Square Feet (NSF)			**4,795**	
	NSF : GSF Grossing Factor			1.35	
	Total Gross Square Feet (GSF)			**6,473**	
	Area Available			**10,000**	
	Difference			**3,527**	

ST. CATHARINES LEVEL 1 SOUTH BUILDING

Room/Space	Department	QTY	NSF	Total	Comments
Generation Group Lease		1	1,046	1,046	
Boardroom		1	470	470	
	TOTAL			**1,516**	
	Total Net Square Feet (NSF)			**1,516**	
	NSF : GSF Grossing Factor			1.35	
	Total Gross Square Feet (GSF)			**2,047**	
	Area Available			**7,640**	
	Difference			**5,593**	Available for Lease

5 ADJACENCIES

Results from the staff surveys and management interviews identified physical adjacencies for each site. Where possible, PRISM reflected requested adjacencies in the space tables and block schematic plans. The following tables summarize recommended adjacencies:

5.1 John Street

Level	Departments	Adjacency Rationale
Basement	1. Mail Room 2. Mostly storage, building infrastructure, parking	
1	**Lobby** 3. Security Reception, Waiting 4. Customer Service Desk and phones 5. Drop box and PC for customers 6. Archival and educational display areas **Current Customer Connections Area** 7. Secure Network Operating Command Centre for all staff including Manager and meeting room for Disaster Control Management 8. New locker rooms, exercise area and bicycle parking 9. Secure storage for CDM trade show materials and displays at loading dock	3. More welcoming environment 7. Provides required space that is less isolated and has dedicated HVAC running 24/7 8. Barrier-free to meet current codes 9. Parking for van on main level
2	10. Customer Service including Billing Clerks from first floor lobby 11. Business Development	10. Existing provides area to expand
3	12. Engineering and Operational Improvement (consolidated except for Network Operating on first floor)	12. Consolidates department and area for expansion
4	13. Supply Chain/Procurement 14. Facilities 15. Healthy Workplace and Safety 16. Corporate lunch room, sick room, multifaith prayer room	13. These departments do similar projects allowing better interaction and communication 16. Area available
5	17. Information Technology (consolidated from various locations) 18. Conservation Distribution Management	17. Consolidate department 18. Close to Executive on 6th floor and allows for planned growth
6	19. Executive Team (including all Vice Presidents) 20. Finance 21. Regulatory 22. Human Resources/Corporate Communication 23. Boardroom	19. Consolidates Executive team and adjacencies identified by CEO

5.2 Nebo Road

Level	Departments/Services	Adjacency Rationale
1	1. Stores and Stores Office 2. Transformer testing area 3. Locker rooms 4. Lunch room 5. New reception with elevator and stairs to mezzanine 6. Data centre, multifaith prayer room, sick room 7. Indoor fleet parking 8. Mechanic garage	1. Most functions are existing. Allows for creation of main entrance and reception to control access 7. Allows for parking area expansion
2 North Mezzanine	9. Stores and Lift	9. Existing
2 South Mezzanine	10. Overhead Lines (Stoney Creek and Nebo combined) 11. Underground Lines 12. Substation Manager 13. Construction and Maintenance 14. Fleet and Stores offices 15. Hotelling spaces for visiting staff	10. Newly constructed spaces with dedicated HVAC and exterior windows on south side. 11. Will address air quality concerns and provide spaces for staff currently hotelling 15. New

5.3 Stoney Creek

Level	Departments/Services	Amenities
1	1. Customer Connections (consolidate from St. Catharines and John Street) 2. Stores 3. Corporate Training Centre 4. Hotelling spaces 5. Sick room, multifaith prayer room, data centre 6. Indoor fleet parking	1. Improved operational efficiency, supervision, inventory management and employee morale 3. Centrally located between St. Catharines and Hamilton 5. New

5.4 St. Catharines

Level	Departments/Services	Amenities
1 North Building	1. Expansion space for Overhead Lines with hotelling spaces and training 2. New entrance and reception for Customer Service 3. New stair and elevator to second floor. 4. Stores 5. Mechanic garage 6. Indoor fleet parking 7. Lunch room / locker rooms 8. Quiet room, sick room, multifaith prayer room	1. Most existing with some upgrades 7. Upgraded 8. New
2 North Building	9. Customer Service 10. Training Centre/Conference Rooms 11. Hotelling spaces	9. Relocated to expand and provide spaces currently lacking 10. Existing 11. New
1 South Building	12. Continue with current tenant 13. Lease out remainder	

6 RECOMMENDATIONS

6.1 Cost Benefit Methodology

PRISM and the consulting teams have provided recommendations for each site and for a few areas of consideration in corporate operations. During discussion with Executive Management Team, the consulting team recognized the need to include an informal cost/benefit analysis for each of the site recommendations. The team understands that the sites do not operate in a vacuum and that changes to one site may well impact on another.

In order to complete the cost benefit analysis, the PRISM team has made a number of qualitative assumptions to define costs and benefits; these are:

Costs

- Initial capital costs – includes the one time capital costs for renovations, additions, enhancements, new equipment, etc;
- Ongoing maintenance costs – upgrades to existing systems, annual maintenance costs for equipment, vehicles, etc;
- Ongoing leasing costs – includes IT equipment, photocopiers, AV equipment, if applicable;
- Loss of productivity/employee morale – includes staff time related to relocations, additional travel time to jobs;
- Health and Safety – includes issues related to maintaining safe and healthy workplaces; and
- Regulation and Legislation – compliance with regulatory and legislative requirements such as Ontario Disabilities Act.

Benefits

- Building performance – improved energy performance of buildings including building systems and infrastructure;
- Decreased maintenance costs – includes vehicles;
- Increased flexibility in space – additional space or better use of space;
- Improved productivity due to adjacencies and co-location of teams;
- Improved employee morale;
- Decreased vandalism and loss of materials;
- Meeting accessibility guidelines and regulations; and
- Improved health and safety aspects of workplace.

The PRISM team has also made a number of quantitative assumptions to determine the costs associated with recommendations. Some internal information such as salary and benefits, maintenance and leasing costs was not available to the consulting team, therefore absolute cost for some initiatives is not known. In these cases, PRISM made a qualitative assumption as a proxy. For example, the cost of staff relocation is estimated with moving and relocation costs, however because productivity loss is not quantifiable for this report, an assumption that a day's work will be lost with the relocation was made.

A cost/benefit matrix is included with the site recommendations provided below. The following scale was used to create the matrix:
Cost
Low - less than $149,999
Medium - $150,000 to $499,999
High – greater than $500,000

Benefits
Low - less than three (3) benefits met
Medium – 3 or 4 benefits met
High – more than five (5) benefits met

Note that the costing provided is construction only. Furniture, equipment, permits, architectural and engineering fees, consultant fees, moving or other soft costs are not included. Additional detail to support the analysis can be found in Appendix G.

6.2 Corporate Operational Recommendations

6.2.1 Space Planning and Furniture Standards

The development of a Master Space Strategy would offer Horizon the ability to plan, implement and adapt various site locations while bringing a high level of consistency and unified identity of a *Horizons* brand to all facilities.

A universal planning approach will respond to future and unpredictable change, and allow staff to move to accommodate change rather than the expense and time to redesign space. The furniture may have different components defining departmental job functions, but the principle of a kit of parts for easy change would allow Horizon to respond to change by moving people instead of furniture, resulting in a low churn rate and providing ultimate flexibility.

Workplace furniture guidelines will bring not only a high level of consistency and strong corporate identity to the workplace, but will provide Horizon with a flexible furniture inventory. Current furniture standards will also ensure that issues of health and safety, environmental opportunities such as LEED, and ongoing technological changes are addressed. Appendix D provides recommendations for space allocation standards and estimated furniture pricing.

6.2.2 Meeting Rooms

To make better use of current and future meeting rooms, Horizon should consider upgrading its audiovisual equipment, including more white boards and smart boards, teleconferencing and videoconferencing equipment for all meeting rooms at all sites. The technology will enable more productive meetings by providing the ability for staff members to meet remotely, thus potentially reducing travel time. (Note, cost is not covered in this report).

6.2.3 Information Technology

Currently, IT equipment is purchased and managed by individual departments. PRISM recommends that Horizon consider centralizing the management, purchasing and maintenance of all IT equipment for better control and improved annual operating capital planning.

A number of single departmental printers or workstation printers exist throughout the corporation. Provision of more networked multi-use devices will require less space and potentially reduce operating costs over time. PRISM recommends Horizon prepare a corporate printer/fax/copier allocation policy and an implementation plan with the goal of reducing the number of devices and moving to more multipurpose, networked devices. (Note, cost is not covered in this report).

6.2.4 Records Management

PRISM believes that Horizon is at risk due to its current records management practice. A records management strategy has been prepared by Horizon's Facilities department which includes partnering with an external records management firm to properly organize and manage the business records, including established retention standards. Benefits of implementing this proposal include:

1. Minimizing Litigation Risk

   Records are stored in secure facilities and disposed of, as set in Horizon's retention strategy. An offsite records management solution will provide a safe location for files as well as a managed record database.

   Presently, records are stored in various locations at all sites and are not managed effectively.

2. Ensuring Regulatory Compliance

   Proper control of record management and disposal would be established, ensuring fast retrieval of documents when necessary.

3. Reducing Operating Costs

   A records management system will reduce the use of valuable real estate to store records. There will also be a reduction in time spent by staff searching for and maintaining records.

4. Establishing new records management technologies such as electronic records management.

   Refer to the Horizon Utilities Records Management proposal in Appendix E.

6.2.5 John Street

6.2.5.1 Short Term Plans

1. Renovate the sixth floor as the Executive suite and include Human Resources, Regulatory and Finance, as well as a new properly sized and equipped boardroom.

   The current tenant is vacating and this provides an opportunity to start the phasing of internal renovations at John Street and establish the adjacencies and needs identified by the CEO.

2. Relocate Customer Connections to Stoney Creek from John Street and St. Catharines.

   Refer to the rationale under Stoney Creek proposals.

3. Renovate John Street Customer Connections space and move Network Operating to the first floor.

   Network Operating is the main command centre monitoring Horizon's network of services. They are the only 24/7 operation at John Street. Due to the nature of their work and sensitive computer systems, the department requires controlled HVAC 24/7. Currently located on the fourth floor, the main building HVAC system runs to support the operation. The staff have also noted security concerns due to the location within the building after hours.

   The current Customer Connections area on the first floor would be ideal to house this group. The space is currently supported by a dedicated HVAC system, thus the main building system could be shut down after hours, potentially resulting in operational efficiencies. The location, adjacent to the main entrance with security support, is ideal for the 24/7 operation. The area is large enough to accommodate planned growth and current service needs to operate as a truly isolated unit. It has been confirmed that the existing server, located on the fifth floor, can remain and support Network Operating in the first floor location.

4. Create new locker rooms, bicycle storage and gym on the first floor at the loading dock.

   The current locker rooms are not fully accessible as access to the space is via stairs. New locker rooms could be constructed within the current Customer Connections space. The existing lunch room could be converted into an exercise facility.

5. Conservation Distribution Management Storage

   The existing meter storage cage is convenient to the loading dock, thus making it a good location to house the trade show materials and display units for Conservation Distribution Management.

6. Renovate fourth floor and occupy.

   This is the only floor in the building that has not been upgraded. Once the Command Centre, Finance and Regulatory departments relocate, most of the floor would be available for upgrading. The washrooms will need to be retrofitted to meet accessibility codes. PRISM recommends that Facilities, Supply Chain and Health and Safety be relocated on this floor. Additionally, there is an opportunity to create a corporate lunch room/cafeteria, multifaith prayer room and sick room on this floor.

7. Reconfiguration of the second, third and fifth floors.

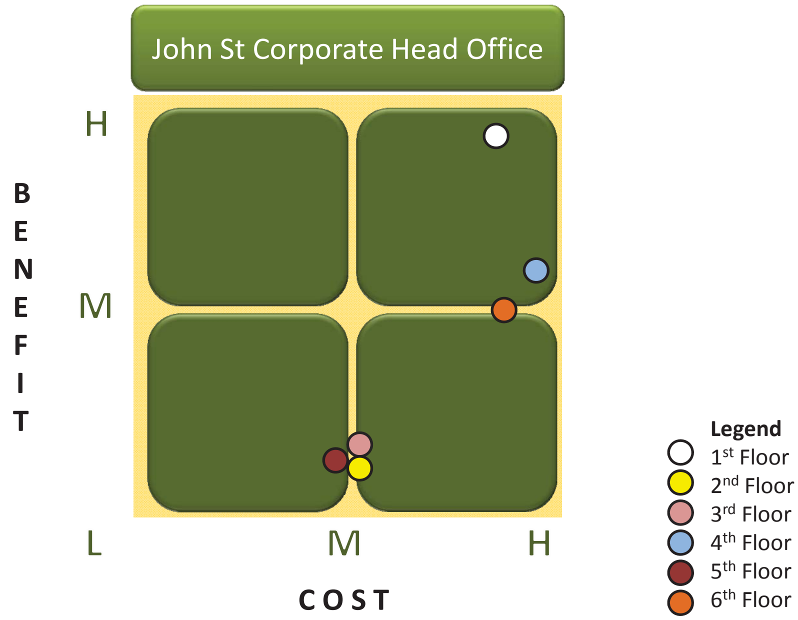
   Minor renovations and workstation reconfiguration can be done over time to accommodate growth and new room requirements.

8. Retrofit Lobby

   Create a more welcoming reception area, customer service area and security desk. Use the area to create an educational and archival information centre.

   Use Man building primarily for storage.

   Estimated Cost: $3,612,050



6.2.5.2 Five to Ten Year Plans

1. Upgrades to electrical distribution system and replacement of fifth floor HVAC.
2. Major changes to the building over longer term are not expected. There is area to grow in future with minor renovations.
3. Depending on growth with acquisitions and mergers, Head Office location may change.

Estimated Cost: $225,000

6.2.6 Nebo Road

6.2.6.1 Short Term Plans

1. Upgrade the garage exhaust system.
2. Stores to implement plan to reduce inventory freeing up the south mezzanine.
3. Relocate the Overhead Lines team from Stoney Creek to this facility to consolidate the Hamilton Overhead Lines team.
4. Renovate the south mezzanine to accommodate all offices, meeting spaces and new team rooms complete with dedicated HVAC system.

5. Construct a new elevator and stairs to the south mezzanine and create a reception and new main entrance at the current staff entrance.

6. Renovate the main floor to expand locker rooms, upgrade the lunch room and add multifaith prayer and first aid rooms.

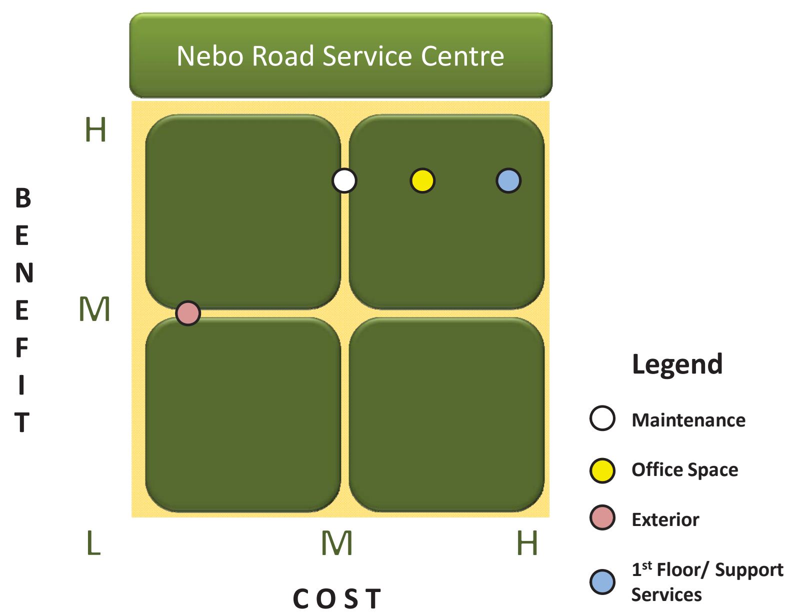
7. Proceed with the external reconfiguration plan for parking, storage and flow. This plan includes a new secure entrance from Nebo Road. Reconfiguration of external parking by moving staff and visitor parking to the south side and fleet parking to the west side will allow for a total of 170 parking spaces:

   - 136 staff parking spaces
   - 10 visitor spaces
   - 24 fleet spaces

8. The main floor garage can be renovated to accommodate 33 new parking spaces once the office and support spaces move to the mezzanine. If implemented, the internal parking count will increase to 92 spaces.

9. Add a security alarm system to the external fencing for stores and card readers for the entrances.

Estimated Cost: $2,634,375



6.2.6.2 Five to Ten Year Plans

1. Retrofit the garage level for more indoor parking and new exhaust system, if not done in short term plan.

2. There is 9,000 square feet of space available on the south mezzanine for future growth.

Estimated Cost: $900,000

6.2.7 Stoney Creek

6.2.7.1 Short Term Plans

1. Consolidate Customer Connections to Stoney Creek with teams relocating from John Street and St. Catharines. Stoney Creek is underutilized and provides an ideal location for the consolidation of the Customer Connections groups, due to its proximity between all service areas. Consolidating the team will result in operational efficiency, improved supervision, better inventory management and staff satisfaction. See proposed business case in Appendix F.

2. Reorganize Stores for better utilization and accommodation of meter stock.

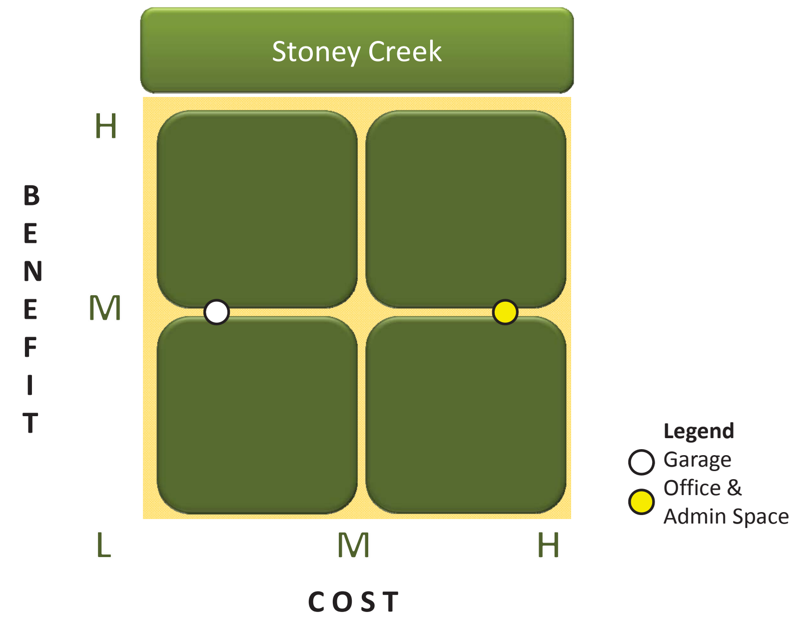
3. Create a permanent training centre with servery and easy access from the front of building, so it does not interfere with Costumer Connections workspaces.

4. Create hotelling stations for staff from other sites at the entrance.

5. Create a shared lunch room for staff.

6. Add a security alarm system to external fencing for stores.

Estimated Cost: $1,406,000



6.2.7.2 Five to Ten Year Plans

1. Expand the mechanic garage to accommodate larger fleet vehicles. (Not required if Overhead relocates to Nebo Road).

   Estimated Cost: $650,000

6.2.8 St. Catharines

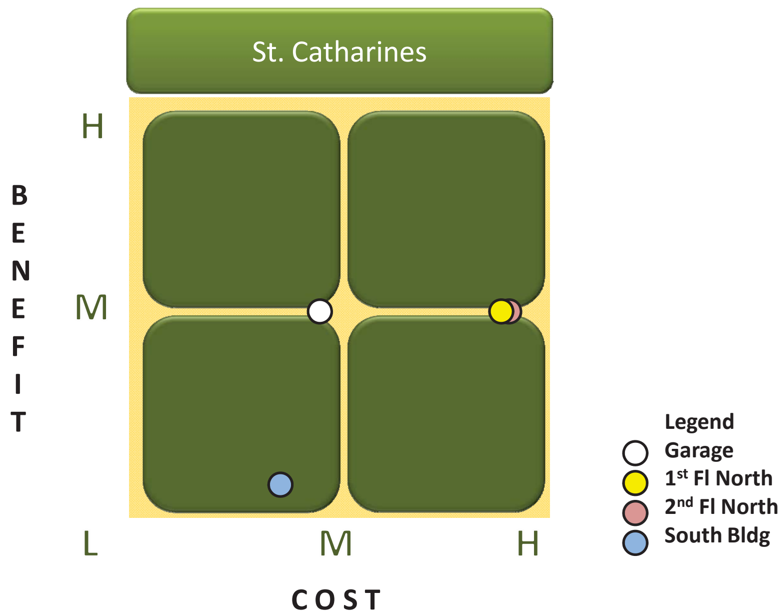
6.2.8.1 Short Term Plans

1. Build new elevator and stairs to second floor (north building).
2. Retrofit main floor entrance and reception at the current staff entrance.
3. Renovate the space to the south of the new entrance for barrier-free washrooms, first aid room and multifaith room.
4. Upgrade locker rooms including the construction of a linewomen's washroom and locker room on the first floor.
5. Renovate second floor to accommodate Customer Service and other functions as per space table.
6. Retrofit the main floor area to allow for Overhead expansion requirements as per space table.

7. Reorganize Stores for better utilization, providing a potential area for small vehicle parking such as vans.

8. Vacate the south building, and lease out the space, or sever and sell. Severing and selling does impact staff parking, therefore a review of the external property should be conducted to determine parking accommodation. Severing does not allow for future growth if required.

Estimated Cost: $2,857,000



6.2.8.2 Five to Ten Year Plans

1. Expand the indoor parking garage to accommodate more fleet parking. Expansion of the garage with 8,860 square feet of more space will accommodate approximately 14 more vehicles.

2. Expand the mechanic shop to accommodate larger vehicles.

3. Fit up vacant space in the North building, levels 1 and 2.

Estimated Cost: $2,860,000

6.3 Priority Phasing Recommendations

The following outlines PRISM's recommended priorities for implementation of the resource and space utilization project. Recommendations not listed here but that are included in the five year plan can be prioritized and planned with annual capital as it becomes available. These priorities are numbered from highest to lowest importance.

6.3.1 Nebo Road

Nebo accommodates a large number of staff, fleet and stores for the organization and has the highest safety risks due to poor indoor air quality and external flow of staff and fleet vehicles and stock. There are challenges working in a cramped facility managing the flow of people, stock and vehicles. Although the air quality is monitored on a regular basis the offices on the first floor do not have the provision of fresh air and there is no way to pressurize the offices to eliminate the exhaust odours. The main vehicle exhaust system is code compliant; however it is designed at the low end of acceptable limits. It was not likely intended to serve as more than vehicle use. The emission exhaust system does not provide acceptable performance. Continued and future use of the building for office areas will necessitate improving the exhaust system along with other good engineering measures to ensure a comfortable and safe working environment for the employees at this site.

Externally there are safety concerns with movement of stock, staff and fleet vehicles crossing paths. We feel that this site should take priority for improvement.

The following should be undertaken:

1. Proceed with Stores plan to reduce stock and move towards a more just-in-time system. This would free up the south mezzanine.

2. Build the offices, meeting rooms and team spaces on the south mezzanine level complete with dedicated HVAC to meet office environment standards. This includes the construction of a new stair and elevator to meet code requirements. This area will accommodate the offices from the garage area, accommodate planned staffing increases and enable the consolidation of Overhead Lines from Stoney Creek and leave approximately 9000 square feet for stores or future growth.

3. Upgrade the garage exhaust system.

4. Relocation of the office and meeting spaces from the first floor provides space to create a new main entrance at the south staff entrance and expansion of the locker facilities and addition of a first aid room and multi-faith room.

5. Reconfigure the external site to separate fleet and staff parking and stores to improve flow and safety.

6.3.2 John Street Sixth Floor

Renovate the sixth floor of John Street. With the current tenant leaving shortly this provides the opportunity to address the congestion and future growth in staff at the John Street facility, creating a phasing plan to address other floors. Most floors have been renovated with the exception of the fourth floor. Levels 2, 3 and 5 can be reconfigured with minimal renovations and mostly the reallocation of existing space to create desired adjacencies. The following is recommended for John Street:

1. Renovate the sixth floor to accommodate the Executive Suite, Human Resources, Finance and Regulatory. This frees up a good portion of the fourth and fifth floors.

6.3.3 Stoney Creek

Stoney Creek is a valuable asset to Horizons and is currently underutilized. Other than stores and fleet parking, only one quarter of the administrative area is being utilized for training. Relocating Customer Connections from John Street and St. Catharines to Stoney Creek will result in operational efficiency, improved supervision, better inventory management and staff satisfaction. This location is ideal for training and a proper training facility should be established at this site. PRISM recommends the following should be undertaken:

1. Relocate Overhead Lines to Nebo, as noted above.

2. Renovate the building to accommodate a proper training facility, Customer Connections and some hotelling stations.

3. Renovate the Customer Connections at John Street to accommodate the requirements for the Command Centre currently on the 4th floor of John Street. They require more space and plan for growth over time. As the only function at John Street working 24/7 they are isolated on the 4th floor after hours. The main building HVAC is running 24/7 to accommodate them on the 4th floor. The 1st floor area has its own dedicated HVAC unit which would result in operational savings with the ability to shut down the main system after hours and provide the staff a safe working environment.

4. Renovate the 4th floor to bring to code including barrier-free washrooms. Consolidate Supply Chain, Facilities and Health and Safety departments to this floor as they work closely and on similar projects which will improve communication and interaction. There is space available on this floor to create a consolidated cafeteria for the building which could be a good source of revenue generation. If not used as a cafeteria it provides future growth space.

6.3.4 St. Catharines

The second floor of St. Catharines north building is used occasionally for training, and is empty except for a female locker room. Customer Service is cramped and noisy on the main level. The

Overhead Lines area is overcrowded. The supervisors do not have a proper area to meet with their teams and there is no area for the service staff to work from when on site. The following is recommended:

1. Renovate the second floor to accommodate Customer Service, a proper meeting/training area and hotelling spaces for staff from other sites. This includes the construction of a new stair and elevator to access the second floor and a new reception in the north building.

2. Renovate the current Customer Connections area to provide additional space for Overhead Lines.

3. Lease the south building to provide additional revenue and ensure future growth needs can be met.

7 ESTIMATED BUDGET COSTING

ESTIMATED BUDGET COSTING

Note: Costing is for construction only and does not include architectural and engineering fees, furniture, equipment, fees, permits, moving or other soft costs or contingency.

Legend

High Urgency Recommendation

Medium Urgency Recommendation

Low Urgency Recommendation

Corporate	Sq Ft	Cost per Sq Ft	Total	Urgency	Notes
Space Planning and Furniture Standards				Medium	
Refer to Budget Costing Breakdowns in Appendix D					
Meeting Room Technology				Medium	
To be prepared by Horizon's Information Technology Department					
IT Equipment Management				Medium	
To be prepared by Horizon's Information Technology Department					
Records Management				High	
Start Up			$7,750		
Annual Operating Cost			$8,100		

John Street Short Term Recommendations	Sq Ft	Cost per Sq Ft	Total	Urgency	Notes
Retrofit Lobby	2,885	$100	$288,500	High	
1st Floor Network Operating Command Centre	1,780	$100	$178,000	High	
1st Floor New Locker Rooms	2,835	$175	$496,125	Medium	
1st Floor Bike Storage and Gym	1,485	$35	$51,975	Low	
1st Floor CDM Storage at Loading Dock	1,000	$5	$5,000	Low	Locked metal storage cage
Subtotal 1st Floor			**$1,019,600**		
2nd Floor Minor Renovations Customer Service	12,635	$25	$315,875	Low	
3rd Floor Minor Renovations Engineering and Op	10,948	$25	$273,700	Low	
4th Floor New Cafeteria and Support Service Depts	10,955	$75	$821,625	Medium	Price does not include cafeteria kitchen
5th Floor Minor Renovations IT Department	11,065	$25	$276,625	Low	
6th Floor Executive Suite	10,795	$75	$809,625	High	
Vehicle Area HVAC add CO/NOX Controls and Timers	1	$15,000	$15,000	Medium	
Man Building HVAC Upgrades	1	$80,000	$80,000	Medium	Dependent on planned use of space
Insulate Walls	1	$536,000	$536,000	Medium	To be done as floors are renovated
Replace Windows	1	$675,000	$675,000	Medium	To be done as floors are renovated
Total John Street Short Term Recommendations			***$4,823,050***		

John Street 5-10 Year Recommendations	Sq Ft	Cost per Sq Ft	Total	Urgency	Notes
Electrical Power Distribution System Upgrades	1	$150,000	$150,000		
5th Floor Long Term Replace HVAC	1	$75,000	$75,000		
Subtotal			**$225,000**		
Total John Street 5-10 Year Recommendations			***$225,000***		

ESTIMATED BUDGET COSTING

Note: Costing is for construction only and does not include architectural and engineering fees, furniture, equipment, fees, permits, moving or other soft costs or contingency.

Legend

High Urgency Recommendation	(pink)
Medium Urgency Recommendation	(yellow)
Low Urgency Recommendation	(green)

Nebo Short Term Recommendations	Sq Ft	Cost per Sq Ft	Total	Urgency	Notes
Garage					
Parking Garage HVAC and Roll-Up Doors	1	$307,000	$307,000	High	
Maintenance Shop HVAC	1	$22,000	$22,000	High	
Emergency and Exit Lighting Upgrades	1	$2,000	$2,000	Medium	
Expand Indoor Parking including demo offices	1	$42,000	$42,000	Medium	Removal of 1st floor offices
Stores Inventory Management	-	$0	$0	High	
Subtotal Garage			**$373,000**		
Mezzanine Offices					
South Mezzanine Converted to Offices	6,600	$115	$759,000	High	leaves 9000 sf future growth
New Elevator and Stair	1	$305,000	$305,000	High	
Subtotal Mezzanine Offices			**$1,064,000**		
First Floor					
First Floor Improvements and New Reception	1	$857,375	$857,375	Medium	includes locker room upgrades
Subtotal First Floor			**$857,375**		and new lunchroom
External Site Work					
External Parking/Storage Safety Flow Improvements	1	$300,000	$300,000	High	
Security System to External Storage and Entrances	1	$40,000	$40,000	High	
Subtotal External Site Work			**$340,000**		
Total Nebo Road Short Term Recommendations			***$2,634,375***		

Nebo Road 5-10 Year Recommendations	Sq Ft	Cost per Sq Ft	Total	Urgency	Notes
Fit up 9000 available at South Mezzanine	9,000	$100	$900,000	Low	
Total Nebo Road 5-10 Year Recommendations			***$900,000***		

ESTIMATED BUDGET COSTING

Note: Costing is for construction only and does not include architectural and engineering fees, furniture, equipment, fees, permits, moving or other soft costs or contingency.

Legend

High Urgency Recommendation	
Medium Urgency Recommendation	
Low Urgency Recommendation	

Stoney Creek Short Term Recommendations	Sq Ft	Cost per Sq Ft	Total	Urgency	Notes
Garage/Stores					
Main Vehicle HVAC and Roll-Up Door improvements	1	$20,000	$20,000	Medium	
Stores reorganization to accommodate meter equipment	1	$5,000	$5,000	Medium	
Subtotal Garage/Stores			**$25,000**		
Office/Training Centre					
Office Area including Customer Connections, Training, hotelling	11,300	$120	$1,356,000	High	
Subtotal Office/Training Centre			**$1,356,000**		
External Site Work					
Security System to External Storage & Entrances	1	$25,000	$25,000	High	
Subtotal Site Work			**$25,000**		
Total Stoney Creek Short Term Recommendations			**$1,406,000**		

Stoney Creek 5-10 Year Recommendations	Sq Ft	Cost per Sq Ft	Total	Urgency	Notes
Expand Parking Garage and Stores	1	$650,000	$650,000	Low	May not be required if Overhead moves to Nebo
Subtotal Stoney Creek			**$650,000**		
Total Stoney Creek 5-10 Year Recommendations			**$650,000**		

ESTIMATED BUDGET COSTING

Note: Costing is for construction only and does not include architectural and engineering fees, furniture, equipment, fees, permits, moving or other soft costs or contingency.

Legend

High Urgency Recommendation	
Medium Urgency Recommendation	
Low Urgency Recommendation	

St. Catharines Short Term Recommendations	Sq Ft	Cost per Sq Ft	Total	Urgency	Notes
Garage/Stores					
Vehicle Area HVAC Upgrades	1	$152,000	$152,000	Medium	
Garage HVAC Upgrades	1	$22,000	$22,000	Medium	
Photocell Sensor for Garage	1	$5,000	$5,000	Medium	
Stores Reorganization	1	$5,000	$5,000	Medium	
Subtotal Garage/Stores			**$184,000**		
Office Areas North Building					
1st Floor North Building Renovations	7,650	$120	$918,000	High	
2nd Floor Renovations North Building Customer Service	11,000	$120	$1,320,000	High	Including new windows/skylight
New Elevator and Stair to 2nd Floor	1	$300,000	$300,000	High	
Subtotal Office Area North Building			**$2,538,000**		
Site work to create more parking	1	$120,000	$120,000	Low	
Subtotal			**$120,000**		
South Building					
Revenue Lease out South Building	7,640	$14	$106,960		Annual Revenue Estimate
Separate Gas Supply Line for Separate Metering	1	$10,000	$10,000	High	
Separate Plumbing Systems for Separate Metering	1	$5,000	$5,000	High	
Subtotal South Building			**$15,000**		
Total St. Catharines Short Term Recommendations			**$2,857,000**		

St. Catharines 5-10 Year Recommendations	Sq Ft	Cost per Sq Ft	Total	Urgency	Notes
Office Areas North and South Buildings					
Fit Up Additional Space 1st Floor North Building	1,840	$50	$92,000	Low	
Fit Up Additional Space 2nd Floor North Building	1,540	$50	$77,000	Low	
Minor Modifications to Use South Building	7,640	$25	$191,000	Low	
Subtotal Office Areas			**$360,000**		
Expand Parking Garage and Mechanic Garage	**1**	**$2,500,000**	**$2,500,000**	Low	
Total St. Catharines 5-10 Year Recommendations			***$2,860,000***		

Appendix K – Building Condition Assessment 2013

Contents

Appendix A – 20 Year Forecast Summary Sheet

Summary Report
Horizon Utilities

1. Introduction

Horizon Utilities commissioned *Evans Consulting Services* in June 2013 to conduct a building condition assessment for 27 facilities owned and operated by the Utility. [1]The purpose of a building condition assessment is to give a measure of the effectiveness of the current maintenance programs because it determines the remaining useful life of components or systems and compares it with the full economic life expected, give good maintenance practices.

Early detection of possible problems in a building is important in preventing deterioration, damage to neighbouring components or systems and the failure of components; leading to increased (costs in) operations and even capital expenditures.

The end objective of a building condition assessment is to forecast replacement costs for major components in a building based on their predicable life. Life Cycle Analysis (LCA) is based on the premise that every component has a predicable life. Several organizations such as R.S. Means, BOMA and IFMA publish lifecycle charts that forecast the expected service life of a building component given its past performance. Building components include items such as roofing, Architectural interior and exterior elements, Heating Ventilation and Air conditioning components and so on.

Another issue that impacts the life of a building component is the effectiveness of *the preventative maintenance program* being applied. For the purpose of this report, we define [2]Preventative maintenance 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 includes inspection, lubrication, adjustment, cleaning, non-destructive testing, and periodic maintenance, usually minor component replacement'.

The balance of any successful preventative maintenance 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. As a result, the measure of the buildings' condition through a building condition assessment is one way to measure the maintenance program.

[1] Taken from the (IRC) _Institute for Research in Construction – Guidelines for building audits.
[2] Taken from The Facility Management Handbook, David G. Cotts Michael Lee.

The other method for measurement is to embark on a regimented *maintenance management* program that through predetermined reporting, continually analyses items such as the rate of reliability, breakdowns, call backs, ratios of demand maintenance to preventative maintenance, emergency maintenance calls, and utilization of resources to name a few.

While the scope of work for this project did not encompass reviewing Horizon Utility's operational practices, we understand that a maintenance management system is available for use by the Facilities Management maintenance section. Information from a facility management system would enhance the results and findings of a building condition assessment in the future.

Another method for stating a building's' overall condition is to specify a facility's condition in terms of FCI. *A Facility Condition Index (FCI)* is an industry standard asset management tool which measures the constructed asset's condition at a specific point in time. It is a functional indicator resulting from an analysis of different but related operational indicators (such as building repair needs) to obtain an overview of a buildings condition as a numerical value.

FCI is obtained by aggregating the total cost of any needed or outstanding repairs, renewal or upgrade requirements of a building compared to the current replacement value of the building components. It is the ratio of the repair needs to replacement value expressed in percentage needs. In the case of Horizon Utilities, these would include code compliance issues, deferred maintenance backlog, system upgrades and legislative requirements such as Accessibility for Ontarians with Disabilities Act (AODA). When determining the FCI of a building, the calculation shown below provides the numeric value.

$$\frac{\text{Total of Building Repair/Upgrade/Renewal Needs}}{\text{Current Replacement Value of Building}}$$

The lower the value of FCI, the better condition that a building is considered to be. Current industry benchmarks indicate the following condition ratings for facilities with various ranges of FCI.

0 to 5% FCI	Asset is in good condition
6 to 10% FCI	Asset is in fair condition
10 to 30% FCI	Asset is in poor condition

Utilizing FCI provides a professional and consistent method of measurement to determine the relative condition index of a single building. As the numeric value of the FCI increases, the assets will experience:

- Increased risk of component failure

- Increased facility maintenance and operating costs
- Greater negative impacts to staff and residents.[3]

As Horizon Utilities is presently undergoing upgrades and renovations in a number of its facilities, this maybe an exercise undertaken in the future along with the results of the next condition assessment findings.

2. Findings and Recommendations

The findings and recommendations in this summary are broken into three areas; General Administration, Major Facilities and Substation Facilities.

2.1 General Administration

Findings:

1. While many of the staff have related experience in facilities maintenance or are ticketed trades staff, there is still a void in life safety and particularly in understanding the Ontario Fire Code and the Ontario Building Code as it applies to the overall responsibility of the facilities they manage. Within the facility reports there are **many incidents** where there is a requirement to upgrade or to review items such as fire stopping, fire extinguishers, exiting practices and upgrades to fire systems. It was quite apparent that staff is not well versed in this area. This knowledge gap presents an opportunity to provide some basic instruction to staff on what makes up a fire separation, proper labeling of fire doors and general maintenance items that are directly related to fire and life safety such as the maintenance of exit signs, rated labels on doors and so on.

2. In a number of instances, maintenance staff was asked questions about the operational characteristics of the facilities, but were unable to answer, or simply indicated that they did not know. This included questions about systems in the building such as HVAC, equipment panels and so on. There is a need for some of the maintainers to become more familiar with the equipment in their buildings. One of the common problems with operators in buildings, (**not specific to Horizon**), is that they become complacent with their environment. More time needs to be spent on orientation and learning the systems and characteristics in their facilities; possibly through the use of drawings, inventory updates or systems validation.

[3] *Taken from Capital Asset Management Asset Strategies,2011*

3. There is a requirement to provide the Supervisor of Facilities with a reference library that would include items such as the Ontario Building Code, Ontario Electrical Code, Ontario Fire Code. – (abbreviated versions, etc.), technical updates on code compliance, Designated substance legislation, AODA reference materials etcetera.

4. Labeling of HVAC equipment was not well done; particularly on equipment located on the roof tops. This is a very important issue when it comes to identifying or trouble shooting equipment. Staff indicated that labels fade and are affected by the sunlight. We submit that it is an industry best practice to label equipment to identify its purpose and its function within the building. It is a best practice that should be encouraged. Equipment should be labeled to coincide with the design and construction drawing information.

5. Similar to the equipment labeling, we noticed that doors and specific rooms are not labeled within the facilities. It would be helpful to put a proper labeling program to into practice. It is easier when referencing drawings to determine HVAC systems performance, and general guidance through the building. Equipment rooms are by code required to be labeled.

6. An opportunity exists to develop building maintenance and renovation standards for construction and ongoing change in the facilities. For example, items such as fire-stopping of penetrations through a fire separation, both vertical and horizontal. It was found numerous times where trades, either through renovations or maintenance, have created penetrations through a fire wall or floor/ceiling into a protected separation and fire stopping had not been used to backfill the opening. This should be an standard practice. Other examples include insulating of piping after a repair or change has been made; it should be part of the initial project cost. Stating types of valves, specifying wire management practices for all cabling including electrical, telecom, computer cable management etc. Once again, this is not a problem unique to Horizon Utilities. Wiring in ceiling spaces within most buildings can be difficult enough to sort out; and contractors especially don't care.

7. Within the major facilities it is important to note that all of the mechanical rooms were in very good order from a best practices perspective. Equipment was labeled and properly identified; the rooms were neat, tidy and orderly as a mechanical room should be. Piping runs were labeled with content and directional flows. Your maintainers are doing a good job in this area.

8. Roof areas in the major buildings were also very well maintained. The roof areas were free from any debris including limbs from trees, fasteners, spare parts etc. This type of care extends the life of a roof membrane.

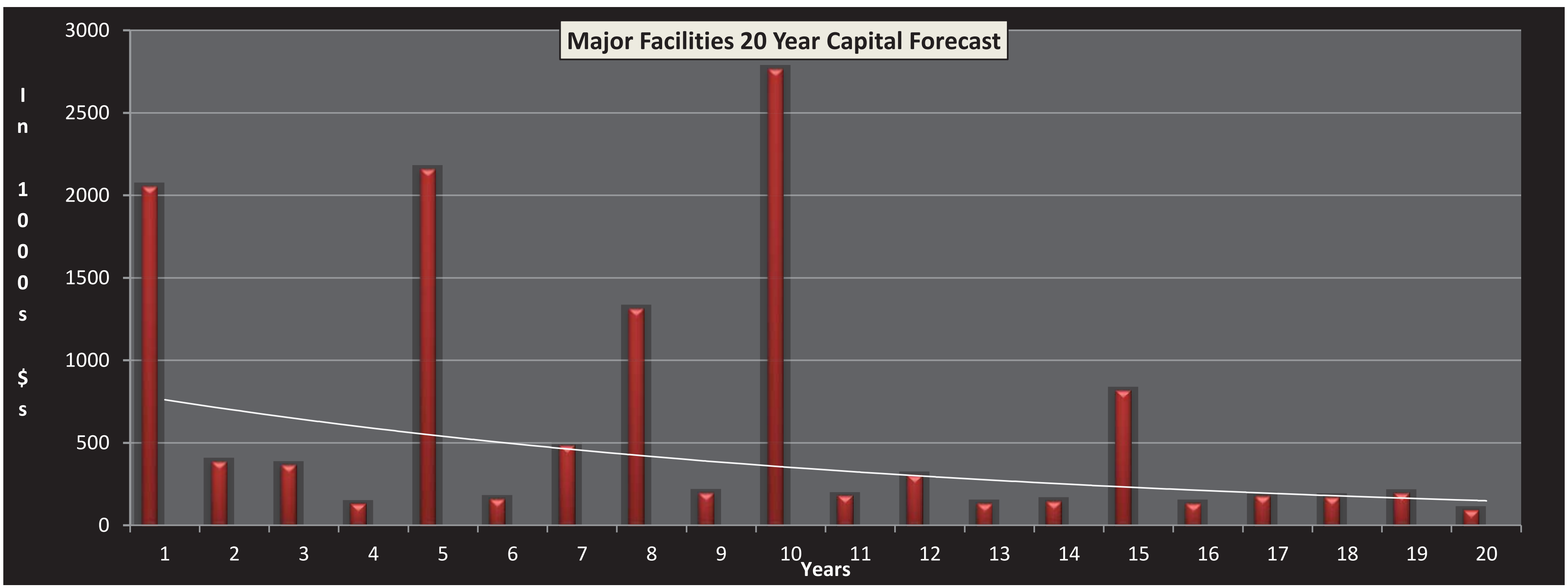
2.2 Major Facilities

A key objective of the building condition assessment report was to create a Capital Forecast Budget for each of the major facilities. For Horizon Utilities, the results call for a long term investment in excess of $12.4 M over the next 20 year period when totaling all four of the locations. (Horizon Headquarters, Stoney Creek Yard, Hamilton, Nebo Yard, and the St. Catharines Office).

Closer examination of the capital expenditures indicates that there are a number of one time expenditure lines in the budgets for costs that are not likely to reoccur. Examples would be fire code upgrades, lighting and electrical upgrades, a ventilation study and upgrades for the lower level of the Head Office building etc. These are elaborated within the sections below.

Table 1 - 20 Year Forecast Major Facilities – in 1.000's

Building	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	total
Hq	956.3	257.6	103.6	73.6	1033.1	91.7	103.1	1197.1	62.6	603.1	40.7	160.6	46.6	69.1	298.1	31.4	55.1	44.1	79.6	37.6	5,345
SC Yrd	351.4	29	123.6	21.6	184.1	10.1	30.6	5	25.6	537.1	45.1	54.6	67.6	15.6	55.6	13.1	5.6	0.6	70.6	0.6	1,647
Ham Yd	443.5	25	129	25	176	20	73	15	15	1153	58	89.5	20	6	207	6	5	66	0	51	2,583
St. Cath	305.6	76.1	12.1	12.1	768.6	40.8	277.8	98.9	95.8	477.1	36.4	0.6	0.6	58	258.6	84.3	114.3	61.8	46.8	5.6	2,832
total	**$ 2,057**	**$ 388**	**$ 368**	**$ 132**	**$ 2,162**	**$ 163**	**$ 485**	**$ 1,316**	**$ 199**	**$ 2,770**	**$ 180**	**$ 305**	**$ 135**	**$ 149**	**$ 819**	**$ 135**	**$ 180**	**$ 173**	**$ 197**	**$ 95**	**$ 12,407**



One of the challenges in developing a capital forecast budget that aligns with the company's strategic business plan, is to flat line expenditures at the same time as keeping priorities in check. We would recommend identifying those areas where life safety issues receive the highest priority and are dealt with in an expeditious manner. A life safety issue can consist of potential for risk, building evacuation, exiting practices and demarcation, fire code violations for door hardware and so on.

Within each of the building condition assessment reports, the excel spreadsheet is capable of being used to sort each individual expenditure with a defined priority. The list of capital expenditures also includes AODA items; AODA expenditures have some discretion and could be re-prioritized to more accurately coincide with either work accommodation requirements or be more in line with the AODA strategy set out by the company to meet the legislation mandate by the year 2025. In the spreadsheets provided, AODA is shown in the first year as it was not in our purview to set these priorities.

HORIZON HEADOFFICE

55 John Street North, Hamilton

Findings

The Horizon Headquarters facility is the main office centre for the Electric Utility located in downtown core of the City of Hamilton. The building's primary use is to provide office and administrative accommodation. There are also some operational activities that are based at this location. The building is approximately 170,000 square feet and dates back to the early and mid -1900's.

According to the information contained in the building condition assessment report, Horizon Utilities will need to invest approximately **$5.344M** in this building asset over the next 20 year period.

Of note in the report are **FIRE AND LIFE SAFETY** related issues which are elaborated on in more depth within the report itself.

- Many areas of the building, especially in the basement areas, require fire stopping for services that pass through a fire rated assembly.
- Requirement to Revise entrances into north and west exit stairwells in order to meet OBC requirements for landings, door swings, hardware and clearances to risers (OBC 3.4.6.11, 3.4.3.4(2), 3.4.6.10 and 3.4.6.3).

- Replace or rate doors and frames which require a fire rating (OBC 3.1.8.4). See section 4 in this report for examples of areas which require rating.
- Add, revise or remove exit signs as outlined in the report to meet OBC requirements for exiting (OBC 3.4.5.1 (2) and 3.3.1.12 (2))
- The fire separation around the generator room needs to be maintained (OBC 3.6.2.8). Currently the door is not rated, there is a gap between the door frame and block wall, and the structural steel did not appear to be rated.
- Floor numbers must be visible at each level of an exit stairwell. Add floor numbers where they currently do not exist (OBC 3.4.6.18).

In addition to fire and life safety in the report is the question of storage and use of the Timber room in the basement area. There are several types of storage occurring in this area, and the `collection area' seems to be accepted as **AN INFORMAL STORAGE/ARCHIVE ROOM AREA**. The Ontario Building and Fire Codes have much stricter requirements than those that exist in the immediate area for this type of use. It was also noted during the site visits that the Stoney Creek Yard has a large amount of informal storage occurring in the vacated area of that facility.

Similarly, in the Stoney Creek Yard report, it is cited that a more formal storage/ archive area needs to be defined. It is therefore recommended in each of the reports that a properly designed **CENTRALIZED ARCHIVE AND ASSET STORAGE AREA** be created at the Stoney Creek Yard/Centre. It would solve the problem of improper use of the space at the Head Office facility at the same time as freeing up some space for other uses. Considerations in the re-design of the space should consider risk management, liability, storage practices, document management policies, security requirements, records management practices and protocols, lighting, material handling, fire safety, fire protection, code compliance. Although this would call for a redesign and repurposing of the space, It is clear that at this time there is no proper or centralized facility for archive or asset storage and the Stoney Creek Yard/Centre would be a good choice.

BUILDING AUTOMATION SYSTEM (BAS)

From the information provided by the Facility Maintainers, Horizon Utilities have a Johnson Medisis system in place at the John Street Headquarters facility that manages the HVAC system and is also extended out to the St. Catharines Office and the Stoney Creek Yard. Within the capital forecast, some funds have been provided to upgrade the software, points on the system and to incorporate any hardware requirements for the development of the Building Automation System. As the Horizon operations are decentralized, it is important to take advantage and to explore the opportunities that can be derived from expanding the BAS. Opportunities include remote access and visibility, energy efficiencies, troubleshooting before dispatching, and making changes in temperature or air flows remotely.

These are all cost saving opportunities. It is further recommended that the development of a visionary plan for this system be completed by the Facilities Management team to determine the future role of the BAS in their operations.

LARGE EXPENDITURES AND IMPACT ON CAPITAL FORECAST

Other line items that stand out in the capital forecast and cause spiking in the total expenditures include:

- Recommendation to review and upgrade the ventilation system in the lower level of the facility; expenditure is shown in 2014 and should be considered a priority. ($100,000)
- Recommendation to upgrade the ventilation system in the facility to a Variable Air Volume System in 2021 ($500,000)
- Numerous electrical upgrades that could be deferred; but lighting and electrical upgrades often have an energy payback associated with them. A more strategic approach should be taken.
- Recommendation to make physical changes to meet the requirement of the fire code; currently out of compliance with stair wells and landings.
- Recommendation to meet AODA ; could be deferred closer to 2025 but still be in compliance.
- Replace exterior windows, ($600,000) 2018; recommend verifying condition closer to replacement timeline.
- Replace brick face ($150,000) 2015; the brick face is in poor condition and should be re-bricked.

ST. CATHARINES OFFICE

340 Vansickle Road

Findings

The St. Catharines Office facility is the most southerly office location for the Electric Utility located in the City of St. Catharines. The building's primary use is to provide a satellite office, repair garage and stores area. There are also maintenance operational activities that are based at this location. The building is approximately 63,367 square feet (gross).

According to the information contained in the building condition assessment report, Horizon Utilities will need to invest approximately **$2.8M** in this building asset over the next 20 year period. During the assessment, the second level of the original building was undergoing renovation and in the demolition stage. Any replacement costs outlined in the report do not include the second floor area.

Most of the items noted in the report are typical lifecycle events. However, there is a requirement to upgrade many of the interior fire separations with fire rated doors; that includes the door, upgrade the frames and door hardware. As a matter of interest, it is possible to engage a consultant to rate the doors and frames with labels assuming they do meet the code requirement. This is especially beneficial when dealing with door frames embedded in concrete block walls.

The same report recommends fire dampers be installed where ductwork penetrates a fire rated assembly. The mechanical engineer also expresses concern that there is not sufficient negative air pressure in the garage area to ensure there is no migration of fumes into the office areas.

There is also a concern for the water damage in the perimeter block walls in the stores area that should be followed up.

Some of the Recommendations in this report for the next twenty year period include the following;

- Post signage on the east side of the parking garage warning workers of vehicle traffic
- Resurface North and East asphalt lots in the next 5 years
- Resurface South and East asphalts parking lots in the next 7 years
- Replace exterior windows of the original building in the next 2 years
- Replace skylights in the next 5 years
- Replace roof hatch in the next 5 years
- Replace carpet flooring throughout both buildings in the next 7 years
- Paint structural ceiling in the garage and stores areas in the next 7 years
- Paint interior block walls throughout both buildings in the next 7 years and every 10 years after
- Paint drywall in the next 7 years.
- Replace interior garage and stores area doors in the next 5 years

- Replace interior doors which require a fire rating and do not currently have one (OBC 3.1.8.4). Doors noted include the door from the meter room into the main hallway, from the meter room into the parking garage, from the change room into the back hallway, from the main hallway into the repair garage and doors leading from the parking garage into the repair garage and stores area.

- Install an exit sign in the change room directing traffic to the back hallway (OBC 3.4.5.1)

- Install manual pull station in the back hallway of the change room (OBC 3.2.4.17)

- Replace exit signs in the stores area with illuminated signs (OBC 3.4.5.1(2))

- Move fire extinguisher in the stores area so that it is located under its sign

- Move fire extinguisher in the call centre so that it is easily accessible

- Fire dampers should be provided at all locations where the duct penetrates a fire-rated enclosure. For example, there is no fire damper on the duct penetrating the wall between the office area and repair garage. As well, there is no fire damper on the duct penetrating the wall between the parking garage and stores area. A detailed study should be completed reviewing drawings, and checking the physical conditions to ensure fire dampers are installed at all the locations where the duct penetrates a fire separation.

- Proper ventilation should be provided to all the rooms to comply with OBC section 6.2.2.1. Outdoor air supplied in the building by ventilation systems shall be not less than the rates required by ASHRAE 62.1 Table 6-1 based on room occupancy category.

- Proper mechanical ventilation systems with proper control should be provided to the repair garage. The Exhaust fan should be controlled by CO/NOx sensors and be in communication with the Building Automation System.

- The mechanical ventilation systems must be designed and balanced to provide air pressure in parking garage and repair garage that is less than the air pressure in the office and storage rooms. The parking garage and repair garage should be *<u>negative air pressure</u>* compared to the (positive) air pressure in the office and stores area to prevent air flowing from the parking garage or repair garage into the office area. It is recommended a review of ventilation systems in this area be completed.

- Engine exhaust system should be provided in repair garage to reduce the general exhaust requirement for the repair garage and increase the energy efficiency.

- Perimeter heating or linear diffusers should be provided at the perimeter zone along the large window area.

- The transite pipes (asbestos containing material) on level 2 should be replaced during the ongoing renovation.
- Provide blank-off plates in panels to isolate the panel bussing.
- Provide covers for all junction boxes, pull boxes, etc. that currently do not have these and have exposed wiring.
- Remove material being stored on the transformer in the meter shop.
- Replace all receptacles within 1.5m of a water source with a GFI type receptacle if this type is not currently installed.
- Re-wire the equipment that is permanently supplied with an extension cord in the main Storage Area.
- Remove the disconnected cabling at the entrance gate.
- Replace all exit lights that have tube style lamps with new energy efficient LED types.
- Clean and re-lamp/re-ballast all existing light fixtures that have been recently installed or are not planned to be replaced in the immediate future.
- Replace light fixtures in change room/washroom areas that contain showers with light fixtures that are suitable for damp locations.
- Confirm the operation of the secondary fire alarm annunciator at the Call Center entrance and relocate closer to the main Call Center entrance.
- Provide additional fire alarm annunciation devices to achieve the audibility requirements as per OBC 3.2.4.19. It is suggested that a full building audibility test be conducted by a certified fire alarm system verification company.
- Re-work the fire alarm pull station layouts in the exit corridors to be in accordance with the OBC.

Items that require additional investigation are;

- Further investigation is required to determine the cause of the interior water damage on the block located in the stores area. The investigation may require some lifting of the roof membrane and repair work afterward. The water damage investigation should include details in how to prevent any further water penetration.

- The location and installation of fire extinguishers should be reviewed to meet current Ontario Building Code and Ontario Fire Code.
- Engineering study should be completed to confirm if any flammable material storage cabinet requires increased ventilation.
- Mechanical ventilation systems serving the building should be able to provide (positive air pressure) so that the pressure in parking garage and repair garage is less than the pressure in the office and storage rooms. The parking garage and repair garage should be negative pressure compare to the pressure in the office area and Store to prevent air flowing from parking garage or repair garage to office area.
- Replace or add new electrical panels to address the existing panels throughout the facility that have no available breaker spaces and are potentially at full capacity. Further investigation is required to determine which panels should be replaced and which ones are potentially overloaded.
- Remove the Vector 3000 panel that is part of an old security system. Further investigation is required to determine if this panel is still active.
- Replace all electrical equipment that is deteriorating, damaged or appears to be approaching the end of its serviceable lifetime. This includes receptacles, switches, light fixtures, conduit, wiring, panels, disconnects, etc. Further investigation is required to determine exact equipment that is currently at the end of its lifetime.
- Provide better access to the significant amount of electrical distribution equipment located on a mezzanine level in the Garage. Further investigation is required to determine the best method to gain access to this area.
- Replace all old, inefficient exterior lighting including pole-mounted fixtures and wall-mounted fixtures with new energy efficient types complete with day lighting and timing controls. It is suggested that a full lighting study be complete for the building's exterior areas. The value of $70,000 is a high level value that includes for an engineering study and design, complete removal of all existing lighting including poles, underground conduits and trenching and new pole-mounted fixtures and wall packs located throughout the property.

Additional Comments:

We rate this building as being in ***good condition*** overall. The building has several life safety concerns as noted in the body of the report. Of significance are the fire exiting and fire separation doors, demarcation of exits, location of fire extinguishers and annunciation of fire bells. The condition assessment also indicates there are concerns with respect to the life of the electrical systems inside the building.

NEBO YARD

Nebo Road, Hamilton

Findings

The Nebo Road Service Yard facility was constructed in 1981. The building is used as a storage garage, repair garage and office area and is located in the City of Hamilton. The building is approximately 107,000 gross square feet.

According to the information contained in the building condition assessment report, Horizon Utilities will need to invest approximately **$2.3M** in this building asset over the next 20 year period.

Of note are **FIRE AND LIFE SAFETY** related issues which are elaborated on in more depth within the report itself dealing with exit signage, fire stopping and upgrading the fire alarm annunciation system.

Other items are minor in nature, but include requirement to install cover plates on electrical junction boxes, pull boxes and receptacles.

<u>Some of the Life Safety Recommendations</u> in this report for the next twenty year period include the following;

- Relocate exit sign at the stairs of the second level stores area (OBC 3.4.5.1(2)).
- Add / Revise exit signs around the mezzanine areas (OBC 3.4.5.1 (2)).
- Add signage for visibility of portable extinguishers (Fire Code 6.2.1.5).
- Remove storage on floor in front of eye wash station in stores area to provide a clear path of travel to the station (OH&S Act, S.124).
- Replace doors from repair garage to adjacent rooms with fire rated doors (OBC 3.3.5.5.)
- Replace doors into elevator machine rooms with fire rated doors (OBC 3.5.3.3)
- Fire stop penetrations going into the elevator machine rooms (OBC 3.1.9.1).
- Install guard rail near roof access (OBC 3.3.1.17)

- Replace doors between the stores area and main garage with fire rated doors (OBC 3.3.5.6)
- Replace windows between the stores area and the main garage with properly rated windows (OBC 3.3.5.6)
- Move pull station at the south east door of the repair garage and conduct alarm verification
- Fire dampers should be provided at all locations where the duct penetrating fire-rated enclosure.
- Proper mechanical ventilation systems with proper control should be provided to Main vehicle parking area and Vehicle maintenance shop.
- Mechanical ventilation systems serving the building should be able to provide that the pressure in the Vehicle maintenance shop and Main vehicle parking area is less than the pressure in the office and storage rooms.
- Engine exhaust system should be provided in Vehicle Maintenance Shop to reduce the general exhaust requirement for this area and increase the energy efficiency.
- Provide covers or enclosures so that only authorized staff have access to circuit breakers for the electrical panels in the office areas.
- Provide blank-off plates in panels to isolate the panel bussing.
- Replace the PVC conduit that is located inside the building and does not comply with OESC. Further investigation is required to determine whether the existing conduit meets the flame spread requirements identified in this rule.
- Clean up areas that have excessive storage in front of electrical equipment to ensure adequate space for access.
- Provide covers for all junction boxes, pull boxes, etc., that currently do not have these and have exposed wiring.
- Provide cover plates for all receptacles, switches and other devices.
- Provide additional emergency lighting to meet the minimum luminance requirements of the OBC.
- Disconnect the old fire alarm monitoring panel and have the newer panel fully monitor the building. Relocate the main control panel to the designated main entrance to be used for fire fighters operation. Replace the fire alarm initiation and notification devices at the end of their projected lifetime in approximately 15 years.

- Provide additional fire alarm annunciation devices to achieve the audibility requirements as per OBC 3.2.4.19. It is suggested that a full building audibility test be conducted by a certified fire alarm system verification company. Provide additional fire alarm detection devices in storage rooms and all other areas as required by the OBC.

Items that include additional investigation include;

- The location and installation of fire extinguishers should be reviewed to meet current Ontario Building Code and Ontario Fire Code.
- Engineering study should be completed to confirm ventilation requirements for chemical storage cabinets.
- Mechanical ventilation systems serving the building should be able to provide that the pressure in the Vehicle maintenance shop and Main vehicle parking area is less than the pressure in the office and storage rooms.
- Engine exhaust system should be provided in Vehicle maintenance shop to reduce the general exhaust requirement for this area and increase the energy efficiency.
- Conduct a study to determine which panels should be replaced and which panels are potentially overloaded. (Replace or add new electrical panels to address the existing panels throughout the facility that have no available breaker spaces and potentially at full capacity).
- Replace all electrical equipment that is deteriorating, damaged or appears to be approaching the end of its serviceable lifetime. (This includes receptacles, switches, light fixtures, conduit, wiring, panels, disconnects, etc.) Further investigation is required to determine exact equipment that is currently at the end of its lifetime.
- Replace the PVC conduit that is located inside the building and does not comply with OESC. Further investigation is required to determine whether the existing conduit meets the flame spread requirements identified in this rule.
- Provide additional fire alarm annunciation devices to achieve the audibility requirements as per OBC 3.2.4.19. It is suggested that a full building audibility test be conducted by a certified fire alarm system verification company. Further investigation is required to determine if additional equipment is required. Should the system not meet the requirements of the OBC, there are potentially significant additional costs that could be incurred.

Additional Comments:

We rate this building as being in ***good condition*** overall.

STONEY CREEK YARD

(Hamilton)

Findings

The Stoney Creek Yard is a satellite operations facility located in the City of Hamilton (SC). The building's primary use is to provide office and administrative accommodation, a parking garage and stores facility. There are also some operational maintenance activities that are based at this location. The building is approximately 36,412 square feet.

According to the information contained in the building condition assessment report, Horizon Utilities will need to invest approximately **$1.7M** in this building asset over the next 20 year period.

The findings of this assessment discovered three abandoned in ground storage tanks along the front elevation of the property; the lids were not properly fastened or secured to the tank's substrate. The recommendation in the report is to remove the tanks to perminantly eliminate the risk.

The Stoney Creek Yard presents an ideal opportunity to create a newly designed storage facility for records retention and the storage of furniture and equipment assets. It is recommended that proper standards and storage facilities would resolve the improper storage of equipment in the Head Office and resolve the compliance issue with the fire code and building code for both facilities.

Other items include fire stopping penetrations in the generator room walls, and balancing the ventilation systems to ensure there is negative air pressure in the garage parking areas.

In addition, the report recommends extending the building automation system to be more active in the Stoney Creek yard for the purpose of remotely controlling the centre and taking advantage of any energy efficiencies in its operation.

Some of the Recommendations in this report for the next twenty year period include the following;

- Decommission and remove the three in ground abandon tanks along the front elevation to the building. This presents a very high risk to Horizon Utilities. **We strongly recommend** removal for life safety and due diligence purposes.
- Replace main entrance concrete walkway in the next 5 years
- Caulk windows seals
- Replace sloped brick under windows in the next year
- Reseal exterior foundation wall
- Replace skylights in the next 3 years.
- Replace vinyl tile flooring in the next 5 years
- Reseal concrete floors in the garage and stores area in the next 7 years and every 10 years after
- Replace the 2x4 suspended acoustic ceiling tiles in the west portion of the building in the next 7 years and in the east portion of the building in the next 3 years.
- Paint drywall ceilings in the next 3 years and every 10 years after
- Paint drywall walls in the next 3 years and every 10 years after.
- Repaint block walls in the next 7 years
- Replace exterior door providing access to the roof in the next 2 years.
- Replace exit sign in the meeting room in the west area of the building (OBC 3.4.5.1(2)).
- Replace door hardware on the door leading from the **current** archive room to the main lobby (OBC 3.4.6.12 and OBC 3.4.6.15(1)). Immediately.
- Replace doors into the generator room (OBC 3.6.2.8) immediately.

  - Fire stop penetrations through the generator room walls (OBC 3.1.9.1) immediately
  - Fix the door between the office area and parking garage which currently does not fully shut (OBC 3.1.8.4) immediately.
  - Replace double doors between the parking garage and stores area (OBC 3.1.8.4 and OBC 3.4.6.12). immediately
  - Replace door into the electrical room (OBC 3.1.8.4). immediately
  - Remove storage from electrical room (OBC 3.6.1.3) immediately
  - Proper ventilation should be provided to all the rooms to comply with OBC section 6.2.2.1. Outdoor air supplied in the building by ventilation systems shall be not less than the rates required by ASHRAE 62.1 Table 6-1 based on room occupancy category.
  - Mechanical ventilation systems serving the building should be balanced to provide negative air pressure in parking garage and positive air pressure in the parking garage to prevent air flowing from the parking garage into adjacent spaces.
  - The Building Automation System at 55 John Street should be extended to the Stoney Creek Yard to provide remote access, control and monitoring of the control systems in Stoney Creek; i.e. ventilation rates, equipment on / off notifications, energy efficiency and so on.

- The main electrical distribution equipment visually appears to be in acceptable condition; however, it is recommended that a certified electrical contractor be retained to perform a detailed inspection of this equipment. No concerns were raised by the Horizon representative regarding the age of the equipment, however, some of the equipment may be approaching the end of its serviceable lifetime as it may be 30+ years old. It is assumed that the equipment has 10 years of functional life remaining.
- Replace or add new electrical panels to address the existing panels throughout the facility that have no available breaker spaces. These panels are potentially at full capacity or are approaching the end of their useful lifetime. Further investigation is required to determine which panels should be replaced and which ones are potentially overloaded.
- Provide labels for all equipment that is not currently labeled. This includes receptacles, telecom pull boxes, conduits, junction boxes, etc.
- Provide coverplates for all receptacles, switches and other devices.
- Ensure that all receptacles and similar devices in office areas are secured to the walls to which they are mounted to.

- Remove the exposed wiring in the kitchenette under the vanity or enclose in a suitable junction box.
- Remove the public address system in the boardroom area that is no longer in use.
- Clean up the extension cords and power bars that have been run across the floors in the boardroom area. Consider adding additional receptacles in strategic locations to address this issue.
- Replace all receptacles within 1.5m of a water source with a GFI type receptacle if this type is not currently installed.
- Remove the junction box and conduit that is directly over the sink in the kitchenette.
- Provide covers for all junction boxes, pull boxes, etc. that currently do not have these and have exposed wiring.
- Provide caps or covers for unused conduits.
- Enclose the overhead door wiring in conduit or junction box.
- Clean up the disorganized and cluttered telecom distribution equipment.
- Repair damaged conduits on the east side of the building.
- Remove the abandoned wiring and junction boxes adjacent to the site sign.
- Provide damp-location certified light fixtures in the washroom/change room area that contains showering facilities and are subject to significant moisture.
- Fill the gap between the fire alarm annunciator and the wall that it is secured to. Determine the use of the low-voltage junction box and LED indicators that are adjacent to the annunciator. Further investigation is required to determine the exact use of the junction box and LED indicators.
- Provide additional fire alarm annunciation devices to achieve the audibility requirements as per OBC 3.2.4.19. It is suggested that a full building audibility test be conducted by a certified fire alarm system verification company. Further investigation is required to determine if additional equipment is required. Should the system not meet the requirements of the OBC, there are potentially significant additional costs that could be incurred.

Items that require additional investigation are;

- Further study required to determine if proper exiting is currently achieved in the stores area.

- A study of the room currently used as an archive room should be completed to determine the extent of work required to change the room from an office use to a storage area. It is not acceptable to leave the room(s) in this condition.

- The location and installation of portable fire extinguishers should be reviewed to meet current Ontario Building Code and Ontario Fire Code.

- Mechanical ventilation systems serving the building should be able to provide Positive Air pressure in the office and stores areas and Negative air pressure in the parking garage to ensure there is no flow of air from the parking areas to the office areas.

- The quantity of diesel stored in the tanks should be confirmed that it is not more than the maximum quantity allowed in the building by Ontario Fire Code 4.2.4. Outdoor storage tank is required if the quantity stored in the building is more than the maximum quantity allowed.

- Replace or add new electrical panels to address the existing panels throughout the facility that have no available breaker spaces, are potentially at full capacity or are approaching the end of their usable lifetime. Further investigation is required to determine which panels should be replaced and which ones are potentially overloaded.

- Replace all electrical equipment that is deteriorating, damaged or appears to be approaching the end of its serviceable lifetime. This includes receptacles, switches, light fixtures, conduit, wiring, panels, disconnects, etc. Further investigation is required to determine exact equipment that is currently at the end of its lifetime.

- Provide additional fire alarm annunciation devices to achieve the audibility requirements as per OBC 3.2.4.19. It is suggested that a full building audibility test be conducted by a certified fire alarm system verification company. Further investigation is required to determine if additional equipment is required. Should the system not meet the requirements of the OBC, there are potentially significant additional costs that could be incurred.

<u>Additional Comments:</u>

We rate this building as being in ***good condition*** overall. The building has several life safety concerns as noted in the body of the report. Of significance are the fire exiting, rated doors, repurposed use of the office area for archival storage and hardware and fire extinguishers. We encourage Horizon Utilities to highlight all life safety issues in this report and act on these areas first.

2.3 Substation Facilities

FINDINGS

Part of the terms of reference of the building condition assessment was to conduct a review of 23 substations to evaluate the architectural, structural, electrical and mechanical disciplines of each facility. The findings of the condition assessments were all very similar at each of the sites. The substations are on average between 1,500 and 2,500 gross square feet in size; some with a basement level and some without.

The capital forecast indicates that the expected investment over the next 20 years will total over $2.8 million for all substations. On average that is $143K per year.

The transformer bays were similar with a metal blast wall on at least one elevation enclosing the sites. One item that was consistent in the report was the requirement for Horizon Utilities to revisit their security measures for each of the sites and determine standards for signage and fencing. It is our opinion that the sites are lacking in terms of adequate signage, and that the Corporation should provide some direction in this area. Further most of the locations require some landscape maintnace as well as the trimming back of vines trees and schrubbery.

We are **very stronglying recommending** that Horizon Utilities consult with their insurer or internal risk management people to develop standard security measures especially for electrical substations. Those standards should include controlling access onto the site, fencing standards (e.g. barbed wire or none, height of fencing), wording and types of signage and amount of signage in a given distance along the perimeter for each site.

It was also noticed that there are two street addresses posted on some of the substations, and that many of the substations are identified differently. We recommend that a signage standard be adopted for the identification of Horizon Utility properties and in particular electrical substations.

With regard to **battery storage and charging rooms;** the Ontario Building Code is somewhat vague in this area. This is of some concern as the storage, handling and charging of batteries can present some hazardous conditions such as fire or explosion. In particular, we note that some of the substations with battery charging rooms have a fire rated assembly separating the area from the rest of the building that includes walls and doors, while other sites do not.

We recommend that Horizon Utilities create and set a design standard *in excess of what the Ontario Building Code stipulates*. That design standard might include a 45 minute fire rated separation for a rated door and frame with positive latch, door closer, rated wall assembly and warning signage on the exterior of the door.

The Ontario Electrical Code and the [4]ASHRAE standard stipulate ventilation rates for battery charging rooms. In our reports, we note that not all substations meet this requirement and that regular maintenance of the ventilation systems should also be provided.

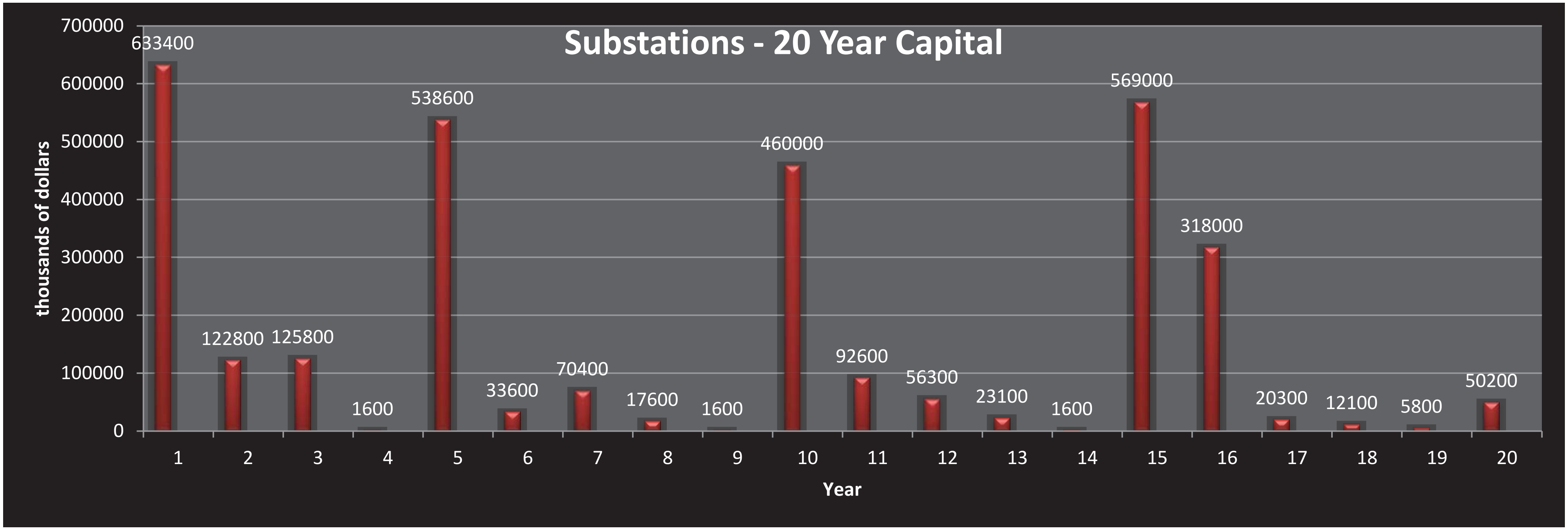
On the subject of **eyewash stations;** some of the Substations only had the *bottle station* which does not meet the 15 minute flushing time required. The bottles can only be used in conjunction with a proper eyewash or deluge shower station. Portable eye wash stations were also found in some sites which do meet the flushing time. However, with portable eyewash stations, the solution must be monitored and replaced regularly. Fixed/plumbed eye wash stations are the recommended option if the water is available. This is an area that should be reviewed more closely by Horizon's Health and Safety Department.

Most of the Substations appear to be having some difficulties with ***Landscape Maintenance***. It was noted during the assessments that most of the properties do not maintain their grounds to a standard that is representative of the neighboring properties. Most grounds were full of weeds, void of grass, untrimmed, overgrown with trees and vines on the fence lines and generally in poor condition. We submit that this is an area where Horizon can improve its image in the community.

In the area of maintenance and preventative maintenance, the inventory equipment listing in this report can be used as a start up for the asset information system that Horizon Utilities is currently running. From this data base, preventative maintenance tasks can be developed and initiated. As an example, if the coils on the electric heaters in the substations were vacuumed each year, it would stop the staining from the burning dust above the units on the walls.

[4] *ASHRAE – American Society of Heating Refrigeration and Air Conditioning Engineers*

Stations	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	total
Aberdeen,	30000	16200	200	200	20300	700	200	200	200	18300	4200	5200	200	200	31700	700	200	200	200	1400	130700
Bartonville,	37200	18400	1500	0	3500	2000	5000	12000	0	5500	2000	0	1500	0	13500	2000	0	4000	0	3200	111300
Caroline,	20600	6000	2500	0	23400	500	0	0	0	32900	500	6000	2500	0	22700	500	0	0	0	1200	119300
Central,	25700	3200	200	200	22200	2200	5400	200	200	17000	2200	3200	200	200	26200	2200	5400	200	200	2900	119400
Cope,	35100	0	16000	0	3700	2000	0	0	0	21400	3500	0	1000	0	28200	2000	0	2500	0	1200	116600
Eastmount	24200	1300	9000	0	28500	500	0	0	0	17900	2600	1000	3000	0	33000	500	0	0	0	2000	123500
Elmwood,	38000	19500	0	0	16300	500	2100	0	0	14200	500	0	0	0	25900	500	0	0	0	1200	118700
Highland,	32300	4000	4000	0	7000	2000	4000	0	0	1500	2000	4000	0	0	17600	2000	0	0	0	1500	81900
Hughson,	61700	0	8000	0	23000	0	2000	0	0	26000	43000	0	4000	0	26600	0	0	0	4200	0	198500
Kenilworth	23500	2200	21700	200	4200	2200	2200	200	200	26900	4700	200	200	200	25700	2200	200	200	200	3100	120400
Mohawk,	32000	7700	200	200	19700	2200	5200	200	200	28200	2200	7400	200	200	50000	2200	5200	200	200	2400	166000
Mountain,	22500	3000	4000	0	17500	500	5000	0	0	18800	500	0	0	0	32100	500	0	0	0	5200	109600
Ottawa,	12750	200	200	200	39000	2200	3200	200	200	27200	700	200	200	200	22700	700	200	200	200	1400	112050
Parkdale,	22900	0	17000	0	22300	500	4000	0	0	9900	3500	0	2000	0	22700	500	0	0	0	1200	106500
Spadina,	30200	0	6500	0	35500	2000	0	0	0	22800	2000	0	7500	0	25500	500	1500	0	0	1200	135200
Strouds Lane,	16200	5000	0	0	35300	2000	14500	2000	0	7000	2000	7500	0	0	17000	2000	0	2000	0	1200	113700
Whitney,	22000	3000	9000	0	27300	500	4000	0	0	9700	500	3000	0	0	13300	500	4000	0	0	1200	98000
Wellington	38600	6200	10200	200	88200	700	10200	2200	200	47000	700	6200	200	200	58200	1900	3200	2200	200	15400	292100
Wentworth,	16550	200	4200	200	35400	2200	200	200	200	39600	2200	200	200	200	27700	2200	200	200	200	1400	133650
Grantham,	26200	2700	11400	200	21300	2700	200	200	200	7700	2700	200	200	200	17600	2700	200	200	200	200	97200
Taylor,	23400	0	0	0	11000	1500	3000	0	0	18500	6400	0	0	0	1500	1500	0	0	0	1700	68500
Vine,	21300	7000	0	0	32000	2000	0	0	0	10100	2000	3000	0	0	14000	2000	0	0	0	0	93400
Welland,	20500	17000	0	0	2000	2000	0	0	0	31900	2000	9000	0	0	15600	2000	0	0	0	0	102000
Totals	**633400**	**122800**	**125800**	**1600**	**538600**	**33600**	**70400**	**17600**	**1600**	**460000**	**92600**	**56300**	**23100**	**1600**	**569000**	**31800**	**20300**	**12100**	**5800**	**50200**	**2868200**



Finally any reference to the assessment should be taken directly from the individual reports. These are only excerpts from the assessments for convenience purposes.

APPENDIX A – 20 CAPITAL FORECAST ALL FACILITIES

Notes:

Appendix L – Horizon Utilities Physical Security Report

This report in its entirety is being filed confidentially.

Appendix M – Horizon Utilities Head Office Window Assessment

MMM Group Limited

Horizon Utilities Head Office

Window Assessment

Prepared for: Horizon Utilities
Month Year | Jan 2014

MMM GROUP

EXECUTIVE SUMMARY

MMM Group Ltd. was contracted by Horizon Utilities to assess the current state of the windows and evaluate upgrade options for their head office in Hamilton, Ontario. A site visit was conducted to visually inspect the windows and obtain information about the buildings systems to be used for the energy model. An air leakage test of three different windows was conducted in accordance with the test methods of ASTM E783-02 *"Standard Test Method for Field Measurement of Air Leakage through Installed Exterior Windows and Doors".* The results of these tests were then used in the energy model to determine the energy loss through air leakage of the existing windows.

The results show that the existing operable windows in the John St. office tower require attention as they have revealed excessive air leakage and heat loss through the assembly. Remediation options prove to yield reasonable returns on the investment; however given the age of the windows, it may not be short enough to put off the replacement of the windows. The best investment for replacement windows is in a mix of operable and fixed windows with fiberglass frames and high performance glazing (low-e (Solarban 60), argon filled, and warm-edge spacers). It is also recommended that any operable windows use an awning operator as it comes with slightly better efficiencies and is more durable than a double hung window.

TABLE OF CONTENTS

1.0 EVALUATION OF EXISTING WINDOWS

Our investigation of the existing windows was conducted through visual inspection, air leakage testing and building energy simulations.

1.1 AIR LEAKAGE TEST

During the site inspection, it was noted that in many cases the double hung windows that comprise of the majority of the glazed openings in the building were in need of repair or replacement. The main issue was found to be that the pile weather stripping was loose, degraded and in some cases missing. The lack of weather stripping was made evident through the air leakage tests conducted in December 2013. In both operable windows (Window 2 and Window 3) tested, the required pressure drop to conduct the test (75 Pa) was not possible to maintain. The airflow for those windows had to be calculated at 30 Pa for a pro-rated pressure differential of 75 Pa. These calculations demonstrate air leakage rates that are much higher than the maximum allowable air leakage rates for operable windows under the National Fenestration Rating Council's (NFRC) rating system. NFRC allows 1.5 L/s/m^2 (A2 classification – minimum code requirement) while the existing windows' infiltration sits close to 15 L/s/m$^{2.}$ Test methodology, results and calculations can be found in Appendix A – Air Leakage Test Results.

1.2 ENERGY MODEL

To show the impact of the air leakage through the existing windows on the utility bills, it was necessary to create an energy model of the facility. Information on the buildings systems was obtain through visual inspection and from drawings provided to us. The results of the aforementioned test were used in the model and expressed as a "Crack Length Co-efficient" in the base building. The model shows that there is a peak savings in infiltration of over 100 kW (400 kbtu/hr) by meeting the maximum allowable air leakage for an A2 rating in the NFRC's system. High infiltration and lack of low-e, argon or warm-edge spacers will result in energy loss and occupant discomfort. The existing windows have been estimated to have a total U value of 4 W/m^2-C$^{\circ}$ (See Appendix B – Energy Model Baseline Assumptions for details on the base building model inputs).

2.0 EVALUATION OF WINDOW UPGRADES

Our evaluation of the existing windows draws to the conclusion that the condition of the operable windows in the John St. office building are poor and require remediation or replacement in order to reduce energy costs and to maintain the comfort of the occupants who work close to the perimeter of the building. Windows in the garage were not investigated due to the low window to wall ratio and low heating set points and existing fixed windows in the Hughson Tower and John St. site have also been excluded as the air leakage tests show they are performing as expected and do not require attention at this time.

2.1 REMEDIATION OPTIONS

We looked at two options for repairing the existing windows. The first option is to replace the weather stripping of the existing windows and restoring them to a state where they meet the maximum allowable infiltration rate of an A2 classified window. This measure will help to ensure that any drafts felt by occupants will be kept to a minimum, however, the lack of low-e coating on the existing windows can create a draft like feeling as the surface of the glass is cold and radiates towards the occupants who work along the perimeter. The second remediation measure is to apply a film to the interior of the windows that provides a modest low-e insulating effect.

Our energy model shows that when both of these measures are coupled together, the payback period is only 6 years with a modest annual cost savings of $8,000 (weatherisation being the larger contributor). The window U value goes down slightly to 3.54 W/m^2-C˚.

2.2 REPLACEMENT OPTIONS

While remediation proves to have a reasonable payback, the existing operable windows are ~20 years old and are close to reaching their life expectancy. Unfortunately the simple payback on investing in replacement windows is long, however, there are some benefits that are not quantifiable that should be considered when reviewing the results of the replacement options. Window replacement can allow for more natural light to enter work spaces by selecting a low or no tint option which can improve the occupant productivity and reduce down time related to seasonal depression and illness. The issues surrounding the perceived comfort of occupants are addressed as low-e coating technology has come a long way since the early 1990's and offer more thermal protection from extreme ambient temperature swings and temperature differences between inside and out. Replacing windows may also preserve the life of room furnishings as they can block some of the UV rays that can fade furniture and carpets.

We looked at several different options for window replacements, including fiberglass frames vs. aluminum, operable vs. fixed windows and a mix of operable and fixed glazing units for each framing system.

Appendix C – Window Improvement Options contains the simulation results and various options explored. The capital costs for the window replacements were obtained through local suppliers and include labour, material and demolition of existing windows. Simple pay back has been shown as it compares with the base building. The second payback calculation assumes that window replacement has already been established and therefore it is reasonable to show the payback from a new baseline that includes the planned window upgrade and all measures below are compared back to that. We assumed that the replacement windows would be identical to the existing windows (mainly single and side by side double hung windows). This column demonstrates that flexibility in design can save money and utility costs in that fixed windows are less expensive and yield better efficiencies than operable windows as it demonstrates that capital and energy savings that can be achieved by allowing 50% of the windows to be fixed as well as if 100% of the windows are fixed. While operable windows give the occupants more local control to maintain their own comfort, they can prove to be detrimental to the heating and cooling costs of the building due to occupant behaviour (leaving windows open at night) and degradation over time. Operable windows also have slightly higher U values than their fixed counterparts due to the additional framing that surrounds the movable sections. Double hung windows have the highest of frame to glass ratios and therefore suggest using an awning type operator in lieu of the double hung. The advantages of the awning operator is that it is more durable and will maintain air tightness for longer as there is less surface area subject to friction from movement and the seals are compressed, they are safer to occupants and generally easier to operate, while being slightly more efficient than other operable systems. See Figure 2-1 for proposed operable strategy.

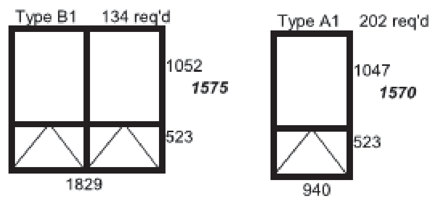


Figure 2-1 Proposed Awning Operable Window

Because the windows are mostly punched windows, this building is an ideal candidate to use fiberglass frames. The incremental cost is between $2-6/SF[1] above the same window with aluminum frames. Fiberglass frames are less conductive and therefore yield a much lower overall U value than an aluminum window with the same glazing components. With the exception of upgrading to a fiberglass system that contains 100% operable windows, all of the fiberglass measures have 0 payback as compared to the assumed new baseline (measure 4a – double hung, aluminum windows with low-e (Solarban 60), argon filled gaps and warm-edge spacers) and have lower paybacks even when compared back to the original base building with existing windows still in place. The energy cost savings outweighs the small incremental cost for the upgrade.

[1] Costs range depending on interior and exterior finishes chosen (premium for metallic look, etc.)

3.0 CONCLUSION

Our investigation into condition of the existing windows at the Horizon Utilities Ltd. headquarters has proven that there is a need for the operable windows to be attended to. While remediation shows a reasonable return on investment, the payback period may exceed the time in which the windows must be replaced. Replacement options are shown to have very long payback periods however (which is consistent with our experience when replacing existing double glazed windows), allowing for fixed windows to replace some or all of the operable windows the payback is drastically reduced and the benefits to the occupants will be realized immediately.

As the window may be replaced regardless, we have also calculated paybacks that are based on the incremental energy cost savings and installation cost over a selected baseline window. As the baseline window is an operable window, equivalent sized inoperable windows are typically less expensive, and have a lower U-value, thus greater savings. In such cases we have indicated the payback as immediate in relation to the baseline window.

APPENDIX A. AIR LEAKAGE TEST RESULTS

Intertek

TEST REPORT

REPORT NUMBER: 101436639TOR-002
ISSUE DATE: December 13, 2013

EVALUATION CENTER

Intertek Testing Services Ltd.
6225 Kenway Drive
Mississauga, Ontario L5T 2L3

RENDERED TO

MMM Group Ltd.
582 Lancaster Street
Kitchener, Ontario N2K 1M3

PRODUCT EVALUATED
3 Windows

EVALUATION PROPERTY
Air Leakage

LOCATION
Horizon Utilities Building – Hamilton, Ontario

Report of air leakage testing for MMM Group Ltd. on three windows in various locations at the Horizon Utilities Building in Hamilton, Ontario conducted in accordance with test methods outlined in ASTM 783-02 (R2010)

1 Table of Contents

2 Introduction

Intertek has conducted air leakage testing on three windows at the Horizon Utilities Building in Hamilton, Ontario. Testing was conducted 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*". The windows were tested at a pressure differential of 75 Pa.

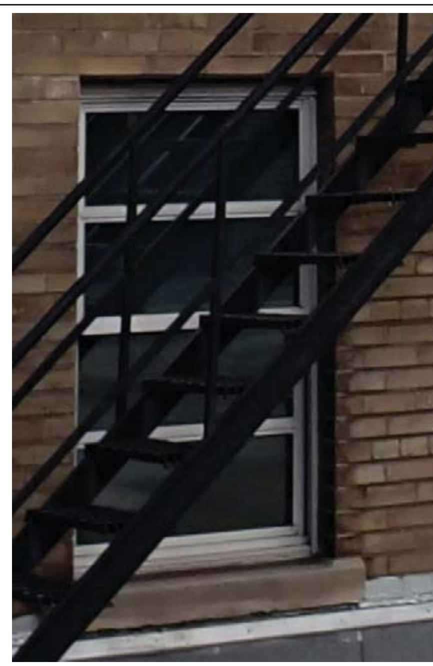
Testing was conducted on December 3, 2013.

3 Test Specimen and Assembly Description

The Horizon Utilities Building is located at 55 John Street N., Hamilton, Ontario

Window 1 - Composite window consisting of 6 fixed vision lites		
LOCATION	-	First Floor, West Side, South-facing, adjacent to men's washroom.
TYPE	-	Composite aluminum windows consisting of 6 vision lites.
OVERALL SIZE	-	1562 mm wide by 2616 mm high.
CONDITION	-	Decent condition.
FRAMING	-	Extruded aluminum frame.
GLAZING	-	Laid-in, dual pane, glazed from the interior.
PERIMETER CAULKING	-	There were no cracks in perimeter caulking .

Window 2 - Combination window consisting of 2 double hung windows			
LOCATION	-	Second floor, east side, south facing, end of hallway adjacent server room.	
TYPE	-	Combination window consisting of two mulled double hung windows.	
OVERALL SIZE	-	1829 mm wide by 1575 mm high.	
CONDITION	-	Decrepit condition. Pile weatherstrip was loose, missing or degraded. Window sashes still operated.	
FRAMING		Extruded aluminum frame. Individual double hung windows were joined together.	
GLAZING	-	Laid-in, glazed from the interior.	
PERIMETER CAULKING	-	Decent condition. There were no cracks in perimeter caulking.	

Window 3 - Double hung window			
LOCATION	-	Second floor, east side, south facing, server room.	
TYPE	-	Double hung window.	
OVERALL SIZE	-	940 mm wide by 1575 mm high.	
CONDITION	-	Decrepit condition. Pile weatherstrip was loose, missing or degraded. - Window sashes still operated.	
FRAMING		Extruded aluminum frame. Individual double hung windows were joined together.	
GLAZING	-	Laid-in, glazed from the interior.	
PERIMETER CAULKING	-	Decent condition. There were no cracks in perimeter caulking .	

4 Testing and Evaluation Methods

The Air Leakage test was conducted in accordance with the test methods of ASTM E783-02 (Reapproved 2010), "*Standard Test Method for Field Measurement of Air Leakage through Installed Exterior Windows and Doors*".

Prior to measuring air leakage, each operable sash was opened and closed five times.

4.1 CONSTRUCTION OF THE INTERIOR TEST CHAMBER

A clear polyethylene sheet was sealed to the interior wall creating a chamber. Roller blinds were installed on the interior side of the double hung windows (Windows 2 and 3). For the purpose of the air leakage test, the roller blinds were not removed and were incorporated into the interior test chamber.

4.2 EXTRANEOUS LEAKAGE

The exterior of the window is sealed with a clear plastic sheet to preclude the possibility of air passage through the window. Air is then evacuated from the interior test chamber and the volume of airflow is monitored. This allows for the determination of extraneous leakage of the chamber at the required test pressure differential.

Due to lack of accessibility, the extraneous leakage of Window 1 was not determined. The air leakage value reported for Window 1 included extraneous leakage. The chamber was sealed against the frame to minimize extraneous leakage as well as the window was in good condition. Hence, the extraneous leakage was deemed to be negligible.

4.3 AIR LEAKAGE TEST

The exterior plastic is then removed and the air within the interior chamber is again evacuated and new flow rate is measured at the desired pressure differential. The differences in the flow rates required to maintain the test pressure differential is attributed to *leakage* through the window. This allows for the derivation of the air leakage rate. The air leakage was measured at a pressure differential setpoint of 75 Pa and evaluated.

4.3.1 Deviation from the Standard Test Method

Once the exterior bag was removed for Window 2, a pressure differential of 75 Pa could not be achieved. A lower pressure was obtained. The air flow for that window had to be calculated at 30 Pa for a pro-rated pressure differential of 75 Pa. Refer to Appendix B for the calculation to obtain a pro-rated air flow at 75 Pa pressure differential.

5 Testing and Evaluation Results

5.1 AIR LEAKAGE RESULTS

Window 1 - Composite window consisting of 6 vision lites – first floor, west side, south facing

Test Pressure Differential	Window Area	Crack Length	Gross Air Leakage Measured	Gross Air Leakage Rate (per area)	Gross Air Leakage Rate (per crack length)
75 Pa Infiltration	4.09 m²	18.19 m	1.20 L/s	0.29 L/s·m²	0.07 L/s·m
75 Pa Exfiltration			1.14 L/s	0.28 L/s·m²	0.06 L/s·m²

Window 2 - Combination window consisting of 2 double hung windows – second floor, east side, south facing

Test Pressure Differential	Window Area	Crack Length	Air Leakage Measured[1]	Air Leakage Rate (per area)	Air Leakage Rate (per crack length)
75 Pa Infiltration	2.88 m²	11.10 m	42.8 L/s	14.9 L/s·m²	3.86 L/s·m
75 Pa Exfiltration			38.5 L/s	13.4 L/s·m²	3.47 L/s·m²

Window 3 - Double hung window – second floor, east side, south facing

Test Pressure Differential	Window Area	Crack Length	Air Leakage Measured	Air Leakage Rate (per area)	Air Leakage Rate (per crack length)
75 Pa Infiltration	1.48 m²	5.55 m	22.9 L/s	15.5 L/s·m²	4.13 L/s·m
75 Pa Exfiltration			18.4 L/s	12.4 L/s·m²	3.32 L/s·m²

A complete set of data sheets is included in Appendix A.

[1] Air Leakage corrected to 75 Pa . Refer to Appendix C

6 Conclusion

Intertek conducted air leakage testing on three windows at the Horizon Utilities Building in Hamilton, Ontario 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. Results are report only and recorded herein.

INTERTEK

Tested and Reported by:

Claudio Sacilotto,P.Eng
Senior Project Engineer, Building Products

Reviewed by:

Robert Giona
Manager, Building Products

7 Appendix A: Datasheets

Datasheets

(3 pages)

Intertek

ASTM E783 Test Data

Client: MMMGroup
Project # G101436639
Date: 03-Dec-13
Standard: ASTM E783-02 (R2010)
Location: First Floor West Side adjacent men's washroom (Composite window consisting of 6 fixed lites)

Reviewed: V. Jones
Technicians: C. Sacilotto

Equipment:

	ID #	Cal Due
Schlegel Apparatus	280-01-0008	-
Fluke Airflow meter	20170392	Mar. 4/14
Magnehelic Manometer:	280-01-0904	Feb. 7/14
Meriam Laminar Flow Element	280-01-0171	Oct. 11/14
Thermometer/Barometer:	273-01-1165	Mar. 5/14

LFE Flow Coefficients	
b =	13.62489
c =	-0.04553512

Test: INFILTRATION

Plate Mask Condition	Chamber Pressure Pa	AT FLOW METER Delta P (in H2O)	Inlet Temp (F)	Absolute Pressure (mbar)	Temp Correction Factor	Pressure Correction Factor	Viscosity Correction Factor	Gross Leakage (SCFM)	Gross Leakage corrected to 75 Pa (SCFM)	Gross Leakage (Sm³/hr)	Gross Leakage (SL/s)
masked	75	0.000	61.3	996	1.0167	0.9830	1.0129	0.00	0.00	0.00	0.00
unmasked	75	0.185	61.3	996	1.0167	0.9830	1.0129	2.55	2.55	4.33	1.20
								NET	2.55	4.33	1.20

	width	height	Area	
imperial (in)	61.50	103.00	43.99	ft²
metric (m)	1.562	2.616	4.09	m²

Crack Length Member	Qty	width	Crack Length	
horizontal	12	28.25	59.67	ft
vertical	4	94.250	18.19	m

	cfm	m^3/hr	L/s
Unit Leakage	2.550	4.333	1.204
	cfm/ft²	(m³/hr)/m²	L/s*m²
Leakage rate/area	0.058	1.060	0.294

	cfm	m^3/hr	L/s
Unit Leakage	2.550	4.333	1.204
	cfm/ft	(m³/hr)/m	L/s*m
Leakage rate/area	0.043	0.238	0.066

Test: EXFILTRATION

Plate Mask Condition	Chamber Pressure Pa	AT FLOW METER Delta P (in H2O)	Inlet Temp (F)	Absolute Pressure (mbar)	Temp Correction Factor	Pressure Correction Factor	Viscosity Correction Factor	Gross Leakage (SCFM)	Gross Leakage corrected to 75 Pa (SCFM)	Gross Leakage (Sm³/hr)	Gross Leakage (SL/s)
masked	75	0.000	61.4	996	1.0165	0.9830	1.0127	0.00	0.00	0.00	0.00
unmasked	75	0.175	61.4	996	1.0165	0.9830	1.0127	2.41	2.41	4.10	1.14
								NET	2.41	4.10	1.14

	width	height	Area	
imperial (in)	61.50	103.00	43.99	ft²
metric (m)	1.562	2.616	4.09	m²

Crack Length Member	Qty	width	Crack Length	
horizontal	12	28.25	59.67	ft
vertical	4	94.250	18.19	m

	cfm	m^3/hr	L/s
Unit Leakage	2.412	4.097	1.138
	cfm/ft²	(m³/hr)/m²	L/s*m²
Leakage rate/area	0.055	1.003	0.278

	cfm	m^3/hr	L/s
Unit Leakage	2.412	4.097	1.138
	cfm/ft	(m³/hr)/m	L/s*m
Leakage rate/area	0.040	0.225	0.063

ASTM E783 Test Data

Client: MMMGroup
Project # G101436639
Date: 03-Dec-13
Standard: ASTM E783-02 (R2010)
Location: Hallway adjacent to Server Room (Combination set of two Double Hung Aluminum Windows)

Reviewed: V. Jones
Technicians: C. Sacilotto

Equipment:

	ID #	Cal Due
Schlegel Apparatus	280-01-0008	-
Fluke Airflow meter	20170392	Mar. 4/14
Magnehelic Manometer:	280-01-0904	Feb. 7/14
Meriam Laminar Flow Element	280-01-0171	Oct. 11/14
Thermometer/Barometer:	273-01-1165	Mar. 5/14

LFE Flow Coefficients	
b =	13.62489
c =	-0.045535120

Test: INFILTRATION

Plate Mask Condition	Chamber Pressure Pa	AT FLOW METER Delta P (in H2O)	Inlet Temp (F)	Absolute Pressure (mbar)	Temp Correction Factor	Pressure Correction Factor	Viscosity Correction Factor	Gross Leakage (SCFM)	Gross Leakage corrected to 75 Pa (SCFM)	Gross Leakage (Sm³/hr)	Gross Leakage (SL/s)
masked	75	2.980	69.0	995	1.0019	0.9820	1.0015	39.61	39.61	67.29	18.69
unmasked	30	5.349	63.9	996	1.0117	0.9830	1.0090	71.82	130.29	221.36	61.49
								NET	90.68	154.07	42.80

	width	height	Area	
imperial (in)	72.00	62.00	31.00	ft²
metric (m)	1.829	1.575	2.88	m²

Crack Length Member	Qty	width	Crack Length	
horizontal	6	33.50	36.42	ft
vertical	8	29.500	11.10	m

	cfm	m^3/hr	L/s
Unit Leakage	90.683	154.071	42.798
	cfm/ft²	(m³/hr)/m²	L/s*m²
Leakage rate/area	2.925	53.497	14.860

	cfm	m^3/hr	L/s
Unit Leakage	90.683	154.071	42.798
	cfm/ft	(m³/hr)/m	L/s*m
Leakage rate/area	2.490	13.881	3.856

Test: EXFILTRATION

Plate Mask Condition	Chamber Pressure Pa	AT FLOW METER Delta P (in H2O)	Inlet Temp (F)	Absolute Pressure (mbar)	Temp Correction Factor	Pressure Correction Factor	Viscosity Correction Factor	Gross Leakage (SCFM)	Gross Leakage corrected to 75 Pa (SCFM)	Gross Leakage (Sm³/hr)	Gross Leakage (SL/s)
masked	50	3.253	75.0	995	0.9906	0.9820	0.9928	42.34	55.11	93.63	26.01
unmasked	10	2.853	77.8	996	0.9855	0.9830	0.9888	36.88	136.64	232.15	64.49
								NET	81.53	138.52	38.48

	width	height	Area	
imperial (in)	72.00	62.00	31.00	ft²
metric (m)	1.829	1.575	2.88	m²

Crack Length Member	Qty	width	Crack Length	
horizontal	6	33.50	36.42	ft
vertical	8	29.500	11.10	m

	cfm	m^3/hr	L/s
Unit Leakage	81.530	138.520	38.478
	cfm/ft²	(m³/hr)/m²	L/s*m²
Leakage rate/area	2.630	48.097	13.360

	cfm	m^3/hr	L/s
Unit Leakage	81.530	138.520	38.478
	cfm/ft	(m³/hr)/m	L/s*m
Leakage rate/area	2.239	12.480	3.467

Intertek

ASTM E783 Test Data

Client: MMMGroup
Project # G101436639
Date: 03-Dec-13
Standard: ASTM E783-02 (R2010)
Location: Server Room (Double Hung Aluminum Window)
Equipment:

Reviewed: V. Jones
Technicians: C. Sacilotto

Equipment	ID #	Cal Due
Schlegel Apparatus	280-01-0008	-
Fluke Airflow meter	20170392	Mar. 4/14
Magnehelic Manometer:	280-01-0904	Feb. 7/14
Meriam Laminar Flow Element	280-01-0171	Oct. 11/14
Thermometer/Barometer:	273-01-1165	Mar. 5/14

LFE Flow Coefficients	
b =	13.62489
c =	-0.04553512

Test: INFILTRATION

Plate Mask Condition	Chamber Pressure Pa	AT FLOW METER Delta P (in H2O)	Inlet Temp (F)	Absolute Pressure (mbar)	Temp Correction Factor	Pressure Correction Factor	Viscosity Correction Factor	Gross Leakage (SCFM)	Gross Leakage corrected to 75 Pa (SCFM)	Gross Leakage (Sm³/hr)	Gross Leakage (SL/s)
masked	75	0.441	64.0	996	1.0115	0.9830	1.0088	6.02	6.02	10.22	2.84
unmasked	75	3.971	58.2	996	1.0228	0.9830	1.0176	54.62	54.62	92.80	25.78
								NET	48.60	82.58	22.94

	width	height	Area	
imperial (in)	37.00	62.00	15.93	ft²
metric (m)	0.940	1.575	1.48	m²

Crack Length Member	Qty	width	Crack Length	
horizontal	3	33.50	18.21	ft
vertical	4	29.500	5.55	m

	cfm	m^3/hr	L/s
Unit Leakage	48.602	82.576	22.938
	cfm/ft²	(m³/hr)/m²	L/s*m²
Leakage rate/area	3.051	55.794	15.498

	cfm	m^3/hr	L/s
Unit Leakage	48.602	82.576	22.938
	cfm/ft	(m³/hr)/m	L/s*m
Leakage rate/area	2.669	14.879	4.133

Test: EXFILTRATION

Plate Mask Condition	Chamber Pressure Pa	AT FLOW METER Delta P (in H2O)	Inlet Temp (F)	Absolute Pressure (mbar)	Temp Correction Factor	Pressure Correction Factor	Viscosity Correction Factor	Gross Leakage (SCFM)	Gross Leakage corrected to 75 Pa (SCFM)	Gross Leakage (Sm³/hr)	Gross Leakage (SL/s)
masked	75	0.891	68.0	996	1.0038	0.9830	1.0029	11.98	11.98	20.35	5.65
unmasked	75	3.989	80.0	996	0.9815	0.9830	0.9857	51.00	51.00	86.64	24.07
								NET	39.02	66.29	18.41

	width	height	Area	
imperial (in)	37.00	62.00	15.93	ft²
metric (m)	0.940	1.575	1.48	m²

Crack Length Member	Qty	width	Crack Length	
horizontal	3	33.50	18.21	ft
vertical	4	29.500	5.55	m

	cfm	m^3/hr	L/s
Unit Leakage	39.018	66.292	18.415
	cfm/ft²	(m³/hr)/m²	L/s*m²
Leakage rate/area	2.449	44.792	12.442

	cfm	m^3/hr	L/s
Unit Leakage	39.018	66.292	18.415
	cfm/ft	(m³/hr)/m	L/s*m
Leakage rate/area	2.143	11.945	3.318

8 Appendix B: Calculation of Air Flow at a Different Pressure Differential

$$Q_{75}/Q_y \qquad = [\Delta p_{75}/\ \Delta p_y]^n \tag{8.1}$$

Where,

Q_{75} Air Flow at 75 Pa (in L/s)

Q_y Calculated air flow at y Pa pressure differential Pa (in L/s)

Δp_{75} Pressure differential of 75 Pa

Δp_y Pressure differential of y Pa

n flow coefficient. A value of n=0.65 represents many cases of window leakage (8.2)

from equation (7.1) above

$Q_{75} = [\Delta p_{75}/\ \Delta p_y]^n \times Q_y$

$Q_{75} = [75/\ \Delta p_y]^{0.65} \times Q_y$

For example

Determine air flow at 75 Pa, if air flow was measured at 30 Pa

Air Flow at 30 Pa was measured to be 71.82 L/s

$Q_{75} = [75/\ \Delta p_{30}]^{0.65} \times Q_{30}$

$= [75/\ 30]^{0.65} \times 71.82$

$= [75/\ 30]^{0.65} \times Q_{30}$

$= 1.814 \times 71.82$

$= 130.3$ L/s

8.1 Hutcheon, N.B., Handegord, G.O.P, NRC-CNRC, Building Science for a Cold Climate, pp. 264, (NRCC 1985)

and

Shaw, C.Y. A method for predicting air infiltration rates for a tall building surrounded by lower structures of uniform height./ *ASHRAE Transactions*, 1979, *85*, (Part 1), pp. 72-84. (NRCC 18029)

8.2 Hutcheon, N.B., Handegord, G.O.P, NRC-CNRC, Building Science for a Cold Climate, pp. 264, (NRCC 1985)

9 Appendix C: Photographs

Photo 1. Exterior view of Window 1 (circled in red)

Photo 2. Interior view of Window 1

Photo 3. Exterior view of Window 2 (circled in red) and Window 3 (circled in dashed green)

Photo 4. Interior view of Window 3

Photo 5. Exterior view of Window 2 and Window 3 bagged on the exterior (bagged in order to calculate extraneous leakage)

Photo 6. Interior view of Window 3

Photo 7. Interior view of Window 3 being tested for air leakage

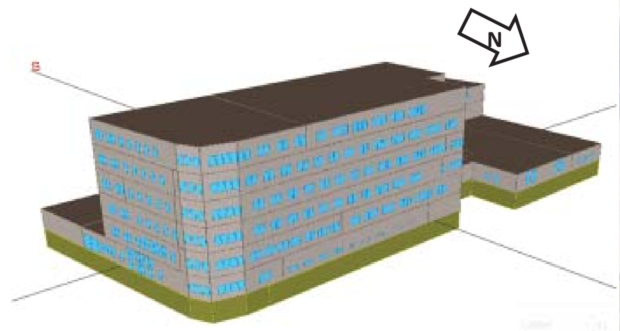
10 Revision Page

Revision No.	Date	Changes	Author	Reviewer
0	December 13, 2013	First issue	Claudio Sacilotto	Robert Giona

END OF DOCUMENT

APPENDIX B. ENERGY MODEL BASELINE ASSUMPTIONS

Model Inputs - Architectural Systems



Window to Wall Ratio

Orientation	Total
North	21%
North-East	22%
East	13%
South-East	13%
South	21%
South-West	25%
West	8%
Overall	**19%**

Building Plan

Building Section	Space Use Category	Area (ft²)	% of Total	Flr-to-Flr (ft)	Flr-to-Clg (ft)
Office	Office, Lobby	114,400	80%	12.5	9.0
Conference & Meeting Rooms	Lobby, Conference/Meeting	5,700	4%	12.5	9.0
Control Centre	Office (24/7)	5,700	4%	12.5	9.0
Parking	Active Storage, Bulky	5,700	4%	14.5	14.5
Maintenance Garage	Active Storage, Bulky	4,300	3%	30.0	30.0
Storage	Active Storage, Fine	4,300	3%	12.5	9.0
Lobby	Lobby, Conference/Meeting	2,900	2%	16.5	16.5
Total		**143,000**			

Building Envelope

Exposed walls, floors, roofs, and opaque doors:

Construction	Description (structure, insulation, air barrier)	R-Nom. (IP)	R-Value (IP)	Area (ft²)	% of Total Env.
Walls	4" Brick wall (w/cladding); air spc; 12" brick/block, plaster	5	5.00	40000	45%
Roof	3" rigid insulation	15	15.00	40000	45%
		Total opaque, exposed surfaces:	**10.00**	**80,000**	**90%**

Windows and glass doors:

Window	Description (coating, fill, framing)	T-vis (%)	SHGC (%)	U-Value (IP)	Area (ft²)	% of Total Env.
Type 1 & 2 (existing windows from 1990's)	CoG: 2-gl, 13mm air, tint film	81%	76%	0.57		
	Total: Alum, dbl hung, alum. Spacer	35%	36%	0.76	7,600	9%
Garage windows (original single pane)	CoG: single pane glass (~1/2" thick)	N/A	90%	0.88		
	Total: Metal framed, awning operator	70%	33%	0.96	300	0%
All other windows (non operable)	CoG: 2-gl, 13mm air, tint film	47%	47%	0.48		
	Total: Alum. fx, 3mm tb, alum. Spacer	43%	43%	0.65	1,000	1%
	Total glazed surfaces:	**37%**	**37%**	**0.75**	**8,874**	**10%**

Notes:
"R-Nominal" is for insulating layers only.
"R-Vlaue" includes the effect of thermal bridging.

	U-value (Btu/hr-ft²-°F)	Area (ft²)	Heat Trans. (kBtu/hr-°F)
Net Envelope:	**9.1**	**88,900**	**807**

Assumptions - Mechanical Systems

Delivery Systems

System	Serving	Description (type, strategy, controls)	Sizing (htg)			Sizing (clg)	
AHU-1	4th & 5th Floor	Constant volume hot deck/cold deck system; perimeter radiant htg HW loop supplies heat and preheat coils; CW loop supplies clg coil Steam humidification RH min 30% max 34% Cycle fans to maintain unoccupied setbacks; OA damper position min. 10%; 100% outdoor air economizer dual temperature control; SAT reset = zone reset Supply fan; 2 spd air-foil TSP = 3.5"; FanEff = 50%; MotorEff = 90% Return fan:; 2 spd air-foil TSP = 2.0", FanEff = 30% MotorEff = 90%	13,000 2.7 536 **Sizing (pre-ht)**	cfm W/cfm MBH	Fan Pw Cap Cap	22,000 1.6 684 423	cfm W/cfm MBH MBH
AHU-2	Bsmt, 1st & 2nd Floor (East)	Constant volume hot deck/cold deck system; perimeter radiant htg HW loop supplies heat and preheat coils; CW loop supplies clg coil Steam humidification RH min 30% max 34% Cycle fans to maintain unoccupied setbacks; OA damper position min. 10%; 100% outdoor air economizer dual temperature control; SAT reset = zone reset Supply fan; 2 spd air-foil TSP = 3.5"; FanEff = 50%; MotorEff = 90% Return fan:; 2 spd air-foil TSP = 2.0", FanEff = 30% MotorEff = 90%	8,000 2.8 259 **Sizing (pre-ht)**	cfm W/cfm MBH	Fan Pw Cap Cap	13,000 1.7 420 352	cfm W/cfm MBH MBH
AHU-3	2nd (West) & 3rd Floors	Constant volume hot deck/cold deck system; perimeter radiant htg HW loop supplies heat and preheat coils; CW loop supplies clg coil Steam humidification RH min 30% max 34% Cycle fans to maintain unoccupied setbacks; OA damper position min. 10%; 100% outdoor air economizer dual temperature control; SAT reset = zone reset Supply fan; 2 spd air-foil TSP = 3.5"; FanEff = 50%; MotorEff = 90% Return fan:; 2 spd air-foil TSP = 2.0", FanEff = 30% MotorEff = 90%	8,000 2.8 259 **Sizing (pre-ht)**	cfm W/cfm MBH	Fan Pw Cap Cap	13,000 1.7 684 352	cfm W/cfm MBH MBH
AHU-4	Hughson Tower	Constant volume system; perimeter radiant htg HW loop supplies htg coils; CW loop supplies clg coil Steam humidification RH min 30% max 34% Cycle fans to maintain unoccupied setbacks; OA damper position min. 10%; 100% outdoor air economizer dual temperature control Supply fan; 2 spd air-foil TSP = 3.0"; FanEff = 40%; MotorEff = 85% Return fan:; 2 spd air-foil TSP = 1.0", FanEff = 25% MotorEff = 85%	4,800 1.5 182	cfm W/cfm MBH	Fan Pw Cap	4,800 1.5 150	cfm W/cfm MBH
AHU-6	1st Floor (back office)	Constant volume hot deck/cold deck system; perimeter radiant htg HW loop supplies heat and preheat coils; CW loop supplies clg coil Steam humidification RH min 30% max 34% Cycle fans to maintain unoccupied setbacks; OA damper position min. 10%; 100% outdoor air economizer dual temperature control; SAT reset = zone reset Supply fan; 2 spd air-foil TSP = 3.5"; FanEff = 50%; MotorEff = 90% Return fan:; 2 spd air-foil TSP = 2.0", FanEff = 30% MotorEff = 90%	???? 20 HP ??? **Sizing (pre-ht)**	cfm Sup MBH	Fan Pw Cap Cap	???? 10 HP ??? ???	cfm Ret MBH MBH
RTU-1 thru 6	6th Floor	DX single zone sytems (4 & 5 serve occupied space - remaining serve shell space), perimeter radiant htg Gas fired burner - 80% thermal efficiency DX coil - EER 9.0 Supply fan - 2.0" w.g.; combined eff - 50%	9 80%	EER %Eff-p	Fan Cool Heat	???? n/a	cfm ton
Garage & Maintenance	Parking Garage	Exhaust Fan interlocked with OA damper to provide ventilation to parking area; controlled with multiple CO sensors located within space. Unit heaters to provide gas heating to 46F. - Run 1 - 2 hours per day. - Fan eff. = 1.0 W/cfm			Fan Cool Heat	???? n/a 700	cfm ton MBH

Distribution Loops

System	Serving	Description (type, strategy, controls)	Efficiency			Sizing	
Hot Water Loop	Heating Coils and Radiators	Two (2) constant volume pumps. Head: 70 ft. Impeller Efficiency: 85% Motor Efficiency: 68% Temperature Setpoint: 170°F (ΔT = 30°F)	37	W/gpm	Flow	200	gpm
Chilled Water Loop	Cooling Coils	Two (2) constant volume pumps. Head: 70 ft. Impeller Efficiency: 85% Motor Efficiency: 72% Temperature Setpoint: 45°F (ΔT = 10°F)	17	W/gpm	Flow	420	gpm
Condensor Water Loop	Cooling Tower & Chillers	Two (2) constant volume pumps. Head: 75 ft. Impeller Efficiency: 85% Motor Efficiency: 71%	20	W/gpm	Flow	540	gpm

Plant Equipment

System	Serving	Description (type, strategy, controls)	Efficiency			Sizing	
Boilers	HW Loop	Four atmospheric boilers each size to 850 MBH Setpoints (supply/return): 170°F / 140°F	85	%EFF-p	Heat	850	MBH
Chillers	CHW Loop	Two rotary chiller each size to 85.3 tons Setpoints (supply/return): 45°F / 55°F	5.2	COP-p	Cool	85	ton
Cooling Tower	Condensor Loop	One closed-loop cooling tower c/w constant volume fans.	28	W/gpm	Flow	540	gpm

Assumptions - Electrical Systems

Interior Lighting

Serving	Description (fixture, strategy, controls)	Area (ft²)	Eff. (W/ft²)
Offices, Meeting & Lobby	Fixture: 3 - T8 lamp fixtures Automatic Controls: locally dimmable, peak shaving control, daylight harvesting and occupancy sensors LPD based on ASHRAE 2001 Office Bldg type.	128,700	1.30 Installed 1.04 Controlled
Garage, Maintenance, Storage and M&E	Fixture: ??? Automatic Controls: None	14,300	0.80 Installed 0.80 Controlled

Total Interior Lighting, Installed: 1.3 W/ft²

Total Interior Lighting, Controlled: 1.0 W/ft²

Plug Loads

Serving	Description	Peak (kW)	Density (W/ft²)
Entire Building	Default MNECB plug loads	n/a	0.5
Entire Building	Elevators = 1,049 kWh/yaer	n/a	0.002
Entire Building	PA / IT / Security	5 kW	0.09
Exterior	Snow and ice melt; melting or idling 2,100 hours/year	24 kW	0.1

Assumptions - Site Conditions

Utility Rate Information

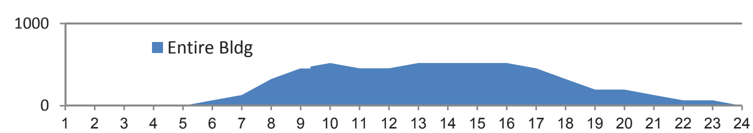
Utility Type	Provider	Rate Schedule	Consumption		Demand	
Electricity	Horizon	Yearly average (2013)	$0.11	per kWh	n/a	per kW
Natural gas	Union Gas	Yearly average (2013)	$0.22	per m³		

Heating and Cooling Setpoints

Area	Heating (°F)		Cooling (°F)		Humidity (%RH)		Notes
	Occ.	Unocc.	Occ.	Unocc.	Min.	Max.	
Office, lobby & meeting	72	70	75	77	30%	34%	
Parking	50	50	50	50	0%	100%	
Mech. Rooms	65	65	-	-	0%	100%	

Occupancy Schedules

Area	Typical Daily Maximum %	Peak Occupancy
Entire Bldg	80%	650
Total Peak Occupancy:		**650**



APPENDIX C. WINDOW IMPROVEMENT OPTIONS

Window Study

Horizon Utilities Head Office

Hamilton, Ontario

Window Improvement Options

	Upgrade	Energy Cost ($)			Energy Intensity (ekWh/m²)			GHG Emissions (tonnes, CO2e)			Increm. Capital Cost	Simple Payback	Simple Payback*	Capital Cost Assumptions
		Total	Δ	%	Total	Δ	%	Total	Δ	%	$	years	years	
0	Base Building	$272,162	-	-	343	-	-	3,245	-	-	-	-		
	Remediation Options													
1	Replace weather stripping	$265,447	$ (6,715)	+2.5%	327	-16	+4.7%	3,103	-142	###	$52,500	8		$7/SF labour and materials
2	Add low-e film to int. surf.	$271,235	$ (927)	+0.3%	341	-2	+0.6%	3,228	-17	###	$37,500	40		$5/SF labour and materials
3	Apply both remediation measures	$264,371	$ (7,791)	+2.9%	325	-18	+5.3%	3,083	-162	###	$45,000	6		$6/SF labour and materials**
	Replacement Options													
4a	Base replacement	$261,788	$ (10,374)	+3.8%	317	-26	+7.5%	3017	-228	###	$525,000	83	0	$115/SF labour and materials
4b	4a + fiberglass frames	$259,777	$ (12,385)	+4.6%	310	-33	+9.6%	2,955	-291	###	$540,000	71	7	$117/SF labour and materials
4c	4b + 50% fixed	$259,572	$ (12,590)	+4.6%	309	-34	+9.8%	2949	-297	###	$450,000	61	0	$100/SF labour and materials
5a	Use fixed units for all Type 2 replacements	$261,032	$ (11,130)	+4.1%	315	-28	+8.3%	2996	-250	###	$420,000	67	0	$95/SF labour and material
5b	5a + triple glazed IGU	$260,389	$ (11,773)	+4.3%	312	-31	+8.9%	2,976	-270	###	$525,000	76	27	$120/SF labour and materials
6a	4a + no operable windows	$259,973	$ (12,189)	+4.5%	311	-32	+9.4%	2,960	-285	###	$412,500	59	0	$96/SF labour and materials
6b	6a + fiberglass frames	$256,856	$ (15,306)	+5.6%	307	-36	####	2924	-321	###	$427,500	48	0	$98/SF labour and material

**Simple payback over lowest cost replacement option 6a.*

***Discount available if the same GC does both remedial options at the same time*

Notes:

4a Base replacement option = high performance alum. dbl hung window, with Low-e (Solarban60), argon filled gaps, warm-edge spacers (at $2-$4 SF for awning operators 1/3 from bottom)

5a Type 2 windows consist of 2 double hung units - appear on their own and within bands of windows on North exposure (6'x5')

-Values shown with 0 payback has no incremental cost from base replacement option 4a (i.e. less capital cost; greater cost savings).

Appendix N – Horizon Utilities Corporation – 55 John St. North, Hamilton – Roof Inspection Review – Fall 2013

Garland Canada Inc.

Roof Asset Management Program

Horizon Utilities Corporation - 55 John St. North, Hamilton - Roof Inspection Review - Fall 2013

Prepared By
Bryce Cheeseman

Prepared For
Reva McCann

November 19, 2013

Table of Contents

Client Data

Client: Horizon Utilities Corporation

Client Data

Name	Horizon Utilities Corporation		
Address 1	55 John Street North	**Address 2**	-
City	Hamilton	**Province**	ON
Postal	L8R 3M8	**Country**	Canada

Contact Info

Contact Person	Reva McCann	**Title**	Commodity Management Specialist
Mobile Phone:	-	**Office Phone:**	(905)521-4916
Email:	reva.mccann@horizonutilities.com		

Facility Summary

Client: Horizon Utilities Corporation

Facility: 55 John Street North - Hamilton

Facility Data

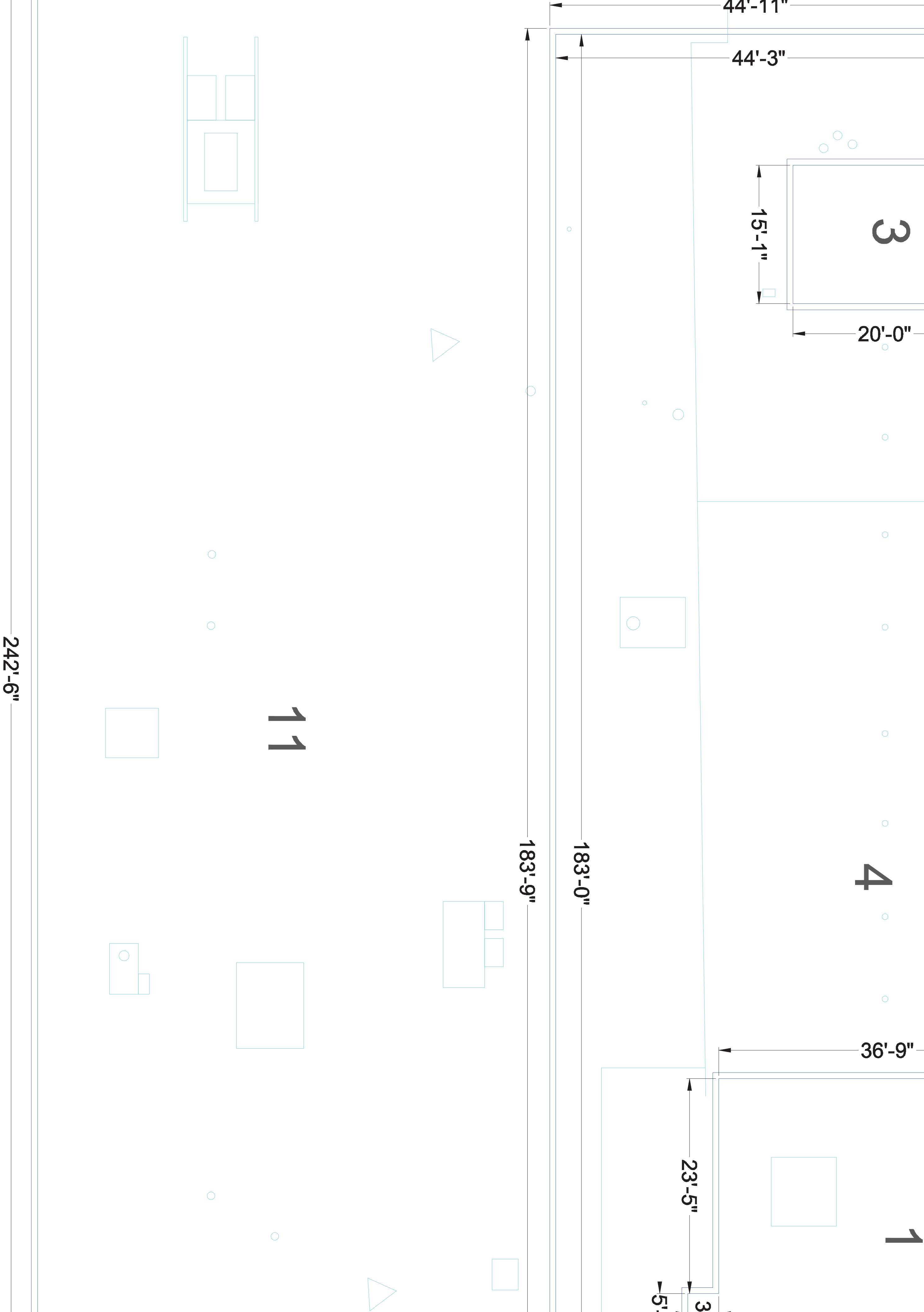
Address 1	55 John Street North
Address 2	-
City	Hamilton
Province	ON
Postal	L8R 3M8
Type of Facility	Commercial
Square Footage	37,366
Contact Person	Reva McCann

Notes

55 John St, Hamilton, is the Head Office for Horizon Utilities.
It is a 37,000 sq ft facilitly, made up of 11 roof sections.
There are 3 main building areas, the tower, the parking garage and the Hughson Substation.

Roof Sections

Name	Date Installed	Square Footage	Roof Access
Roof Area 11	1999	14,248	Penthouse
Roof Areas 1,2,3,4	1999	12,146	Penthouse
Roof Areas 5,6,7,8,9,10	1999	10,971	Penthouse


44'-11"
44'-3"
15'-1"
3
20'-0"
242'-6"
11
183'-9"
183'-0"
4
36'-9"
23'-5"

Construction Details

Client: Horizon Utilities Corporation

Facility: 55 John Street North - Hamilton

Roof Section: Roof Areas 1,2,3,4

Roof Info

Year Installed	1999	**Square Footage**	12,146
Slope Dimension	.5/12	**Roof Height**	80
Roof Access	Penthouse	**System Type**	Modified Bitumen
		Contractor	Spinton Roofing Frank Francella 1800368-8441 (Office) (905)971-3493 (Mobile) Frank@spintonroofing.com

Roof Assembly

Roof #	Layer Type	Description	Attachement	R-Value	Insulation Thickness
1	Deck	Metal Deck	Mechanically attached	-	-
1	Vapor Retarder	Asphalt/Felt	Spot Mopped	-	-
1	Insulation	Polyisocyanurate	Mechanically attached	12	2
1	Protection Mat	No-Woven Fabric	Hot asphalt	-	-
1	Membrane	Mod Bit - 2 ply	Torch applied	-	-

Details

Perimeter Detail	Parapet Wall
Flashing Material	Modified Membrane
Drain System	Internal Roof Drains
Parapet Wall	Pre-Cast Concrete
Coping Cap	Stone

Notes

This Roof Section includes the roof tower and the 3 penthouse roofs associated with the tower.

Inspection Report

Client: Horizon Utilities Corporation

Facility: 55 John Street North - Hamilton

Report Date: 09/12/2013

Roof Section: Roof Areas 1,2,3,4

Inspection Information

Inspection Date	09/12/2013	**Core Data**	Yes
Inspection Type	Core Analysis	**Leakage**	Yes
Deck Conditions	Excellent		

Flashing Conditions

Perimeter	Good	**Wall**	Good
Projections	Good	**Counterflashing**	N/A

Miscellaneous Details

Reglets	Good	**Debris**	No
Control Expansion Joints	N/A	**Ponding Water**	Minor
Parapet Wall	Good	**Coping Joints**	Excellent

Perimeter

Rating	Good
Condition	The parapet wall is in good condition. The coping stone is holding up very well. The membrane running up the parapet wall is in good condition.

Field

Rating	Good
Condition	The field membrane is in good condition. The roof system is 14 years old and is holding up fairly well. The 2 ply modified roof membrane holds some water from ponding. The roof has slope from tapered insulation, however, there are areas where water ponds. Ponding is where water will sit on a flat roof for more than 48 hours after rainfall.The roof system is asphalt based and asphalt will disolve in water over time. The water will deteriorate the membrane over time. There are a few small blisters on the roof area. Blisters are caused when air and/or air vapour is trapped within the system. The air will expand and contract with temperature change and deteriorate the strength of the roof system.

Penetrations

Rating	Fair
Condition	The flashing membrane is deteriorating at some of the projections. The flashing membrane has come apart at some of the flashing seams of the mechanical units. There have been some leaks at the flashing membrane.

Drainage

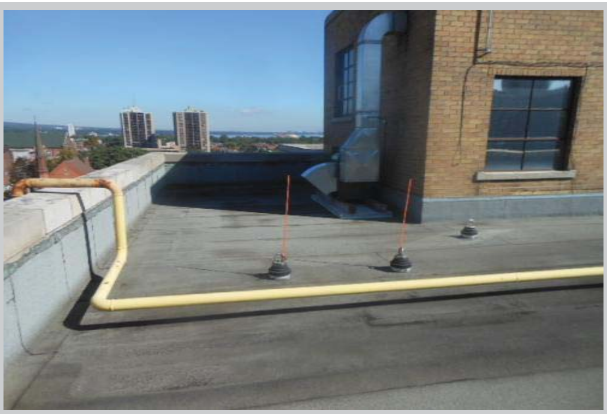
Rating	Fair
Condition	The insulation has been installed to create slope to the drains. However, the roof holds water after heavy rain and snow. The ponding water is starting to deteriorate the roof system.

Other

Rating	Poor
Condition	The walls on this upper roof section (The Tower) are in poor condition. The walls are taking on water through heavy and driving rain, and have no way to drain out, other than into the building. The mourtar of the brick wall is deteriorating and the walls and mourtar is cracking. The windows are also in very poor condition. The windows are very old and many of these windows are leaking. Many of them are not needed and provide no significant light to the facility.

Overall

Rating	Good
Condition	The roof system is 14 years old and we are starting to see signs of deterioration. The membrane is holding up, but because of ponding water, high winds and other elements, the roof membrane is starting to degranulate and lose its strength and UV resistance.



View by the penthouse where the membrane is darker from ponding water.

View of section 4 looking towards the east.

View of core cut reveals 2" polyisocyanurate, 1/8" separation sheet and 2 plies of modified membrane

View of brick wall which has been repaired temporarily in the past.

More brick work attempted repairs.

View of the southside of section 4 facing west.

The electrical should normally be run into a separate tall cone, but may have been done based on the concrete deck. This mastic should be aluminized and will always be a maintenance item.

These walls are in very poor shape and should be protected better with new cladding, stucco or a coating.

View of the east side of section 4 where an exaggerated cricket/saddle was installed to help with the drainage.

More signs of mortar repairs in the brickwork.

View of the northside of section 4 where a small area was already replaced recently (note lighter grey patch along the perimeter)

View of the northside of section 4

The redundant sleepers should be removed. This is the view from the west side of section 4 facing the east.

Signs of ponding water to the left of the HVAC unit, towards the middle of the roof section.

View of penthouse brick work that needs to be better protected as leaks are coming through these walls.

signs of previous attempts to repair the deteriorated mourtar in the brick work.

Closer view of current cracks in the brick founnd in a varietyof areas below roof sections 1, 2 and 3.

View of badly deteriorated membrane located on the north side of section 3

Solution Options

Client: Horizon Utilities Corporation

Facility: 55 John Street North - Hamilton

Roof Section: Roof Areas 1,2,3,4

Repair Options

Solution Option:	Repair	**Action Year:**	2014
Section Square Footage:	12,146	**Expected Life Years:**	1
Estimated Cost:	$7,500.00		
Scope of Work:	The following repairs should be completed in 2014, unless the roof can be restored within the next 2 years and wall cladding can be installed, covering all of the existing deteriorated brick walls. Repoint all of the deteriorated brick walls, where the mortar is deteriorated. Repair any roof leaks, with rubberized mastic and reinforced with fiberglass mesh. Seal any open seams in the modified membrane.		

Restore Options

Solution Option:	Restore ✔	**Action Year:**	2014
Section Square Footage:	12,146	**Expected Life Years:**	20
Estimated Cost:	$145,000.00		
Scope of Work:	The solution option includes restoring the existing modified membrane of all the roofs, including the penthouse roofs. The roof restoration involves the following: 1) Cut out all wet insulation as determined through the thermographic roof scan. 2) Replace all wet insulation and membrane. 3) Sweep the entire roof membrane, removing all minerals, dirt or debris. 3) Repair all roof anomolies, ridges, blisters and ridges. 4) Install new flashing modified membrane (high performance), adhered with fibered mastic. Butter all seams with rubberized mastic, reinforced with fiberglass mesh. 5) Coat the entire roof membrane with cold applied rubberized resaturant. 6) Cover the entire roof with white gravel. 7) Install new perimeter and curb sheet metal. The system comes with a 10 year warranty, and a life expectancy of 15-20 years.		

Replace Options

Solution Option:	Replace	**Action Year:**	2020

Section Square Footage:	12,146	**Expected Life Years:**	30
Estimated Cost:	$350,000.00		

Scope of Work:

3-Ply System: High Strength Mod-Bit Cap Sheet w/ Type IV Glasfelts Inter plies

Please note the above cost is a budget number not a firm price. A firm price would be determined by a competitive bid process.

This replacement includes the following and is performed by a contractor and incorporates the best performance qualities of both the single ply rubber roof system and the multi layers inorganic built-up roof system. The modified system uses intermittent layers of type III asphalt and fiberglass roofing felts along with a super thick and strong rubber modified/fiberglass reinforced bitumen cap sheet. The multiple layers are covered by a heavy top pour of type III asphalt and are surfaced with protective roofing gravel. This modified membrane dramatically improves the performance and life expectancy of the roof system.

SCOPE OF WORK

Replace Existing Roof Membrane
• Tear off and properly dispose of existing roof membrane and metal coping flashings.
Field of Roof (3-Ply Mod-Bit Membrane)
• Install Kraft Paper vapour barrier, in a hot spot mopping of asphalt.
• Install 2.5” ISO insulation (R20), hot mopped on top of the vapour barrier.
• Install tapered insulation, and then install 1/2" high density, asphalt coated, fibre insulation board (R1.5), staging the seams with the ISO to reduce the effects of thermo bridging.
• Taper the insulation around the perimeter of all internal drains, creating a sumped drain which will assist in the removal of water from the roof surface.
• Install 2-plys of Type IV Glasfelts using Type III asphalt at a rate of 25 lbs / sq.
• Install 1-ply of High Strength (Tensile Strength >500 lbf/in, Tear Strength >500 lbf) using Type III asphalt at a rate of 30 lbs / sq.
• Flood coat with Type III asphalt at a rate of 60 lbs / sq and embed 3/8" pea gravel (at a rate of 500-600 lbs / sq.) to create a durable UV reflective surface.

NOTE: Installing a 3-ply Mod-Bit roof membrane will offer multiple layers of protection against a water penetration with the added protection of the top Mod-Bit cap-sheet which offers excellent durability against UV aging, thermal shock with a cold weather flexibility surpassing the ASTM 6163 test standards @ -30oC.

NOTE: Garland Canada does not recommend the use of Type 15 organic felts (Tensile Strength = 25 lbf/in, Tear Strength = no rating) as the base plies for a built up roof (BUR) system, as they offer no flexibility and are manufactured from organic materials that rot and deteriorate over time, leading to reduced roof life

Solution Options

Client: Horizon Utilities Corporation

Facility: 55 John Street North - Hamilton

Roof Section: Roof Areas 1,2,3,4

Repair Options

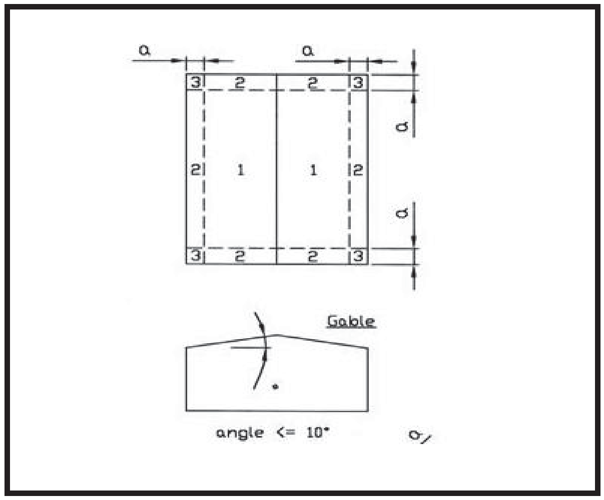
Solution Option:	Repair	**Action Year:**	2014
Section Square Footage:	12,146	**Expected Life Years:**	30
Estimated Cost:	$100,000.00		
Scope of Work:	Install metal wall cladding, covering all of the walls of the penthouses. The scope of work involves the following: 1) Cover all of the walls with a self adhering waterproof membrane. 2) Install Z-Bars, framing the entire wall system 3) Insulate the walls, using the Z-Bars to support the insulation. 4) Cover all of the walls with high grade metal wall panels, with no exposed fasteners. 5) Cap all walls and ends of the walls. The wall cladding system comes with a 30 year waterproof warranty.		

The Garland Company, Inc.
Low Slope Roofing Wind Uplift Calculations
3800 East 91st Street
Cleveland, Ohio 44105-2197
Phone: (800) 321-9336 Fax (216) 883-2046

Project **Horizon Utilities**
Roof **Section 1**
Sales Rep. **Bryce Cheesman** Location **Hamilton, ON**

Zone 1 psf (mid roof)	**40.1**	Zone 2 psf (eaves, ridge, hip)	**62.9**	Zone 3 psf (corners)	**85.8**

Edge Zone Width "a" **12** ft. **8** in.



Fastener Safety Factor	**3.00**
Importance	**III**
Importance Factor	**1.15**
Wind Speed (mph)	**90**
Ultimate Pullout Value	**456**
Exposure Category	**C**
Design Roof Height	**95.00**
Minimum Building Width	**126.00**
Roof Pitch (X, Y)	**0.25** : **12**
Snow Load (psf)	

System Type: **Modified Bitumen**
System Type: **Modified Bitumen Cold**
Surfacing: **Coated Finish**
Attachment Method: **Mech/ Fasten Insul/Board**

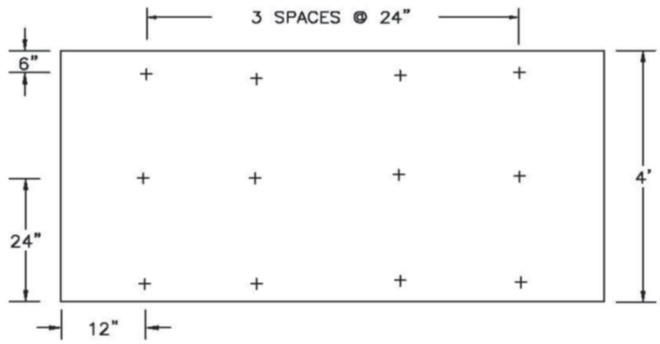
Zone 1		**Zone 2**		**Zone 3**	
(mid roof)	_12__ fasteners per 4' x 8' board	(eaves, ridge, hip)	_18__ fasteners per 4' x 8' board	(corners)	_24__ fasteners per 4' x 8' board

NOTES: Attachment pattern is for attaching poly iso to metal deck. A min. .25" densdeck or securock was assumed to be adhered to the poly iso. Insulation adhesive was assumed to be Insul-Lok HR applied in 3/4" continuous beads spaced 12 in. o.c. per the attached diagram.

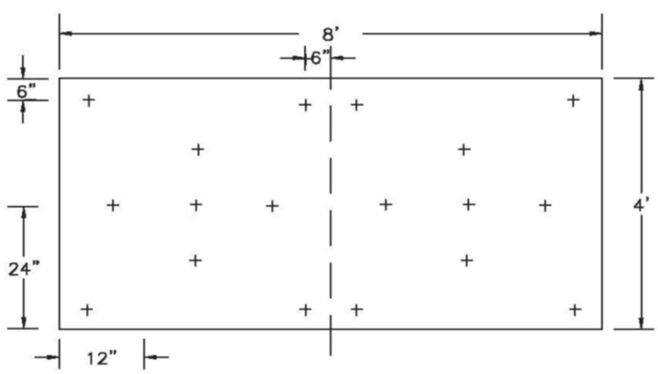
*Unless specifically stated otherwise, these calculations are based on ASCE 7-05 (American Society for Civil Engineers); if a specific building code is required, please specify.
*It is recommended to include the "Negative Uplift Pressures" in the specifications as well as the Safety Factor, Importance Factor, Building Category, Wind Speed, Ultimate Pullout Value, and Exposure.
*The Wind Speed is determined based upon geographical location.
*The Exposure and Importance Factors are needed to determine the uplift pressures.

If you have any questions, please call 800-321-9336 or respond to engineering@garlandind.com

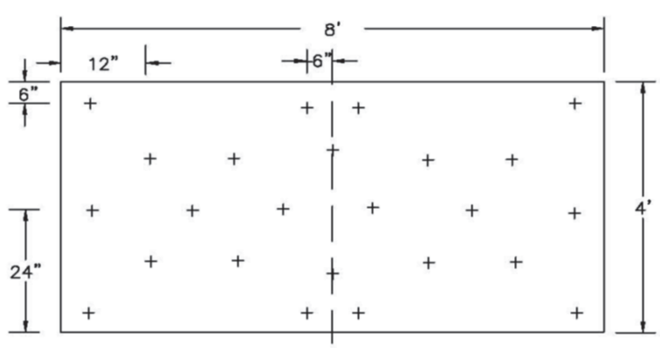
ZONE 1 INSULATION BOARD FASTENER PATTERN: 12 FASTENERS PER BOARD



ZONE 2 INSULATION BOARD FASTENER PATTERN: 18 FASTENERS PER BOARD



ZONE 3 INSULATION BOARD FASTENER PATTERN: 24 FASTENERS PER BOARD



THE GARLAND COMPANY, INC.

GARLAND

3800 EAST 91st STREET
CLEVELAND, OHIO 44105-2197
—PHONE 1-800-321-9336—
FAX 1-216-641-0633

DETAIL:

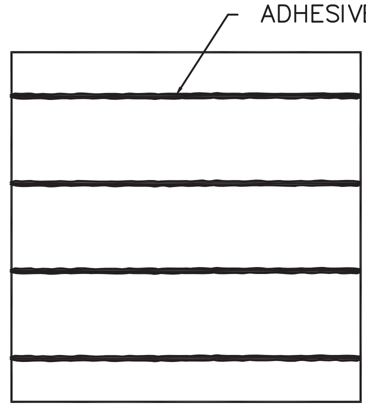
4 X 8 BOARD PATTERN

SECTION:

INSULATION BOARD FASTENER PATTERN

REV: 1 9/05

TYPICAL ZONE 1 INSULATION BOARD ADHESIVE PATTERN: 12" OC BEADS PER BOARD



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DETAIL:

4 X 4 BOARD PATTERN

SECTION:

INSULATION BOARD ADHESIVE PATTERN

REV: 3 28/07

The Garland Company, Inc.
3800 East 91st Street
Cleveland, Ohio 44105-2197
Phone: (800) 321-9336 Fax (216) 883-2046

PROJECT	**Horizon Utilities**
ROOF SECTION	**Section 1**
DATE	**11/5/2013**
BASIC VELOCITY PRESSURE	**25.38** psf
DESIGN CODE	**ASCE 7-05**

System & Attachment Data

SYSTEM TYPE	Modified Bitumen
SYSTEM SCOPE	Modified Bitumen Cold
SURFACING	Coated Finish
ATTACHMENT METHOD	Mech/ Fasten Insul/Board
SUBSTRATE MATERIAL	Steel
SUBSTRATE THICKNESS	22 gauge
FASTENER TYPE	Steel: OMG Standard
FASTENER SAFETY FACTOR	3
ULTIMATE FASTENER PULLOUT	456 lbs/screw
ALLOWABLE FASTENER PULLOUT	152 lbs/clip

Building & Site Data

BASIC WIND SPEED	90	mph
EXPOSURE CATEGORY	C	
TOPOGRAPHY FACTOR	1.00	
BUILDING TYPE	Enclosed	
ROOF PITCH (X, Y)	0.25	12
RUN TO RIDGE	63	
EAVE HEIGHT	95	
DESIGN ROOF HEIGHT	95.00	ft
IMPORTANCE CLASS / FACTOR	III	1.15
MIN. BLDG WIDTH	126	ft
WIND-BORNE DEBRIS REGION	No	
PARAPET	No	
ROOF ANGLE	1.19	deg
PROTECTED OPENINGS	Yes	
ROOF TYPE	Gable	

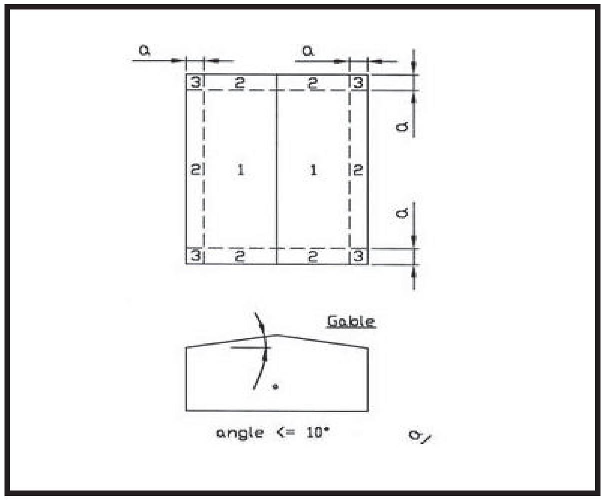
	ZONE 1	**ZONE 2**	**ZONE 3**	**ZONE 4**	**ZONE 5**		
ROOF PRESSURE (psf)	40.1	62.9	85.8	27.6	50.2		
OVERHANG PRESSURE (psf)	43.14	43.14	71.06				
EDGE ZONE WIDTH "a" =	12.60	ft					

The Garland Company, Inc.
Low Slope Roofing Wind Uplift Calculations
3800 East 91st Street
Cleveland, Ohio 44105-2197
Phone: (800) 321-9336 Fax (216) 883-2046

Project **Horizon Utilities**
Roof **Section 4**
Sales Rep. **Bryce Cheesman** Location **Hamilton, ON**

Zone 1 psf (mid roof)	**38.7**	Zone 2 psf (eaves, ridge, hip)	**60.7**	Zone 3 psf (corners)	**82.7**

Edge Zone Width "a" **12** ft. **8** in.



Fastener Safety Factor	**3.00**
Importance	**III**
Importance Factor	**1.15**
Wind Speed (mph)	**90**
Ultimate Pullout Value	**456**
Exposure Category	**C**
Design Roof Height	**80.00**
Minimum Building Width	**126.00**
Roof Pitch (X, Y)	**0.25** : **12**
Snow Load (psf)	

System Type: **Modified Bitumen**
Surfacing: **Coated Finish**
System Type: **Modified Bitumen Cold**
Attachment Method: **Mech/ Fasten Insul/Board**

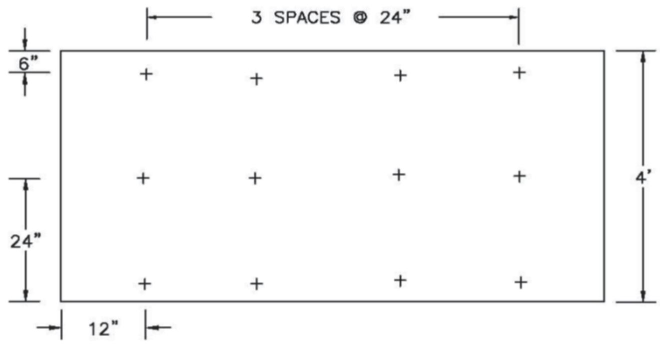
Zone 1		**Zone 2**		**Zone 3**	
(mid roof)	_12__ fasteners per 4' x 8' board	(eaves, ridge, hip)	_18__ fasteners per 4' x 8' board	(corners)	_24__ fasteners per 4' x 8' board

NOTES: Attachment pattern is for attaching poly iso to metal deck. A min. .25" densdeck or securock was assumed to be adhered to the poly iso. Insulation adhesive was assumed to be Insul-Lok HR applied in 3/4" continuous beads spaced 12 in. o.c. per the attached diagram.

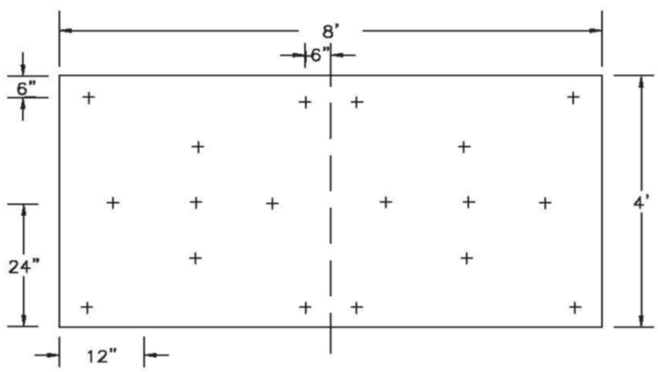
*Unless specifically stated otherwise, these calculations are based on
ASCE 7-05 (American Society for Civil Engineers); if a specific building code is required, please specify.
*It is recommended to include the "Negative Uplift Pressures" in the specifications as well as the Safety Factor, Importance Factor, Building Category, Wind Speed, Ultimate Pullout Value, and Exposure.
*The Wind Speed is determined based upon geographical location.
*The Exposure and Importance Factors are needed to determine the uplift pressures.

If you have any questions, please call 800-321-9336 or respond to engineering@garlandind.com

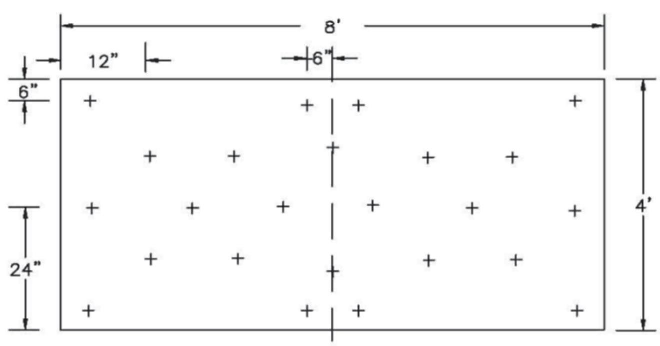
ZONE 1 INSULATION BOARD FASTENER PATTERN: 12 FASTENERS PER BOARD



ZONE 2 INSULATION BOARD FASTENER PATTERN: 18 FASTENERS PER BOARD



ZONE 3 INSULATION BOARD FASTENER PATTERN: 24 FASTENERS PER BOARD



THE GARLAND COMPANY, INC.
3800 EAST 91st STREET
CLEVELAND, OHIO 44105-2197
—PHONE 1-800-321-9336—
FAX 1-216-641-0633

DETAIL:

4 X 8 BOARD PATTERN

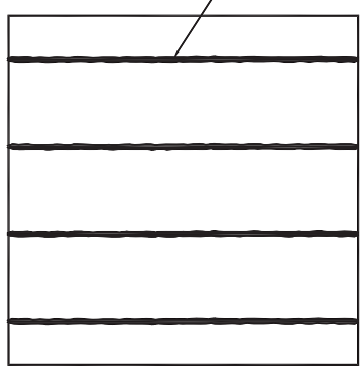
SECTION:

INSULATION BOARD FASTENER PATTERN

REV: 1 9/05

TYPICAL ZONE 1 INSULATION BOARD ADHESIVE PATTERN: 12" OC BEADS PER BOARD

ADHESIVE RIBBON ENLARGED FOR CLARITY



4 ADHESIVE RIBBONS
EQUALLY SPACED AT
12" (15.2cm) O.C. (TYP.)

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REV: 3 28/07

The Garland Company, Inc.
3800 East 91st Street
Cleveland, Ohio 44105-2197
Phone: (800) 321-9336 Fax (216) 883-2046

since 1895

PROJECT	**Horizon Utilities**
ROOF SECTION	**Section 4**
DATE	**11/5/2013**
BASIC VELOCITY PRESSURE	**24.48** psf
DESIGN CODE	**ASCE 7-05**

System & Attachment Data

SYSTEM TYPE	Modified Bitumen
SYSTEM SCOPE	Modified Bitumen Cold
SURFACING	Coated Finish
ATTACHMENT METHOD	Mech/ Fasten Insul/Board
SUBSTRATE MATERIAL	Steel
SUBSTRATE THICKNESS	22 gauge
FASTENER TYPE	Steel: OMG Standard
FASTENER SAFETY FACTOR	3
ULTIMATE FASTENER PULLOUT	456 lbs/screw
ALLOWABLE FASTENER PULLOUT	152 lbs/clip

Building & Site Data

BASIC WIND SPEED	90	mph
EXPOSURE CATEGORY	C	
TOPOGRAPHY FACTOR	1.00	
BUILDING TYPE	Enclosed	
ROOF PITCH (X, Y)	0.25	12
RUN TO RIDGE	63	
EAVE HEIGHT	80	
DESIGN ROOF HEIGHT	80.00	ft
IMPORTANCE CLASS / FACTOR	III	1.15
MIN. BLDG WIDTH	126	ft
WIND-BORNE DEBRIS REGION	No	
PARAPET	No	
ROOF ANGLE	1.19	deg
PROTECTED OPENINGS	Yes	
ROOF TYPE	Gable	

	ZONE 1		**ZONE 2**	**ZONE 3**	**ZONE 4**	**ZONE 5**		
ROOF PRESSURE (psf)	38.7		60.7	82.7	26.7	48.5		
OVERHANG PRESSURE (psf)	41.61		41.61	68.53				
EDGE ZONE WIDTH "a" =	12.60	ft						

Construction Details

since 1895

Client: Horizon Utilities Corporation

Facility: 55 John Street North - Hamilton

Roof Section: Roof Areas 5,6,7,8,9,10

Roof Info

Year Installed	1999	**Square Footage**	10,971
Slope Dimension	1/12	**Roof Height**	40
Roof Access	Penthouse	**System Type**	Modified Bitumen
		Contractor	Spinton Roofing Frank Francella 1800368-8441 (Office) (905)971-3493 (Mobile) Frank@spintonroofing.com

Roof Assembly

Roof #	Layer Type	Description	Attachement	R-Value	Insulation Thickness
1	Deck	Metal Deck	Mechanically attached	-	-
1	Vapor Retarder	2 ply hot	Hot asphalt	-	-
1	Insulation	Polyisocyanurate	Hot asphalt	12	2"
1	Membrane	Mod Bit - 2 ply mineral surfaced	Torch applied	-	-

Details

Perimeter Detail	Parapet Wall, Wall Flashing, Drip Edge
Flashing Material	Modified Membrane
Drain System	Internal Roof Drains, Gutter System
Parapet Wall	Poured In Place Concrete
Coping Cap	Metal

Notes

Roof Areas 5, 6, 7, 8, 9 and 10 make up the original Hughson Substation.
The building is extremely old and has been designated as Historic Building.

Inspection Report

Client: Horizon Utilities Corporation

Facility: 55 John Street North - Hamilton

Report Date: 09/12/2013

Roof Section: Roof Areas 5,6,7,8,9,10

Inspection Information

Inspection Date	09/12/2013	**Core Data**	Yes
Inspection Type	Core Analysis	**Leakage**	No
Deck Conditions	Excellent		

Flashing Conditions

Perimeter	Good	**Wall**	Good
Projections	Good	**Counterflashing**	Good

Miscellaneous Details

Reglets	Good	**Debris**	No
Control Expansion Joints	N/A	**Ponding Water**	None
Parapet Wall	Good	**Coping Joints**	Good

Perimeter

Rating	Good
Condition	The perimeter flashing detail is in good condition. The parapet walls are in excellent condition. The seams of the flashing membrane are well sealed.

Field

Rating	Good
Condition	The field membrane is in good condition. There is excellent natural slope, built into the concrete deck. The roof membrane is holding up very well, because of the excellent slope.

Penetrations

Rating	Good
Condition	There are pitch pockets that were installed too low and have had some minor roof leaks. most of the penetrations are in good condition.

Drainage

Rating	Good
Condition	There is excellent slope to the exterior gutters. None of the roofs hold water. The roof membrane is holding up very well.

Overall

Rating	Good
Condition	The roof membrane is 14 years old, but because of the excellent slope, the membrane is holding up well.

View of section 5, 6 and 8

View of section 9, 8 and 7 (starting from the top and moving down, left to right)

View of section 8 and the poorly installed railing that do not have proper pitch pans (seen on the right). Note the deteriorated membrane in the middle of the roof.

View of section 8

View of section 8

The membrane is in poor shape as seen here on section 8 where it ties into section 9 on the north side.

Recently installed new modifed membrane where it was leaking at the base of the post.

View of section 9

View of ponding water on the left which will only be rectified when tapered insulation is installed.

Moss growth seen here where water is getting in behind the membrane/metal flashing above

Membrane has delaminated as seen here by the corner of section 9

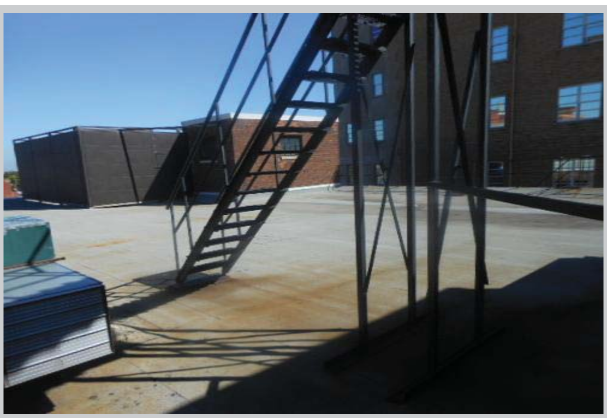
Minerals have badly deteriorated here from excessive water held here.

This conduit was not properly installed in a proper pitch pan.

View of section 10, ponding water is excessive on the right

The lower roof #10,
This roof has already been replaced because of sloppy workmanship and poor quality material.
The insulation was soaked.
The roof was replaced in approximately 2007

All the debris should be removed from the drain strainer over section 10



View of section 8

There are some mortar issues along the wall at the lower brick work of section 9

Moss growth from water that is getting from in behind the metal counter flashing.

View of deteriorated membrane as seen on the right dark spots

View of parapet wall located on the west side of section 6

View of section 6 which is sloped 2:12

View of canopies that need to be repaired along the souhtwest corner that wraps around the corner of section 6.

View of deteriorated membrane that has started to crack along the perimeter of the overhang.

Solution Options

Client: Horizon Utilities Corporation

Facility: 55 John Street North - Hamilton

Roof Section: Roof Areas 5,6,7,8,9,10

Repair Options

Solution Option:	Repair	**Action Year:**	2014
Section Square Footage:	10,971	**Expected Life Years:**	2
Estimated Cost:	$5,000.00		
Scope of Work:	The following repairs should be completed as required, and only if the roof system can not be restored in the next few years. The roof has issues, and should be repaired as necessary. The mortar in the brick work should be repointed.		

Restore Options

Solution Option:	Restore	**Action Year:**	2016
Section Square Footage:	10,971	**Expected Life Years:**	20
Estimated Cost:	$100,000.00		
Scope of Work:	Restore the entire roof section with the same technique used to restore the garage roof and the tower roofs. Restoration involves the following: Remove all of the wet and moist insulation, and replace (matching existing) and replace the modified membrane. Sweep the entire existing roof membrane, removing all loose minerals, dirt and debris. Repair the existing roof membrane, repairing all ridges, blisters, and any annomolies. Install new flashing membrane, which is High Strength Modified Membrane, adhered with Fibered Mastic. Butter all flashing seams with rubberized mastic, reinforced with fiberglass mesh. Coat the entire field of the roof system with cold applied rubberized roof resaturant. Cover the existing resaturant with white gravel. Aluminize all exposed flashing membrane. Secure the membrane with termination bars. Also, the roof's safety rails need to be repaired or replaced to meet code. The restoration comes with a 10 year warranty and a life expectancy of 15-20 years.		

Replace Options

Solution Option:	Replace	**Action Year:**	2021
Section Square Footage:	10,971	**Expected Life Years:**	30
Estimated Cost:	$225,000.00		
Scope of Work:	3-Ply System: High Strength Mod-Bit Cap Sheet w/ Type IV Glasfelts Inter plies Please note the above cost is a budget number not a firm price. A firm price would be		

determined by a competitive bid process.

This replacement includes the following and is performed by a contractor and incorporates the best performance qualities of both the single ply rubber roof system and the multi layers inorganic built-up roof system. The modified system uses intermittent layers of type III asphalt and fiberglass roofing felts along with a super thick and strong rubber modified/fiberglass reinforced bitumen cap sheet. The multiple layers are covered by a heavy top pour of type III asphalt and are surfaced with protective roofing gravel. This modified membrane dramatically improves the performance and life expectancy of the roof system.

SCOPE OF WORK

Replace Existing Roof Membrane
• Tear off and properly dispose of existing roof membrane and metal coping flashings.
Field of Roof (3-Ply Mod-Bit Membrane)
• Install Kraft Paper vapour barrier, in a hot spot mopping of asphalt.
• Install 2.5" ISO insulation (R20), hot mopped on top of the vapour barrier.
• Install 1/2" high density, asphalt coated, fibre insulation board (R1.5), staging the seams with the ISO to reduce the effects of thermo bridging.
• Taper the insulation around the perimeter of all internal drains, creating a sumped drain which will assist in the removal of water from the roof surface.
• Install 2-plys of Type IV Glasfelts using Type III asphalt at a rate of 25 lbs / sq.
• Install 1-ply of Modified Membrane(Tensile Strength >500 lbf/in, Tear Strength >500 lbf) using Type III asphalt at a rate of 30 lbs / sq.
• Flood coat with Type III asphalt at a rate of 60 lbs / sq and embed 3/8" pea gravel (at a rate of 500-600 lbs / sq.) to create a durable UV reflective surface.

NOTE: Installing a 3-ply Mod-Bit roof membrane will offer multiple layers of protection against a water penetration with the added protection of the top Mod-Bit cap-sheet which offers excellent durability against UV aging, thermal shock with a cold weather flexibility surpassing the ASTM 6163 test standards @ -30oC.

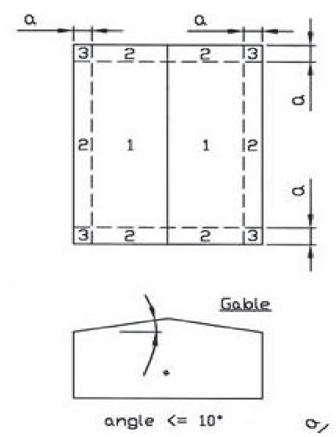
NOTE: Garland Canada does not recommend the use of Type 15 organic felts (Tensile Strength = 25 lbf/in, Tear Strength = no rating) as the base plies for a built up roof (BUR) system, as they offer no flexibility and are manufactured from organic materials that rot and deteriorate over time, leading to reduced roof life

The Garland Company, Inc.
Low Slope Roofing Wind Uplift Calculations
3800 East 91st Street
Cleveland, Ohio 44105-2197
Phone: (800) 321-9336 Fax (216) 883-2046

Project **Horizon Utilities**
Roof **Section 6**
Sales Rep. **Bryce Cheesman** Location **Hamilton, ON**

Zone 1 psf (mid roof)	**24.9**	Zone 2 psf (eaves, ridge, hip)	**43.3**	Zone 3 psf (corners)	**64.0**

Edge Zone Width "a" **12** ft. **8** in.



Fastener Safety Factor	**N/A**
Importance	**III**
Importance Factor	**1.15**
Wind Speed (mph)	**90**
Ultimate Pullout Value	**N/A**
Exposure Category	**C**
Design Roof Height	**60.00**
Minimum Building Width	**126.00**
Roof Pitch (X, Y)	**2** : **12**
Snow Load (psf)	

System Type: **Modified Bitumen** System Type: **Modified Bitumen Cold**

Surfacing: **Coated Finish** Attachment Method: **Insulation Adhesive**

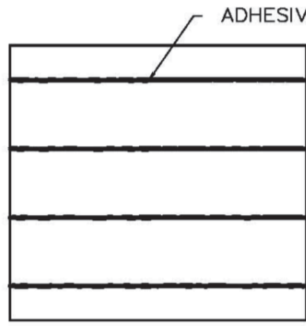
Zone 1 (mid roof)	**Zone 2** (eaves, ridge, hip)	**Zone 3** (corners)
Beads spaced _12"__ o.c. per 4' x 4' board	Beads spaced _12"__ o.c. per 4' x 4' board	Beads spaced _12"__ o.c. per 4' x 4' board

NOTES: Attachment pattern is for adhering poly iso to concrete and min. .25" densdeck or securock to poly iso. Insulation adhesive was assumed to be Insul-Lok HR applied in 3/4" continuous beads spaced per the attached diagram.

*Unless specifically stated otherwise, these calculations are based on
ASCE 7-05 (American Society for Civil Engineers); if a specific building code is required, please specify.
*It is recommended to include the "Negative Uplift Pressures" in the specifications as well as the Safety Factor, Importance Factor, Building Category, Wind Speed, Ultimate Pullout Value, and Exposure.
*The Wind Speed is determined based upon geographical location.
*The Exposure and Importance Factors are needed to determine the uplift pressures.

If you have any questions, please call 800-321-9336 or respond to engineering@garlandind.com

TYPICAL ZONE 1 INSULATION BOARD ADHESIVE PATTERN: 12" OC BEADS PER BOARD



since 1895	THE GARLAND COMPANY, INC. GARLAND CANADA, INC. THE GARLAND COMPANY UK, LTD	DETAIL: 4 X 4 BOARD PATTERN SECTION: INSULATION BOARD ADHESIVE PATTERN

REV: 3 28/07

3800 East 91st Street, Cleveland, Ohio 44105-2197 Phone: (800) 321-9336

The Garland Company, Inc.
3800 East 91st Street
Cleveland, Ohio 44105-2197
Phone: (800) 321-9336 Fax (216) 883-2046

PROJECT	Horizon Utilities
ROOF SECTION	Section 6
DATE	11/5/2013
BASIC VELOCITY PRESSURE	23.04 psf
DESIGN CODE	ASCE 7-05

System & Attachment Data

SYSTEM TYPE	Modified Bitumen	
SYSTEM SCOPE	Modified Bitumen Cold	
SURFACING	Coated Finish	
ATTACHMENT METHOD	Insulation Adhesive	
SUBSTRATE MATERIAL	Concrete	
SUBSTRATE THICKNESS	6 in	
FASTENER TYPE	N/A	
FASTENER SAFETY FACTOR	N/A	
ULTIMATE FASTENER PULLOUT	N/A	lbs/screw
ALLOWABLE FASTENER PULLOUT	N/A	lbs/clip

Building & Site Data

BASIC WIND SPEED	90	mph
EXPOSURE CATEGORY	C	
TOPOGRAPHY FACTOR	1.00	
BUILDING TYPE	Enclosed	
ROOF PITCH (X, Y)	2	12
RUN TO RIDGE	30	
EAVE HEIGHT	60	
DESIGN ROOF HEIGHT	60.00	ft
IMPORTANCE CLASS / FACTOR	III	1.15
MIN. BLDG WIDTH	126	ft
WIND-BORNE DEBRIS REGION	No	
PARAPET	No	
ROOF ANGLE	9.46	deg
PROTECTED OPENINGS	Yes	
ROOF TYPE	Gable	

	ZONE 1	ZONE 2	ZONE 3	ZONE 4	ZONE 5		
ROOF PRESSURE (psf)	24.9	43.3	64.0	27.0	33.2		
OVERHANG PRESSURE (psf)	20.73	50.68	85.24				
EDGE ZONE WIDTH "a" =	12.60	ft					

The Garland Company, Inc.
Low Slope Roofing Wind Uplift Calculations
3800 East 91st Street
Cleveland, Ohio 44105-2197
Phone: (800) 321-9336 Fax (216) 883-2046

Project **Horizon Utilities**
Roof **Section 9**
Sales Rep. **Bryce Cheesman**   Location **Hamilton, ON**

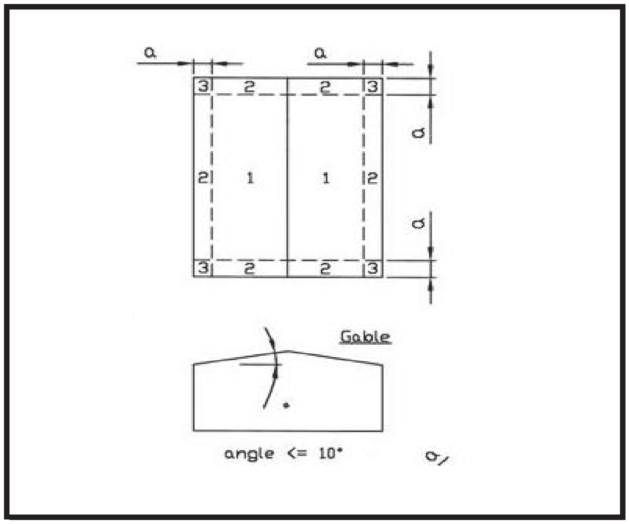
Zone 1 psf **25.0**
(mid roof)

Zone 2 psf **41.9**
(eaves, ridge, hip)

Zone 3 psf **63.0**
(corners)

Edge Zone Width "a" **12** ft. **8** in.

Fastener Safety Factor	**N/A**
Importance	**III**
Importance Factor	**1.15**
Wind Speed (mph)	**90**
Ultimate Pullout Value	**N/A**
Exposure Category	**C**
Design Roof Height	**40.00**
Minimum Building Width	**126.00**
Roof Pitch (X, Y)	**0.25** : **12**
Snow Load (psf)	



System Type: **Modified Bitumen**
System Type: **Modified Bitumen Cold**

Surfacing: **Coated Finish**
Attachment Method: **Insulation Adhesive**

Zone 1
(mid roof)
Beads spaced _12"__ o.c. per 4' x 4' board

Zone 2
(eaves, ridge, hip)
Beads spaced _12"__ o.c. per 4' x 4' board

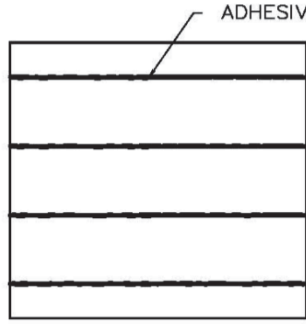
Zone 3
(corners)
Beads spaced _12"__ o.c. per 4' x 4' board

NOTES: Attachment pattern is for adhering poly iso to concrete and min. .25" densdeck or securock to poly iso. Insulation adhesive was assumed to be Insul-Lok HR applied in 3/4" continuous beads spaced per the attached diagram.

*Unless specifically stated otherwise, these calculations are based on
ASCE 7-05 (American Society for Civil Engineers); if a specific building code is required, please specify.
*It is recommended to include the "Negative Uplift Pressures" in the specifications as well as the Safety Factor, Importance Factor, Building Category, Wind Speed, Ultimate Pullout Value, and Exposure.
*The Wind Speed is determined based upon geographical location.
*The Exposure and Importance Factors are needed to determine the uplift pressures.

If you have any questions, please call 800-321-9336 or respond to engineering@garlandind.com

TYPICAL ZONE 1 INSULATION BOARD ADHESIVE PATTERN: 12" OC BEADS PER BOARD



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THE GARLAND COMPANY, INC.
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DETAIL:
4 X 4 BOARD PATTERN

SECTION:
INSULATION BOARD ADHESIVE PATTERN

REV: 3 28/07

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Phone: (800) 321-9336 Fax (216) 883-2046

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PROJECT	Horizon Utilities
ROOF SECTION	Section 9
DATE	11/5/2013
BASIC VELOCITY PRESSURE	21.15 psf
DESIGN CODE	ASCE 7-05

System & Attachment Data

SYSTEM TYPE	Modified Bitumen	
SYSTEM SCOPE	Modified Bitumen Cold	
SURFACING	Coated Finish	
ATTACHMENT METHOD	Insulation Adhesive	
SUBSTRATE MATERIAL	Concrete	
SUBSTRATE THICKNESS	6 in	
FASTENER TYPE	N/A	
FASTENER SAFETY FACTOR	N/A	
ULTIMATE FASTENER PULLOUT	N/A	lbs/screw
ALLOWABLE FASTENER PULLOUT	N/A	lbs/clip

Building & Site Data

BASIC WIND SPEED	90	mph
EXPOSURE CATEGORY	C	
TOPOGRAPHY FACTOR	1.00	
BUILDING TYPE	Enclosed	
ROOF PITCH (X, Y)	0.25	12
RUN TO RIDGE	30	
EAVE HEIGHT	40	
DESIGN ROOF HEIGHT	40.00	ft
IMPORTANCE CLASS / FACTOR	III	1.15
MIN. BLDG WIDTH	126	ft
WIND-BORNE DEBRIS REGION	No	
PARAPET	No	
ROOF ANGLE	1.19	deg
PROTECTED OPENINGS	Yes	
ROOF TYPE	Gable	

	ZONE 1	ZONE 2	ZONE 3	ZONE 4	ZONE 5		
ROOF PRESSURE (psf)	25.0	41.9	63.0	24.7	30.5		
OVERHANG PRESSURE (psf)	35.96	35.96	59.23				
EDGE ZONE WIDTH "a" =	12.60	ft					

Construction Details

Client: Horizon Utilities Corporation

Facility: 55 John Street North - Hamilton

Roof Section: Roof Area 11

Roof Info

Year Installed	1999	**Square Footage**	14,248
Slope Dimension	.5/12	**Roof Height**	20
Roof Access	Penthouse	**System Type**	Modified Bitumen
		Contractor	Spinton Roofing Frank Francella 1800368-8441 (Office) (905)971-3493 (Mobile) Frank@spintonroofing.com

Roof Assembly

Roof #	Layer Type	Description	Attachement	R-Value	Insulation Thickness
1	Deck	Metal Deck	Mechanically attached	-	-
1	Vapor Retarder	1 ply organic felt	Spot Mopped	-	-
1	Insulation	Polyisocyanurate	Fully Adhered	12	2"
1	Membrane	Mod Bit - 2 ply mineral surfaced	Torch applied	-	-

Details

Perimeter Detail	Parapet Wall
Flashing Material	Modified Membrane
Drain System	Internal Roof Drains
Parapet Wall	Pre-Cast Concrete
Coping Cap	Stone

Notes

Roof Area 11 is the lower roof or the parking garage

Inspection Report

Client: Horizon Utilities Corporation

Facility: 55 John Street North - Hamilton

Report Date: 09/12/2013

Roof Section: Roof Area 11

Inspection Information

Inspection Date	09/12/2013	**Core Data**	Yes
Inspection Type	Core Analysis	**Leakage**	No
Deck Conditions	Good		

Flashing Conditions

Perimeter	Good	**Wall**	Good
Projections	Good	**Counterflashing**	N/A

Miscellaneous Details

Reglets	N/A	**Debris**	No
Control Expansion Joints	N/A	**Ponding Water**	Minor
Parapet Wall	Good	**Coping Joints**	Good

Perimeter

Rating	Good
Condition	The flashing membrane is in good condition. Flashing seams are holding up well.

Field

Rating	Good
Condition	The field membrane is holding up well. The roof is 14 years old and has experienced some minor leaks, mainly caused at projections. There was also a wall that fell on the roof system at the south east corner and crushed the deck.

Penetrations

Rating	Fair
Condition	There are many penetrations on the roof, with mechanical units, boilers and other plumbing stacks etc. The penetrations have all been sealed many times with rubberized mastic and have been aluminized.

Drainage

Rating	Good
Condition	There is a slight slope to the internal drains. There is slope, however the roof still holds water in areas. This ponding water is deteriorating the roof membrane.The granules of the membrane are delaminating from the membrane. The ponding water is starting to deteriorate the roof membrane.

Overall

Rating	Good
Condition	The roof membrane is in good condition. The 2 ply modified membrane is starting to show some signs of aging, but it is holding up nicely. The roof is 14 years old and the roof is losing granules (which protect the membrane from UV)

Overview of roof. Note that the middle of the roof shows signs of excessve ponding water. ***Ponding***: ponding water occurs as rain or snow melt water collects in large pools on the surface of a roof system. These pools begin to form because of two reasons: (1) roof drains are blocked or clogged with debris, (2) roof drains are built along side building support columns which maintain a consistent height while the rest of the roof system is built on a deck which tends to move and deflect under the downward pressure of weight. In both cases, roof depressions that collect and hold water will tend to grow in size as the added weight of the ponding water will continue to deflect the roof deck even further.

Ponding water has many negative effects on a roof system. The added weight can crush insulation to the point where it becomes a useless thermal barrier - this will cost you big money since your HVAC system will have to work longer and harder to maintain a comfortable interior temperature. In the winter ponding water will expand as it freezes. This expansion will weaken small imperfections in the roof system. Small cracks and tears will widen until they rupture to allow water into the building. Ponding water also accelerates the aging of a roof. The natural waterproofing oils in the asphalt will separate from the membrane if the system remains submerged under water for periods longer than 48 hours. And finally, a negatively deflected deck becomes a structural concern. The deck’s tolerances will only accept a limited amount of weight and deflection before it becomes a candidate for a roof collapse

Busy part of roof where there are signs of significant ponding water.

Example of ponding water around one of the larger HVAC units in the middle of the roof.

View of perimeter flashing along the base of the windows

Mosses are small, soft plants that are typically 1–10 cm (0.4-4 in) tall, though some species are much larger. They commonly grow close together in clumps or mats in damp or shady locations. They do not have flowers or seeds, and their simple leaves cover the thin wiry stems. At certain times mosses produce spore capsules which may appear as beak-like capsules borne aloft on thin stalks.

These roots from plant growth can damage the underlying membrane

Signs of extreme ponding water. ***Ponding***: ponding water occurs as rain or snow melt water collects in large pools on the surface of a roof system. These pools begin to form because of two reasons: (1) roof drains are blocked or clogged with debris, (2) roof drains are built along side building support columns which maintain a consistent height while the rest of the roof system is built on a deck which tends to move and deflect under the downward pressure of weight. In both cases, roof depressions that collect and hold water will tend to grow in size as the added weight of the ponding water will continue to deflect the roof deck even further.

View of small area which was recently replaced.
A wall from the firehall fell and collapsed the deck.

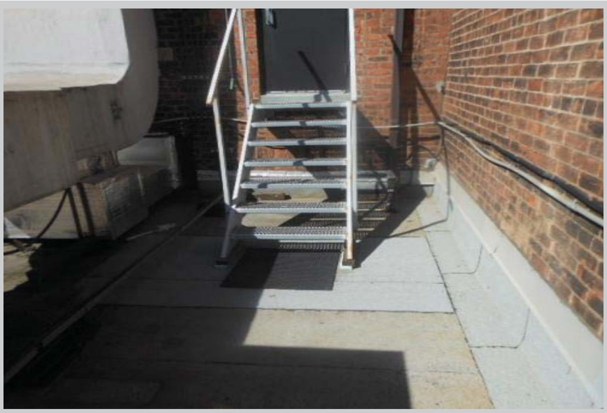
This cone will need to be replaced as the corrosion here has badly deteriorated the base.

View of roof shows that the perimeter by the windows was tapered to the middle, however, the drains are not receiving the water well here.

View of small part of section

Another view of small part of section that leads to the stairs to section 8

View of railing at the edge of section 6



View of ponding water between the large units on section 11

This detail around the HVAC unit that ties into the wall needs to be repaired.

Area that needs to be repaired.

View of perimeter detail around all the busy HVAC units

Solution Options

Client: Horizon Utilities Corporation

Facility: 55 John Street North - Hamilton

Roof Section: Roof Area 11

Inspection Options

Solution Option:	Inspection	**Action Year:**	2014
Section Square Footage:	14,248	**Expected Life Years:**	1
Estimated Cost:	$2,900.00		

Scope of Work:

The roof should be thermal scanned to verify the amount of wet insulation. This cost can be a cost effective method with other flat roofs on the property to determine options. Doing more than one roof at one time will reduce the individual costs.
Due to the history and of the roof it is extremely important to determine whether or not the roof system is holding wet insulation in any areas. The infra red scan will give us a snap shot of which areas are wet and allow us to develop a long term roof asset management plan (depending on results of the scan).

The following is included as part of the Garland Infra Red Scan Service:

The logical starting point for your roof maintenance program is to perform an accurate Infrared Thermal Scan. The Scan is a diagnostic tool and acts very much like an X-ray to determine the condition of the roof and insulation that are not visible to the naked eye. It will detect areas of wet insulation and invisible roof leaks.

Utilizing the most up to date equipment, and performing the scan at the optimal time will ensure the most accurate readings. The use of a thermal scan assists in setting priorities. Funds are spent on correction of wet insulation thereby correcting leaks and minimizing long-term costs.

1. A complete scan of the designated roofs with any problem areas marked directly on the roof surface.
2. A scale drawing of the roof with all sections of wet insulation marked to scale.
3. Built up membrane analysis determining the roof felt condition, number of plies of roofing felt, adhesion between plies, pliability of the core(s) taken and adhesion of the gravel on the surface.
4. Analysis of the flashing at all areas including all perimeters and projections. Additionally, all metal counter flashing, expansion/control joints, reglet joints, copings, plumbing vents, pitch pockets, skylights, drains, and air intake and exhaust units. Notation of areas of exposed roofing felt, ridging of the roof membrane, blisters, ponding and other weaknesses.
5. Core cuts determining the type, thickness, R-value and condition of the insulation. Type of deck and air/vapour retarder noted.
6. Thermograms and photos of all problem areas.
7. Recommendations for any required work to bring the roofs up to a watertight condition immediately and recommendations for the future as related to restoration and/or replacement.

Once the scan is completed you will have the scientific information you require to make proper maintenance decisions regarding your roof system. Let me know if you have any further questions in regards to this procedure.

Repair Options

Solution Option:	Repair	**Action Year:**	2014
Section Square Footage:	14,248	**Expected Life Years:**	2
Estimated Cost:	$7,500.00		
Scope of Work:	The following roof repairs should be done in 2014, in order to keep the building watertight, until the capital funds can be allocated to the roof section: 1) Repoint all of the brick walls, repairing all of the deteriorated mortar, 2) Recaulk all of the windows. 3)Repair any roof leaks and open seams in the modified flashing membrane. All of these repairs will only be neccessary if the funds are not available to cover the brick walls with metal cladding and to restore the existing roof membrane.		

Restore Options

Solution Option:	Restore ✓	**Action Year:**	2015
Section Square Footage:	14,248	**Expected Life Years:**	15
Estimated Cost:	$110,000.00		
Scope of Work:	Restoring the existing modified membrane involves the following scope of work; 1) Conduct a thermographic roof scan, to determine the presence of moisture in the existing roof system. 2) Cut out and replace any wet insulation and membrane. The membrane will match the existing, and will be installed with torch application. 3) Sweep the existing roof membrane. Clean the roof of all loose ganuals, dirt or debris. 4) Repair any roof membrane issues, including blisters, ridges etc. Repair the existing membrane with cold adhesive and reinforced with modified membrane. 5) Install a new modified membrane flashing membrane, with cold applied fibered mastic. The membrane needs to be secured at the top of the wall with termination bars. 6) Butter all seams with rubberized mastic, reinforced with fiberglass mesh. 7) cover the existing modified membrane with a cold applied rubberized resaturant. 8) Cover the entire roof with white gravel. 9) Install new perimeter metal. Aluminize all exposed flashing membrane with fibered aluminizer. The above solution comes with a 10 year warranty and should extend the life of the roof by 15-20 years.		

Replace Options

Solution Option:	Replace	**Action Year:**	2020
Section Square Footage:	14,248	**Expected Life Years:**	30
Estimated Cost:	$250,000.00		
Scope of Work:	3-Ply System: High Performance Mod-Bit Cap Sheet w/ Type IV Glasfelts Inter plies Please note the above cost is a budget number not a firm price. A firm price would be determined by a competitive bid process. This replacement includes the following and is performed by a contractor and incorporates the best performance qualities of both the single ply rubber roof system and the multi layers inorganic built-up roof system. The modified system uses intermittent layers of type III asphalt and fiberglass roofing felts along with a super thick and strong rubber modified/fiberglass reinforced bitumen cap sheet. The multiple layers are covered by a heavy top pour of type III asphalt and are surfaced with protective roofing gravel. This modified membrane dramatically		

improves the performance and life expectancy of the roof system.

SCOPE OF WORK

Replace Existing Roof Membrane
• Tear off and properly dispose of existing roof membrane and metal coping flashings.
Field of Roof (3-Ply Mod-Bit Membrane)
• Install Kraft Paper vapour barrier, in a hot spot mopping of asphalt.
• Install 2.5" ISO insulation (R20), hot mopped on top of the vapour barrier.
• Install tapered fiberboard, and then install 1/2" high density, asphalt coated, fibre insulation board (R1.5), staging the seams with the ISO to reduce the effects of thermo bridging.
• Taper the insulation around the perimeter of all internal drains, creating a sumped drain which will assist in the removal of water from the roof surface.
• Install 2-plys of Type IV Glasfelts using Type III asphalt at a rate of 25 lbs / sq.
• Install 1-ply of Modified Membrane (Tensile Strength >500 lbf/in, Tear Strength >500 lbf) using Type III asphalt at a rate of 30 lbs / sq.
• Flood coat with Type III asphalt at a rate of 60 lbs / sq and embed white gravel (at a rate of 500-600 lbs / sq.) to create a durable UV reflective surface.

NOTE: Installing a 3-ply Mod-Bit roof membrane will offer multiple layers of protection against a water penetration with the added protection of the top Mod-Bit cap-sheet which offers excellent durability against UV aging, thermal shock with a cold weather flexibility surpassing the ASTM 6163 test standards @ -30oC.

NOTE: Garland Canada does not recommend the use of Type 15 organic felts (Tensile Strength = 25 lbf/in, Tear Strength = no rating) as the base plies for a built up roof (BUR) system, as they offer no flexibility and are manufactured from organic materials that rot and deteriorate over time, leading to reduced roof life.

The Garland Company, Inc.
Low Slope Roofing Wind Uplift Calculations
3800 East 91st Street
Cleveland, Ohio 44105-2197
Phone: (800) 321-9336 Fax (216) 883-2046

since 1895

Project	**Horizon Utilities**
Roof	**Section 11**
Sales Rep.	**Bryce Cheesman**
Location	**Hamilton, ON**

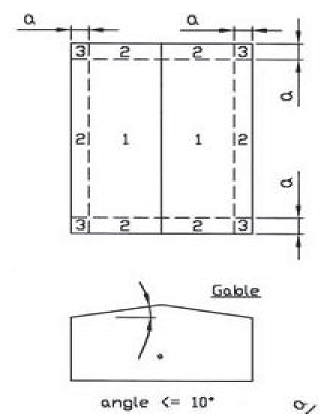
Zone 1 psf **16.8**
(mid roof)

Zone 2 psf **28.1**
(eaves, ridge, hip)

Zone 3 psf **42.3**
(corners)

Edge Zone Width "a" **7** ft. **8** in.

Fastener Safety Factor	**3.00**
Importance	**III**
Importance Factor	**1.15**
Wind Speed (mph)	**90**
Ultimate Pullout Value	**456**
Exposure Category	**B**
Design Roof Height	**19.00**
Minimum Building Width	**126.00**
Roof Pitch (X, Y)	**0.25** : **12**
Snow Load (psf)	



System Type: **Modified Bitumen**

System Type: **Modified Bitumen Cold**

Surfacing: **Coated Finish**

Attachment Method: **Mech/ Fasten Insul/Board**

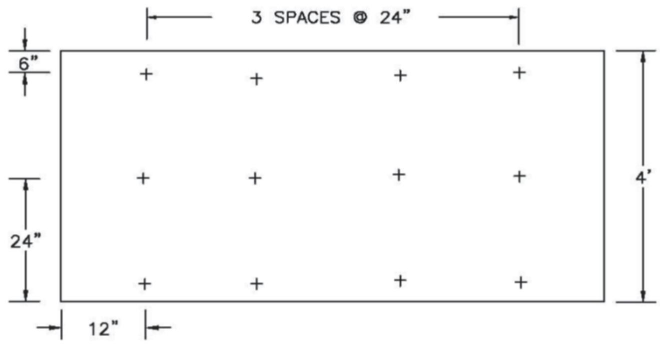
Zone 1		**Zone 2**		**Zone 3**	
(mid roof)	_12__ fasteners per 4' x 8' board	(eaves, ridge, hip)	_18__ fasteners per 4' x 8' board	(corners)	_24__ fasteners per 4' x 8' board

NOTES: Attachment pattern is for attaching poly iso to metal deck. A min. .25" densdeck or securock was assumed to be adhered to the poly iso. Insulation adhesive was assumed to be Insul-Lok HR applied in 3/4" continuous beads spaced 12 in. o.c. per the attached diagram.

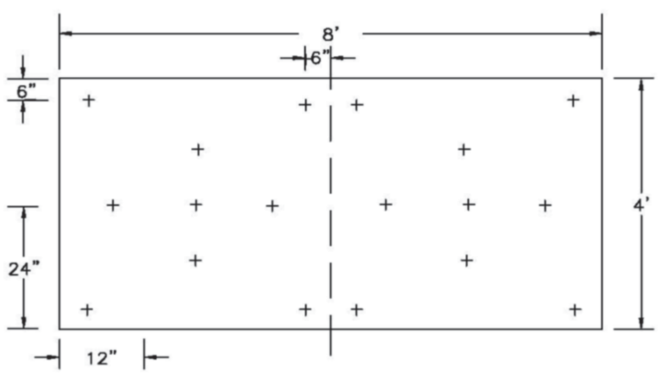
*Unless specifically stated otherwise, these calculations are based on
ASCE 7-05 (American Society for Civil Engineers); if a specific building code is required, please specify.
*It is recommended to include the "Negative Uplift Pressures" in the specifications as well as the Safety Factor, Importance Factor, Building Category, Wind Speed, Ultimate Pullout Value, and Exposure.
*The Wind Speed is determined based upon geographical location.
*The Exposure and Importance Factors are needed to determine the uplift pressures.

If you have any questions, please call 800-321-9336 or respond to engineering@garlandind.com

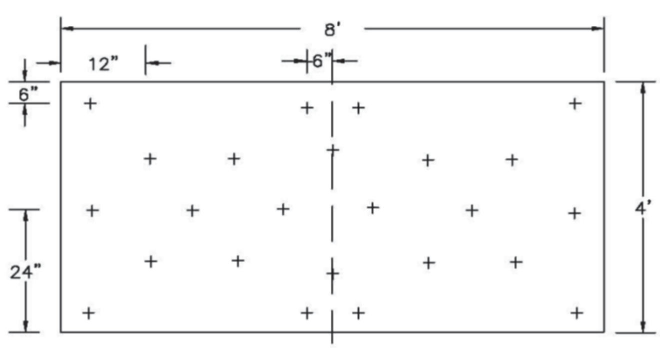
ZONE 1 INSULATION BOARD FASTENER PATTERN: 12 FASTENERS PER BOARD



ZONE 2 INSULATION BOARD FASTENER PATTERN: 18 FASTENERS PER BOARD



ZONE 3 INSULATION BOARD FASTENER PATTERN: 24 FASTENERS PER BOARD



THE GARLAND COMPANY, INC.
3800 EAST 91st STREET
CLEVELAND, OHIO 44105-2197
—PHONE 1-800-321-9336—
FAX 1-216-641-0633

DETAIL:

4 X 8 BOARD PATTERN

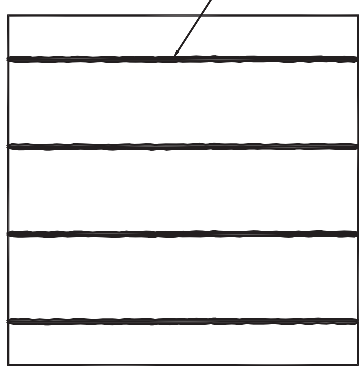
SECTION:

INSULATION BOARD FASTENER PATTERN

REV: 1 9/05

TYPICAL ZONE 1 INSULATION BOARD ADHESIVE PATTERN: 12" OC BEADS PER BOARD

ADHESIVE RIBBON ENLARGED FOR CLARITY



4 ADHESIVE RIBBONS
EQUALLY SPACED AT
12" (15.2cm) O.C. (TYP.)

THE GARLAND COMPANY, INC. GARLAND CANADA, INC. THE GARLAND COMPANY UK, LTD since 1895	DETAIL: 4 X 4 BOARD PATTERN
	SECTION: INSULATION BOARD ADHESIVE PATTERN

REV: 3 28/07

The Garland Company, Inc.
3800 East 91st Street
Cleveland, Ohio 44105-2197
Phone: (800) 321-9336 Fax (216) 883-2046

since 1895

PROJECT	**Horizon Utilities**
ROOF SECTION	**Section 11**
DATE	**11/5/2013**
BASIC VELOCITY PRESSURE	**14.20** psf
DESIGN CODE	**ASCE 7-05**

System & Attachment Data

SYSTEM TYPE	Modified Bitumen
SYSTEM SCOPE	Modified Bitumen Cold
SURFACING	Coated Finish
ATTACHMENT METHOD	Mech/ Fasten Insul/Board
SUBSTRATE MATERIAL	Steel
SUBSTRATE THICKNESS	22 gauge
FASTENER TYPE	Steel: OMG Standard
FASTENER SAFETY FACTOR	3
ULTIMATE FASTENER PULLOUT	456 lbs/screw
ALLOWABLE FASTENER PULLOUT	152 lbs/clip

Building & Site Data

BASIC WIND SPEED	90	mph
EXPOSURE CATEGORY	B	
TOPOGRAPHY FACTOR	1.00	
BUILDING TYPE	Enclosed	
ROOF PITCH (X, Y)	0.25	12
RUN TO RIDGE	63	
EAVE HEIGHT	19	
DESIGN ROOF HEIGHT	19.00	ft
IMPORTANCE CLASS / FACTOR	III	1.15
MIN. BLDG WIDTH	126	ft
WIND-BORNE DEBRIS REGION	No	
PARAPET	No	
ROOF ANGLE	1.19	deg
PROTECTED OPENINGS	Yes	
ROOF TYPE	Gable	

	ZONE 1	**ZONE 2**	**ZONE 3**	**ZONE 4**	**ZONE 5**		
ROOF PRESSURE (psf)	16.8	28.1	42.3	16.6	20.4		
OVERHANG PRESSURE (psf)	24.14	24.14	39.76				
EDGE ZONE WIDTH "a" =	7.60	ft					

Executive Summary

Client: Horizon Utilities Corporation

Facility *	Section *	System Type	Age(years)	Square Footage	Leakage	Rating	Recommendation	Action Year
55 John Street North - Hamilton	Roof Area 11	Modified Bitumen	14 Year(s)	14,248	NO	Good	**Restore**	**2015**
55 John Street North - Hamilton	Roof Areas 1,2,3,4	Modified Bitumen	14 Year(s)	12,146	YES	Good	**Restore**	**2014**
55 John Street North - Hamilton	Roof Areas 5,6,7,8,9,10	Modified Bitumen	14 Year(s)	10,971	NO	Good	**Restore**	**2016**
Facility Total:				**37,365**				
Client Total:				**37,365**				

Cost Estimate

Client: Horizon Utilities Corporation

Facility *	Section *	System Type	Square Footage	Recommendation	Action Year	Cost Estimate
55 John Street North - Hamilton	Roof Area 11	Modified Bitumen	14,248	Restore	2015	$110,000.00
55 John Street North - Hamilton	Roof Areas 1,2,3,4	Modified Bitumen	12,146	Restore	2014	$145,000.00
55 John Street North - Hamilton	Roof Areas 1,2,3,4	Modified Bitumen	12,146	Repair	2014	$100,000.00
55 John Street North - Hamilton	Roof Areas 5,6,7,8,9,10	Modified Bitumen	10,971	Restore	2016	$100,000.00
Facility Total:						**$455,000.00**
Client Total:						**$455,000.00**

since 1895

Priority Summary

Client: Horizon Utilities Corporation

Facility *	Section *	System Type	Age(years)	Leakage	Rating
Good					
55 John Street North - Hamilton	Roof Area 11	Modified Bitumen	14 Year(s)	NO	Good
55 John Street North - Hamilton	Roof Areas 1,2,8,4	Modified Bitumen	14 Year(s)	YES	Good
55 John Street North - Hamilton	Roof Areas 5,3,6,7,9,10	Modified Bitumen	14 Year(s)	NO	Good

Yearly Budget Summary

Client: Horizon Utilities Corporation

Facility *	Section *	Recommendation	Cost	Expected Life
Year: 2014				
55 John Street North - Hamilton	Roof Areas 1,2,3,4	Restore	$145,000.00	20 Year(s)
55 John Street North - Hamilton	Roof Areas 1,2,3,4	Repair	$100,000.00	30 Year(s)
Total for 2014:			**$245,000.00**	
Year: 2015				
55 John Street North - Hamilton	Roof Area 11	Restore	$110,000.00	15 Year(s)
Total for 2015:			**$110,000.00**	
Year: 2016				
55 John Street North - Hamilton	Roof Areas 5,6,7,8,9,10	Restore	$100,000.00	20 Year(s)
Total for 2016:			**$100,000.00**	

EGBERTS ENGINEERING LIMITED
CONSULTING ENGINEERS

November 15, 2013

Garland Canada
1290 Martingrove Road
Toronto, Ontario M9W 4X3

Att: Bryce Cheeseman

Re: Review of Roof deck at Horizon Utilities
55 John Street North, Hamilton
Toronto, Ontario, Our File 2013-158

Dear Client:

We were requested to review the roof deck at the above site to assess the capacity to support a revised roofing assembly. The existing modified bitumen roof is to be replaced by a 3 ply felt, hot asphalt and gravel ballast assembly.

It is our opinion that the proposed change in roofing materials is a safe proposal, with the added dead load returning to the original roof assembly and where measurements have allowed structural review, well within the load capacity of the roof structure measured on site.

SITE REVIEW

The site was reviewed with Shane McGowan, Garland Canada on October 10, 2013. The site is an assembly of numerous attached buildings and additions from an original building likely from around 1920; an original 3 story office tower possibly in the 1940's or 1950's which was changed to a 6 story building in 1960; plus a 1 level garage on the south side possibly in the range of 1970. No dates were provided and limited records have been located. While requests for existing building plans from the owner were not fruitful, a request to the Hamilton Building Department located a partial set of building permit plans showing various architectural, mechanical and electrical permit plans and some of the plans for the 3 story addition to the office tower.
Structural plans defining framing and design loads were generally not located at the City Building Department.

The site review was limited to the roof of the garage and portions of the original utility buildings at the rear of the site. The garage roof is conventional galvanized steel deck, supported by a steel beam and purlin assembly. The original utility building is a concrete slab, supported on rolled steel beams (ie American "I" shapes).

The roof of the tower could not be accessed due a vermiculite plaster ceiling, likely with diamond wire lath attached to the steel roof joists.

GARAGE ROOF

The roof area (see attached plan SK-1) is approximately 75 ft x 180 ft and is framed with deep steel beams (24 and 33" deep) spanning 40 ft and 55 ft, with 12" deep steel beam purlins between spanning just over 20 ft and spaced at 7 ft c/c. Standard galvanized steel roof deck (estimated as 1.5" deep x 18 ga) is placed over the top of the steel framing. There is no ceiling and limited mechanical distribution except for roof mounted equipment in specific locations.
Steel members were measured on site and evaluated using a steel grade customarily used in Canada from about 1965 to 1995 (ie 44 ksi or 300 MPa), based on the appearance and likely age of the structure.
Snow accumulation on this low roof adjacent to the 6 story office tower was considered in evaluating the steel framing and considerable live load capacity was found – in the range of 100 to 130 psf, allowing for 15 to 20 psf roofing and deck self-weight. This loading capacity well exceeds the required snow loads for this roof, and hence minor changes in the roofing dead load are acceptable and safe.
The steel roof deck was measured and is estimated as 18 ga (0.048") however measurement was difficult to obtain in the limited exposed edges that were available. The deck is adequate for the loads assuming this measurement is correct. A thinner deck guage would be deficient for the snow loads and would require reinforcing. The deck should be exposed and measured during roofing to verify capacity.

OFFICE TOWER ROOF

We were not able to readily access the roof structure due to a vermiculite plaster ceiling. This would have required considerable demolition, possible environmental issues and cleanup, before being able to access and measure the framing components.
We did obtain partial plans for the tower from the City Building Department, showing a three story addition to an existing three story building, and a roof framing plan was included. The plans specify a general roof load of 40 psf, without any added snow accumulation around the penthouse, and a dead load including a 2" concrete slab of 40 psf. The plans also show roofing details specifying "20 year felt and gravel roof". The roof framing may be described as: felt and gravel roofing, 2" concrete slab and steel deck, W10x15 steel purlins and W14 x30 or larger main steel beams; 7/8" vermiculite plaster ceiling, dropped acoustic ceiling with electrical and mechanical services generally located between the two ceilings.

We feel the dead load allowance used understated the actual conditions, and that 50 psf should have been used for the apparent roof construction, but the snow loading used in the original design (ie Live load in those days) is almost double the current required snow load of 22 psf. This provides some reserve capacity which may be used for added dead load.

Typical purlin beams (W10x15) and main roof beams within the main roof area (ie W14 x30 and W14 x 34), plus roof perimeter beams (W16x36) were design checked using likely A36 grade steel and all found to be more than adequate for the current and original design loads, allowing for a full felt and gravel roofing assembly and corrected over-all dead load of 50 psf. The purlin beams (which may be thought of as joists) were also checked for snow accumulation loads consistent with current Code requirements and a corrected dead load. They were found to still be adequate for the proposed roof revision.

ORIGINAL HYDRO BUILDING

The area reviewed is south of the elevator shaft and the room below is a part storage room. This original roof was constructed as an 8" concrete slab over steel beams. Three steel beams were measured and design-checked. A low grade A36 steel was assumed to have been used for this construction although grades slightly lower at 33,000 psi yield may have been used. The available live (ie snow) load, allowing for an 8" concrete roof slab and a conventional felt and gravel roof, varies from 75 to 145 psf. The required current basic snow loading is 22 psf, increasing to about 40 psf, due to snow accumulation against the elevator walls and mechanical screens. There is sufficient capacity in this area to allow an increase in roofing dead load.

CONCLUSION

There is sufficient capacity in the three roof areas reviewed to allow an increase in the roofing dead load assembly. Documents indicate that the original roofing assembly on the office tower was similar to the proposed roofing replacement.

However the roof deck over the garage, immediately adjacent to the tower perimeter could be deficient to support snow accumulation against the tower walls. It is recommended that the deck edges be exposed clearly and guage be confirmed while roofing is installed. Should reinforcing be deemed required this can be implemented from below, independent of roofing operations.

Yours very truly,

G.A.L.Egberts, M.Eng. P.Eng.
EGBERTS ENGINEERING LIMITED

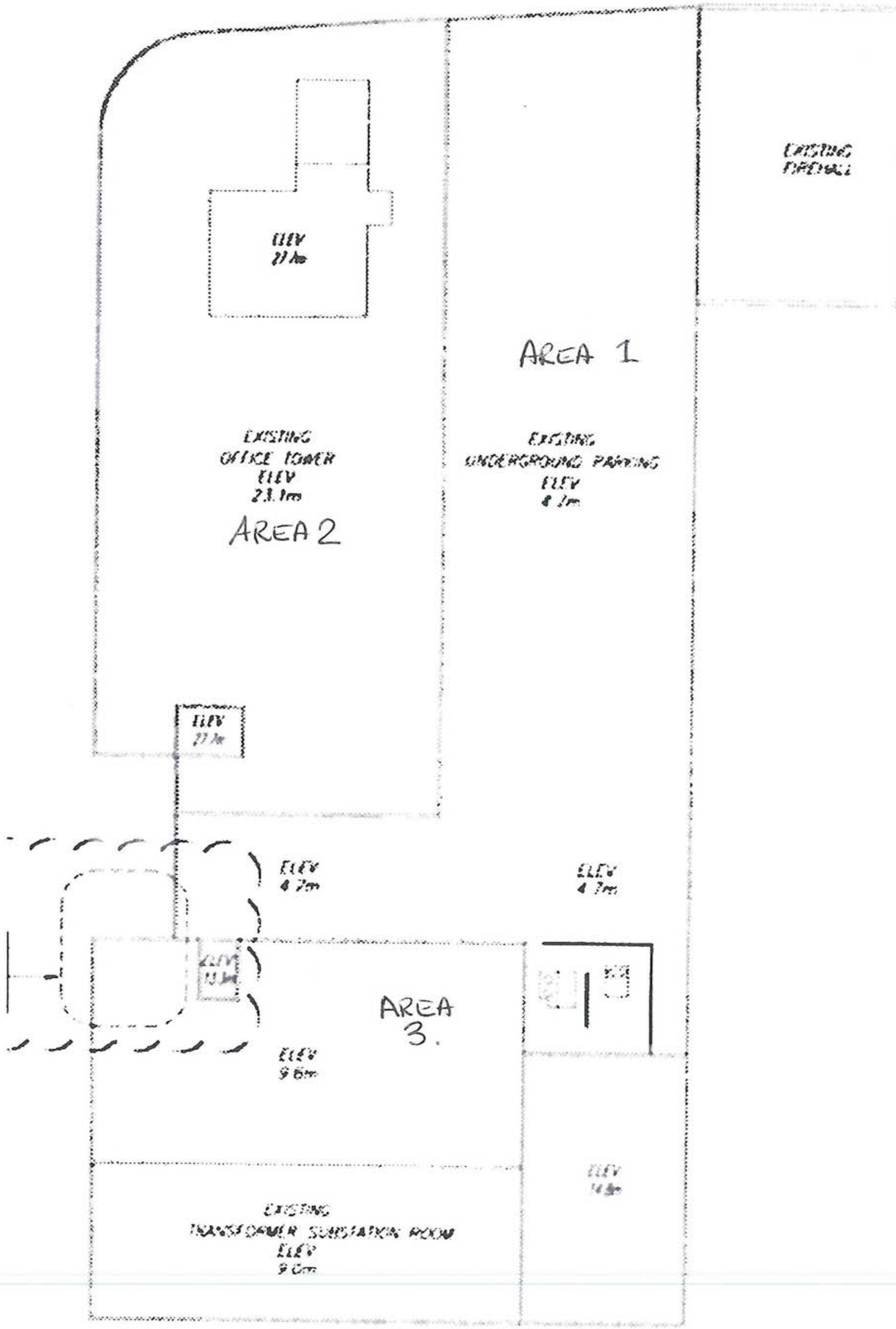
LICENSED PROFESSIONAL ENGINEER
G.A.L. EGBERTS
12943015
PROVINCE OF ONTARIO

ATTACHMENTS

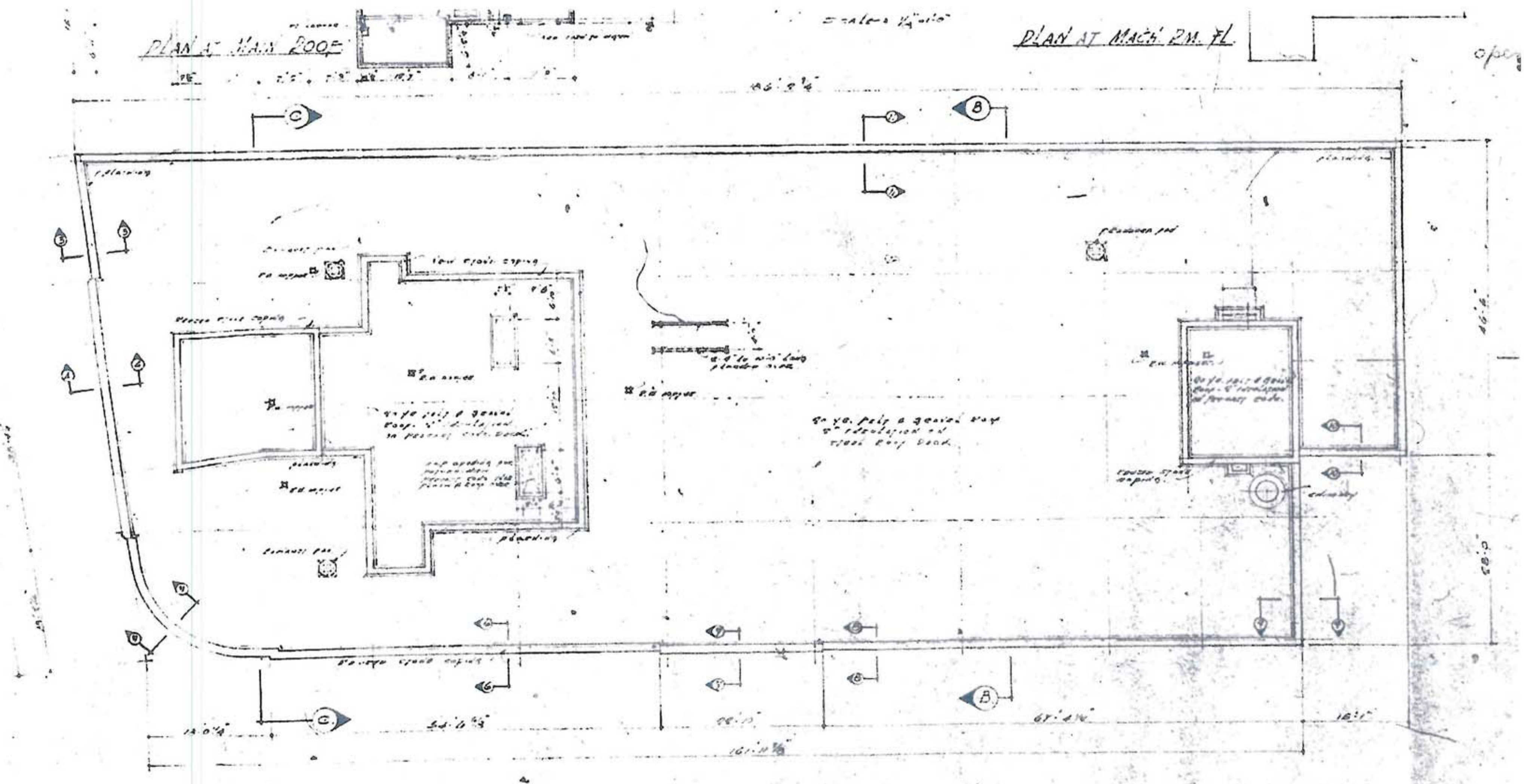
1. Roof key plan – Area 1: Garage roof; Area 2 : Office Tower roof; Area 3 Original Hydro Building

2. Roof plan of the Office Tower

3. Framing plan for the Office Tower

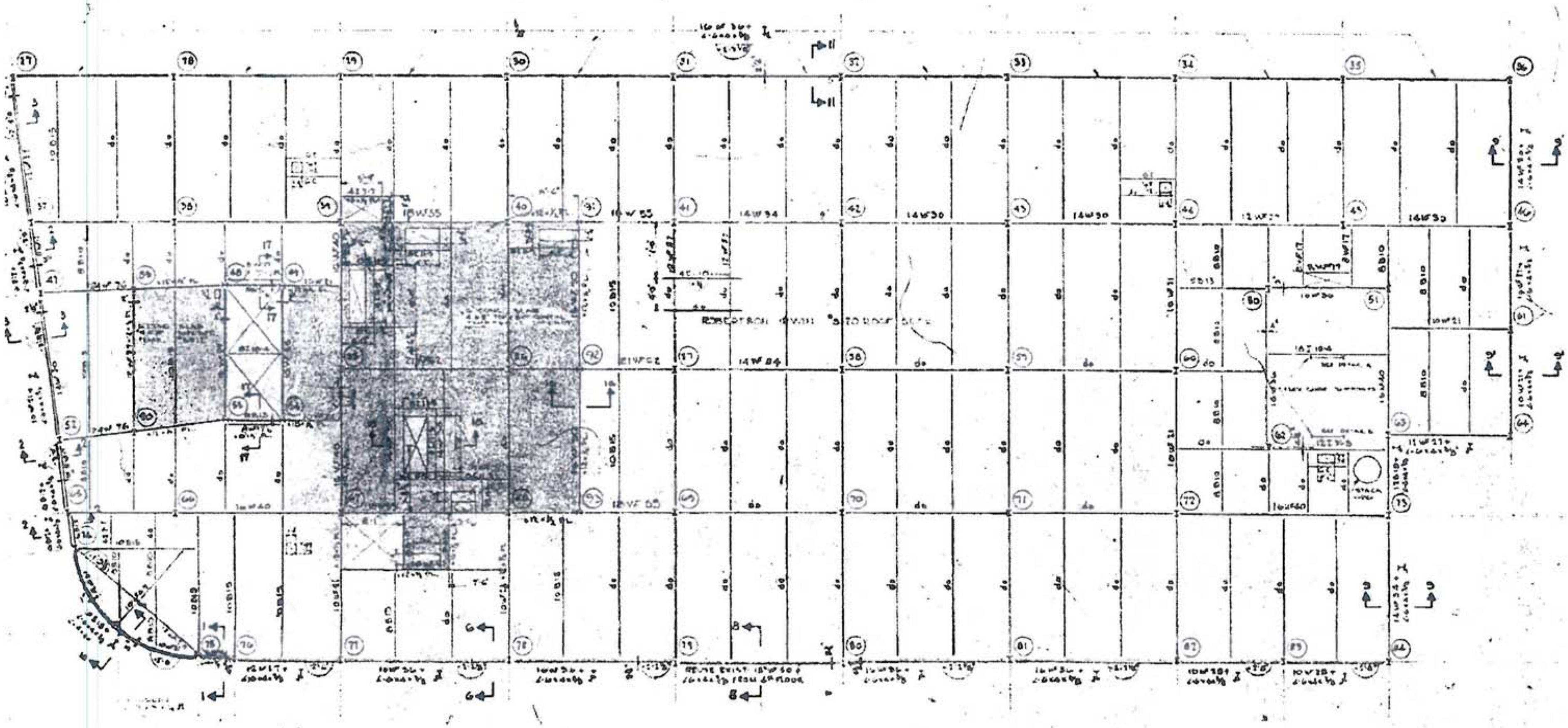


ROOF KEY PLAN



ROOF PLAN

1960 TOWER



ROOF FRAMING PLAN

BUILT-UP ROOF RESTORATION – SECTION 07562

PART 1 GENERAL

1.1 SECTION INCLUDES

Restoration system over the properly prepared gravel surfaced built-up and mineral surface roof system.

1.2 RELATED SECTIONS

A. Section 01300 - Submittals.
B. Detail Drawings
   1. Coping Cap – Cold Applied
   2. Expansion Joint – Cold Applied
   3. Gravel Finish – Cold Applied
   4. Internal Drain - Cold Applied

1.3 REFERENCES

A. American Society for Testing and Materials (ASTM):
   1 ASTM D451- Test Method for Sieve Analysis of Granular Mineral Surfacing for Asphalt Roofing Products.
   2 ASTM D1079- Terminology Relating to Roofing, Waterproofing and Bituminous Materials.
   3 ASTM D1227- Specification for Emulsified Asphalt Used as a Protective Coating for Roofing.
   4 ASTM D1863- Specification for Mineral Aggregate Used as a Protective Coating for Roofing.
   5 ASTM D2822- Specification for Asphalt Roof Cement.
   6 ASTM D2824- Specification for Aluminum-Pigmented Asphalt Roof Coating.
   7 ASTM D4601- Specification for Asphalt Coated Glass Fiber Base Sheet Used in Roofing.
   8 ASTM D5147- Test Method for Sampling and Testing Modified Bituminous Sheet Materials.
   9 ASTM D6162- Specification for Styrene Butadiene Styrene (SBS) Modified Bituminous Sheet Materials Using a Combination of Polyester and Glass Fiber Reinforcements.
   10 ASTM D6163- Specification for Styrene Butadiene Styrene (SBS) Modified Bituminous Sheet Materials Using Glass Fiber Reinforcements.
   11 ASTM E108- Test Methods for Fire Test of Roof Coverings.
   12 ASTM D41 Standard Specification for Asphalt Primer Used in Roofing, Dampproofing and Waterproofing.

B. Factory Mutual Research (FM):
   1. Roof Assembly Classifications.

C. National Roofing Contractors Association (NRCA) Canadian Roofing Contractors Association (CRCA):
   1. Roofing and Waterproofing Manual.

D. Underwriters Laboratories, Inc. (UL):

1. Fire Hazard Classifications.

E. Warnock Hersey (WH):
1. Fire Hazard Classifications.

1.4 SYSTEM DESCRIPTION

It is the intent of this specification to install a long-term, quality restoration system that meets or exceeds all current NRCA (CRCA) guidelines as stated in the most recent edition of the NRCA(CRCA) Roofing and Waterproofing Manual. Please discuss any concerns with the Owner and Roofing System Manufacturer.

1.5 SUBMITTALS FOR REVIEW

A. Product Data: Provide manufacturer's technical product data for each type of roofing product specified. Include data substantiating that materials comply with specified requirements.

1. Samples: Submit [two (2)] samples of the following:

i). 1 lb. sample of roofing aggregate for review to meet minimum SRI.

ii). 1 quart quart of each bituminous material

iii). 12" x 12" sample of each roll membrane

2. Specimen Warranty: Provide an unexecuted copy of the warranty specified for this Project, identifying the terms and conditions required of the Manufacturer and the Owner.

B. Manufacturer's Installation Instructions: Submit installation instructions and recommendations indicating special precautions required for installing the membrane.

C. Manufacturer's Certificate: Submit a certified copy of the roofing manufacturer's ISO 9001 compliance certificate and has approved third party testing facility in accordance with ASTM E108, Class [A or B or C] for external fire and meets local or nationally recognized building codes.

D. Test Reports: Submit test reports, prepared by an independent testing agency, for all modified bituminous sheet roofing, indicating compliance with ASTM D5147.

E. Written certification from the roofing system manufacturer certifying the applicator is currently authorized for the installation of the specified roof system.

F. Any material submitted as equal to the specified material must be accompanied by a report signed and sealed by a professional engineer licensed in the state in which the installation is to take place. This report shall show that the submitted equal meets the Design and Performance criteria in this specification. Substitution requests submitted without licensed engineer approval will be rejected for non-conformance.

G. Qualification data for firms and individuals identified in Quality Assurance Article below.

H. Submit under provisions of Section 01300.

1.6 CONTRACT CLOSEOUT SUBMITTALS

A. General: Comply with Requirements of Division 01 Section - Closeout Submittals.

B. Special Project Warranty: Provide specified warranty for the Project, executed by the authorized agent of the Manufacturer.

C. Roofing Maintenance Instructions. Provide a manual of manufacturer's recommendations for maintenance of installed roofing systems.

D. Insurance Certification: Assist Owner in preparation and submittal of roof installation acceptance certification as may be necessary in connection with fire and extended coverage insurance on roofing and associated work.

E. Demonstration and Training Schedule: Provide a schedule of proposed dates and times for instruction of Owner's personnel in the maintenance requirements for completed roofing work. Refer to Part 3 for additional requirements.

1.7 QUALITY ASSURANCE

A. Manufacturer: Company specializing in manufacturing the products specified in this section to have ISO 9001 certification.

B. Installer: Company specializing in roof restoration, with not less than 10 years experience and authorized by roofing system manufacturer as qualified to install manufacturer's roofing materials

C. Installer's Field Supervision: Maintain a full-time Supervisor/Foreman on job site during all phases of roofing work and at any time roofing work is in progress. Maintain proper supervision of workmen. Maintain a copy of the specification**s** in the possession of the Supervisor/Foremen and on the roof at all times.

D. Immediately correct roof leakage during construction. If the Contractor does not respond within twenty four (24) hours, the Owner has the right to hire a qualified contractor and backcharge the original contractor.

E. Insurance Certification: Assist Owner in preparation and submittal of roof system installation acceptance certification as may be necessary in connection with fire and extended coverage insurance on the roofing and associated work.

1.8 PRE-INSTALLATION CONFERENCE

A. Pre-Roofing Conference: Convene a pre-roofing conference approximately two (2) weeks before scheduled commencement of restoration system application and associated work**.**

B. Require attendance of installer of each component of associated work, installers of deck or substrate construction to receive roofing work, installers of rooftop units and other work in and around roofing which must precede or follow roofing work (including mechanical work if any), Architect, Owner, roofing system manufacturer's representative, and other representatives directly concerned with performance of the Work, including (where applicable) Owner's insurers, testing agencies and governing authorities.

C. Objectives of conference to include:

1. Review foreseeable methods and procedures related to roofing work.

2. Tour representative areas of roofing substrates (decks), inspect and discuss condition of substrate, roof drains, curbs, penetrations and other preparatory work performed by others.

3. Review roofing system requirements

4. Review required submittals both completed and yet to be completed.

5. Review and finalize construction schedule related to roofing work and verify availability of materials, installer's personnel, equipment and facilities needed to make progress and avoid delays.

6. Record discussion of conference including decisions and agreements (or disagreements) reached and furnish copy of record to each party attending. If substantial disagreements exist at conclusion of conference, determine how disagreements will be resolved and set date for reconvening conference.

7. Review notification procedures for weather or non-working days.

8. The Owner's Representative will designate one of the conference participants to record the proceedings and promptly distribute them to the participants for record.

9. The intent of the conference is to resolve issues affecting the installation and performance of roofing work. Do not proceed with roofing work until such issues are resolved to the satisfaction of the Owner and Consultant of Record. This shall not be construed as interference with the progress of Work on the part of the Owner or Consultant of Record.

1.9 DELIVERY, STORAGE AND HANDLING

A. Deliver products to site with seals and labels intact, in manufacturer's original containers, dry and undamaged.

B. Store and handle roofing sheets in a dry, well-ventilated, weather-tight place to ensure no possibility of significant moisture exposure. Store rolls of felt and other sheet materials on pallets or other raised surface. Stand all roll materials on end. Cover roll goods with a canvas tarpaulin or other breathable material (not polyethylene).

C. Do not leave unused materials on the roof overnight or when roofing work is not in progress unless protected from weather and other moisture sources.

D. It is the responsibility of the contractor to secure all material and equipment on the job site. If any material or equipment is stored on the roof, the contractor must make sure that the integrity of the deck is not compromised at any time. Damage to the deck caused by the contractor will be the sole responsibility of the contractor and will be repaired or replaced at his expense.

1.10 MANUFACTURER'S INSPECTIONS

When the project is in progress, the roofing system manufacturer will provide the following:

A. Keep the Owner's representative informed as to the progress and quality of the work

B. Provide job site inspections a minimum of four days a week and/or on a daily basis when work is being performed.

C. Report to the Owner's representative in writing any failure of refusal of the Contractor to correct unacceptable practices called to the Contractor's attention.

D. Confirm after completion that manufacturer has observed no applications procedures in conflict with the specifications other than those that may have been previously reported and corrected.

1.11 PROJECT CONDITIONS

A. Weather Condition Limitations: Do not apply roofing membrane during inclement weather or when a 40% chance of precipitation is expected.

B. Materials shall be stored at room temperature until immediately prior to application when the ambient temperature is 40F, 5C or below. Discontinue the application if the material cannot be stored at a temperature, which permits even distribution during application.

C. Do not expose materials vulnerable to water or sun damage in quantities greater than can be weatherproofed during same day.

D. Proceed with roofing work only when existing and forecasted weather conditions will permit unit of work to be installed in accordance with manufacturer's recommendations and warranty requirements.

E. When applying materials with spray equipment, take precautions to prevent over spray from damaging or defacing surrounding walls, building surfaces, vehicles or other property.

F. Avoid inhaling spray mist; take precautions to ensure adequate ventilation.

G. Protect completed roof sections from foot traffic until fully cured.

H. Take precautions to ensure that materials do not freeze.

I. Minimum temperature for application is 40F, 5C and rising.

J. Do not apply materials if rain is imminent.

K. All slopes greater than 2:12 require back-nailing to prevent slippage of the ply sheets. Use ring or spiral-shank one (1) inch cap nails, or screws and plates at a rate of one (1) fastener per ply (including the membrane) at each insulation stop. Place insulation stops at 16 ft o.c. for slopes less than 3:12 and four (4) ft o.c. for slopes greater than 3:12. On non-insulated systems, nail each ply directly into the deck at the rate specified above. When slope exceeds 2:12, install all plies parallel to the slope (strapping) to facilitate backnailing. Install four (4) additional fasteners at the upper edge of the membrane when strapping the plies.

1.12 SEQUENCING AND SCHEDULING

A. Sequence installation of restoration system with related units of work specified in other sections to ensure that roof assemblies including roof accessories, flashing, trim and joint sealers are protected against damage from effects of weather, corrosion and adjacent construction activity.

B. Fully complete all roofing field assembly work each day. Phased construction will not be accepted.

1.13 WARRANTY

A. Upon completion of installation, and acceptance by the Owner and Owner's representative, the manufacturer will supply to the Owner a ten (10) year warranty.

B. Installer will submit a minimum of a two (2) year warranty to the membrane manufacturer with a copy directly to Owner.

C. Membrane manufacturer will provide an annual inspection for the life of the warranty.

PART 2 PRODUCTS

2.1 ACCEPTABLE MANUFACTURERS

A. When a performance standard is specified it shall be indicative of a standard required.

B. Roof restoration system, including modified flashing plies must meet the provisions identified within Sections 01300.

C. Any item or materials submitted must comply in all respects as to the quality and performance specified. The Owner's representative/Owner shall be the sole judge as to whether or not an item submitted as a substitute is truly equal. The Contractor shall assume all monetary or other risk involved, should the Owner's representative/Owner find the proposed system unacceptable.

D. Substitutions: Products proposed as equal to the products specified in this Section shall be submitted in accordance with Bidding Requirements and Division 01 provisions.

1. Proposals shall be accompanied by a copy of the manufacturer's standard specification section. That specification section shall be signed and sealed by a professional engineer licensed in the state in which the installation is to take place. Substitution requests containing specifications without licensed engineer certification shall be rejected for non-conformance.
2. Include a list of three (3) projects of similar type and extent, located within a one hundred mile radius from the location of the project. In addition, the three projects must be at least five (5) years old and be available for inspection by the Owner or Owner's Representative.
3. Equivalency of performance criteria, warranty terms, submittal procedures, and contractual terms will constitute the basis of acceptance.
4. The Owner's decision regarding substitutions will be considered final. Unauthorized substitutions will be rejected.

2.2 DESCRIPTION

1. **Restoration** – Built Up Roof work including but not limited to:

A. A rubberized, heavy bodied fibered reinforced, fire-rated restoration treatment designed to restore the weathering surface of modified membrane systems.

B. Modified Flashing Plies:

1. Modified Cap Flashing Ply: Modified Membrane: 145 mil SBS and SIS (Styrene-Butadiene-Styrene and Styrene-Isoprene-Styrene) rubber modified membrane incorporating post consumer recycled rubber and reinforced with a fiberglass and polyester composite scrim

2. **Spot Replacement** - Built up and mineral surface spot replacement roofing work including but not limited to:

A. Minimum (2) plies - Approved SBS torch applied base and SBS (Styrene-Butadiene-Styrene) modified cap sheet. The base sheet shall meet and/or exceed ASTM D 6163, Type II with a minimum tensile of 210 lbf./in and tear strength of 250 lbf., with a nominal thickness of 110 mil. The modified cap sheet shall be SBS (Styrene-Butadiene-Styrene) rubber modified roofing membrane reinforced with a fiberglass and polyester composite scrim. This membrane is designed for torch applications and has a burn-off backer that indicates when the material is hot enough to be installed. The cap sheet shall meet or exceed ASTM D 6162, Type III with a minimum tear strength of 310 lbf/in. and tear strength of 510 lbf, with a nominal thickness of 180 mils. It must also have a low temperature flexibility of -40 degrees Celsius.
bonded to the prepared substrate (same thickness as existing insulation, combination of ISO and ½" protection board with approved insulation adhesive. Add one layer of modified bitumen cap sheet, as above.

B. VOC compliant adhesive requirements between insulation boards are as follows:

- Tensile Strength ASTM D 412-92	250 psi
- Density ASTM D 1875-90	8.5 lb/gal.
- Viscosity ASTM D 2556-93a	22000 – 60000 cP
- Peel Strength ASTM D903	17 lb./in.
- Flexibility ASTM D 816-82	Pass @ -56.7 Celsius
- VOC status	0 g/l

C. Installation requirements: The old membrane/system shall be removed down to the deck and disposed at an authorized dumpsite. Concrete deck shall be prepared by filling any honeycombing and imperfections in deck surface with latex filler. The vapour barrier shall be created by installing a torch applied fiberglass ply using a suitable heat source adhere one ply to the entire surface. Shingle in direction of slope of roof to shed water on each roof area. For a metal deck, the deck shall be verified for any corrosion and treated as required. Note the owner and consultant must be notified immediately if the deck is to be treated or replaced.

1. Install one layer of SBS Torch Base Sheet to a properly prepared substrate. Shingle in proper direction to shed water on each area of roofing.

2. To a suitable substrate, lay out the roll in the course to be followed and unroll six (6) feet (1.8m).

3. Using a roofing torch, heat the surface of the coiled portion until the burn-off backer melts away. At this point, the material is hot enough to lay into the substrate. Progressively unroll the sheet while heating and press down with your foot to insure a proper bond.

4. After the major portion of the roll is bonded, re-roll the first six (6) feet (1.8m) and bond it in a similar fashion.

5. Repeat this operation with subsequent rolls with side laps of four (4) inches (101mm) and end laps of eight inches.

6. Give each lap a finishing touch by passing the torch along the joint and spreading the melted bitumen evenly with a rounded trowel to insure a smooth, tight seal.

7. Extend underlayment two (2) inches (50mm) beyond top edges of cants at wall and projection bases.

8a) Install modified capsheet. Over the SBS Torch Base Sheet underlayment(s), lay out the roll in the course to be followed and unroll six (6) feet. Seams for the top layer of modified membrane will be staggered over the SBS Torch Base Sheet seams.

b) Using a roofing torch, heat the surface of the coiled portion until the burn-off backer melts away. At this point, the material is hot enough to lay into the substrate. Progressively unroll the sheet while heating and press down with your foot to insure a proper bond.

D. A minimum two-hour fire watch is required for each day that torch-applied membranes are installed.

E. Keep an ABC rated fire extinguisher in a central location where all workers know where it is and how to operate in properly

2.3 BITUMINOUS MATERIALS

A. Asphalt Primer: V.O.C. compliant, ASTM D41.

B. Asphalt Roofing Mastic: V.O.C. compliant, ASTM D2822, Type II.

C. Flashing Adhesive: V.O.C. complaint, ASTM D 4586, Type II, Class I, having the following:

- Viscosity @77_F	7 sec.
- Density @77_F	8.3 lb/gal.
- Non-Volatile (ASTM D4479)	Typical 70%
- Flash Point (ASTM D93)	39.4 C min.
- VOC Status	200 g/l max.

D. Resaturant: Heavy-bodied, rubberized, fiber reinforced, fire rated, low solvent, Class A approved, having the following characteristics:

- Viscosity @77_F	20-25 sec.
- Density @77_F	9.1 lb/gal.
- Non-Volatile (ASTM D4479)	Typical 75%
- Asphalt Content (ASTM D4479)	Typical 63 l%
- Uniformity (ASTM D4479)	Pass
- VOC Status	285 g/l max.

2.4 SHEET MATERIALS

A. Modified Base Flashing Ply: (for replacement only)

40 mil SBS modified membrane with dual fiberglass scrim reinforcement with the following minimum performance requirements according to ASTM D-5147.

Tensile Strength (ASTM D5147) 2 in/min. @73.4 ± 3.6°F	MD 215 lbf/in	CMD 215 lbf/in
Tear Strength (ASTM D-5147) 2 in/min. @ 73.4 ± 3.6°F	MD 275 lbf	CMD 275 lbf

Elongation at Maximum Tensile (ASTM D-5147)

2 in/min. @ 73.4 ± 3.6°F MD 4.5% CMD 4.5%

Low Temperature Flexibility (ASTM D5147): Passes -30°F (-34°C)

B. Modified Cap Flashing Ply:

Modified Membrane Properties (Finished Membranes); ASTM D6162, Type III Grade G

1. Tensile Strength (ASTM D5147)
   a. 2 in/min. @ 73.4 ± 3.6°F MD 1,000 lbf/in CMD 1,100 lbf/in
   b. 50 mm/min. @ 23 ± 3°C MD 175 kN/m CMD 192.5 kN/m
2. Tear Strength (ASTM D5147)
   a. 2 in/min. @ 73.4 ± 3.6°F MD 1,700 lbf CMD 1,800 lbf
   b. 50 mm/min. @ 23 ± 3°C MD 7,561.6 N CMD 8,006.4 N
3. Elongation at Maximum Tensile (ASTM D5147)
   a. 2 in/min. @ 73.4 ± 3.6°F MD 16.0% CMD 16.0%
   b. 50 mm/min. @ 23 ± 3°C MD 16.0% CMD 16.0%
4. Low Temperature Flexibility (ASTM D5147): Passes -40°F (-40°C)

PART 3 EXECUTION

3.1 EXAMINATION

A. Examine substrate surfaces to receive associated work and conditions under which roofing will be installed. Do not proceed with roofing until unsatisfactory conditions have been corrected in a manner acceptable to installer. A Thermographic scan with full drawing is to be done and paid for by the contractor, which is to include all core cuts. Three hard copies of a complete TS report are to be submitted to the owner, submit one PDF copy of the report to the owner.

3.2 GENERAL INSTALLATION REQUIREMENTS

A. Cooperate with manufacturer, inspection and test agencies engaged or required to perform services in connection with installing the roof system.

B. Insurance/Code Compliance: Where required by code, install and test the roofing system to comply with governing regulation and specified insurance requirements.

C. Protect other work from spillage of roofing materials and prevent materials from entering or clogging drains and conductors. Replace or restore other work damaged by installation of the roofing system to match existing.

D. Coating shall be applied per manufacturers application instructions for the type of coating used.

E. Apply roofing materials as specified herein unless recommended otherwise by manufacture's instructions. Keep roofing materials dry during application. Do not permit phased construction.

3.3 CLEANING AND SURFACE PREPARATION

A. All defects such as deteriorated roof decks, saturated insulation board, etc. must be repaired or replaced per roof system manufacturer specifications prior to application of the restoration materials.

B. Remove all loose roofing gravel, dirt and foreign debris from the roof surface.

C. Do not damage roof membrane in cleaning process.

D. All surface defects (splits, blisters, tears) must be repaired:

E. Blister Repair

1. Clean and prime the area.
2. All blisters must be cut and opened down to the solidly adhered plies of the existing roof system. Use a roofer's knife to open the blister with an "X" or "H" cut. Fold the flaps and remove any existing moisture. Permit the area to dry before applying repair materials.
3. Apply a liberal coating of bituminous material into the blister. Firmly press the flaps into the bituminous material and trim the edges to ensure proper fit.
4. Apply a coating of bituminous material over the repaired area extending a minimum of eight (8) inches beyond the cuts. Install a torch applied modified cap sheet, same as indicated for the spot replacement ensuring there is good bleed out along the seams of the torched down membrane.

F. Edge Detail Repair

1. Remove all loose dirt and debris along the edge detail and prime with an asphalt primer.
2. Secure all loose metal to the wood nailer.
4. Install a bond breaker at moving joints.
4. Apply a liberal coat of mastic over the prepared area and embed fabric into the mastic.
5. Apply a liberal coat of mastic over the fabric. Sufficiently cover the fabric to

obliterate the weave from sight.
6. Apply surfacing to the repair.

G. Pitch Pocket Repair/Drains
1. Fill the pitch pocket with an elastomeric roof cement. Taper the mastic at the edge of the pitch pocket to ensure water run-off.
2. Clean and prime the area with an asphalt primer.
3. Apply a liberal coating of mastic around the pitch pocket extending a minimum of twelve (12) inches onto the horizontal roofing surface.
4. Cut four (4) strips of fabric. Each strip should be twelve (12) inches wide and be of sufficient length so as to extend a minimum of twelve (12) inches beyond the pitch pan.
5. Embed a strip into the mastic along each side of the pitch pocket. Brush or roll the fabric into place to ensure proper embedment.
6. Top dress the area with mastic.
7. Install rain bonnet, draw band and caulk.
8. All drains to be installed are to be as detail drawings.

3.4 MODIFIED FLASHING INSTALLATION

A. Prepare all walls, penetrations and expansion joints to be flashed and where shown on the drawings, with asphalt primer at the rate of one hundred (100) square feet per gallon. Allow primer to dry tack free.

B. With trowel grade mastic, the modified membrane will be used as the flashing and nailed off 12” O.C. at all vertical surfaces. Around the perimeter edge the membrane will be run up the cant across the top and nail 6” O.C on the outer edge.

C. The entire sheet of flashing membrane must be solidly adhered to the substrate. All flashing shall be 36” wide at maximum with a 4” overlap at seems.

D. Seal all vertical laps of flashing membrane with a three-course application of one part elastomer and fiberglass mesh.

E. Seal junction of flashing membrane and roof with a three-course application of cold flashing adhesive and 6” mesh.

F. All metal flashings, (counter-flashings, met cap flashings, expansion joints caps and similar work) are to receive new 26 gauge prepainted metal (colour to match existing). Perimeter metal details will require a continuous starter strip secured 18” O.C. Metal is to have s-locks and is to be secured by use of screws in the s-locks. There are not to be any fasteners through the metal into the cant. Do not fasten metal through face of flashing.

G. When metal wall panels are present, the fasteners are to be loosened to allow the panel to be pulled away from the wall. The flashing membrane shall go up the wall a minimum of 12” and be fastened with an aluminum termination bar 6” O.C. A bead of one part elastomer is to be put along the top edge of the membrane and termination bar. All flashing membrane is to extend a minimum of 9” on to the roof surface.

3.5 COATING APPLICATION

A. Remove debris from roof surface and make necessary repairs as specified in 3.3.D.

B. Apply primer to roof surface as required per manufacturer's instructions.

C. Brush, spray or squeegee the restoration material onto the roof surface at a rate of not less than seven (7) gallons per one hundred (100) square feet.

D. Immediately embed white calcite aggregate conforming to ASTM D-1549 Solar Reflectance with a minimum solar reflectance index (SRI) of 83, at a nominal rate of five hundred (500) pounds per one hundred (100) square feet. Ensure that none of the black resaturant can be seen throughout the field.

3.6 FIELD QUALITY CONTROL

A. Perform field inspection as required.

B. Correct defects or irregularities discovered during field inspection.

C. Require attendance of roofing materials manufacturers' representatives at site during installation of the roofing system.

3.7 CLEANING

A. Remove bitumen adhesive drippings from all walls, windows, floors, ladders and finished surfaces.

B. In areas where finished surfaces are soiled by asphalt or any other sources of soiling caused by work of this section, consult manufacturer of surfaces for cleaning instructions and conform to their instructions.

C. Repair or replace defaced or disfigured finishes caused by work of this section.

3.8 FINAL INSPECTION

A. At completion of roofing installation and associated work, meet with Contractor, installer, installer of associated work, Owner, roofing system manufacturer's representative, and other representatives directly concerned with performance of roofing system.

B. Walk roof surface areas of the building, inspect perimeter building edges as well as flashing of roof penetrations, walls, curbs and other equipment. List all items requiring correction or completion and furnish copy of list to each party in attendance.

C. The roofing system manufacturer reserves the right to request a thermographic scan of the roof during final inspection to determine if any damp or wet materials have been installed. The thermographic scan shall be provided by the Roofing Contractor.

D. If core cuts verify the presence of damp or wet materials, the Roofing Contractor shall be required to replace the damaged areas at his own expense.

E. Repair or replace deteriorated or defective work found at time above inspection as required to a produce an installation which is free of damage and deterioration at time of Substantial Completion and according to warranty requirements.

F. Notify the Owner upon completion of corrections.

G. Following the final inspection, provide written notice of acceptance of the installation from the roofing system manufacturer.

3.9 BUILDING SPECIFIC

A. All gas lines are to be coated with 2 coats of epoxy fortified rust coating.

B. Blueboard insulation is to be placed under all wood blockings and aluminized (insulation only). All defective wood blocking is to be replaced with new quick blocks of similar sizing. Hold down anchors for piping are to be replaced where replacement blocking occurs.

C. Coat all rusted units and stacks with 2 coats of aluminized rust coating.

END OF SECTION

SUBMITTALS – SECTION 01300

PART 1 – GENERAL

1.1 Related Sections

.1 Section 07562: Roof Restoration

1.2. Material Performance

.1 Resaturant

The modified cold process restoration coating to be employed shall be ratable to Class A, rubberized, heavy bodied fibered reinforced, fire-rated restoration treatment designed to restore the weathering surface of gravel surfaced BUR and modified membrane systems.

The modified restoration material to be employed shall meet or exceed the following ASTM standards:

A. Non-Volatile (ASTM D 4479) – Typical 75%

B. Asphalt Content (ASTM D 4479) – Typical 63 I%

C. Flash Point (ASTM D 93) - >100 degrees F.

D. Uniformity (ASTM D 4479) – Pass

E. VOC Status – 285 g/I maximum

F. Viscosity @ 77 degrees _F - 20-25 seconds

G. Density @ 77 degrees _F - 9.1 lb/gal.

2. Modified Base Flashing Ply (spot replacement only)

40 mil SBS modified membrane with dual fiberglass scrim reinforcement having the following minimum performance requirements according to ASTM D-5147.

Tensile Strength (ASTM D5147) 2 in/min. @73.4 ± 3.6°F	MD 210 lbf/in	CMD 210 lbf/in
Tear Strength (ASTM D-5147) 2 in/min. @ 73.4 ± 3.6°F	MD 275 lbf	CMD 275 lbf
Elongation at Maximum Tensile (ASTM D-5147) 2 in/min. @ 73.4 ± 3.6°F	MD 4%	CMD 4%

Low Temperature Flexibility (ASTM D5147): Passes -30°F (-34°C)

3. Modified Cap Flashing Ply (flashing only)

Modified Membrane Properties (Finished Membranes); ASTM D6162, Type III Grade G

1. Tensile Strength (ASTM D5147)

a. 2 in/min. @ 73.4 ± 3.6°F MD 1,000 lbf/in CMD 1,100 lbf/in

b. 50 mm/min. @ 23 ± 3°C MD 175 kN/m CMD 192.5 kN/m

2. Tear Strength (ASTM D5147)

a. 2 in/min. @ 73.4 ± 3.6°F MD 1,700 lbf CMD 1,800 lbf

b. 50 mm/min. @ 23 ± 3°C MD 7,561.6 N CMD 8,006.4 N

3. Elongation at Maximum Tensile (ASTM D5147)

a. 2 in/min. @ 73.4 ± 3.6℉ MD 16.0% CMD 16.0%

b. 50 mm/min. @ 23 ± 3℃ MD 16.0% CMD 16.0%

4. Low Temperature Flexibility (ASTM D5147): Passes -40℉ (-40℃)

4. Modified Cap Flashing Ply (field only for spot replacement)

Modified Membrane Properties (Finished Membranes): ASTM D6162, Type III Grade S

1. Tensile Strength (ASTM D5147)

a. 2 in/min. @ 73.4 ± 3.6℉ MD 310 lbf/in CMD 310 lbf/in

b. 50 mm/min. @ 23 ± 3℃ MD 54.2 kN/m CMD 54.2 kN/m

2. Tear Strength (ASTM D5147)

a. 2 in/min. @ 73.4 ± 3.6℉ MD 510 lbf CMD 510 lbf

b. 50 mm/min. @ 23 ± 3℃ MD 2269 N CMD 2269 N

3. Elongation at Maximum Tensile (ASTM D5147)

a. 2 in/min. @ 73.4 ± 3.6℉ MD 6.0% CMD 6.0%

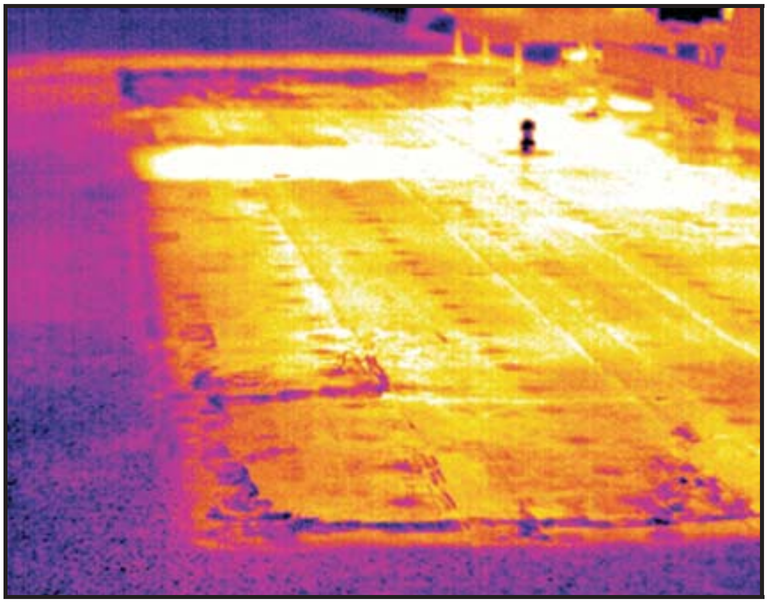
b. 50 mm/min. @ 23 ± 3℃ MD 6.0% CMD 6.0%

4.Low Temperature Flexibility (ASTM D5147): Passes -40℉ (-40℃)

END OF SECTION

No Funds for Replacement? Consider Restoration.

By Tom Stuewe



When moisture penetration is suspected, analytical testing of a core sample may be required. This infrared scan reveals wet insulation that visual inspection alone could not detect.

Restoration can be a viable interim solution for prolonging the service life of building roofs. This is particularly true for roofs that have already been recovered one or more times since restorations add minimal weight, compared to installing a new roof on top of an existing one. Typically, building codes require a total tear-off and reroofing after a maximum of two layers of roofing.

In addition, since the federal government expects you to depreciate your commercial roofs over a 39-year period, it makes sound economic sense to do everything possible to extend roof life to meet that standard if at all possible. Unlike reroofing, restorations are financed through maintenance rather than capital budgets, offering financial advantages at tax time.

Fortunately, the roofing industry offers a number of cost-effective, highly proven solutions for restoring older, but still sound, roofs. Today's high-tech restoration coatings can add 10 to 15 years of service life to an existing roof system. The average cost for restoration is $3-5 per square foot, compared to $7 to $12 per square foot for roof replacement, a figure that can rise substantially if continued neglect results in damage to the underlying deck.

Restoration options are available for virtually every type of roof system, including:
- Asphalt-based gravel-surfaced modified bitumen/built-up roofs
- Asphalt-based smooth or mineral surfaced modified bitumen/built-up roofs
- Coal-tar-based gravel-surfaced built-up roofs
- Single-ply roofs
- Metal roofs

Benefits Beyond the Obvious

Compared to roof replacement, restoration offers a host of benefits that add up to savings, including:

- **Tax credits and energy rebates —** Depending on geographic location, tax credits and other valuable financial incentives may be available for implementing solutions that can be independently verified (e.g., through ENERGY STAR®[1] qualification, LEED®[2] point contribution, etc.) to improve energy efficiency.
- **Maintenance vs. capital expense —** As a maintenance expense, restoration allows you to immediately expense your costs, as opposed to reroofing, which, as a capital expense, must be depreciated over the anticipated 39-year working life of the roof.
- **Sustainability —** Restoration temporarily eliminates the need for disposal to a landfill, thereby reducing short-term expense and adverse environmental impact. More importantly, restoration provides the most fundamental sustainability benefit of all – extended service life.
- **Insurance savings —** Depending on the system chosen, a restoration may upgrade your roof to a Class A fire rating, promoting safety and reducing insurance costs.
- **Less disruption —** Roof restoration is typically faster, cleaner, and less labor intensive than roof replacement, making it less disruptive to the buildings, properties, and people.

In addition, some restoration solutions incorporate highly reflective coatings, which can increase solar reflectivity by 70 to 90 percent, dramatically reducing interior cooling costs for the added benefit of energy savings.

Is Your Roof Right for Restoration?

There is a good reason why roofing professionals frequently prefer to recommend tear-off and replacement to restoration: analyzing a roof's viability as a candidate for restoration requires a high level of technical skill and training. First and foremost, the roof has to be well maintained and free of leaks and wet insulation. A thorough roof inspection should be performed, no more than six months before the restoration, to determine:

- Whether the roof has adequate slope
- A comprehensive history documenting the pattern of any roof leaks
- The condition of the insulation and underlying deck, as identified through core analysis
- The precise location of any water penetration, as identified through the use of scientific instrumentation, such as an infrared scan

[1] ENERGY STAR® is a registered trademark of the U.S. government. The ENERGY STAR Program represents a voluntary partnership between businesses and organizations and the federal government to promote energy efficiency and environmental activities.
[2] LEED® Buildings performance refers to the Leadership in Energy and Environmental Design® (LEED) Green Building Rating System®, which is a voluntary, consensus-building national standard that was initiated by the U.S. Green Building Council (USGBC) for developing high-performance sustainable buildings. LEED®, Leadership in Energy and Environmental Design®, and Green Building Rating System® are registered trademarks of The U.S. Green Building Council.

Written documentation of these findings should be accompanied by a formal recommendation of solutions, including a comparative ROI analysis and possibly an energy audit, evaluating the costs and benefits of restoration versus replacement.

Roof restorations are typically warranted for five to ten years (compared to 15 to 30 years for new roofs), although specific terms and conditions may vary. Be sure you understand what is covered, how to file a claim, and who may perform the warranty work.

Address Problems First

If restoration is a viable option for your roof, the first step is to resolve any existing roof problems. If your roof is fundamentally sound, most problems can be easily and cost-effectively addressed.

The majority of roof leaks occur at termination points and where penetrations occur. This includes areas such as flashings, edge details, perimeter details, scuppers, drains, and curbs. Prior to restoration, all termination and penetration points should be repaired or replaced, depending on their condition. It may also be advisable to add drainage crickets to areas prone to ponding, keeping in mind that roof surfaces vulnerable to ponding are not usually good candidates for restoration. In addition, masonry walls and other components must be repaired and/or treated with weatherproofing sealants. Protecting such areas with metal wall panels is frequently the best long-term solution.

Even roofs where moisture has partially penetrated the insulation may be candidates for restoration — if the damage is well confined. Such cases typically call for a dual strategy in which only the seriously damaged portions of the roof are replaced, after which the entire roof is restored.

Choosing the Right Technology

Today, a wide range of technologies are used for roof restorations. These include material solutions that are based on asphalt, coal-tar, urethane, polyurea, silicone, and acrylic technologies; solvent-based elastomeric technologies; emulsion technologies; and hybrid materials that combine one or more of these chemistries. At the higher end of the quality spectrum are coatings that provide exceptional waterproofing integrity while closely matching the original roof's appearance.

When identifying an appropriate restoration technology, there are many factors to consider.

These include, but are not limited to:

- Roof type, e.g., BUR, modified bitumen, single ply, or metal
- Surfacing type, e.g., flood and gravel, smooth, or mineral
- Performance requirements, such as greater reflectivity, improved fire rating, etc.
- Other factors such as the number of years a facility will be in service, macro (geographical) and micro (site conditions, facility use) environmental concerns, number of rooftop units, access to the roof, sensitivity to odor, degree of slope, time available for the job, etc.

Your professional roofing partner can help you analyze these factors and recommend a technology that is appropriate to the specific conditions of your roof, ensuring that your roof restoration meets or exceeds all specified performance requirements.

Conclusion

Restoration can be an efficient, cost-effective way to make a good roof better, significantly extending the interval between more costly roof replacements. Just as appealing, restoration offers the added benefits of reducing energy use, tax and insurance expenditures, adverse environmental impact, and facility downtime. Evaluating a roof to determine its viability for restoration, and analyzing the comparable efficacies of vying restoration technologies, requires a high level of roofing knowledge and competence. But in a challenging economy, timely restorations can be an effective and worthwhile method of extending the watertight performance of your facilities.

Degreed in construction management from The Ohio State University, Tom Stuewe has worked in construction for over eight years. In his current role as product manager for The Garland Company, Inc., he provides technical support and assistance for the field team responsible for the proper application of coating and mastic products. Garland is a Cleveland-based manufacturer of high-performance solutions for the total building envelope.

Restore instead of reroof

With the high costs of operating a facility, many building owners are looking for alternatives to roof replacement. With the soaring costs of insulation and other construction materials, restoring an existing roof system could be the best use of an owner's maintenance budget.

There are a variety of restoration products and systems that will extend the life of low-sloped commercial roofs. These restoration systems use coatings that are efficiently applied using conventional tools and spray equipment, which makes the process easy for the contractor and affordable for the building owner.

Restoring an existing roof has the added benefits of conserving resources and minimizing landfill disposal. Finishing the roof with a reflective coating will reduce electric consumption of air conditioning equipment. All of these "green" benefits are extremely desirable for building owners.

"With the soaring costs of insulation and other construction materials, restoring an existing roof system could be the best use of an owner's maintenance budget."

KURT SOSINSK - CSI, CDT, PRODUCT MANAGER
Tremco Inc., Beechwood, OH

Not all roofs are restorable

If the existing roof is not in good condition, the owner will be wasting his money attempting to upgrade a roof that has little service life remaining. Additionally, the contractor and coating manufacturer would be blamed for the inevitable failure, since they are the ones who recommended the restoration. However, by following a process for evaluating the roof, you can minimize the risks of restoration.

First, determine the condition of the insulation. Wet insulation not only transmits heat out of the building, but it also leads to deterioration of the structural roof deck and provides an optimum climate for mold. Areas of wet insulation must be removed during any roof work per building codes.

Wet insulation can be easily detected with commonly available field analytical equipment, such as an infra-red camera. The results of this analysis should be documented to clearly identify wet insulation that must be removed. Take a roof core (and properly patch) during the moisture analysis to identify the insulation type and thickness, including the deck type. This info will be valuable if the building must be reroofed.

Perform a thorough visual inspection of the roof membrane. From this inspection, identify the type of membrane and the type of bitumen or polymer it consists of, such as asphalt, coal tar, SBS, APP, EPDM, CSPE, PVC, etc. You will need to know what materials the roof is made of in order to determine a compatible coating system and procedures for surface prep, repairs, and coating application.

Include flashings, walls, copings, curbs, and penetrations in your inspection. In many cases, the roof is in good shape but the details need work. A roof membrane is commonly and incorrectly blamed for problems with air handlers or other non-membrane flashings. The best practice is to rework problem areas and install new flashings during a restoration.

Determine if inferior conditions can be corrected during the restoration process. Small areas of wet insulation can be replaced, but beware of roofs with widespread blisters, splits, tears, or numerous punctures. These defects most likely indicate the roof should not be restored, but replaced instead. Present the results of your inspection, including photographs, to the building owner to justify your recommendations.

Specifying the new coating system is the final step. Consult with reputable roof coating manufacturers to ensure your recommendations are correct. Make sure the new coating system will retain the fire rating that the building requires. Your thorough evaluation and development of a solid scope of work will ensure a successful roof restoration system that will provide years of energy efficient and leak free service for the building owner. Odds are the building owner will be equally impressed with your approach and will seek you out when it comes time to do additional work.

The Roof Coatings Manufacturers Association [RMCA] is the national trade association that represents the manufacturers of cold-applied roof coatings, cements and waterproofing agents, as well as the suppliers of products, services and equipment to the industry. RCMA is committed to improving performance and quality of roofing. For additional information, contact RCMA at: 202-207-0919; or visit: www.roofcoatings.org. RSI

Appendix O – 2014-2019 Fleet Replacement Plan

Confidential Document
Internal Use Only

Horizon Utilities
2014–2019 Fleet Replacement Plan

TABLE OF CONTENTS

Introduction

Horizon Utilities maintains a fleet of 184 vehicles including 45 trailers with garages in St. Catharines and Hamilton to ensure safe, reliable and dependable vehicles for our employees to perform their daily activities. In 2012, Horizon Utilities extended the hours of operation 8am to 11pm Monday to Friday. These extended hours allow time for; the mechanics to perform emergency repairs and ensure next day availability of vehicles; and an increase in tool time for the construction and maintenance personnel, as a result of mechanics fueling vehicles after normal business hours of operation.

The Six-Year Vehicle Replacement Plan will outline the replacement criteria based on vehicle class, vehicle specifications, vehicle condition, customers' requirements, employee safety, and environmental risks. This plan also provides the Fleet group with clear guidance and focus in managing our fleet inventory.

Plan Objectives

- Annually update a long-term Vehicle Replacement Plan to support our customers' present and future needs
- Align our vehicle replacement criteria with utility, vehicle manufacturers, and other industry standards
- Develop vehicle specification standards by vehicle class to expedite delivery timelines and reduce processes
- Ensure that Horizon Utilities' fleet operates in compliance with federal, provincial, and municipal legislations, and specific licences
- Establish a fleet that can meet existing and future geographic challenges and environments
- On-going investigation and business case benefits of fleet inventory with vehicles powered by alternative sources of energy
- The six-year plan must support Horizon Utilities' Environmental and Sustainability Development initiatives

Vehicle Replacement Criteria

Horizon Utilities' six-year vehicle replacement forecast chart within this plan is based on the following criteria guidelines:

- Manufacturing Standards
- Industry Standards
- Non-Industry Standards
- Vehicle Operational Conditions
- Vehicle Age
- Vehicle Total Mileage
- *Highway Traffic Act* (HTA)
- Canadian Motor Vehicle Safety Standards (CMVSS)
- All related CSA standards, specifically those that relate to aerial devices and hydraulic equipment

- Motor Vehicle Inspection Station (MVIS) requirements
- Infrastructure Health & Safety Association (IHSA) of Ontario, where applicable
- Corporate Health & Safety and Environmental Policies

Replacement Screening Process

A "first pass" screening process is used based on vehicle age at which time, mileage, engine hours, utilization, and power take off (PTO) hours are documented. This provides a baseline to initiate the capital replacement process. During this time, vehicle utilization is also reviewed and discussions take place with Business Unit (BU) Managers/Directors on whether a vehicle should be retained, re-allocated, or replaced with the same class of vehicle or a completely different vehicle configuration.

Vehicle Replacement Assessment

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.

Annual Replacement Schedule Plan

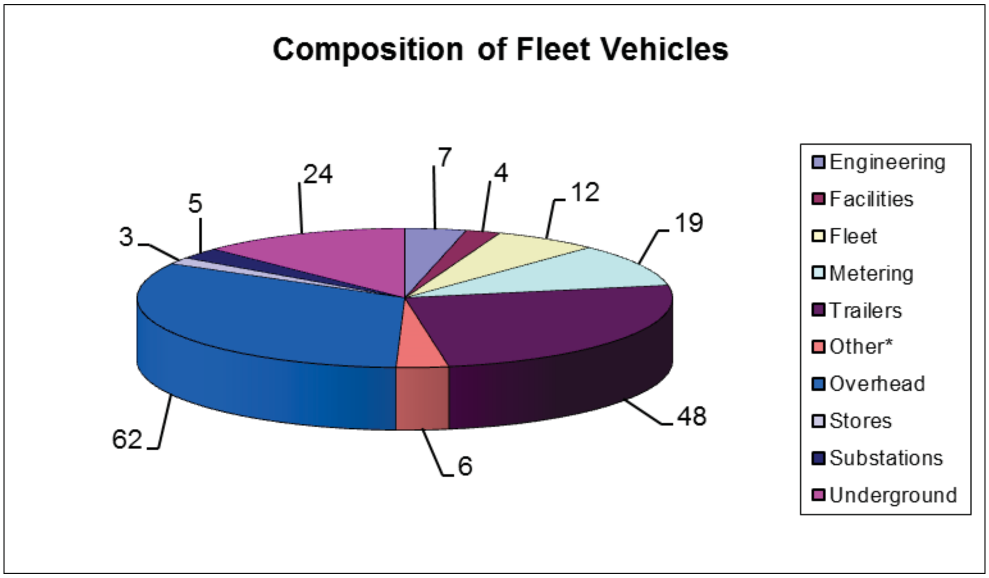
Initiatives	Objectives	Targets
Compile list of vehicles to be replaced	Fleet is assessed according to the Replacement Criteria Model.	May/June
Tender to reflect "turnkey" approach	Any changes in vehicle specifications are determined. Tenders are developed according to final specifications and published.	June/July
Fleet Capital Budget	Fleet capital budget is developed using figures from suppliers selected.	August/September
Place Order	Tenders are awarded and Purchase Orders are issued based on the approved budget.	January/February

Risks & Mitigations

The following risks and mitigations have been identified that may prevent the deliverables and targets of the initiatives and strategies within this plan.

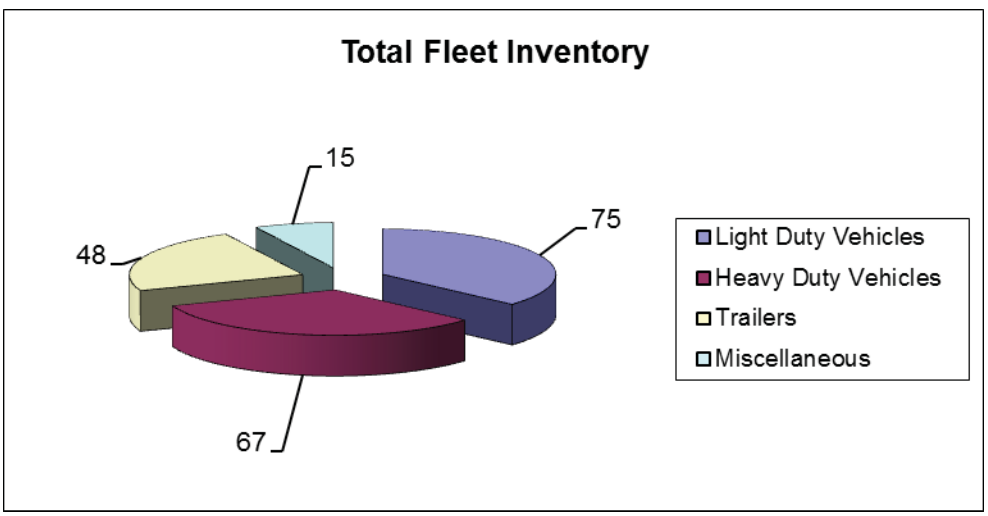
Risks	Mitigations
Capital Budget Reductions	Reassess scheduled replacements and determine other options such as refurbishing or postponing the replacement.
Refocus of Environmental Strategies	Reduce initiative scope.
New Vehicle Technologies	Ongoing understanding and knowledge of new technology.
Change to Customers' Vehicle Requirements	Determined if the change is short or long-term. Reduce replacement forecasts and realign vehicles.
Outsourcing Initiatives	Understand the impact, and reduce replacement forecast scope.
Mergers	Proceed with safety related replacements and/or what is on order and hold any further orders.

Current Composition of Vehicles



* Other – Outside Contractors, Conservation Demand Management (CDM), Trouble

Total Fleet Inventory Structure:



* Miscellaneous – Air Compressors, Backhoes, Forklifts, Salt Spreaders

Alternative Energy Source Vehicles

Horizon Utilities is committed to being a leader in environmental initiatives and has identified its fleet as an area of focus to support our environmental social and community responsibilities. Currently, approximately 10% of Horizon Utilities' fleet are powered by alternative source of energy, reducing GHG Emissions and Carbon Footprint. Going forward, Horizon Utilities will develop and obtain management approval of procuring vehicles with alternative source of energy. This process will take place annually during the budget and business plan process.

Benefits of Alternative Source of Energy Vehicles:

- Reduce operating costs
- Reduce fuel consumption
- Longer vehicle life cycle
- Operate PTO while stationary for 4 + hours per day
- Reduce idling times
- Improve operating environment (quieter, lower emissions)
- Reduce carbon footprint (if mandated)
- Green image – community and social responsibility
- Improve air quality
- Reduce GHG emission (global warming)
- Reduce dependence on foreign oil
- Support sustainability initiative – Global Reporting Initiative (GRI)

Six-Year Vehicles Replacement Plan:

* The six-year replacement plan may change annually due to either availability of alternative technologies or other contributing factors, such as budget assessments or business unit needs.

Replacement Plan Key Initiatives

Initiatives	**Strategy**
Establish Replacement Criteria	Establish formally structured replacement criteria based on utility, other industries, and regulation and manufacturer standards.
Establish Specification Standards by Vehicle Classes	Develop standard vehicle specifications for all vehicle classes to improve the delivery timelines and reduce costs.
Yearly Assessment for Replacing or Refurbishing Trailers	Prior to proceeding with the replacement or refurbishing of any trailers, a need and condition assessment is conducted based on data collected in IFS on maintenance and repairs, and customers' requirements.

Focus on Smaller Heavy Duty Vehicles	In the coming years, Horizon Utilities will continue to focus on procuring smaller and lighter vehicles whenever possible by working with manufacturers' vehicle specifications and design. Larger vehicles increase fuel consumption, operating costs, and emissions, and are difficult to operate in older downtown areas due to narrow streets and overhead tree limbs.
Maintain 10% of Total Fleet, Operated by Alternative Energy Source	Identify alternative means of energy to operate vehicles to support environmental and sustainable development initiatives and regulations.
Turnkey Vehicle Order Approach	To date, Horizon Utilities has had good success in procuring vehicles based on turnkey orders that have reduced the hours of mechanics time. Horizon Utilities will continue to work with manufacturers in improving delivery times and vehicle specifications.
Reduce Fleet Inventory	Reinforce the Fleet Idling Policy using the GPS solution. KPIs using GPS data are measuring, tracking and reporting on fleet activity to improve productivity that in turn will reduce fuel consumption.
Replace Aging Fleet and Trailers	A number of existing vehicles have surpassed their life cycle and have been scheduled for replacement during this six-year plan.
Vehicles' Refurbishing Opportunities	For heavy duty vehicles, Horizon Utilities has extended the replacement cycle to 16 - 19 years with an assessment on the 11th year. During the assessment we may decide to refurbish vehicles to extend their life cycle to meet budget limitations.

Six-Year Replacement Forecast

The following chart provides a six-year replacement forecast of our fleet between Hamilton and St. Catharines, based on the replacement criteria. The replacement forecast captures the vehicles that should be replaced based on the replacement criteria and is used as a guide for the Manager Fleet annually during the budget process. Vehicle replacement is based on both the fleet replacement forecast and available capital budget. The forecast may change due to yearly budget availability and/or adjustments to business unit needs.

Centre	**Vehicle Class**	**Replacement Year**					
		2014	2015	2016	2017	2018	2019
Hamilton	Single Bucket Manlift Truck	0	0	1	1	2	2
	Knuckle Crane Truck	0	0	1	0	0	0
	Passenger Vehicle/Cargo/Step Van	0	2	1	1	0	1
	Cable Pulling/Digger Derrick Truck	0	0	0	0	0	0
	Trailer	0	0	0	0	0	0
	Double Bucket MHAD Truck	1	1	0	0	0	0
	Heavy Duty / Light Duty Pickup	1	3	1	3	2	0
	Air Compressor	0	0	0	0	0	0
	SUV	0	0	1	1	0	0
	Flat Deck	0	0	0	0	0	0
	Hybrid or Electric Car	0	0	0	0	0	0
	TOTALS	2	5	4	6	4	3
St. Catharines	Single Bucket Manlift Truck	0	0	0	0	0	0
	Knuckle Crane Truck	0	0	0	0	0	0
	Passenger Vehicle/Cargo/Step Van	0	0	0	0	0	0
	Cable Pulling/Digger Derrick Truck	0	0	0	0	0	0
	Trailer	2	0	0	0	0	0
	Double Bucket MHAD Truck	0	0	0	0	0	0
	Heavy Duty / Light Duty Pickup	0	1	0	0	0	0
	Air Compressor	0	0	0	0	0	0
	SUV	0	0	0	0	0	0
	Flat Deck	0	0	0	0	0	0
	Hybrid or Electric Car	0	0	0	0	0	0
	TOTALS	2	1	0	0	0	0
Grand Total	**Hamilton & St. Catharines**	4	7	4	6	4	3

Conclusion

By maintaining a long-term Fleet Replacement Plan, Horizon Utilities will move forward in a better position to support our internal and external customers, reduce operating costs, decrease carbon footprint, and continue to provide a safe and dependable fleet inventory.

Prepared By: Joseph Botas, Manager Fleet
November, 2013