HydroOttawa

Distribution System Plan 2016

Material Investments

System Renewal

1 Station Transformer Replacement

1.1 Project/Program Summary

Station transformers are critical assets operating within HOL's distribution system. They provide voltage transformation from transmission line voltage to a lower voltage to distribute throughout the city.

Station transformers are unique assets due to a number of factors including replacement costs ranging from $300,000 to $2,500,000; a failure will have medium to major consequence, and a replacement is a six to twenty-four months project cycle. In addition, station transformer replacements may require additional upgrades such as oil containment, ground grid upgrades, cable replacement, and protection & control upgrades. In some cases a full substation upgrade (switchgear and transformers) may be triggered by a transformer replacement.

1.2 Project/Program Description

1.2.1 Assets in Scope

HOL's replacement policy is to replace transformers with a standard capacity rating that is rated equal or greater than the existing capacity rating. Note that the HOL's Capacity Plan will be consulted to determine if an upgraded capacity rating is required.

If the transformer is part of a sub-transmission system, considerations for a voltage conversion will be reviewed as an alternative to replacing the transformer.

HOL plans to replace 21 power transformers over the 2015-2020 period. The equivalent estimated yearly cost of the proposed station transformer replacement program is $8 million per year. Over the 2011-2014 period, HOL has replaced an average of 3 power transformers per year. The proposed approach to replacement represents a 0.5% increase in units replaced per year. Increase in the number of power transformers replaced during the rate filing period to 3.5 from 3 in 2015 eliminates a risk of operating assets beyond useful life in the 5-10 year horizon. Operating these assets beyond useful life increases risks to reliability and is detrimental to system performance.

Historically, power transformer replacements have been prioritized based on age and health index. Transformers prioritized in the 2016-2020 period have been assessed using a similar approach. As such, poor and critical condition transformers are scheduled for replacement while further inspection and condition assessments continue to identify high priority power transformers for replacement.

The station transformers targeted for replacement in 2015 and 2016 are identified in the specific projects listed in Section 8 of this program narrative. These transformers were identified using HOL's transformer health assessment detailed in subsequent sections. HOL will continue to conduct power transformer inspections and improve in-service asset demographics to continually improve asset identification for replacement.

1.2.2 Asset Life Cycle and Condition

HOL owns and operates 170 station transformers distributed over primary voltages: 103 at 13.2kV, 39 at 44kV, 22 at 115kV and 6 at 230kV. These voltages are stepped down to 27.6kV, 12.8kV, 8.32kV, and 4.16kV.

The age demographic of station transformers is illustrated below in Figure 1. A large distribution of assets in the 40-45 year range is attributed to rapid economic development in HOL's service area in the past. The majority of these transformers have primary voltages of 13.2kV or 44kV. Given that the expected useful life of a station transformer is 50 years, and many are approaching end of life in the 5-10 year horizon, there are currently 6 transformers that have reached end of life and there will be a total of 16 by the end of 2020. HOL plans to replace additional transformers that are approaching end of life in order to reduce the impact of the large amount of transformers build or re-built in the 1970s.

To manage this aging asset group, HOL implemented an active inspection and maintenance program to maintain acceptable operating conditions and provide information to prioritize replacement projects. To further enhance monitoring capabilities, monitoring units that provide information on key gas generation, moisture, and oil temperature will be installed on many transformers. Information will be communicated back through the SCADA network.

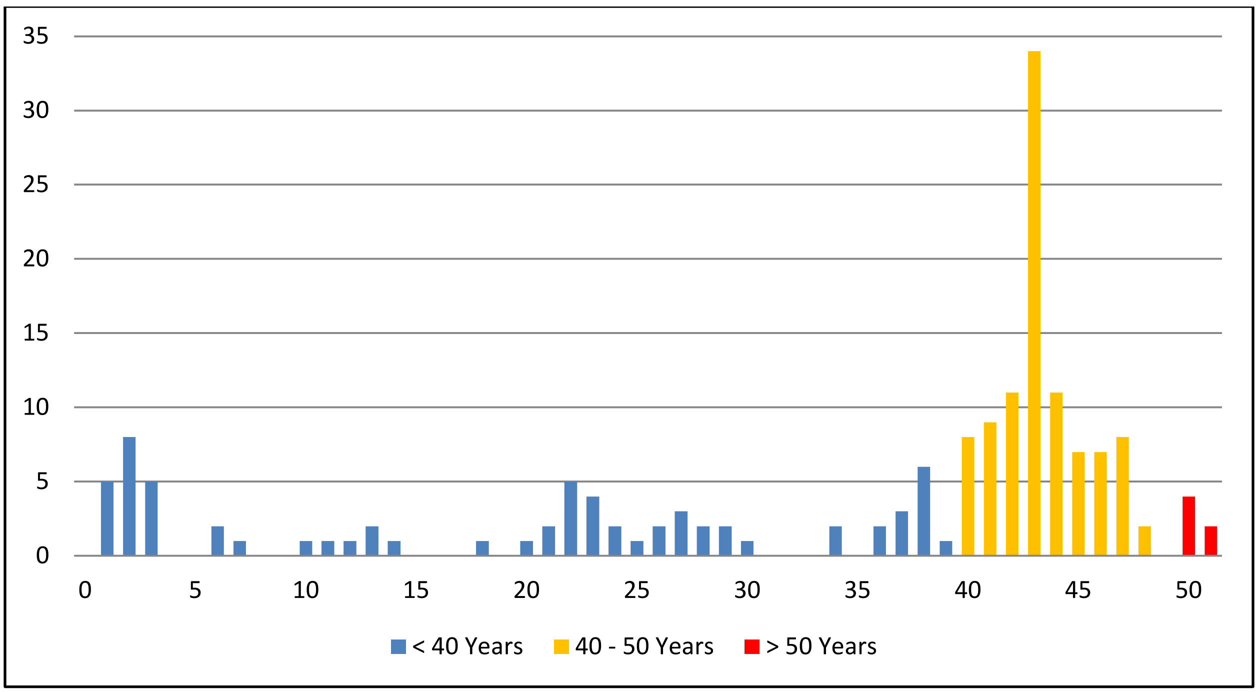


Figure 1 - Station Transformer Demographics

The health of a transformer can be broken down into three main components: thermal, electrical, and mechanical stresses.

- Thermal stresses occur due to internal heating or local overheating due to short-time overload. They can be measured using dissolved gas analysis, paper deterioration, and infra-red scanning.

- Dielectric stresses occur due to system overvoltages, transient impulse conditions or internal resonances within the windings. They can be measured through oil analysis, partial discharge, and power factor tests.
- Mechanical stresses can occur between conductors, windings, or leads due to short-term overcurrents, faults, and inrush currents. They can be measured through frequency response analysis, capacitance, and inductance measurements.

HOL currently tracks the health index through results from dissolved gas analysis. The transformer health index is based on the dissolved gas condition, the generation rate of these dissolved gases and the oil or fluid condition, given by the following equation.

$$Health\,Index = \left(\frac{Gas\,Score + Rate\,Score + Fluid\,Score}{3}\right) \times 5$$

The following figure provides an indication of the condition of the station transformer population calculated using the above equation.

Category	Health Index (HI)
Good	HI = 0
Fair	0 < HI <=1
Requires Attention	HI > 1

Table 1 - Station Transformer Health Index Rating

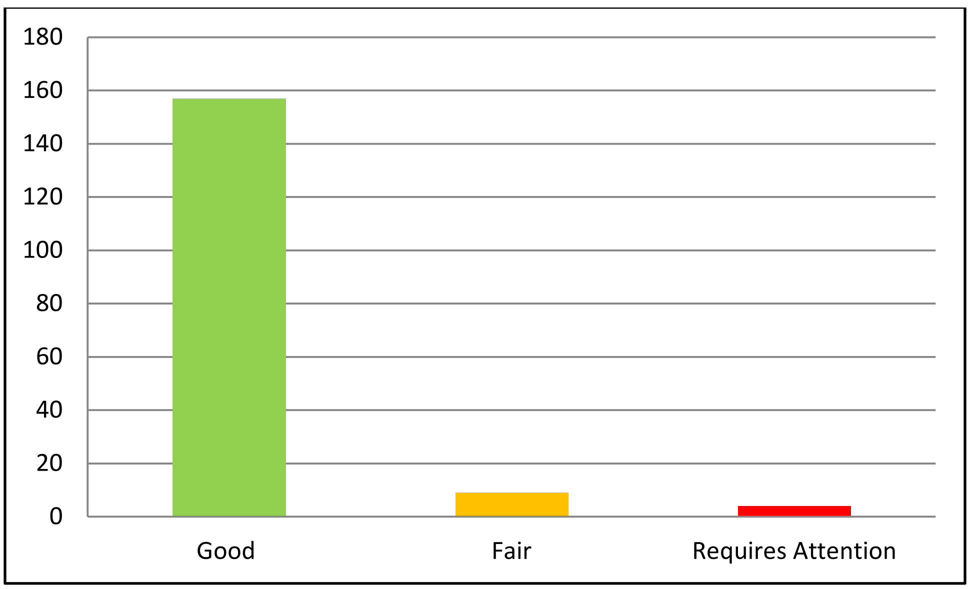


Figure 2 - Station Transformer Health

Transformer failures occur due to contamination in mineral oil, degradation of winding insulation as well as windings themselves. Failures have an extreme negative impact on reliability and can result in system operating without contingency in place.

1.2.3 Consequence of Failure

Station transformers have a large consequence of failure as they are an integral component to the distribution system. Station transformer failure will have reliability, safety and environmental consequences.

Substations are designed with contingencies in the event of a transformer failure. However, with long lead times and projects with high complexities, identifying and prioritizing station transformers that are at end of life before failure is critical. Capacity constraints are also a factor when a contingency unit is required to support the entire load of a station. Aging or overloaded transformers are at a higher risk of failure and can have high consequences if they fail.

Transformers that fail catastrophically have the potential to damage other surrounding equipment, even damage the transformer that will be used as contingency to restore power.

Historical reliability for station transformer defective equipment is provided in the graph below.

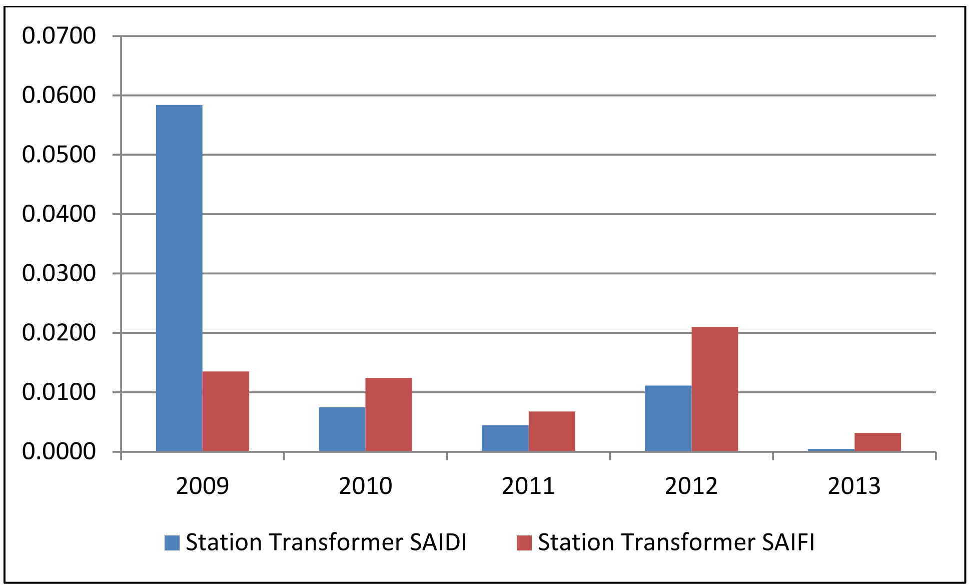


Figure 3 - Historical SAIDI and SAIFI, Station Transformer Defective Equipment

Additional failure impacts include environmental issues resulting from contamination of soil. HOL reports to the Ministry of the Environment information on oil spilled and the cost of remediation. In 2009, a large amount of mineral oil was released due to the failure at Beacon Hill substation. This emphasizes the importance of active inspection and replacement of station transformers to mitigate this environmental impact.

1.2.4 Main and Secondary Drivers

The drivers are represented in the table below.

Driver		Explanation
Primary	**Failure Risk**	6 transformer units have passed end of life criteria that will grow to 16 by the end of rate filing period 2020.
Secondary	**Reliability**	Station transformer has a direct impact on system reliability, as all customers connected will experience a power outage in the event of a failure. Increasing number of power transformer failures impact on SAIFI and SAIDI

Table 2 - Station Transformers Main Drivers

1.2.5 Performance Targets and Objectives

HOL employs key performance indicators for measuring and monitoring its performance. With the implementation of the station transformer replacement program, improvements are expected in the following measurements:

- Defective Equipment SAIDI
- Defective Equipment SAIFI

1.3 Project/Program Justification

1.3.1 Alternatives Evaluation

1.3.1.1 *Alternatives Considered*

In order to address the drivers and achieve the performance objectives of the program HOL considered four alternatives for the replacement policy. All the alternatives stabilize the replacement amount at the same level beyond 2016-2020 rate filing period. The following scenarios were analyzed:

- Run-to-Failure scenario with only reactive replacement of power transformers
- Replace 1 power transformer per year
- Replace 3 power transformers per year
- Replace 5 power transformers per year

1.3.1.2 *Alternatives Evaluation*

HOL evaluates all alternatives with consideration of the following criteria:

Criteria	Description
Failure / Reliability	The increased potential of failure posed by these aging assets will impact the organization's ability to guard worker and public safety. The selected alternative shall maintain or improve the reliability performance of the system.
Safety	HOL puts the safety of its employees and the public at the center of its decision-making process. The preferred alternative must not impose additional risks on the safety of HOL's employees and the public.
Resource	Unplanned replacements are usually carried out by HOL's own crews, whereas planned replacements can utilize both internal and external resources. Therefore, alternatives that incur more on-failure replacements are less favourable as it will be more challenging from a resource perspective.
Financial	Financial costs and benefits shall include all direct and indirect impact on the utility's performance and rates. The preferred alternative shall be at least cost or the most beneficial in the long-term to the stakeholder and to the customers.

Table 3 – Alternative Evaluation Criteria

1.3.1.3 *Preferred Alternative*

The preferred alternative is to replace 3 transformers per year. It is expected that this option will maintain the condition of the asset class, therefore, to maintain the current failure rate by managing the risk of an aging demographic.

Failure / Reliability

HOL performed an analysis to calculate the projected failure rate, using historical failure data and the probability of failure at a particular age. Based on a probability of failure, a predictive analysis can be completed depicting the future failure rate of the asset. Active replacements can be incorporated into this analysis to show the effects of varying replacement rates on failures. This analysis is shown in Figure 4.

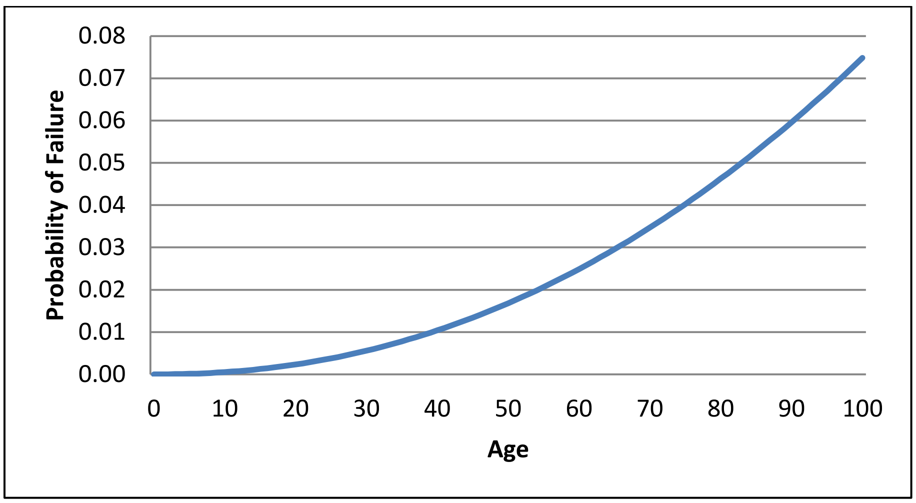


Figure 4 - Station Transformer Failure Probability

The failure curve used in the analysis is a calculated Weibull probability based on the total age demographic and the age at failure. The Weibull distribution is used industry wide for electrical equipment. This allows a curve to be built not only on failure data but incorporates the surviving population. As inspection processes develop and failure data is recorded in more detail, the failure curve will be updated to more accurately represent long term projected failures. Projected failure rates for various levels of replacements are presented in Figure 5.

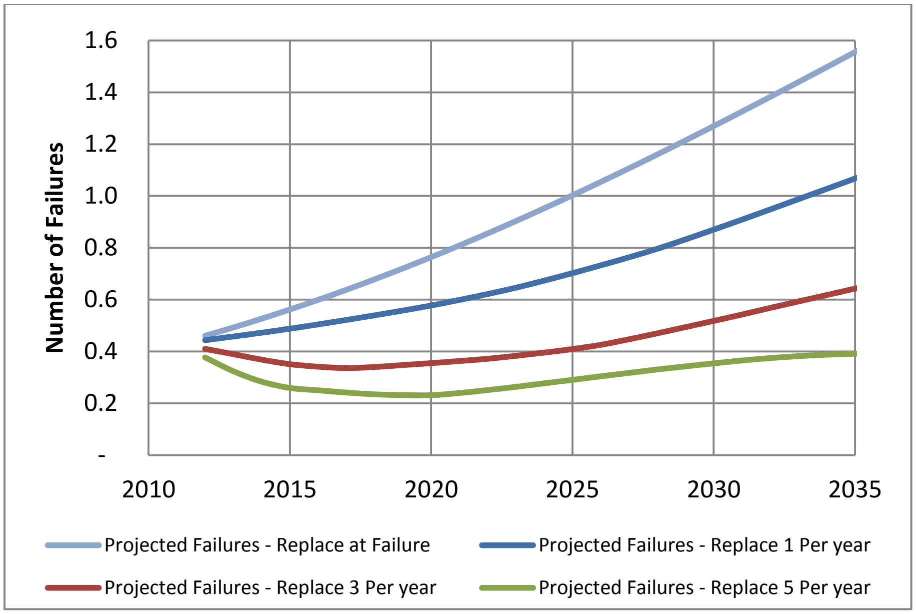


Figure 5 - Station Transformer Replacement Policy Failure Rates per Year

Safety

With a more aggressive approach to station transformer replacement end of life assets will be reduced at an accelerated pace. In instances where risk to the workforce is a catastrophic station transformer failure - this will be mitigated.

Resources

With assets on the system continuing to age and deteriorate, inadequate planned replacements of end of life assets will lead to accumulation of poor/critical assets and potential increase in unplanned replacements that will stress the available resources of HOL at its current staffing level.

Financial

The costs associated with replacing transformers in an emergency situation are higher than planned replacements as temporary measures will need to be put into place to restore contingencies until the transformer is replaced. The do-nothing policy would see more frequent transformer failures resulting in a high cost impact.

Replacing unscheduled failed transformers also affects HOL's ability to complete other planned projects throughout the year. With a do-nothing approach, both labour time and budget resources will be taken away from scheduled work throughout the year by focusing on replacing unscheduled failed transformers.

1.3.2 Project/Program Timing & Expenditure

Table 4 provides information on the expenditures and station transformer units replaced that was completed in the historical period. The average cost per transformer replaced in projects completed from 2010 to 2012 is provided by TX size:

- 5MVA: $430k

- 9MVA: $900k
- 30MVA: $1,990k
- 45MVA: $2,590k

	Historical ($M)					Future ($M)				
	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Total Expenditure	$2.5	$5.79	$3.74	$4.16	$10.77	$10.73	$4.62	$6.53	$8.23	$7.97

Table 4 - Expenditure History of Comparative Projects

HOL has replaced 12 station transformers between 2011 and 2014. 21 are planned for replacement between 2015 and 2020.

Station Transformer replacement projects vary depending on the criticality and the ability to supply load. Some projects require a staged approach such that the new transformer is constructed while keeping the existing transformer in-service. Once constructed, the connections are transferred to the new transformer with minimal interruption to the customers.

1.3.3 Benefits

Key benefits that will be achieved by implementing the station transformer replacement program are summarized in Table 5 below.

Benefits	Description
System Operation Efficiency and Cost-effectiveness	Other assets are typically replaced in conjunction with these projects such as: protections and control upgrade, new egress cables, monitoring devices, disconnect switches and breakers. This collaboration of asset replacement has been found to be cost-effective.
Customer	Improved reliability due to decreased transformer failures and availability of redundant systems. Improved reliability and safety due to upgraded protection and control systems, and monitoring.
Safety	Station transformers have potential to fail catastrophically if the mineral oil were to reach its flash point. Replacing the transformer reduces this risk. Upgraded protection and control systems allow for better internal fault detection, which will isolate the transformer from potential catastrophic failure.
Cyber-Security, Privacy	(Not applicable)
Co-ordination, Interoperability	For station transformer replacement projects that involve transmission connection requirements, HOL coordinates with Hydro One to complete the transmission connection.
Economic Development	HOL hires third party contractors to complete certain projects when the projects cannot be completed with its own internal resources.
Environment	HOL aims to minimize oil spills by the installation of an oil containment unit underneath each transformer.

Table 5 – Station Transformer Program benefits

1.4 Prioritization

1.4.1 Consequences of Deferral

If this program is deferred to the next planning period or adequate replacement levels are not achieved this asset group will pose an increased risk to safety and reliability, as a result of the increase in station transformer failures per year.

Deferral of station transformer replacements will also create a backlog of poor condition power transformers that will require an increased level of investment in the future. As evident in Figure 6 below, if increase in station transformer replacements is deferred until 2020 the asset demographics show a higher level in poor condition.

1.4.2 Priority

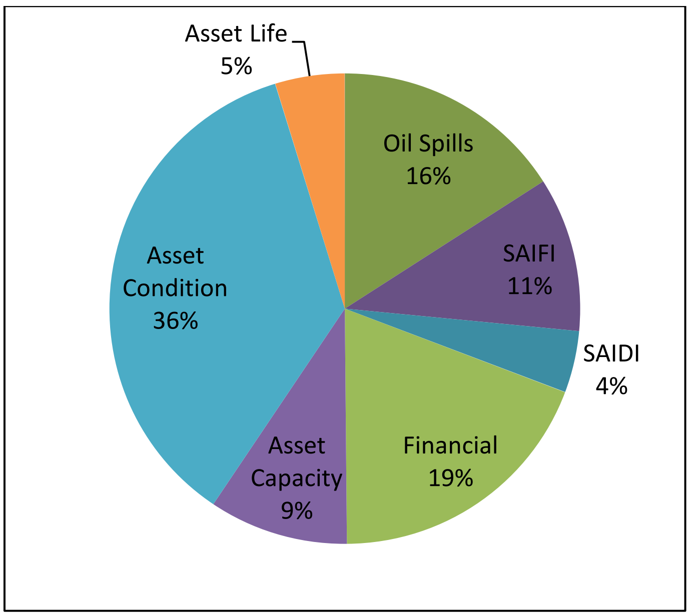


Figure 6 - Typical Project Score - Station Transformer Replacement

Typical station transformer replacement project score: 1.257

1.5 Execution Path

1.5.1 Implementation Plan

HOL is planning for the following transformer replacements in 2015-2016:

- Merivale DS, 2 transformers
- Longfields DS, 1 transformer
- Albion DS, 3 transformers
- Bronson DS, 2 transformers

Station transformer replacement projects typically span over 2-3 years. The project starts with the design, followed by equipment procurement, installation, and commissioning.

1.5.2 Risks to Completion and Risk Mitigation Strategies

Risk	Mitigation
Typical risks to completion include: • Coordinating activities in areas where multiple parties are working; • Adherence to schedules; • Material compatibility with existing station equipment; • Quality of materials	HOL has dedicated project managers who oversee the project to ensure that risk is managed accordingly.

Table 6- Station Transformer Risks to Completion and Mitigation Strategies

1.5.3 Timing Factors

Transformer projects are typically planned to include any civil construction outside of the winter months to avoid issues with concrete. Construction timing at the manufacture plant typically dictates the schedule of the project.

1.5.4 Cost Factors

Cost factors that affect replacement projects are:

- Project creep with including additional assets to be replaced. Most are identified early on in the project.
- Delays in the project schedule.
- Compatibility with existing equipment.

HOL has minimized the controllable costs of this project by implementing a number of measures.

- A competitive Request For Proposal (RFP) process was used for determining consulting resources. These consultants are retained for a minimum 3 year timeframe to ensure that they are able to efficiently meet our needs and have a good understanding of HOL's internal processes and standards.
- All contractors and vendors are selected through a competitive RFP process. These contractors and vendors are pre-screened to ensure that they have the abilities and expertise to meeting the needs of HOL and are able to maintain timelines required.
- The use of in house project management allowed for efficient use of resources and experience from past projects within HOL. Project management best practices at HOL are based on PMI (Project Management Institute).
- Workforce planning is used to ensure internal resources requirements are identified early. If outside resources are required this is identified early in the project to ensure the roll out is implemented smoothly and efficiently.

1.6 Renewable Energy Generation

HOL's station transformer purchasing standard includes designing new transformers with the ability to have reversed current flow through the transformer. This will reduce restrictions due to thermal overloading of transformers for new generation connections.

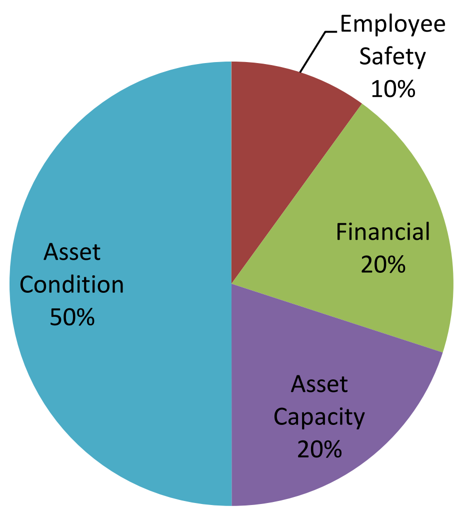
1.7 Leave-To-Construct

(Not applicable for this program)

1.8 Project Details and Justification

1.8.1 Merivale DS Rebuild

Project Name:	Merivale DS Rebuild
Project Number:	920084859
Capital Cost:	$17,125,785
O&M:	N/A
Start Date:	February 2014
In-Service Date:	August 2018
Investment Category:	System Renewal
Main Driver:	Risk of Failure
Secondary Driver(s):	Reliability
Customer/Load Attachment	1600 customers/50 MVA
Project Scope	
The project is to replace two end of life transformers, 72T1 and 72T2, at Merivale DS. The new transformers will also provide upgraded capacity of 15/20/25MVA each. There will be replacement transformer foundations and oil containment, upgraded circuit breakers, reclosers, disconnect switches, metalclad switchgear, new Protection and Control (P&C) equipment and a new P&C house. While not being in the scope of this project, the upgraded station capacity will allow an additional feeder and a duct bank will be put in place to prepare for this future egress. This project takes place within the boundaries of the Hydro One Networks Inc-owned Merivale transmission station at 31 Woodfield Drive. It is important to note that although Hydro One owns the land upon which the station resides, HOL Limited owns the equipment pertaining to its distribution station, and it is anticipated that this project will receive official permission from Hydro One to move forward.	
Priority	



Project Score = 1.01

Work Plan
HOL Limited is awaiting official permission from Hydro One Networks Inc. to do this station work on Hydro One's property. HOL Limited owns the station equipment at Merivale distribution station and expects approval to do this work. Hydro One is fully aware of the plans for this project. Once all procurement is complete, construction will begin with the demolition of existing electrics to allow the removal of both station transformers. With the transformers removed, the foundations and oil containment will be constructed. The new transformers will be installed, followed by the upgraded circuit breakers, reclosers, disconnect switches and metalclad switchgear. New P&C equipment will be installed and finally, commissioning and energization will take place. Any necessary station outages should be coordinated with the 92008497 Prim Fuse to C-Switcher – Epworth T1 and the 92006413 Borden Farms Switchgear Replacement projects. This will ensure that there will be adequate station capacity to supply the load in the area while this work is being done.
Customer Impact
The main driver of this project is to enhance reliability by replacing two station transformers which have both surpassed the end of their service life. The secondary driver of this project is to upgrade the capacity of the station so that it can meet the current and future demands required of it. It is estimated that Merivale DS requires additional capacity within the next 10-20 years to supply the proposed load, but the end of life transformers require replacement within the next two years. The oil containment will be replaced which ensures that the station's environmental impact will be kept to a minimum.

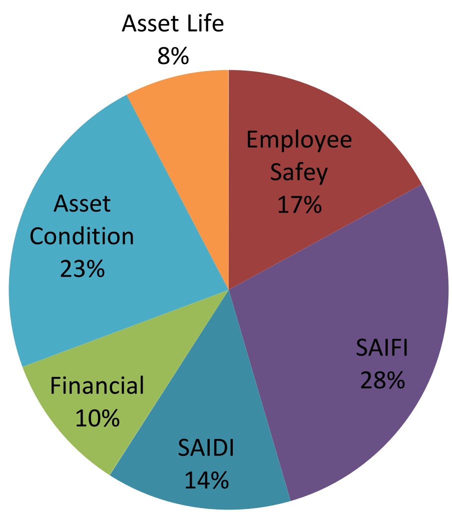
1.8.2 Bronson T1 & T2

Project Name:	Bronson T1 & T2
Project Number:	92008661
Capital Cost:	$3,223,099
O&M:	N/A
Start Date:	2016 – Q1
In-Service Date:	2017 – Q4
Investment Category:	System Renewal
Main Driver:	Risk of Failure
Secondary Driver(s):	Reliability
Customer/Load Attachment	1000 customers/2.5 MVA

Project Scope

Replace 2 end of life transformers at Bronson Substation located at 247 Glebe Avenue.
New 13.2kV 6.7 MVA ONAF transformers will be installed. Replace oil containment as it will be demolished during removal of existing transformers. Install new Protection & Control equipment. Station capacity and number of feeders are not affected by this project.

Priority



Score = 1.173

Work Plan

- Demolition of existing oil containment around SBT1 and SBT2 transformers
- Removal of existing transformers
- Construction of replacement foundations for new transformers
- Installation of new transformers
- Construction of new oil containment pit
- Installation of new instrumentation transformers and new Protection & Control equipment

Customer Impact

Reliability improvements due to replacement of end of life assets with new equipment.

1.8.3 Longfields Transformer Base Replacement – Including CS/CB

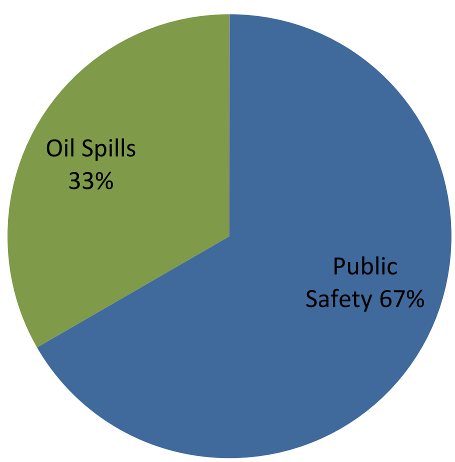
Project Name:	Longfields XFRM Base Rpl- Including CS/CB
Project Number:	92008491
Capital Cost:	$4.34 M
O&M:	N/A
Start Date:	March 2015
In-Service Date:	2016 – Q1
Investment Category:	System Renewal
Main Driver:	Risk of Failure
Secondary Driver(s):	Reliability
Customer/Load Attachment	1,535 customers/ 20MVA

Project Scope

This project involves replacing and upgrading assets at Longfields DS and will include:

- Building a temporary station using one of the current station transformers. The temporary station will be used to service customers while the new transformer base is in construction.
- Construction of T2 transformer base and oil containment
- Upgrade fuse protection to circuit switchers/breakers. New 44kV air break switches, circuit breakers, bus, and all associated structures and foundations. New 27.6kV circuit breakers, tie switch, load break disconnect switches, instrument transformers, and all associated structures and foundations.
- New P&C outdoor panels, SCADA, ground grid, lightning protection, AC and DC station service, cable trenches, cable duct, noise abatement, and privacy fence.

Priority



Project Score: 0.9

Work Plan

The work plan for this project is as follows:

- Design and major equipment procurement started in 2014, to be completed in 2015.
- Civil construction for temporary station occurring in March 2015.
- Electrical construction for temporary station (currently planned to be completed by HOL electricians and technicians) occurring in March 2015.
- Civil construction for new station occurring in 2015 (starting end of Q2, ending end of Q4)
- Electrical construction for new station (currently planned to be completed by HOL station electricians and technicians) occurring in 2016 (starting in Q1).
- New station (T1 and T2) to be energized in 2016.

Customer Impact

The primary driver of this project is to prevent risk of failure by creating protection and environmental upgrades. This project upgrades the primary protection of the station, transformer base and oil containment. These upgrades result in a more reliable and safe station.

1.8.4 Transformer Replacement – 13/4.16kV Albion UA T1, T2 & T3

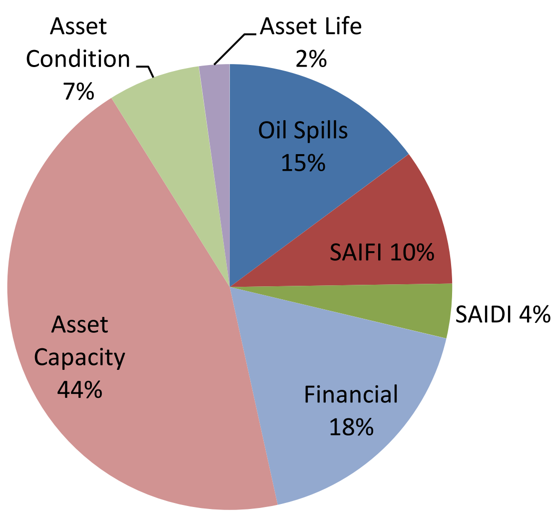
Project Name:	TFX Repl- 13/4.16kV Albion UA T1&T2&T3
Project Number:	92008579
Capital Cost:	$2.97M
O&M:	N/A
Start Date:	2015
In-Service Date:	2016
Investment Category:	System Renewal
Main Driver:	Risk of Failure
Secondary Driver(s):	Reliability
Customer/Load Attachment	3,688 customers/ 9.6MVA

Project Scope

This project involves replacing and upgrading assets at Albion UA and will include:

- The replacement of 3 existing 5.6MVA 13.2-4.16kV transformers
- New transformer foundation and oil containment
- New primary and secondary cables

Priority



Project Score: 1.347

Work Plan

The work plan for this project is as follows:

- Design and major equipment procurement occurring in 2015
- Delivery of equipment, and construction to begin in 2016
- Project to be completed by Q4 2016

Customer Impact

The primary driver of this project is to prevent risk of failure due to aging assets. Replacement of the aged transformers with new units mitigates the failure risk.

2 Station Switchgear Replacement

2.1 Project/Program Summary

Station switchgears are commonly employed at substations to provide protection for electrical equipment, and to allow control and isolation during faults and planned maintenance activities. Station switchgears, therefore, have a direct impact on the reliability of electricity supply to customers. Station switchgear failure will have reliability, safety and environmental consequences. The station switchgear replacement program targets the planned replacement of switchgears based on their age and qualitative information to maintain system reliability and safety in the most cost-effective manner.

2.2 Project/Program Description

2.2.1 Assets in Scope

HOL's station switchgear asset class consists of breakers, switches, bus insulation, support structures, protection and control systems, arrestors, control wiring, ventilation, and fuses. The base unit of this asset class is a switchgear assembly, which includes bus work, feeder breakers, and appurtenances. HOL's current standard is to install arc resistant switchgears. This standard has not always been in place and has been incorporated to minimize safety risks.

The station switchgears targeted for replacement by 2017 are shown in Table 7.

Switchgear	Year	Scope of the replacement	Reason for Replacement
Woodroffe UW	2016	Switchgear being decommissioning, customers to be supplied by Woodroffe TW	At end of life.
Woodroffe TW	2017	Switchgear being replaced	Condition.
Bayshore Primary CS	2012-2015	Replace switch and fuse protection with differential. Replace circuit switcher with breaker.	Protection Upgrade.
Borden Farms Switchgear	2013-2015	Installation of new metal clad switchgear. Replace fuses with breakers. Add differential protection.	Switchgear installation and protection upgrade.
Epworth T1 CS	2014-2015	Primary fuse being replaced with circuit switcher. Differential protection added.	Protection upgrade.
Overbrook TO Switchgear	2016	Replace the existing switchgear and breakers. Install new protection and control and cable work.	Condition.
Bells Corners	2014-2015	Replacement of reclosers and controllers. Replace low side protection for AC/DC services with modern load center and fusing blocks.	At end of life. Protection upgrade.

Table 7 - Planned Station Switchgear Replacements

HOL recommends a replacement rate of 3-5 station's switchgear assemblies a year. Under this scenario the expected number of switchgear failures will be reduced and kept constant.

2.2.2 Asset Life Cycle and Condition

HOL currently manages switchgear assemblies in 83 substations containing a total of 936 breakers and 67 reclosers. These substations range in operating voltage from 5kV to 27.6kV.

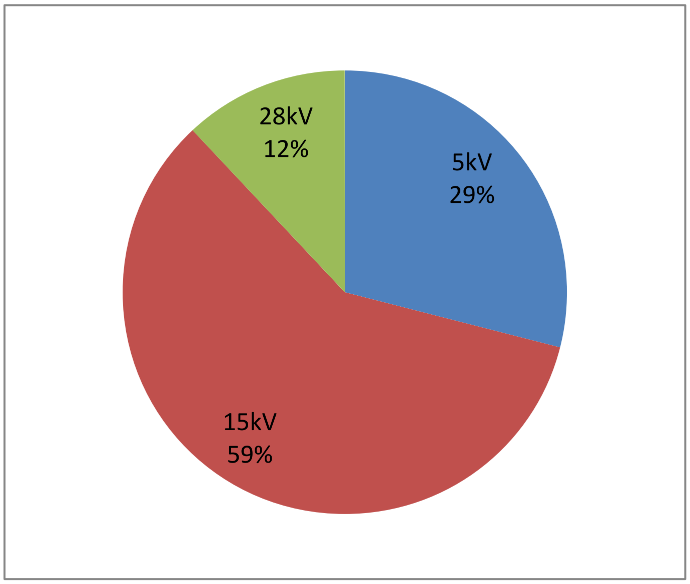


Figure 7 - Station Switchgear Voltage Rating Distribution

Demographic information for the station switchgear has been collected from various sources included in HOL's existing condition assessment and maintenance programs. The financial life cycle of this asset class is 40 years, while the technical end of life is anticipated to be 45 years. This variation is to ensure that the asset is fully depreciated by the time it has a high probability of failure. Roughly 58% of HOL's station switchgear breakers and reclosers are at or have passed their financial usefulness, while 43% of the equipment is at or past their end of life criteria. In addition, in the next ten years another 26% of station switchgear breakers and reclosers will be at or past their end of life criteria.

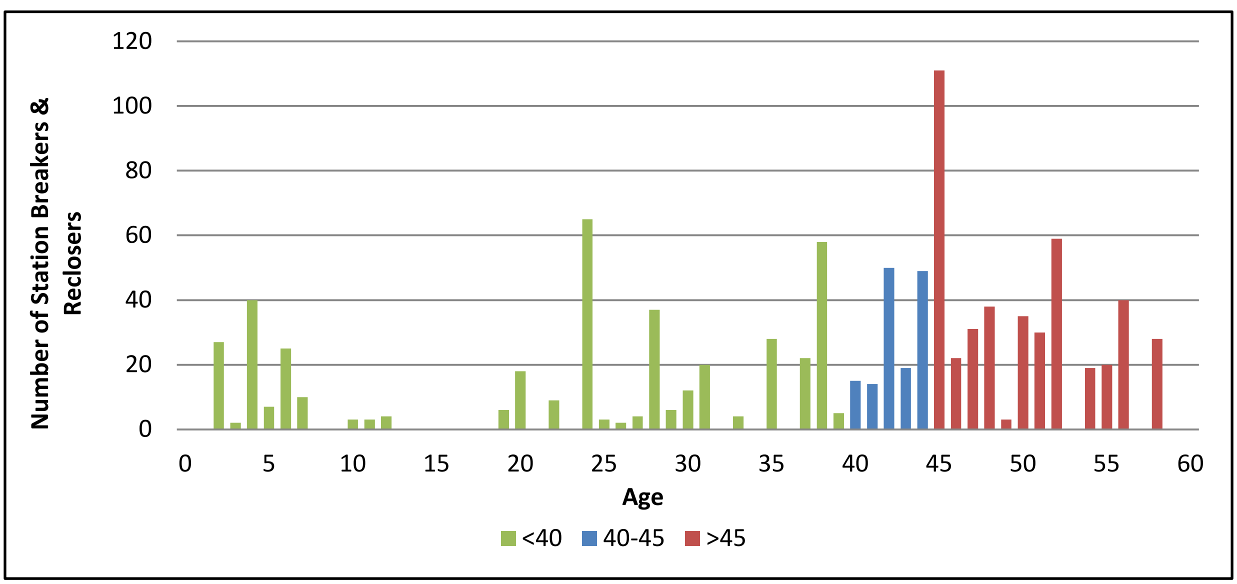


Figure 8- Station Breaker and Recloser Demographics by Age

HOL's health condition evaluation of station switchgear assemblies takes into account the many functional and supporting parts. A qualitative assessment of the equipment condition, based on subject matter experience, is done on the switches, breakers, bus, insulation, and supporting structures. The equipment is then reviewed for functional obsolesce and the availability of spare parts. The health index is calculated using this information and the age of the equipment.

On average, there has been 1.7 station breaker or recloser failures per year experienced over the last six years, seen in Figure 9. This trend is expected to stay the same and potentially increase due to the number of assets past their end of life age. Therefore a replacement plan is required to maintain the number of failures.

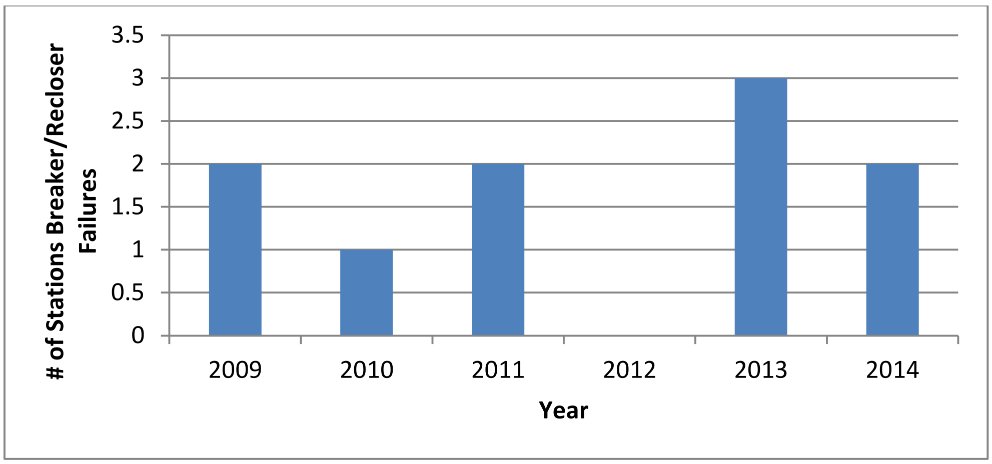


Figure 9 - Historical Station Switchgear Failures

2.2.3 Consequences of Failure

In general, switchgear failures will result in power loss to customers connected to that device. Outages as a result of a failed component of the switchgear are significant in the amount of customers affected, but also the duration of the outage. Through switching and station work, customers can be restored, however, the typical delivery time for a new breaker or recloser is roughly 6 months. In the last six years the worst outage affected 4479 customers for 6.2 hours.

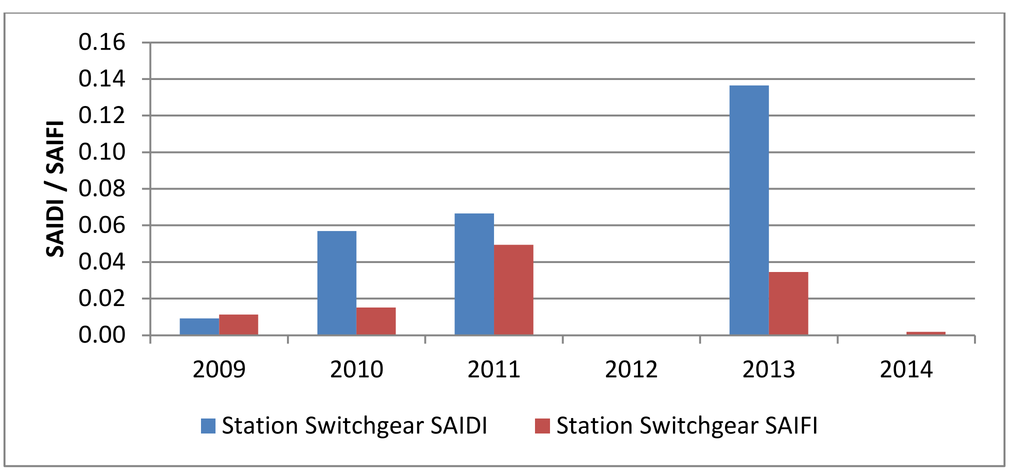


Figure 10 - Reliability Metrics Associated with Station Switchgear Failures

*Note: In 2014 there was a breaker failure that would have contributed considerably to the SAIFI and SAIDI. However, it had been offloaded earlier in the day.

Historically, station switchgear has contributed to about 10 percent of the Defective Equipment SAIFI over the historical period. This has remained unchanged in the past five years with minor fluctuations.

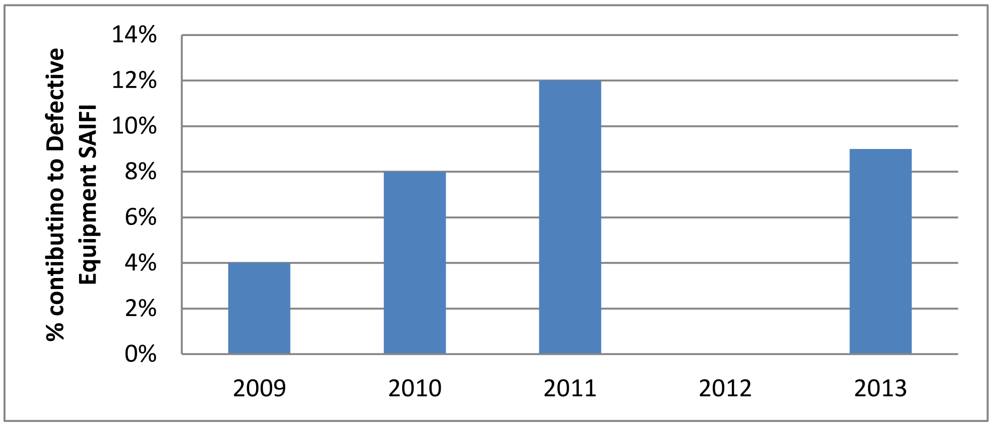


Figure 11 - Station Switchgear Contribution to Defective Equipment SAIFI

Failure of switchgear that contains oil as a cooling and interrupting medium can have an extensive impact on the safety of HOL employees and the public. A failure of this type of switchgear can result in burning oil and gas clouds. Older switchgear were not designed to withstand internal arc fault. High energy arcing fault inside the switchgear can lead to explosion, fire, and other catastrophic events that could result in extensive damage to buildings and properties nearby and severe injury or even death of personnel. Furthermore, it can cause oil spills that contaminate the surrounding environment.

2.2.4 Main and Secondary Drivers

Drivers for the station switchgear replacement program are summarized and described in Table 8 below.

Driver		Explanation
Primary	**Failure Risk**	43% (436) of the breakers and reclosers in HOL`s system are at 45 years or older. This will grow by 26% (260) over the next 10 years.
Secondary	**Reliability**	Station switchgear has a direct impact on system reliability, as all customers connected will experience a power outage in the event of a switchgear failure. The amount of customers that are affected and the duration can be substantial.
	Environment	Station switchgear failures can lead to oil leaks. HOL mitigates this risk through the use of appropriate enclosure and oil containment. However, it is still possible for explosions to cause an oil leak.
	Safety	Station switchgear failure can potentially lead to injury or even death of HOL employees and the public. HOL's standard is to incorporate arc resistant switchgears to replace station switchgears without arc flash protection. This furthers the safety to employees and the public.

Table 8 - Station Switchgear Program Drivers

Figure 12 - Station Switchgear Explosion

Figure 13 - Bridlewood Recloser Exploded Internally

2.2.5 Performance Targets and Objectives

The objective is to also decrease the number of station breakers and reclosers operating past their end of life in HOL`s system. This is expected to increase the systems reliability.

HOL employs key performance indicators for measuring and monitoring its performance. With the implementation of the station switchgear replacement program, improvements are expected in the following measurement:

- Defective Equipment SAIFI
- Defective Equipment SAIDI

2.3 Project/Program Justification

2.3.1 Alternatives Evaluation

2.3.1.1 *Alternatives Considered*

In order to address the drivers and achieve the performance objectives of the replacement program, HOL considered four alternatives for the replacement policy levels.

I. **Station Switchgear Replacement Policy**

Using the rate of failure model developed for station switchgear, HOL analyzed an impact of several replacement alternatives on the performance outcome. Only the alternatives of replacing three to five switchgears a year, stabilizes the replacement amount in the rate filing period (2016-2020). The following scenarios were analyzed:

- Do Nothing, running assets to failure,
- Replace 1 switchgear / year
- Replace 3 switchgears / year
- Replace 5 switchgears / year

2.3.1.2 *Alternatives Evaluation*

HOL evaluates all alternatives with consideration of the following criteria:

Criteria	Description
Failure / Reliability	The selected alternative shall maintain or improve the reliability performance of the system.
Safety	HOL puts the safety of its employees and the public at the center of its decision-making process. The increased potential of failure posed by these aging assets will impact the organization's ability to guard worker and public safety. The preferred alternative must not impose additional risks on the safety of HOL's employees and the public.
Resource	Unplanned replacements are usually carried out by HOL's own crews, whereas planned replacements can utilize both internal and external resources. Therefore, alternatives that incur more on-failure replacements are less favorable as it will be more challenging from a resource perspective.
Financial	Financial costs and benefits shall include all direct and indirect impact on the utility's performance and rates. The preferred alternative shall be at least cost or the most beneficial in the long-term to the stakeholder and to the customers.

Table 9 – Alternative Evaluation Criteria

2.3.1.3 *Preferred Alternative*

The preferred alternative is to maintain the current reliability level for the station switchgears by replacing three station switchgears a year. It reflects the optimal balance between the reliability and required investment levels. It also eases the stress on the system while transferring the load and reducing the system flexibility required replacing the switchgear.

Failure / Reliability

HOL performed an analysis to correlate an equipment failure rate with the age of the asset. The curve used in the analysis is a calculated Weibull probability based on the total age demographic and the age at failure. This allows a curve to be built not only on failure data but incorporates the surviving population. This translates into the failure probability curve shown in Figure 14.

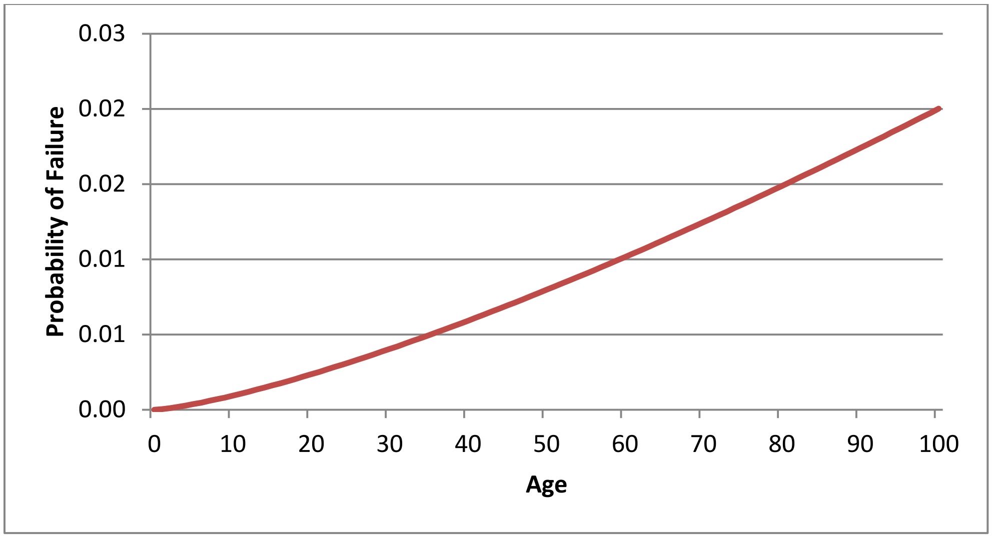


Figure 14 - Station Switchgear Failure Probability

Using the demographics of HOL's station switchgears, numerous rate of failures have been projected for the next 20 years under each replacement scenario, as shown in Figure 15.

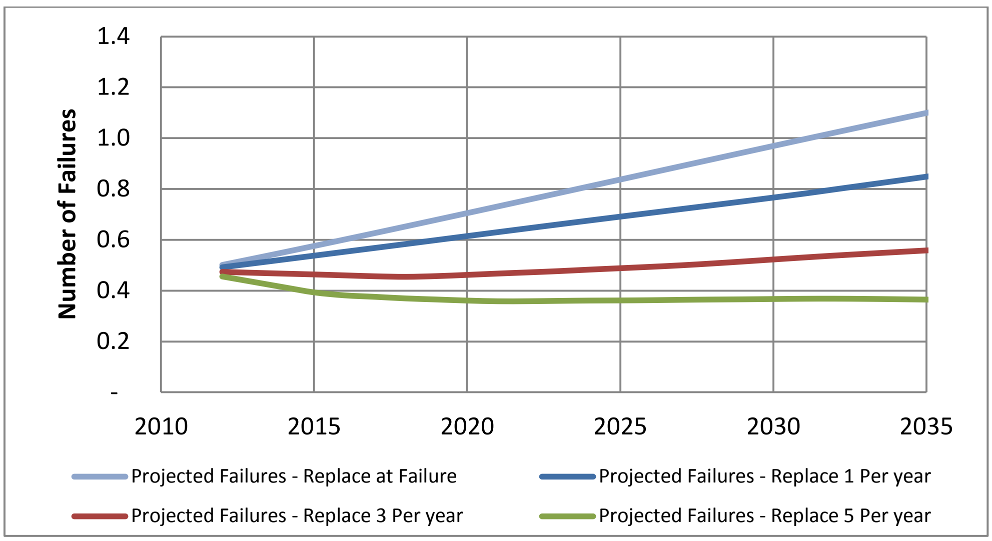


Figure 15 - Station Switchgear Recommended Replacement Rate

Replacing three station switchgear assemblies a year will help to maintain the current reliability levels in the near to medium term.

Safety

An increased station switchgear replacement policy would minimize the risk to safety of HOL employees and the public by reducing the number of switchgears that are likely to fail based on age.

Resources

With assets on the system continuing to age and deteriorate, inadequate planned replacements of aging station switchgears will lead to accumulation of end of life assets. This has the potential to increase unplanned replacements that will stress the available resources of HOL at its current staffing level.

Planned station switchgear replacements are much more easily handled due to the ability to schedule work rather than replacing upon failure which is done as soon as possible.

Financial

The cost associated with replacing station switchgears in an emergency situation has been estimated to be substantially higher than the cost of scheduled station switchgear replacements. This can be due to many factors including over time labour and express ordering equipment that was used as an emergency replacement. The do-nothing policy would see more frequent station switchgear failures resulting in a high cost impact of replacing unscheduled station switchgears. By increasing the replacement policy, the average costs to replace a switchgear, scheduled and unscheduled, will be reduced and provide long-term financial benefit.

Replacing unscheduled station switchgears also affects HOL's ability to complete other planned projects throughout the year. With a do-nothing approach, both labour time and budget resources will be taken away from scheduled work throughout the year by focusing on replacing unscheduled failed switchgears.

2.3.2 Project/Program Timing & Expenditure

Table 10 provides information on the expenditures replaced in the historical and future period. It also shows the number of projects being worked on in the respective year. These projects have the ability to carry on for more than one year due to the work involved. The projects identified in Table 10 are those that have greater than $25k spent in order to eliminate design phase work and capture years of construction and years that equipment was ordered. Costs vary year to year based on the size of switchgear required and how many projects are executing. The projects scope also vary anywhere from the reclosers to the whole metal clad switchgear.

	Historical ($M)						Future ($M)			
	2011	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Total Expenditure	1.567	2.521	5.254	8.349	6.241	5.424	7.088	7.408	6.871	7.965
Projects	3	5	5	8	6	5	N/A*	N/A*	N/A*	N/A*

Table 10 - Expenditure History of Comparative Projects

*The number of specific projects has yet to be determined and will depend on the number of combined switchgear/transformer projects.

Variations in annual capital spending are dependent on pacing of investments and combining works with other replacement projects.

To achieve higher cost efficiency, future station switchgear replacements will be carried out in conjunction with station transformer replacements where economic benefits exist.

Station switchgear replacement projects are usually staged such that the new switchgear is constructed while keeping the existing switchgear in-service. Once constructed, the feeders are transferred to the new switchgear with minimal interruption to the customers.

2.3.3 Benefits

Key benefits that will be achieved by implementing the station switchgear replacement program are summarized in Table 11 below.

Benefits	Description
System Operation Efficiency and Cost-effectiveness	New switchgears can have the added benefit of replacing switches at stations. This allows for operation from HOL's system operation control room and eliminated the need for a crew to manual operate them. This saves both time and money. The proactive replacement of units at end of life, but before failure results in labour cost savings compared to unplanned replacement of a failed unit.
Customer	With the program in place the failure rate of the station switchgears will be maintained over the investment period compared with the run-to-failure approach. Maintained reliability is expected to positively impact customer satisfaction, specifically considering the lengthy nature of the restoration process as a result of the switchgear failure.
Safety	Switchgear replacements reduce the risk to employee safety by implementing new standards for arc-resistant switchgear.
Cyber-Security, Privacy	(Not applicable)
Co-ordination, Interoperability	(Not applicable)
Economic Development	HOL engages contractors to construct and install station switchgear, thereby creating job opportunities. Internal resources are used for the commissioning and acceptance testing of the equipment.
Environment	Proactive replacement of end of life station switchgears mitigates the risk of oil spilling in the event of a switchgear failure.

Table 11 - Station Switchgear Program Benefits

2.4 Prioritization

2.4.1 Consequences of Deferral

If this program is deferred to the next planning period or adequate replacement levels are not achieved, this asset group will pose an increased risk to safety and reliability, as a result of the increased potential for switchgear in-service failures. HOL is expected to experience significantly higher failure rates within the next five years without this program in place.

In the long term, deferral of station switchgear replacements will also create a backlog of bad assets that will require more capital investment in the future in order to bring the overall condition of the entire asset class to an acceptable level. This will place a high stress on HOL's internal resources at its current staffing level.

2.4.2 Priority

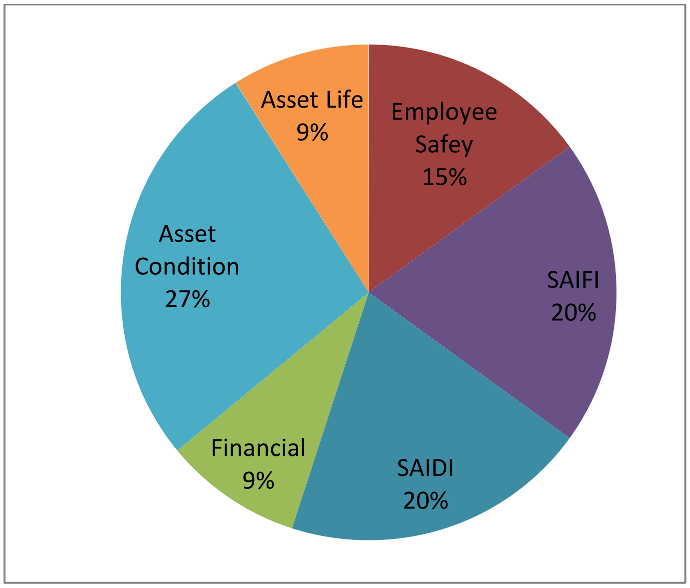


Figure 16 - Station Switchgear Replacement Avoided Risk

Score = 1.333

2.5 Execution Plan

2.5.1 Implementation Plan

HOL's health condition evaluation of station switchgear assemblies takes into account the many functional and supporting parts. A qualitative assessment of the equipment condition, based on subject matter experience, is done on the switches, breakers, bus, insulation, and supporting structures. The equipment is then reviewed for functional obsolesce and the availability of spare parts. The health index is calculated using this information and the age of the equipment.

Once the station switchgears are prioritized, they are scheduled with either internal or external work crews. Adequate planning and load switching is necessary during the switchgear replacement in order to minimize impact to customers.

2.5.2 Risks to Completion and Risk Mitigation Strategies

Risk	Mitigation
Typical risks to completion include: • Project planning to minimize outages to customers and that coordinate with other planned work in the area; • Adherence to schedules; • Timely procurement of equipment; • Quality of materials	HOL has dedicated project managers who oversee the project to ensure that risk is managed accordingly. It is HOL practice to schedule and coordinate all work (planned and emergency) through our System Office to ensure effective use of resources and ensure continued system operability and safety in areas where crews are working.

Table 12 - Station Switchgear Program Risks and Mitigation Strategies

2.5.3 Timing Factors

Switchgear projects are typically planned to include any civil construction outside of the winter months to avoid issues with concrete. Construction timing at the manufacture plant typically dictates the schedule of the project.

Delivery of the assets can also be a risk that is dependent on the manufacturer.

2.5.4 Cost Factors

The final cost of the program is affected by the number of station switchgears to be targeted for replacement. If a switchgear fails before replacement is performed, the cost of replacing the failed switchgear will be more than if the work is performed proactively. Failure of the switchgear will also incur increased costs as it will experience customer outages if the electrical assets are damaged.

HOL has minimized the controllable costs of this project by implementing a number of measures.

- A competitive Request For Proposal (RFP) process was used for determining consulting resources. These consultants are retained for a minimum 3 year timeframe to ensure that they are able to efficiently meet our needs and have a good understanding of HOL's internal processes and standards.
- All contractors and vendors are selected through a competitive RFP process. These contractors and vendors are pre-screened to ensure that they have the abilities and expertise to meet the needs of HOL and are able to maintain the timelines required.
- The use of in-house project management allowed for efficient use of resources and experience from past projects within HOL. Project management best practices at HOL are based on the PMI (Project Management Institute).
- Workforce planning is used to ensure internal resources requirements are identified early. If outside resources are required this is identified early in the project to ensure the roll out is implemented smoothly and efficiently.

2.6 Renewable Energy Generation

HOL's purchasing specification for new switchgears is designed to eliminate any short circuit restriction to connect new generation. Leave-To-Construct

(Not applicable for this program)

2.7 Project Details and Justification

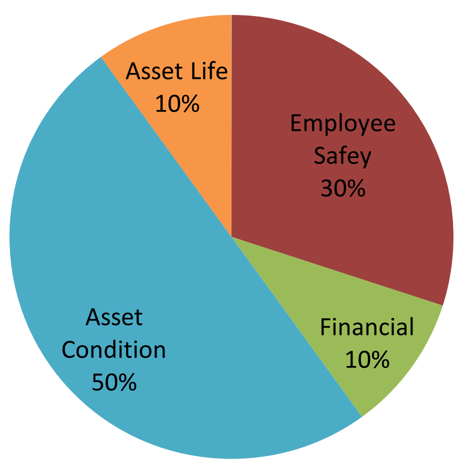
2.7.1 Primary Fuse to Circuit Switcher – Epworth T1

Project Name:	Prim Fuse to C-Switcher – Epworth T1
Project Number:	92008497
Capital Cost:	$1,148,693
O&M:	N/A
Start Date:	2014 – Q1
In-Service Date:	2015 – Q4
Investment Category:	System Renewal
Main Driver:	Risk of Failure
Secondary Driver(s):	Reliability
Customer/Load Attachment	1400 customers/8400 KVA

Project Scope

The project is to upgrade the protection for the 58T1 transformer at Epworth DS from a 115kV fuse to a circuit switcher. The secondary bus switch will be replaced with a bus breaker to add differential protection. The assets involved in this project are a new 115kV primary circuit switcher, a new 8.32kV bus breaker cell, new P&C panels, new protective relaying equipment and new secondary 15kV copper cable. This project takes place entirely within the boundaries of HOL Limited's Epworth distribution station at 22 Epworth Avenue. The substation capacity will not be affected by this project, nor will the feeders be altered in any way.

Priority



Project Score = 1.14

Work Plan

Once all procurement is complete, the 58T1 transformer will be taken offline and all construction work will occur during one outage. The implementation strategy for this project is to remove the existing primary fused disconnect and the old 8.32kV 58T1 bus disconnect cell. Then the new 8.32kV 58T1 bus breaker cell will be installed and the new P&C panels will be constructed. Next is the installation of new protective relaying equipment and the new primary circuit switcher. The old overhead secondary bus will be removed from the 58T1 to the switchgear, and new secondary cable from the transformer to the bus breaker cell will be installed. The final stage is commissioning and energization.

This project must be coordinated with the 92006413 Borden Farms Switchgear Replacement and 92008485 Merivale DS Rebuild projects to ensure that station outages will not affect capacity. It must be analyzed whether the area will still have adequate supply if multiple stations take outages at once.
Customer Impact
The main driver for this project is to enhance station reliability by replacing the manual disconnect with a motorized circuit switcher, and upgrading the transformer protection to HOL Limited's current standard. The motorized circuit switcher also provides a safer mode of operation. The new electrical protection configuration of the 58T1 transformer will be similar to that of the other transformer at the station, allowing consistency on both sides.

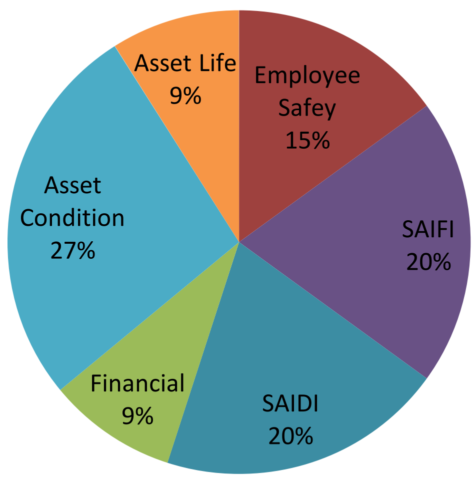
2.7.2 Woodroffe TW – 13.2kV Switchgear Replacement

Project Name:	Woodroffe TW – 13.2kV SG Replacement
Project Number:	92008657
Capital Cost:	$7,346,447
O&M:	N/A
Start Date:	2016 – Q2
In-Service Date:	2017 – Q4
Investment Category:	System Renewal
Main Driver:	Risk of Failure
Secondary Driver(s):	Reliability
Customer/Load Attachment	5000 customers/12.2 MVA

Project Scope

- Decommissioning 4.16kV switchgear and transformers
- Replacement of 13.2kV switchgear with new equipment
- New Protection & Control building
- Potential for differential protection upgrade

Priority



Score = 1.333

Work Plan

Decommission 4.16kV equipment first once transferred to 13.2kV system under the Woodroffe Voltage Conversion project.
Build 2 new metalclad switchgear lineups and Protection & Control building. Transfer customers to new 13.2kV switchgear.
Decommission 2 of the 4 existing 13.2kV metalclad switchgear lineups.
Install 2 more 13.2kV metalclad switchgear lineups. Transfer customers to new 13.2kV switchgear.
Decommission the final 2 end of life 13.2kV metalclad switchgear lineups.

Customer Impact

Reliability improvements by removing end of life assets.

2.7.3 Borden Farms Switchgear Replacement

Project Name:	Borden Farms Switchgear Replacement
Project Number:	92006413
Capital Cost:	$7,269,000
O&M:	N/A
Start Date:	2013 – Q1
In-Service Date:	2015 – Q4
Investment Category:	System Renewal
Main Driver:	Risk of Failure
Secondary Driver(s):	Reliability
Customer/Load Attachment	13MVA

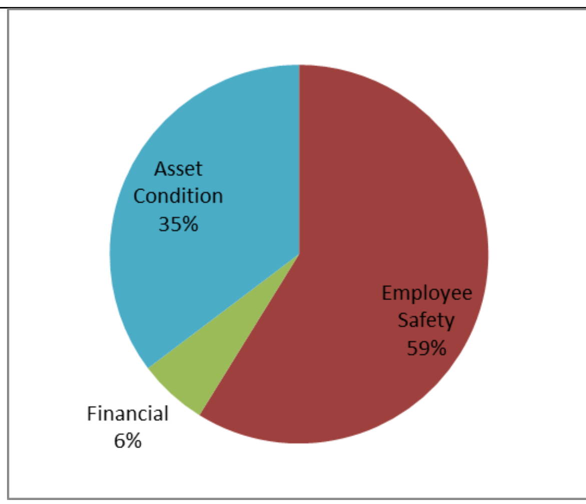
Project Scope

This project will replace end of life assets at Borden Farms DS and include:

- Replacement of two (2) 44kV to 8.32kV transformers,
- Installation of a 15kV metalclad SG with 6 feeders,
- Replacement of two (2) primary 44kV fuse disconnect switches with new primary 44kV circuit breakers and,
- Installation of a new protection & control building.

The station is located at 266 Viewmount Drive. The installation will include new oil containment c/w pad for each transformer, new UG duct systems, new primary and secondary riser cables, ground grid upgrade, system neutral and station services (to feed new transformer and Kelman unit) and new Kelman DGA online monitor. Upgrade of existing protection & control will allow the facilitation of differential protection for the transformers. The new transformers will be sized as a 9/12/15MVA with LTR ratings of 22.5MVA for Winter and 19.5MVA for Summer.

Priority



Project Score: 1.02

Work Plan

The project will begin with the construction of the new switchgear lineup which will house all of the new feeder breakers. Once construction is complete, the old switchgear lineups can be cut-over to the new and decommissioned. Work can then commence on replacing both transformers and primary switchgear. One transformer will be replaced at a time in order to keep the station functional during the construction.

Customer Impact

The customers connected to Borden Farms DS will see an increase in service availability from this project reducing the risk of asset failures.

2.7.4 Bayshore Primary Circuit Switcher

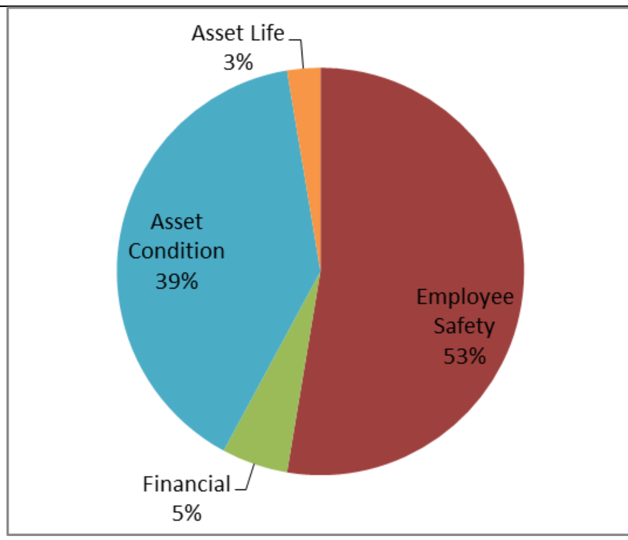
Project Name:	Bayshore Primary CS
Project Number:	92006411
Capital Cost:	$3,782,000
O&M:	N/A
Start Date:	2013 – Q1
In-Service Date:	2015 – Q2
Investment Category:	System Renewal
Main Driver:	Risk of Failure
Secondary Driver(s):	Reliability
Customer/Load Attachment	12MVA

Project Scope

The main driver for this project is to reduce the risk of failure due to aging assets. The existing primary disconnects switches have been in disrepair for a few years and there are concerns with the integrity of the supporting wall they are attached to.

This project will take the opportunity to update the primary protection to the current HOL practices by installing breakers which will serve to facilitate transformer differential protection.

Priority



Project Score: 1.14

Work Plan

This project is to replace the existing 44kV primary disconnect switches and tie switch with new 44kV primary air break switches and breakers. In addition, a new protection and control cabinet housing the controls for both circuit breakers, RTU, satellite clock, network switch, and power quality metering. The power quality metering will be measured by the existing CTs (in transformer and switchgear) and PTs in the existing switchgear. For differential protection from the secondary side perspective, new protection class CTs will be installed inside the existing switchgear. A new DC battery cabinet will also be installed. A feasibility study will be performed to determine how to install a primary side tie switch between both transformers. The subsequent design and construction for the tie switch & breaker will also be performed. The overhead bus inside the building will be replaced with underground cables (transformer secondary) and overhead cabling for secondary tie bus. The project design began in 2013 with the majority of the work taking place in 2014.

Customer Impact

Reliability improvements due to added protection of station transformers. Risk of outages and equipment damage is reduced.

2.7.5 Overbrook TO Switchgear Replacement

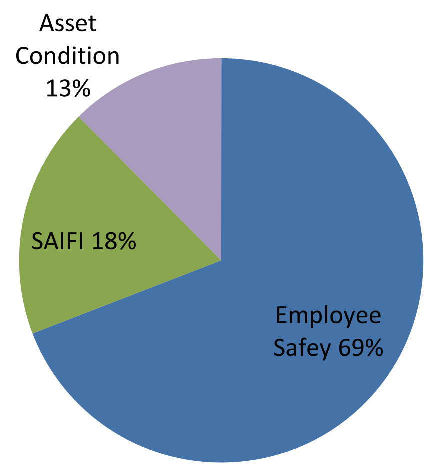
Project Name:	Overbrook TO Switchgear Replacement
Project Number:	92010241
Capital Cost:	$7.13 M
O&M:	N/A
Start Date:	2015
In-Service Date:	2018
Investment Category:	System Renewal
Main Driver:	Risk of Failure
Secondary Driver(s):	Reliability
Customer/Load Attachment	6,845 customers/ 89 MVA

Project Scope

This project involves replacing and upgrading assets at Overbrook TO and will include:

- Replacement of the 13.2kV switchgear and breakers
- New P&C, new cable between switchgear terminations and splices in the basement

Priority



Project Score: 1.447

Work Plan

The work plan for this project is as follows:

- Design and major equipment procurement occurring in 2016
- Delivery of equipment, installation, and energization will occur in 4 stages -1 stage per bus of the TO
  - Stage 1 (bus 1) -2016-2017
  - Stage 2 (bus 2) -2017
  - Stage 3 (bus 3) -2017
  - Stage 4 (bus 4) – 2017-2018
- Project to be completed by Q2 2018

Customer Impact

The primary driver of this project is to prevent risk of failure due to aging assets. This project will replace the existing switchgear with new arcproof switchgear, limiting risk to employee safety.

2.7.6 Startop Protection Upgrade

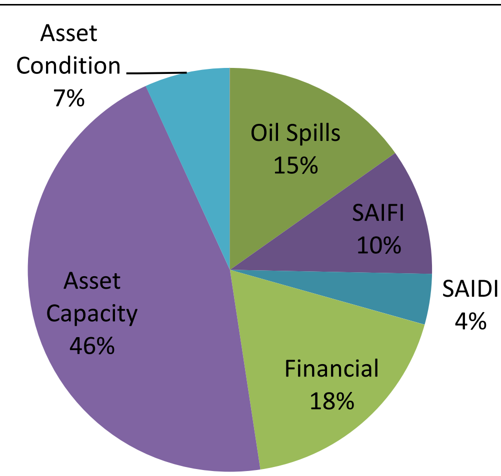
Project Name:	Startop Protection Upgrade
Project Number:	92007348
Capital Cost:	$4,768,000
O&M:	N/A
Start Date:	2013 – Q1
In-Service Date:	2015 – Q4
Investment Category:	System Renewal
Main Driver:	Risk of Failure
Secondary Driver(s):	Reliability
Customer/Load Attachment	16MVA

Project Scope

The project involves replacing and upgrading assets at Startop DS and will include:

- Replacement of two (2) existing transformers,
- Replacement of two(2) primary bus switches with breakers,
- Replacement of two (2) secondary bus switches with breakers,
- Installation of new tie breakers on both primary and secondary bus,
- Upgrade of existing station protection & control to include line protection, transformer differential and bus partial differential.

Priority



Project Score: 1.32

Work Plan

Project design will begin in 2013 with material procurement and construction commencing in 2014. The Startop T1 transformer will be in service by 2015 – Q1 and the remainder of the station by 2015 – Q4.

Customer Impact

The main driver for this project is reliability. HOL has identified that creating a loop of the 44kV sub-transmission feeder that supplies many of the City's east stations will greatly reduce the duration of unplanned system interruption. This study required Startop DS to install a primary tie breaker and upgrade the station's protection and control.

The goal is also to prevent the risk of failure due to aging assets. The scope of this project has expanded to include the replacement of the transformers and secondary bus breakers.

3 Pole Replacement

3.1 Project/Program Summary

The HOL overhead distribution system is supported both electrically and mechanically by a system of poles and fixtures. The reliability and safety of the overhead distribution is contingent on the performance of these poles and fixtures.

The pole replacement program replaces wood poles, and pole fixtures, on the overhead distribution system that are aged or in poor condition. Existing composite, concrete and metal poles, in general, are in good condition and will not require replacement.

Poles and fixtures will be replaced with an equivalent pole on a like-for-like basis. New poles are fully treated western red cedar. HOL's current practice is to replace porcelain insulators with ones made of a polymer material. The conductor will not typically be replaced at the same time as the pole as experience has shown very little failure rates resulting from conductors.

Under specific circumstances, a wood pole will be replaced with a new composite pole. Composite poles are of a fiber-reinforced material and are used in areas that have a high probability of woodpecker damage or when installed in high moisture soil conditions.

HOL recommends a replacement rate on average of 1,250 poles a year in 2016-2020, which represents 10% of the entire population of distribution poles. Increase in the amount of poles replaced during the rate filing period to 1,250 units from 600 poles in 2015 which reduces the risk of having poles in a critical or poor condition.

3.2 Project/Program Description

3.2.1 Assets in Scope

The poles targeted for replacement are either in poor or critical condition or are at high risk to degrade to poor condition in the next several years. This approach helps HOL to more effectively utilise the resources and increase customer satisfaction by avoiding multiple construction project set-ups in the same area.

The poles targeted for replacement in 2016 and 2017 are identified in the specific projects listed in Section 8 of this business case. Poles are also being replaced in voltage conversion projects which require the replacement of poor condition poles to accommodate the change in voltage. These poles have been identified based on the results on the annual inspection program performed by the utility, reports received from the construction and maintenance crews while performing their regular activities. HOL will use the same approach to identify poles for replacement in the remaining period, 2018-2020.

3.2.2 Asset Life Cycle and Condition

HOL owns 47,815 wood poles and 537 non-wood poles and operate on an additional 11,635 wood and 126 non-wood poles which are owned by third parties.

Currently, HOL has installation date information for approximately 25% of its poles. Those poles for which installation information is not available, install data has been estimated using manufacture date, estimated from the adjacent property legal records, or assumed to be equivalent to the average age of the known poles in that region (roughly 41% of asset group).

Typical lifecycle of wood poles is 45 years. The overall age demographics of wood poles in HOL's distribution system are shown in Figure 17. Percentage of wood poles that have passed end of life criteria is 40%. Majority of the poles, roughly 54%, were installed within the period of 1960 and 1990. Therefore, percentage of poles passed the end of useful life will grow to 52% by the end of rate filing period 2020. In addition, in the next ten year period in 2020-2030 another 16% of wood poles will reach the end of useful life.

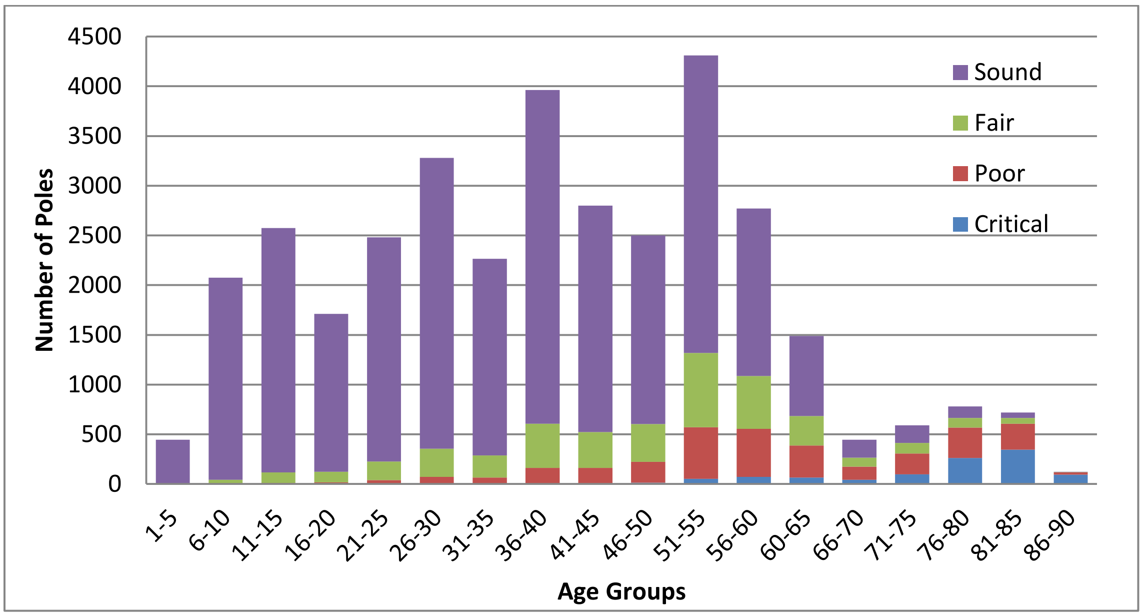


Figure 17 – Proportion of Wood Poles by Installation date and condition (Known and Estimated)

Wood pole health is assessed relative to the ability to perform its designed function: support overhead plant under anticipated maximum climatic stress. In general, this can be assessed as a function of a pole's remaining strength at the ground line (which is the area of maximum stress on a pole). As per Canadian Electrical Code - CSA 22.3, poles should be replaced once they fall below 60% of the required strength. HOL adopts this recommendation as key criteria for wood pole replacement decision. However, while remaining strength is a primary driver for evaluating pole condition there are other factors that are considered for replacement criteria. These factors include: shell condition, pole top condition, and woodpecker damage.

- Shell Condition – Weathering and external rot on the pole surface may not significantly impact the strength of the pole. However, it does impact the aesthetics and may present a safety hazard or impede HOL work if it is in a location where climbing the pole is required.

- Pole Top – Weathering and rot at the pole top will not significantly impact the strength of the pole. It will however increase the risk of pole hardware coming loose (due to bolts pulling through the wood). It is also unsightly and may present a perceived issue/concern to the public.
- Woodpecker Damage – Smaller holes are repairable and present predominantly aesthetic issues. Large woodpecker holes, depending on their location along the length of the pole, can significantly impact the strength of a pole. Woodpecker holes left un-repaired can potentially reduce the life of a pole, as the untreated pole heart-wood is exposed to elements which can lead to decay and insect attack.

The condition of the poles is assessed based on results obtained through an inspection program which entails a visual check and non-destructive Resistograph drilling introduced in 2010. It is utilized for the detection and measurement of internal decay and measurement of the remaining shell thickness with minimal damage to the pole. Visual inspection is conducted on all poles in a section of overhead line, and approximately 20% of the poles in each pole line are tested using the Resistograph drill, the results of which can be extrapolated to all poles within the section, or poles of similar vintage.

Required design strengths are based on the expected maximum climatic forces which the installation must endure. Even when a pole has reached end of life and/or that it has degraded to 60% or less of the required design strength, the actual failure of the pole is contingent on it being stressed by external forces approaching or equal to these maximal design conditions. Once a pole reaches end of life, it may remain standing and in service for many years before external forces result in a failure.

HOL performed earlier an analysis to correlate the pole condition to failures in order to develop a hazard curve and estimate the probability of failure at any given age. With the increased availability of inspection data for the distribution poles, current analysis has been carried out to correlate the remaining strength to pole age. The remaining strength to pole age correlation will become more accurate as more inspection data is collected every year.

Based on this analysis, poles have been grouped into 4 categories as shown in Table 13. The resulting pole distribution based on this model can be seen in Figure 18.

Group	Remaining Strength
Critical	Less than 25%
Poor	25 – 60%
Fair	60 – 75 %
Sound	75 – 100%

Table 13 - Pole Condition to Remaining Strength

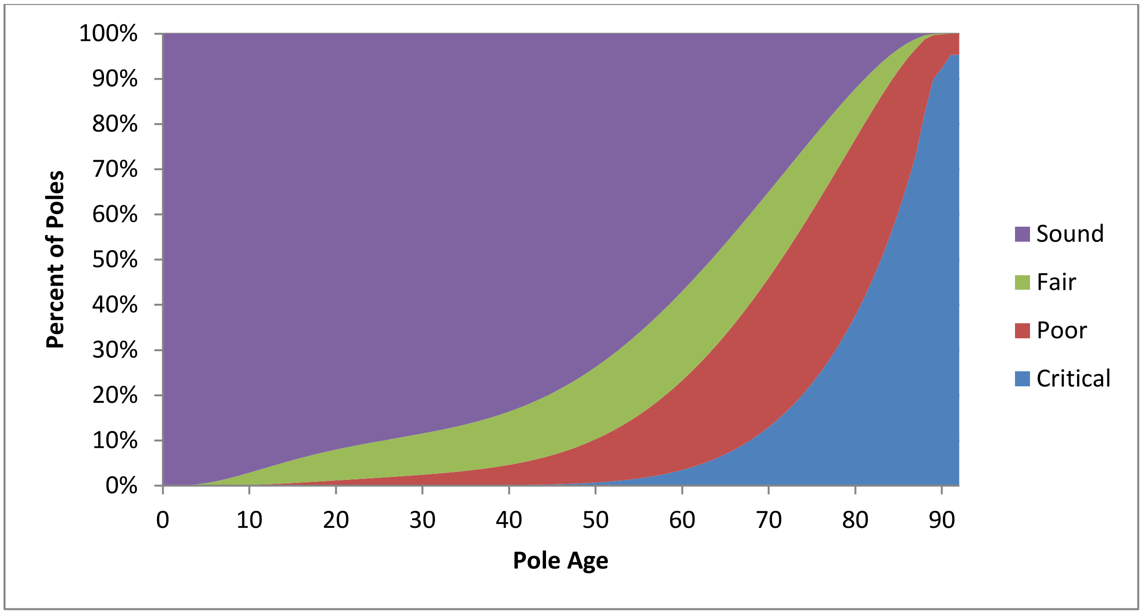


Figure 18 - Proportion of Wood Poles by Age

By extrapolating the results of the condition survey to the entire pole population, it is estimated that 4,901 wood poles exist in the field that are in poor or critical condition. Details of the wood pole condition are represented on Figure 19.

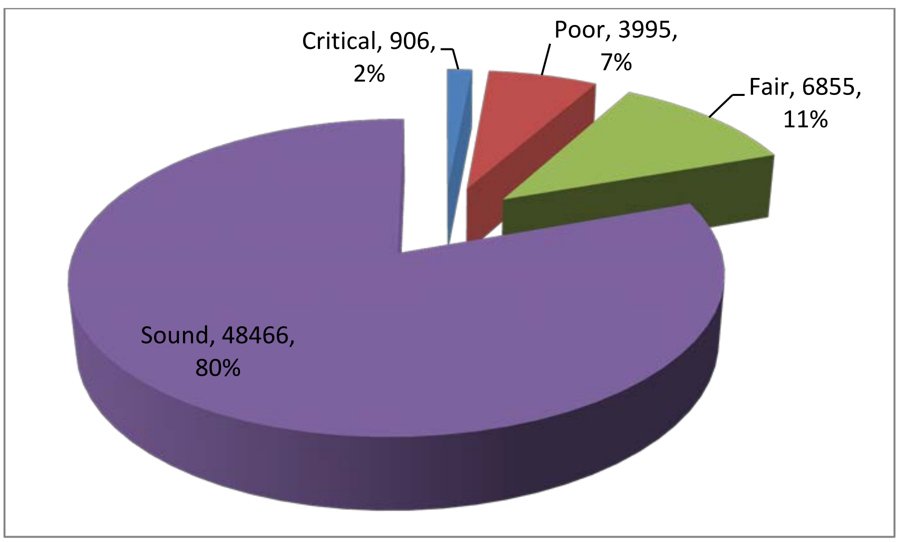


Figure 19 - Remaining Strength of HOL's Pole Population

Poles in poor or critical condition have technically failed as they no longer have the required strength to perform the function for which they are designed. They will not necessarily be identified and may not fail unless subjected to external forces approaching the design forces (i.e. severe wind storm). Based on average pole failures it is estimated that only 1 in 10 critical poles and 1 in 150 poor quality poles will fail annually. If this trend continues it will result in an annually increasing organizational risk due to the increasing number of poles which will not be able to weather severe storms.

The records of pole failures from 2009 to 2013, as shown in Figure 20, indicate an upward trend in the number of failures per year. Based on the data, the number of pole failures has been increased by 65% in 2013 from 2009 number.

An increasing trend with the experienced number of failures is indicative of the deterioration of the condition of poles. Therefore a more aggressive replacement plan is required to maintain system reliability.

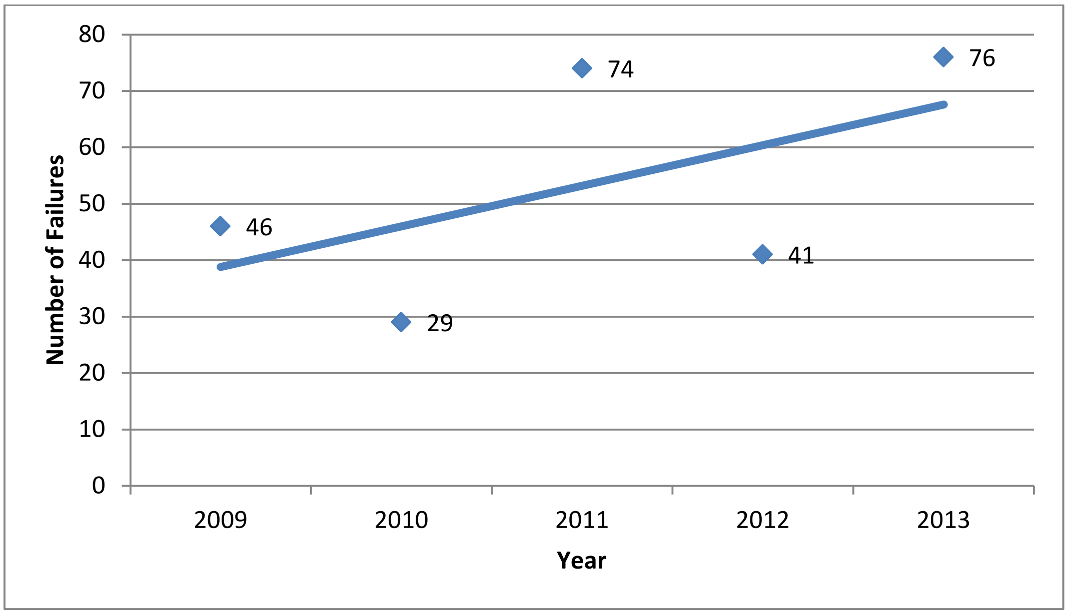


Figure 20 – Distribution Pole Failures

Pole fixtures are typically run-to-failure or are replaced in concert with the replacement of the pole (or other equipment) to which they are affixed. However, they do from time to time require proactive replacement in response to known design or manufacture defects. Issues have been encountered due to the failure of several styles of porcelain insulators.

3.2.3 Consequence of Failure

In general, pole failures will result in outages affecting customers connected to that pole. While outages as a result of pole failures are typically limited in customers impacted and duration, as the density of poor quality poles increases, the chance of cascading failures and simultaneous failures during severe weather also significantly increases. Such events can have a high impact on overall system reliability.

Figure 21 shows the Defective Equipment SAIDI & SAIFI contributed by overhead poles from 2009 to 2013.

In 2013, overhead poles contributed to 8.6 of the total SAIFI caused by defective equipment in that year.

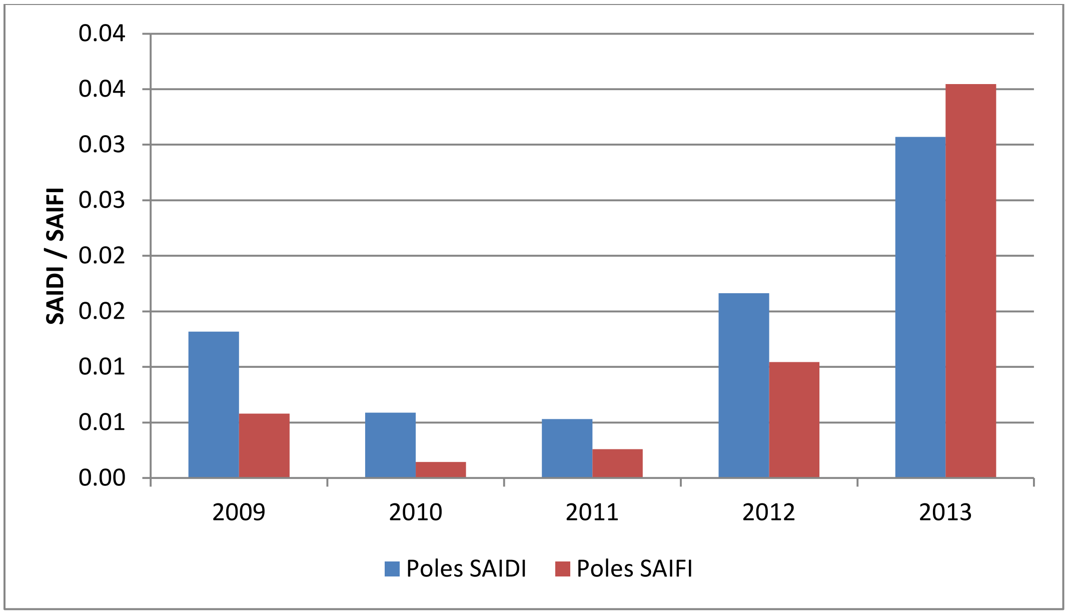


Figure 21 – Defective Equipment Poles SAIDI & SAIFI

When poles fail they also pose a significant safety risk to the public, employees and property as the result of downed wires and poles.

In addition, when a pole supports oil filled transformers there is the chance of environmental impact due to the release of oil.

3.2.4 Main and Secondary Drivers

The drivers are represented in the table below.

Driver		Explanation
Primary	**Failure Risk**	Percentage of wood poles that have passed end of life criteria is 40% that will grow to 52% by the end of rate filing period 2020. Approximately 9% of HOL's wood poles have been determined to be in poor or critical condition and require replacement. Increasing number of pole failures and impact on SAIFI
Secondary	**Safety**	Risks of pole failures leading to injuries of HOL employees and the public.

Table 14 - Wood Pole Replacement Main Drivers

3.2.5 Performance Targets and Objectives

HOL employs key performance indicators for measuring and monitoring its performance. With the implementation of the pole replacement program, improvements are expected in the following measurements:

- Defective Equipment SAIDI
- Defective Equipment SAIFI

3.3 Project/Program Justification

3.3.1 Alternatives Evaluation

3.3.1.1 *Alternatives Considered*

In order to address the drivers and achieve the performance objectives of the program HOL considered two alternatives for the pole standard to be used while replacing the pole as well as four alternatives for the replacement policy levels.

I. **Pole material standard**

Wood poles can be replaced on a like-for-like basis with an equivalent wood pole or with a pole made from a composite material.

II. **Pole Replacement Policy**

Using the degradation model developed for wood poles, HOL analyzed an impact of several replacement alternatives on the performance outcome. All the alternatives stabilize the replacement amount at the same level beyond 2016-2020 rate filing period. The following scenarios were analyzed:

- Run-to-Failure scenario with only reactive replacement of the poles,
- Status-Quo scenario (400 poles / year) by maintaining a pole annual replacement amount on the current level
- Replace 750 poles / year to maintain mid-term reliability levels
- Replace 1250 poles / year to maintain long-term reliability levels
- Replace 1500 poles / year to improve mid and long-term reliability levels

3.3.1.2 *Alternatives Evaluation*

HOL evaluates all alternatives with consideration of the following criteria:

Criteria	Description
Failure / Reliability	The increased potential of failure posed by these aging assets will impact the organization's ability to guard worker and public safety. The selected alternative shall maintain or improve the reliability performance of the system.
Safety	HOL puts the safety of its employees and the public at the center of its decision-making process. The preferred alternative must not impose additional risks on the safety of HOL's employees and the public.
Resource	Unplanned replacements are usually carried out by HOL's own crews, whereas planned replacements can utilize both internal and external resources. Therefore, alternatives that incur more on-failure replacements are less favorable as it will be more challenging from a resource perspective.
Financial	Financial costs and benefits shall include all direct and indirect impact on the utility's performance and rates. The preferred alternative shall be at least cost or the most beneficial in the long-term to the stakeholder and to the customers.

Table 15 – Alternative Evaluation Criteria

3.3.1.3 *Preferred Alternative*

I. **Pole material standard**

The preferred alternative is replacing the wood poles on a like-for-like basis. However, HOL considers the possibility of increasing the proportion of composite pole installations in the future.

Composite poles have been HOL's Standard for use in wood-pecker prone areas, as well as in areas where treated wood-poles cannot be used due to standing water.

Failure / Reliability

Composite poles are more likely to bend in severe winds compared to other materials decreasing the likelihood of a break. In addition, the composite material used cannot sustain fire.

The main drawbacks to the use of composite poles are that they cannot be climbed and are more susceptible to external damage from vehicles and snowplows.

Safety

Composite poles weigh significantly less than wood poles, reducing potential for strain injuries when poles are installed. They are also hydrophobic and non-conductive, reducing potential for second point of contact injuries, and help prevent arcing caused by lightning and switching.

Resources

Since the composite poles that HOL purchases are modular assemblies, an extra step is required to assemble composite poles before they are set in place.

Financial

HOL's data indicates that wood poles have a life span between 40 and in rare cases 92 years, and where external attack is prevalent shorter service life has been seen. Composite poles by contrast will not rot, splinter or decay, nor are they susceptible to insect or woodpecker damage. Composite poles will degrade due to exposure to UV light. HOL has trialed composite poles from RS Technologies. Their poles have been engineered for a minimum service life of 65 years in high UV environments such as Florida. In the less demanding climate it is anticipated that pole life could be expected to last 125 years.

Due to the composite pole material cost, the total installed cost is estimated to be roughly 1 to 11% higher than a wood pole in spite of its lower weight and modular design that reduces transportation and warehousing costs.

Other

Wood poles require deforestation (each pole is a tree), and requires chemical treatment in order achieve appropriate service life. By contrast, composite poles are manufactured from inert materials, preserving trees, and eliminating any leaching of preserving chemicals. They also result in lower emissions due to reduced transportation requirements.

With these benefits and potential savings and only moderate increase in direct capital costs, it is recommended that HOL considers the possibility of increasing the proportion of composite pole installations. While this will increase the capital costs in the short term, it will reduce overall program costs in the long term, while decreasing HOL's environmental footprint. With the increased minimum life of composite poles the life cycle capital costs for composite poles are expected to be on par or lower for composite poles (assumed minimum life wood-40 years, composite-70 years). Wood poles can be replaced on a like-for-like basis with an equivalent wood pole or with a pole made from a composite material.

II. Pole Replacement Policy

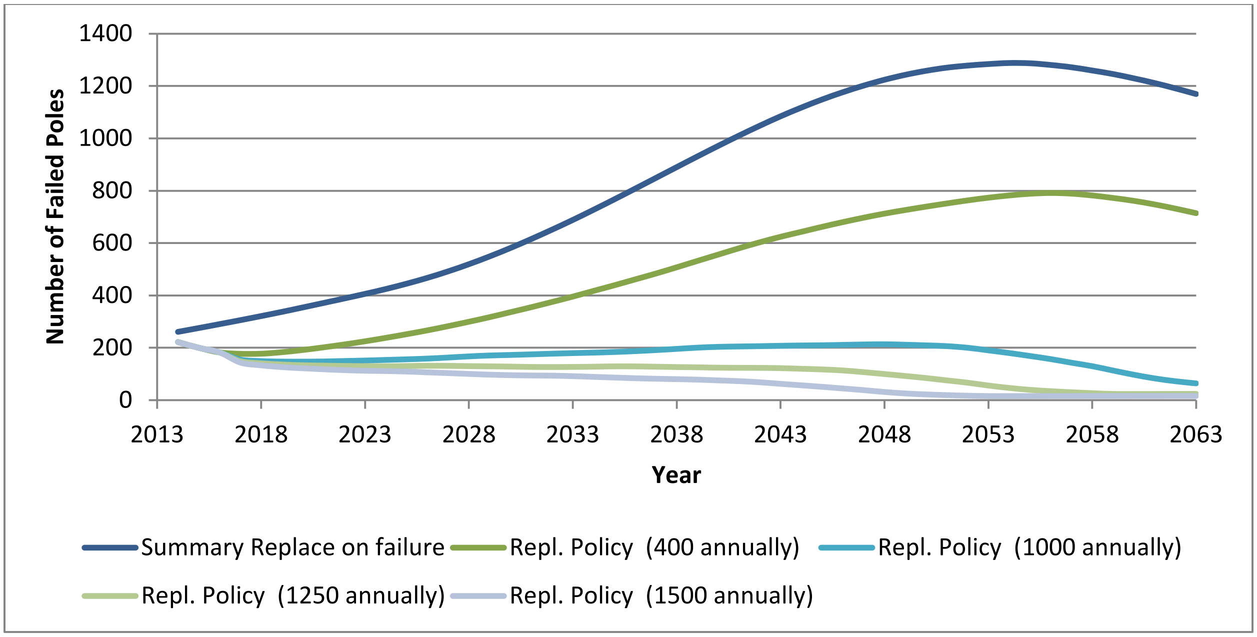
The preferred alternative is replacing the poles in poor and critical condition at 1,250 poles per year.

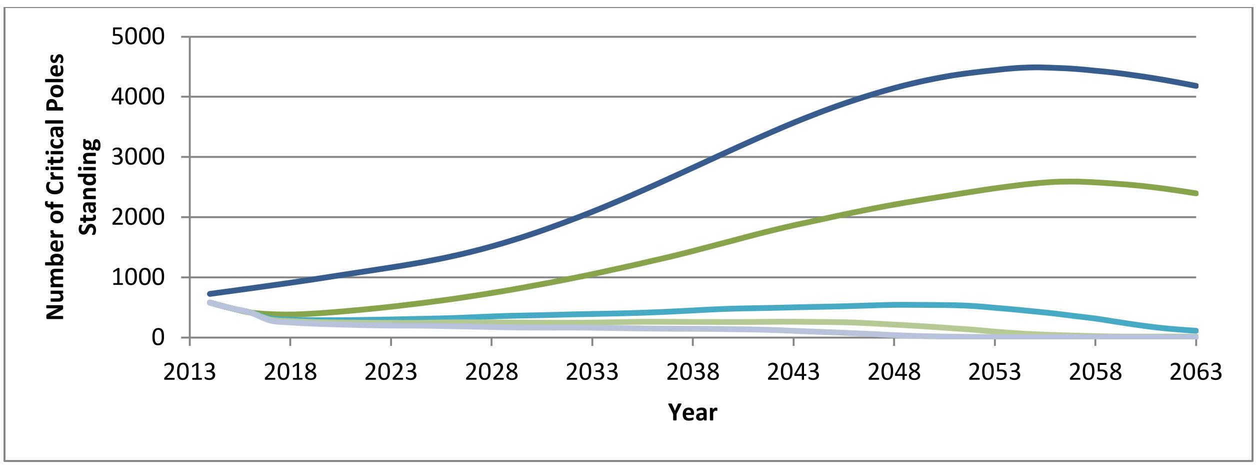
The 1,250 replacement level is based on an assumed 100% program efficiency, that is to say only the oldest and poorest condition poles are replaced first. This level of program efficiency does not occur in practice, rather as areas are targeted for replacement all poles within 5-10 years of end of life are replaced. This approach allows for financial efficiencies, and reduced customer inconvenience, over the piece-meal approach of only replacing poles currently at end of life. It is estimated that the replacement program is typically around 50% efficient, that is, 50% of the poles that are projected to fail annually are able to be replaced in a planned fashion. If the annual planned replacements exceed this value the remaining planned replacement are assumed to be the oldest poles in the system. In order to achieve the results as the 100% efficiency 1250 pole replacement program, 1300 poles annually would be required at 50% efficiency and 1558 poles at 25% efficiency. Based on this analysis it is recommended that roughly 1400 poles annually be targeted for replacement in order to achieve the desired results.

Failure / Reliability

HOL has analyzed the impact of several replacement policies using the degradation model developed for wood poles. Results of this analysis indicated that an increase of replacements to 1,250 poles annually would be required to manage failures while bringing the number of poles in critical and poor condition to an acceptable level.

Based on this analysis, it can be seen that an increase of replacements to 1,250 poles annually would be required to manage failures while bringing the number of poles in critical and poor condition to an acceptable level. The number of failed poles indicated in the first graph represents the number of poles that have reached end of life and/or degraded to 60% or less of the required design strength. The actual failure of the pole is contingent on it being stressed by external forces approaching or equal to these maximal design conditions.





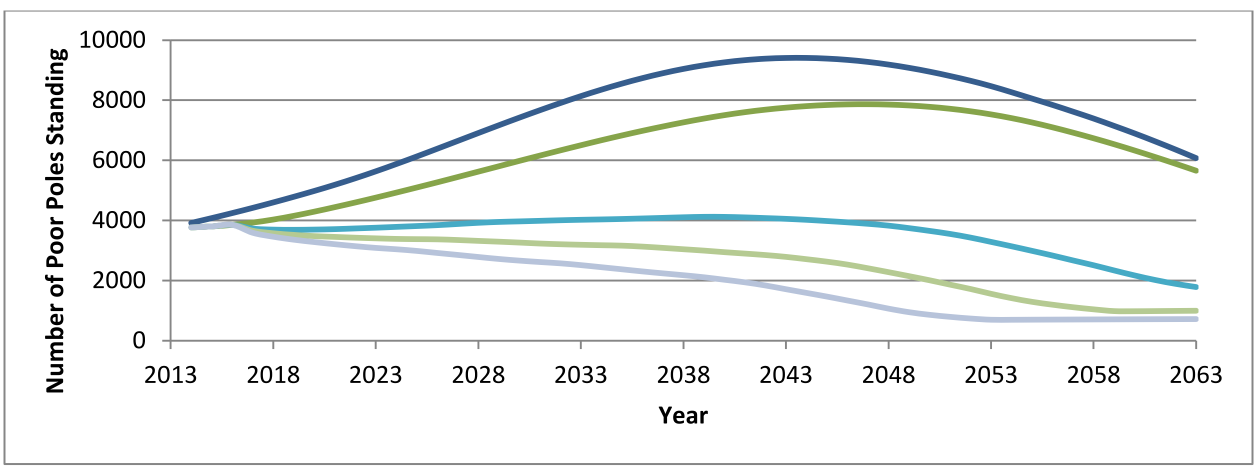


Figure 22 - Pole Forecast Under Different Replacement Policies

Safety

An increased pole replacement policy would minimize the risk to safety by reducing the number wood poles that are in critical and poor condition.

Resources

With assets on the system continuing to age and deteriorate, inadequate planned replacements of EOL assets will lead to accumulation of poor/critical assets and potential increase in unplanned replacements that will stress the available resources of HOL at its current staffing level.

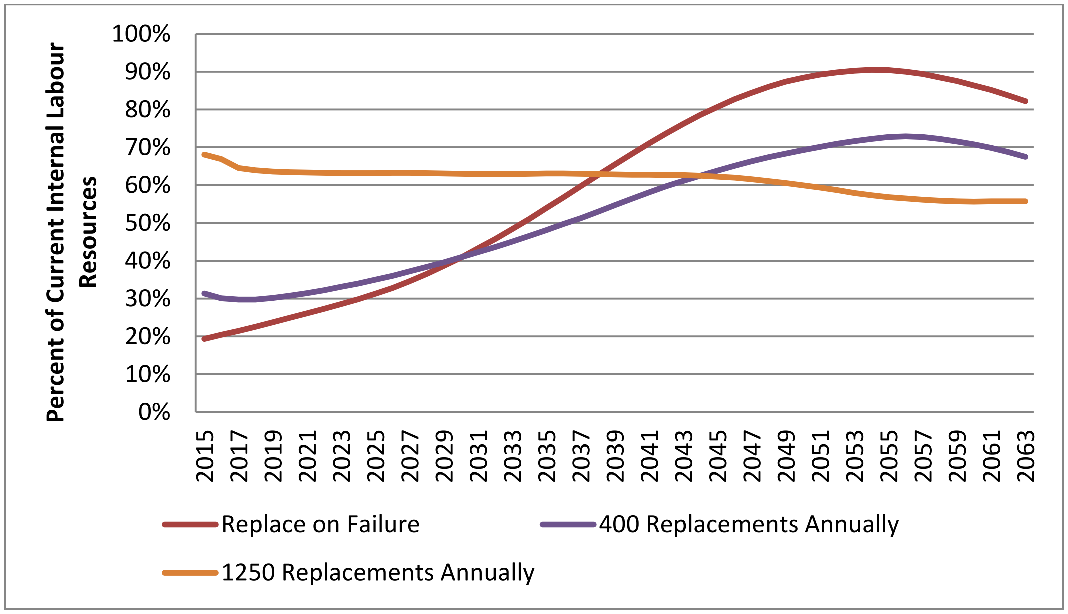


Figure 23: Labour Requirements

Estimated labor requirements for planned and unplanned pole replacement work are shown in Figure 23. With the proposed planned program, by 2063 unplanned pole replacements are anticipated to be reduced to approximately 2% of the available labour. Conversely, with a 400 annual replacement policy unplanned replacements account for 50% of the available labour. A planned labour approach allows for the program to be scaled from year to year and contractor resources to be brought in to assist in the replacement program. With the replace at failure approach the majority of replacements would require the use of internal resources. In addition, the unplanned work would not be divided evenly between years as shown. Plant failure trends show that while the average annual number of pole failures annually since 2005 is 42, the maximum occurred in 2013 with 76 failures – almost 200% of the average. If this trend holds true under a 400 poles annual replacement program the unplanned replacement labour requirement would be anticipated to fluctuate between 20% and 65% of current internal staffing levels.

Financial

The costs associated with replacing wood poles in an emergency situation has been estimated to upwards of double the cost of scheduled pole replacements. The do-nothing policy would see more frequent pole failures resulting in a high cost impact of replacing unscheduled poles. By increasing the replacement policy, the average costs to replace poles, scheduled and unscheduled, will be reduced and provide long-term financial benefit.

Replacing unscheduled poles also affects HOL's ability to complete other planned projects throughout the year. With a do-nothing approach, both labour time and budget resources will be taken away from scheduled work throughout the year by focusing on replacing unscheduled failed poles.

3.3.2 Project/Program Timing & Expenditure

Table 16 provides information on the expenditures and number of poles that were completed in the historical period. The average cost for replacing a pole in projects completed from 2010 to 2012 was $18,000, compared to the YTD cost per pole of $21,000 under this program. Poles are replaced in other programs such as voltage conversion, plant relocation, and service connections.

	Historical ($M)					Future ($M)				
	2011	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Total Expenditure	$5.47	$7.30	$6.00	$5.79	10.48	8.64	6.59	7.60	6.88	7.18
Units Replaced	372	374	257	210	500	411	313	362	328	342
Other Programs (New & Replaced)	598	557	820	845	N/A	N/A	N/A	N/A	N/A	N/A

Table 16 - Expenditure History of Comparative Projects

In 2013 & 2014, funds were moved from the pole replacement program to a system voltage conversion project which planned to replace poles to accommodate the change in voltage.

Specific pole replacement projects are coordinated to allow for optimal efficiency of crew resources by sub-dividing the work into suitable packages by geographic region or operational zones. To ensure cost-effectiveness, in conjunction with the pole replacement all pole fixtures are replaced and connecting transformers are reviewed and identified for replacement where required. In order to maximize system operation, phase balancing is also reviewed prior to pole replacement to see if any load connections should be relocated to a different phase during the work.

3.3.3 Benefits

Key benefits that will be achieved by implementing the pole replacement program are summarized in Table 17 below.

Benefits	Description
System Operation Efficiency and Cost-effectiveness	The costs associated with replacing wood poles in an emergency situation has been estimated to upwards of double the cost of scheduled pole replacements. The do-nothing policy would see more frequent pole failures resulting in a high cost impact of replacing unscheduled poles. By increasing the replacement policy, the average costs to replace poles, scheduled and unscheduled, will be reduced and provide long-term financial benefit.
Customer	Improvement to Defective Equipment related reliability statistics due to the decrease in pole and pole fixture failures.
Safety	Pole replacement reduces the risk of cascading failure of lines, thereby reducing the health and safety risk to employees and the public. Replacing

	poles that are located in areas that require climbing reduces the hazard to employees performing daily activities
Cyber-Security, Privacy	(Not applicable)
Co-ordination, Interoperability	(Not applicable)
Economic Development	HOL hires third party contractors to complete certain projects when the projects cannot be completed with its own internal resources.
Environment	Proactive replacement of end of life poles mitigates the risk of oil spilling from oil-filled transformers in the event of a pole falling down.

Table 17 – Pole Replacement Program Benefits

3.4 Prioritization

3.4.1 Consequences of Deferral

If this program is deferred to the next planning period or adequate replacement levels are not achieved this asset group will pose an increased risk to safety and reliability, as a result of the increased potential for cascading pole failures, and/or simultaneous pole failures during severe weather.

Deferral of pole replacements will also create a backlog of bad poles that will require more investment in the future. As evident in Figure 24, if increase in pole replacements is deferred until 2020 the annual pole replacements required to achieve the same results as increasing the number of pole replacements to 1,250 in 2016, would be 1,317.

A summary of the impact of different deferrals on forecasted pole failures is provided in Figure 24.

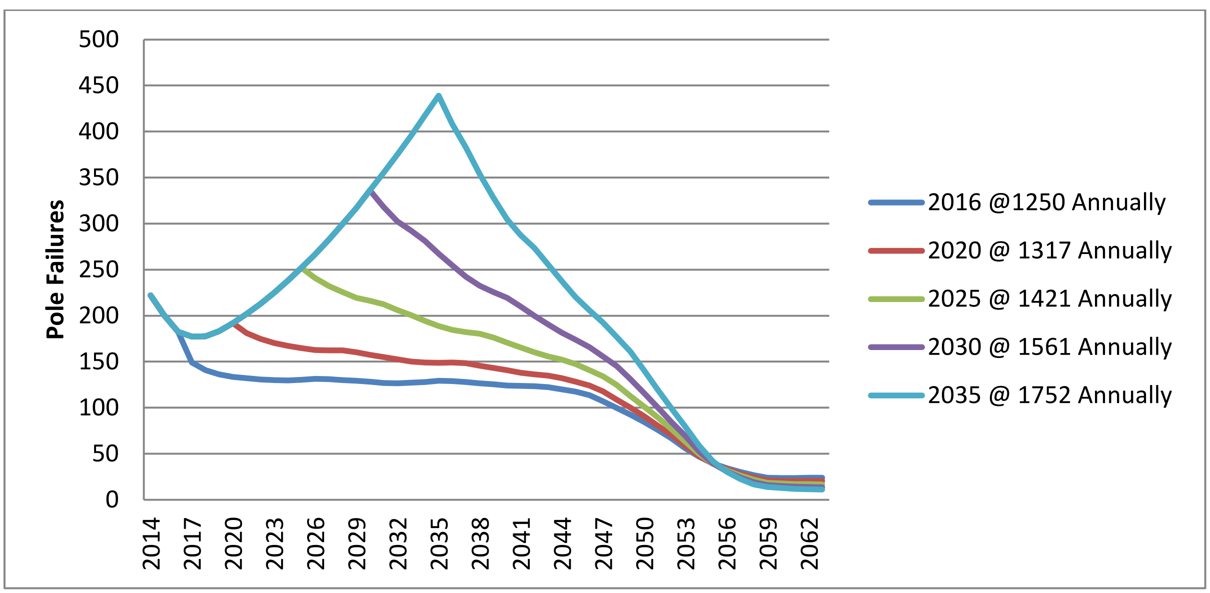


Figure 24: Impact of Deferral

3.4.2 Priority

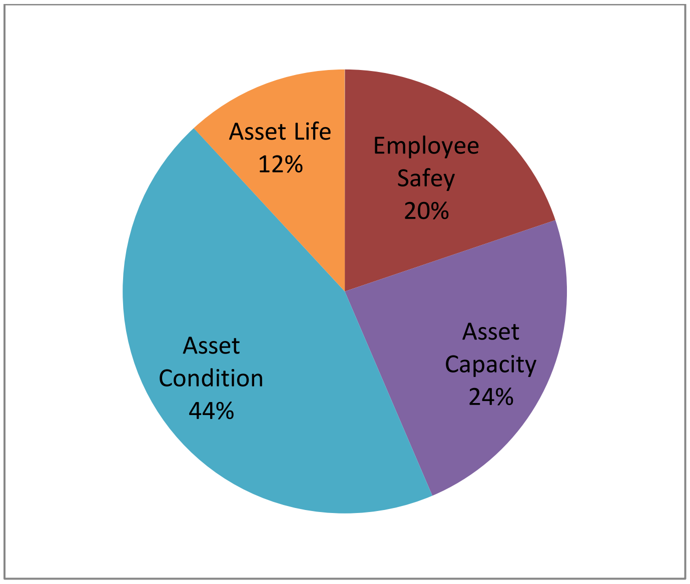


Figure 25 - Typical scoring for Pole replacement projects.

Typical Pole replacement project score: 1.01

3.5 Execution Path

3.5.1 Implementation Plan

HOL has prioritized pole inspections based on information about age of the distribution system and when it was built, and information from area construction crews.

The planned pole replacement projects will be prioritized based on the condition information retrieved from the inspections.

3.5.2 Risks to Completion and Risk Mitigation Strategies

Risk	Mitigation
Typical risks to completion include: • Obtaining road cut permits from the City of Ottawa; • Coordinating activities in areas where multiple parties are working; • Getting approval for traffic plans where required	It is standard practice to engage early and communicate plans for future work with the City of Ottawa to coordinate effort and potential resources.

Table 18 - Pole Replacement Risks and Mitigations

3.5.3 Timing Factors

Typical factors that affect timing of projects:

- Acquiring road-cut permits
- Availability of contractors
- Disconnecting customers for periods of time

3.5.4 Cost Factors

Typical factors that affect cost of replacement:

- Rock below grade
- Tree trimming
- Cable risers on poles

3.5.5 Other Factors

N/A

3.6 Renewable Energy Generation

(Not applicable for this program)

3.7 Leave-To-Construct

(Not applicable for this program)

3.8 Project Details and Justification

3.8.1 Centretown East Pole Replacement

Project Name:	Centretown East Pole Replacement
Project Number:	92008625
Capital Cost:	$7,416,239
O&M:	N/A
Start Date:	2014 – Q1
In-Service Date:	2016 – Q4
Investment Category:	System Renewal
Main Driver:	Risk of Failure
Secondary Driver(s):	Reliability
Customer/Load Attachment	135 customers/ 3000 kVA

Project Scope

This is a pole replacement project for EOL poles in the Centretown East area determined by pole testing and inspections programs. This project is scheduled to take place in several phases separated by area. To date a total of 12 phases of this project have been completed with 130 poles replaced with an estimated budget of $3,246,000. For 2015 a total of 5 phases are scheduled to be completed with 85 poles to be replaced with an estimated budget of $2,357,000. For 2016, 3 more phases are scheduled to be completed with 50 poles to be replaced with an estimated budget of 2,600,000. The variation in expenditure is due to the expected man hours, equipment needed, and plant that is being transferred or replaced. This is dependent on the physical location of the poles.

Priority

Score: 0.95

Work Plan

During pole replacement projects other assets are replaced such as transformers, switches and cables where necessary. Also, circuitry is updated where deemed necessary to bring older designs to current standards.

Work completed to date includes 12 phases in the following phases:

- Cartier Street: 20 Poles
- Gloucester Street: 4 Poles
- Cooper Street: 14 Poles
- Gilmour Street: 12 Poles
- Gladstone Avenue: 3 Poles
- McLeod Street: 12 Poles
- Park Avenue: 6 Poles
- Argyle Avenue: 14 Poles
- The Driveway: 6 Poles
- Robert Street: 4 Poles
- Waverly Street: 21 Poles
- Frank Street: 14 Poles

Work scheduled in 2015 includes 6 phases:

- Nepean Street: 13 Poles
- Lisgar Street: 13 Poles

• MacLaren Street: 24 Poles • Somerset Street West: 17 Poles • Bank and Catherine: 2 Poles • Metcalfe Street: 16 Poles (Started in 2014) Work scheduled in 2016 includes 2 phases: • Elgin Street: 24 Poles • O'Connor Street: 26 Poles
Customer Impact
This project will improve distribution system reliability and decrease the risk of asset failure in the planned areas.

3.8.2 64A3A – South East Kilborn Area Pole Replacement

Project Name:	64A3A – South East Kilborn Area
Project Number:	92008551
Capital Cost:	$1,054,000
O&M:	N/A
Start Date:	2015 – Q1
In-Service Date:	2016 – Q2
Investment Category:	System Renewal
Main Driver:	Risk of Failure
Secondary Driver(s):	Reliability
Customer/Load Attachment	278 customers / 1290 kVA

Project Scope

This is a pole replacement project consisting of 85 wood poles and secondary buss replacement including transformers. This project was identified by pole testing to the north side of Walkley road which showed poles in this area to have internal or external decay and rot. This option was decided given the dense area and the number of EOL poles, and the alternatives to replacement such as stubbing or remediation are not practicable at this time. During pole replacement projects other assets are replaced such as transformers, switches and cables. Also, circuitry is updated where deemed necessary to bring older designs to current standards.

Priority

Score: 1.01

Work Plan

The work plan is to install and replace 85 wood poles, transfer existing primary conductors & street lights, frame poles according to standards provided, install new dual voltage transformers, install 266 MCM pre spun bus secondary cable, remove existing poles and transformers. Work is scheduled to begin in Q1 – 2015 and will continue throughout the year.

This project will take place in 8 parts with the areas and the number of poles to be replaced in each area below.

- Part 1: Installation of 12 Poles on Lorraine Avenue
- Part 2: Installation of 13 Poles on Arizona Avenue
- Part 3: Installation of 6 Poles on Florida Avenue
- Part 4: Installation of 6 Poles on Palm Street
- Part 5: Installation of 8 Poles on Michigan Avenue
- Part 6: Installation of 11 Poles on Connecticut Avenue
- Part 7: Installation of 16 Poles on Featherston Drive
- Part 8: Installation of 13 Poles on Ryder Street

Customer Impact

This project will upgrade aging infrastructure which will increase the reliability in this area in the future. The ability of the system to operate through adverse weather without interruption will also be improved.

3.8.3 54B4A – Riverside Park South Pole Replacement

Project Name:	54B4A - Riverside Park South Pole Replacement
Project Number:	92008591
Capital Cost:	$4,565,301
O&M:	N/A
Start Date:	2015 – Q1
In-Service Date:	2015 – Q4
Investment Category:	System Renewal
Main Driver:	Risk of Failure
Secondary Driver(s):	Reliability
Customer/Load Attachment	100 customers/ 500 kVA

Project Scope

This is a pole replacement project taking place in an area south of Walkey Road, between the Airport Parkway and McCarthy Drive. Prior to commencing this project extensive pole testing done in this area shows lots of rotten poles. There are a total of 379 poles in this plot boundary. A total of 201 poles were identified to be replaced as part of this project. During pole replacement projects other assets are replaced such as transformers, switches and cables. Also, circuitry is updated where deemed necessary to bring older designs to current standards.

Priority

Score: 0.95

Work Plan

This project has been divided into two areas, East and West of McCarthy. Work is scheduled to begin in Q1- 2015 and will take place throughout the year.

For West of McCarthy, 103 poles will be replaced, 15 transformers as well as the transfer of all existing conductors, guys/anchors, street lights, pole dips as well as installing 266 MCM pre spun bus secondary cable. This area has been divided into 6 groups listed below.

- Group 1 Cowan: 21 Poles
- Group 2 Southmore: 20 Poles
- Group 3 Buxton: 20 Poles
- Group 4 Farmington: 13 Poles
- Group 5 Hartman: 20 Poles
- Group 6 Otterson: 9 Poles

For East of McCarthy, 98 poles will be replaced as well as the transfer of all existing conductors, guys/anchors, street lights, pole dips as well as installing 266 MCM pre spun bus secondary cable. This area has been divided into 7 groups listed below.

- Group 1 Marcel – Hyde – McCarthy: 22 Poles
- Group 2 McCarthy @ Southmore: 3 Poles
- Group 3 Southmore – Stanstead: 17 Poles
- Group 4 Southmore South Side: 13 Poles
- Group 5 Southmore South Side: 13 Poles
- Group 6 Garwood – Rand – Throndale: 26 Poles
- Group 7 Garwood @ Southmore: 4 Poles

Customer Impact

This project will increase the reliability and decrease the risk of asset failure in the area; also the ability of the system to operate through adverse weather without interruption is improved.

3.8.4 45B4 – Grandview Road Pole Replacement

Project Name:	45B4 – Grandview Road Pole Replacement
Project Number:	92006285
Capital Cost:	$1,085,809
O&M:	N/A
Start Date:	2015 – Q1
In-Service Date:	2015 – Q3
Investment Category:	System Renewal
Main Driver:	Asset Condition, Risk of Failure
Secondary Driver(s):	Reliability
Customer/Load Attachment	158 customers/ 2190 kVA

Project Scope

There are 80 poles to be replaced, pole testing results show that these poles are in bad condition and are approaching end of life. Includes both utility and service poles. Very few poles owned by Bell. Secondary is also being upgraded. Primary is not being replaced, except for ~250m along Hastings Street due to current poor condition.

Grandview Road north of Carling is a long, dead end street by the Ottawa River. HOL Limited is addressing all issues along this street so as not to require another project here.
Location: Grandview Road (North of Carling)

Priority

Score: 1.01

Work Plan

HOL Limited's West region crew will begin construction in March 2015. The West crew has been assigned this project in the South for scheduling purposes. Poles will be replaced along with secondary services, and old primary will be transferred to new poles. Along Hastings Street, new conductor will be installed.

Customer Impact

Reliability improvements due to new equipment and removal of end of life assets.

3.8.5 54A4C4 Pole Replacement

Project Name:	54A4C4 Pole Replacement
Project Number:	92008541
Capital Cost:	$694,764
O&M:	N/A
Start Date:	2015 – Q2
In-Service Date:	2015 – Q4
Investment Category:	System Renewal
Main Driver:	Asset Condition, Risk of Failure
Secondary Driver(s):	Reliability
Customer/Load Attachment	725 KVA
Project Scope	
27 poles in this area have reached end of life and are in need of replacement. Locaton: Cleopatra Drive, Caesar Avenue, Camelot Drive, Enterprise Avenue	
Priority	
Score: 0.95	
Work Plan	
• Replace 27 poles • Install 7 new overhead transformers • Install new fuses and replace secondary services at select locations	
Customer Impact	
Reliability improvements due to replacement of aged assets with new equipment.	

3.8.6 Centretown West Pole Replacement

Project Name:	Centretown West Pole Replacement
Project Number:	92010273
Capital Cost:	$6,680,865
O&M:	N/A
Start Date:	2016 – Q1
In-Service Date:	2017 – Q4
Investment Category:	System Renewal
Main Driver:	Risk of Failure
Secondary Driver(s):	Reliability
Customer/Load Attachment	650 customers/ 1600 kVA

Project Scope

This is a pole replacement project for EOL poles in the Centretown West area determined by pole testing and inspections. This project is scheduled to take place in several phases separated by area. For 2016, one phase (Gilmour Street) is scheduled to be completed with the replacement of 22 poles with a planned budget of $440,000. For 2017, ten phases are scheduled to be completed with the replacement of 105 poles with a planned budget of $2,237,000.

Priority

Score: 0.78

Work Plan

During pole replacement projects other assets are replaced such as transformers, switches and cables where necessary. Also, circuitry is upgraded where deemed necessary to bring older designs to current standards.

Work scheduled for 2016 includes 1 phase:

- Gilmour Street: 22 Poles

Work scheduled for 2017 includes 10 phases:

- Lisgar Street: 7 Poles
- Albert and Bay: 8 Poles
- Nepean Street: 14 Poles
- Laurier and Bay: 3 Poles
- Cooper Street: 11 Poles
- Gloucester Street: 11 Poles
- Slater Street: 8 Poles
- Kent Street: 29 Poles
- Somerset (west of Bank): 4 Poles
- Maclaren Street: 10 Poles

Customer Impact

This project will improve distribution system reliability and decrease the risk of asset failure in the planned areas.

3.8.7 Alphabet Avenue Pole Replacement

Project Name:	Alphabet Ave Phase 1 Pole Replacement
Project Number:	92010253
Capital Cost:	$1,223,795
O&M:	N/A
Start Date:	2016 – Q1
In-Service Date:	2016 – Q4
Investment Category:	System Renewal
Main Driver:	Risk of Failure
Secondary Driver(s):	Reliability
Customer/Load Attachment	287 customers/ 901 kVA

Project Scope

This is a pole replacement project that will target EOL 4.16kV poles along an area surrounding Avenue N to Avenue U including Tremblay Road both rear lot and front lot construction. The conditions of poles are tested on an ongoing basis. Areas with poles which are determined to be in the poorest condition are identified for replacement. The project is still in the preliminary stages, but at this point it is estimated that approximately 65 poles will need to be replaced as part of this project.

During pole replacement projects other assets are replaced such as transformers, switches and cables. Also, circuitry is updated where deemed necessary to bring older designs to current standards and protection on all distribution laterals will be added.

Priority

Score: 0.92

Work Plan

Work for this project is scheduled to begin in Q1 – 2016. Pole replacement projects continue throughout the year. In certain cases considerations of the customers must take place which adjusts the dates of the work plan.

Customer Impact

This project will increase the reliability and decrease the risk of asset failure in the area. The ability of the system to operate through adverse weather without interruption will also be improved.

3.8.8 Prince of Wales & Greenbank South of Barnsdale Pole Replacement

Project Name:	Prince of Wales & Greenbank South of Barnsdale
Project Number:	92006287
Capital Cost:	$2,456,004
O&M:	N/A
Start Date:	2016 – Q1
In-Service Date:	2016 – Q3
Investment Category:	System Renewal
Main Driver:	Reliability
Secondary Driver(s):	Voltage Conversion
Customer/Load Attachment	1.73MVA

Project Scope

Poles are approaching end of life and require replacement. The South Nepean area will be converted to 27.6kV within the next few years, so preparation for voltage conversion will be done in conjunction with pole replacement. 2 circuits will be held on new pole line.
Poles along Greenbank Road are owned by Bell Canada, and will require Joint Use agreement to replace. Approximately 23 Bell Poles and 43 HOL Poles.

Out of Scope: Replacement of poles on Barnsdale Road and Viewbank Road, extending line to Bankfield (Stopping 2-3 spans after Greenbank/Prince of Wales intersection) as location of proposed station is not yet decided.

Priority

Score: 1.01

Work Plan

Installation of 60 foot poles to accommodate 2 ccts of 556mcm, 336mcm tensioned neutral, 46kv rated insulators, dual high voltage transformers, poles re-spanned to eliminate the existing long spans which are non-standard. Anchor easements will be attained.

Customer Impact

Reliability improvements due to new equipment and looped circuit supply.
Additional capacity to support new development once voltage conversion takes place.

3.8.9 Trans-Canada Trail Pole Line (Eagleson to Terry Fox)

Project Name:	Trans-Canada Trail Pole Line (Eagleson to Terry Fox)
Project Number:	92010158
Capital Cost:	$670,228
O&M:	$0
Start Date:	2016 – Q1
In-Service Date:	2016 – Q4
Investment Category:	System Renewal
Main Driver:	Risk of Failure
Secondary Driver(s):	Reliability
Customer/Load Attachment	6294 customers/ 13856 kVA

Project Scope

The main driver of this project is to convert an overhead distribution to underground. The scope of this project has recently changed due to the City of Ottawa considering the use of the Trans-Canada trial line as an option for LRT in the future. The pole line along the Trans Canada Trail has reached EOL and begun failing.

The current 27.6kV line along the Trans-Canada Trail will be moved to Michael Cowpland Drive and run parallel to an existing 27.6kV line up to Eagleson Road coming out of Terry Fox MTS. The 27.6kV feeder will make use of existing concrete encased duct structure existing on Michael Cowpland Drive.

The 8.32kV overhead line along the Trans-Canada Trail will eventually be converted to an underground 27.6kV circuit.

Priority

Score: 0.95

Work Plan

- Pull cables through underground duct
- Install new risers and make all connections
- Remove overhead distribution equipment
- Conversion of distribution equipment from 8.32kV to 27.6kV

Customer Impact

This project will increase the reliability of service in the area, and decrease the risk of asset failure.

4 Distribution Transformer Replacement – Polemounted

4.1 Project/Program Summary

The polemounted transformer asset class includes roughly 16,000 service transformers which convert electrical power from its primary distribution voltage to service level voltage, nineteen (19) step transformers which convert from one primary distribution voltage to another and three (3) voltage regulators. The polemounted distribution transformer replacement program focuses on the optimal the time to replace an asset just before it fails. Inspections help identify the condition of the transformers so that they can be prioritized and replaced.

4.2 Project/Program Description

4.2.1 Assets in Scope

The HOL overhead distribution system uses three types of pole mounted transformers to convert electricity from medium distribution voltage to a lower distribution voltage or to a service level voltage as well as for voltage regulating. Step transformers are used to convert medium distribution voltage to a lower distribution voltage which are used for reliability back-up and avoid extensive costs by completing a voltage conversion. Service level voltages are used to supply residential, commercial, and industrial customers. Voltage regulators are used to regulate the medium distribution voltage on long lines experiencing voltage drops below the minimum allowable ±6% of system voltage.

The reliability of the overhead distribution system is dependent on the performance of step transformers and voltage regulators due to their integration into the trunk of the system. Failures of service transformers are less impactful to the overhead system because they have means of disconnection through a fuse in the event of the failure.

Polemounted transformers are replaced for numerous reasons including: asset failure, leaking oil, voltage conversion, insulator degradation identified by IR scans, and in conjunction with pole replacement. The transformers that experience failure are replaced with a like-for-like transformer in order to provide electricity to the customer in a timely manner. Replacement completed during other projects will generally be like-for-like as well, however, the loading is assessed and there is the possibility for a smaller or larger capacity transformer to be used for economic or environmental benefits.

In addition, it is HOL’s standard to replace polemounted transformers with like-for-like, but includes installation of animal guards on the bushings of the transformer. This is due to the high number of failures experienced on the overhead system due to animals making contact between the primary wire and the grounded transformer case.

Federal Regulation SOR 2008-273 dictates that all polemounted equipment with oil containing PCBs in concentrations of 50 mg/kg or greater must be removed from service by 2025. There are 150 known PCB containing HOL polemounted transformers remaining in service, and 2 voltage regulators. As a result of the regulatory obligations, HOL has elected to take an accelerated approach to remove these remaining transformers from service. Aging infrastructure work will be superseded by the removal of the remaining PCB containing transformers, expected to be complete in 2016. Two of the six voltage regulators contained concentrations of PCBs in excess of 50mg/kg and all six were replaced with three (3) new units in 2014.

HOL recommends an annual replacement rate of 250 polemounted transformers per year which represents 1.6% of the entire population of polemounted transformers. Under these scenarios transformers are still expected to fail, but the level of failures will be kept constant, if not reduced due to the proactive replacement.

4.2.2 Asset Life Cycle and Condition

HOL owns 16,000 service transformers, nineteen (19) step transformers and three (3) voltage regulators.

Currently, HOL has installation or manufactured date information for approximately 97% of its polemounted service transformers, 89% of the step transformers and 100% of the voltage regulators. The voltage regulators contain concentrations of PCBs in excess of 50mg/kg and are to be replaced in 2014.

Typical lifecycle of polemounted transformers is in the average of 90 years. The percentage of polemounted transformers that have passed end of life criteria is 1% and is expected to reach 2% by 2020.

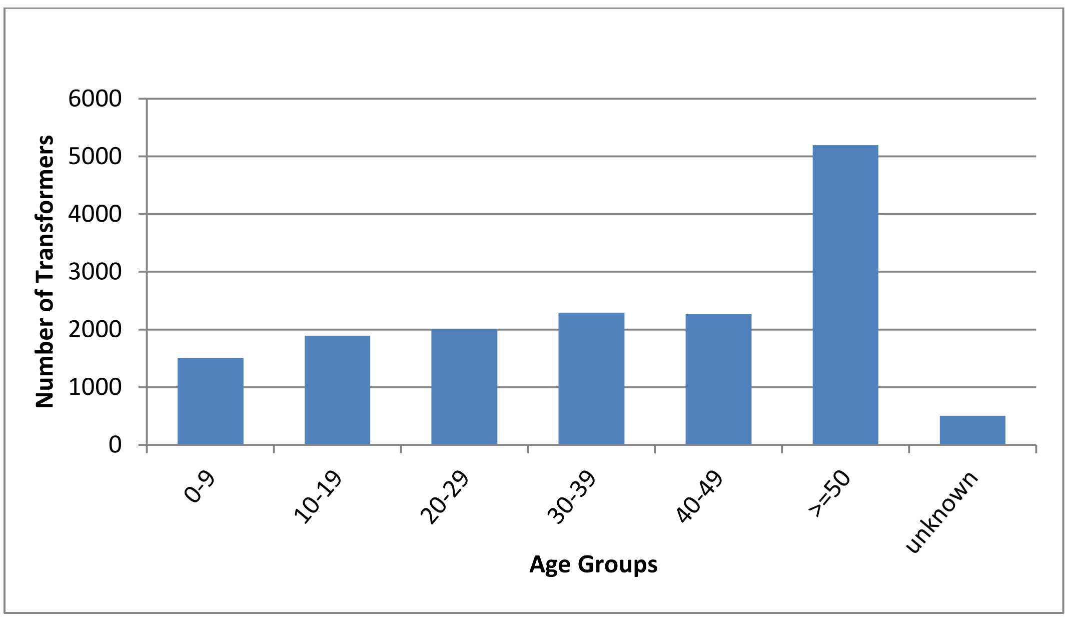


Figure 26 - Age of Service Transformers

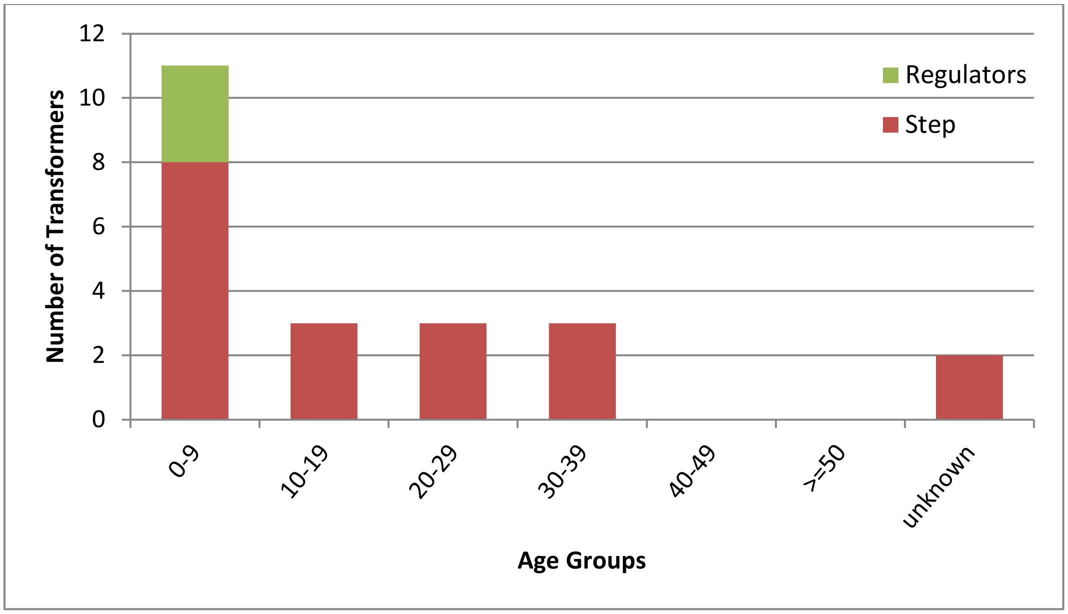


Figure 27 - Age of Step Transformers & Voltage Regulators

Infrared (IR) and inspections are also carried out on polemounted transformers. HOL attempts to inspect these transformers on a three year cycle. Most of the problems identified can be mitigated by cleaning connections, replacing minor components, or tightening connects, thus avoiding the need to replace the entire asset.

In order to effectively use the IR scanning information, an equipment health index was created for all IR scanned equipment. This can be seen below. The condition rating is based on the temperature difference between the reference temperature and the equipment's actual measured temperature.

Critical - (>75°C), immediate repair
Major Problem - (>36°C-75°C), repair as soon as possible
Intermediate - (>10°C- 36°C)
Minor - 10°C or less

Table 19 - Infrared Condition Rating

The records of polemounted transformer failures from 2009 to 2013 indicate an upward trend in the number of failures per year. Based on the data, the number of polemounted transformer failures has increased by 24% in 2013 from 2009. Increasing number of failures indicate an increasing condition deterioration of polemounted transformers due to aging transformers. Therefore an aggressive replacement plan is required to maintain the number of failing transformers.

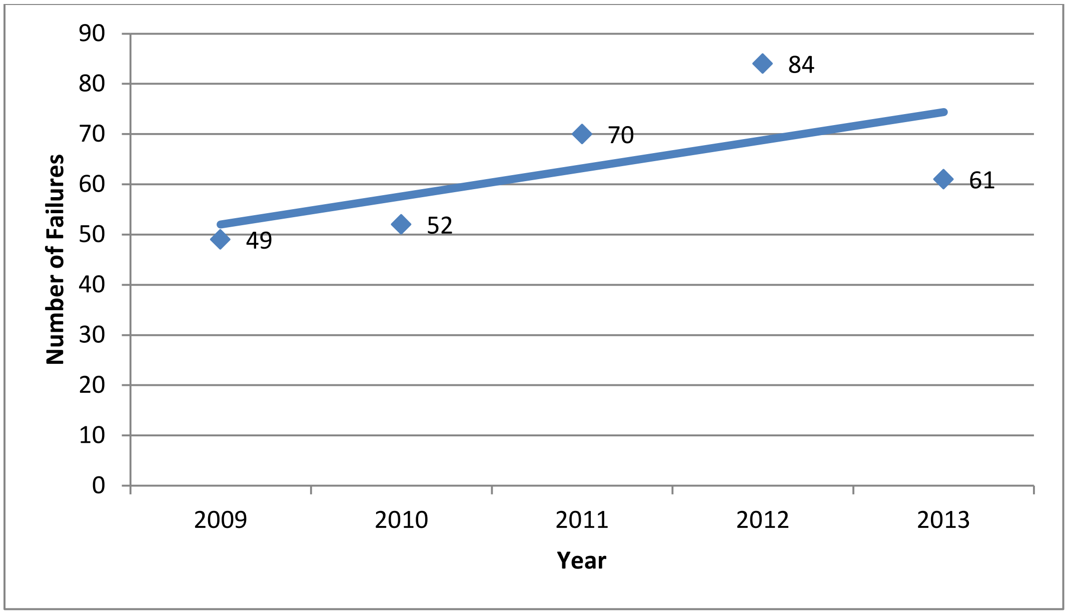


Figure 28 - Polemounted Transformer Failures

The majority of failures experienced on polemounted transformers are a result of animals making contact between the primary wire and the grounded transformer case. It is HOL's standard to replace polemounted transformers with like-for-like, but includes installation of animal guards on the bushings of the transformer. This is expected to reduce the number of failures of polemounted transformers.

Polemounted transformers are typically run-to-failure or are replaced in conjunction with projects such as pole replacement or voltage conversion. However, they do from time to time require proactive replacement in response to known defects identified through IR and visual inspection. Issues have been encountered due to loose connections, equipment overload, cracked bushings, exposed electrical hazards, etc.

4.2.3 Consequence of Failure

Polemounted transformers have a low probability of failure due to the number of transformers exceeding the average life of a polemounted transformer and are more susceptible to failure due to animal contact. The three-year rotational visual inspection and IR scanning identifies transformers before failure so that proactive replacement can be completed. The consequence failure includes some or all of the following:

- Customer outage effects. This will include "event" effects due to the outage (SAIFI), "duration" effects (SAIDI), and effects on critical customers;
- Health and safety consequences; and
- Environmental consequences.

Polemounted transformers have been forecasted under different replacement policies. Based on this analysis, replacement of roughly 250 units annually is required to reduce annual failures from the 61 seen in 2013 to a more averaged number of failures around 40. Given the low correlation between risk of failure and age, and the renewal impact of polemounted PCB replacements at this time, proactive replacement of this asset is not recommended.

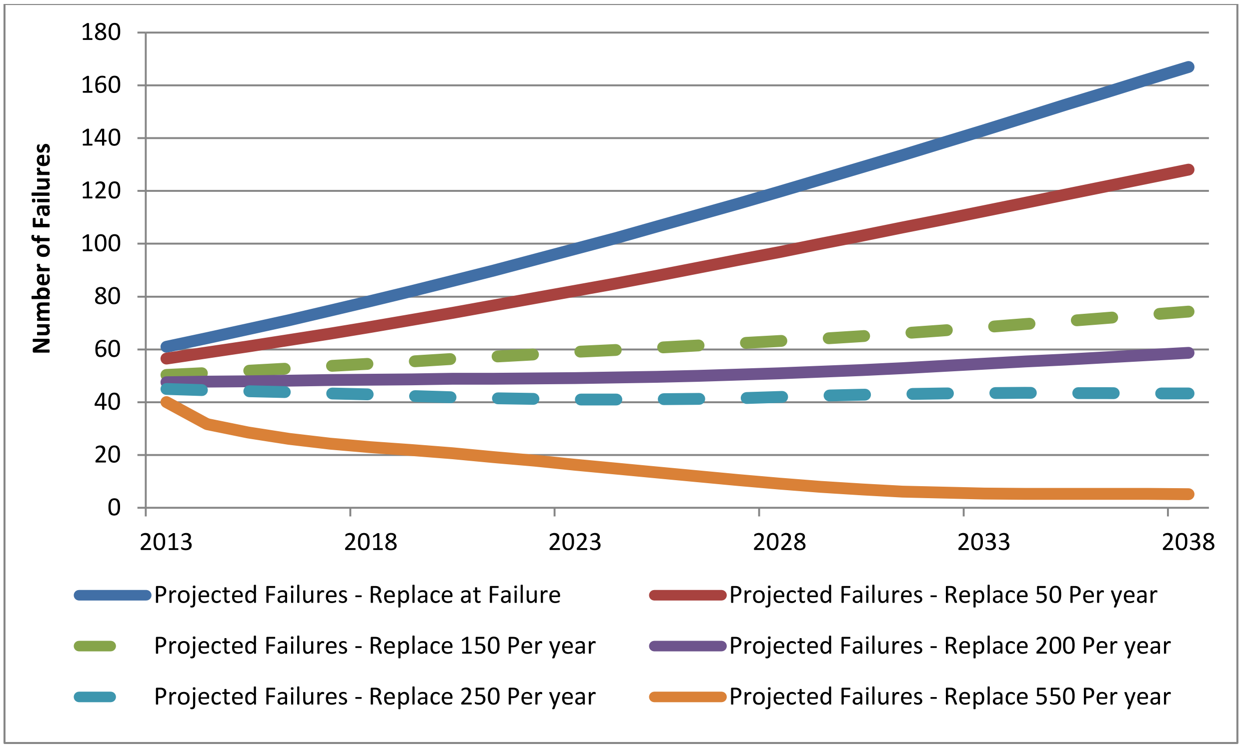


Figure 29 - Polemounted Transformer Recommended Replacement Rates

4.2.4 Main and Secondary Drivers

The drivers are represented in the table below.

Driver		Explanation
Primary	**Failure Risk**	1% of the polemounted transformers have exceeded their life expectancy, totalling 186. It is estimated that the number will grow to 246 by the end of 2020.
Secondary	**Safety**	Risks of the polemounted transformer failure could lead to potential injuries to the public as a result of being located on poles above the ground and have the potential to fall.
Tertiary	**Environment**	Risks of the polemounted transformer failure could lead to potential release of oil into the environment.

Table 20 - Polemounted Transformers Replacement Program Main Drivers

4.2.5 Performance Targets and Objectives

Targets of the distribution polemounted transformer replacement program are to continue on the current path of replacing polemounted transformers containing PCBs in accordance with regulation SOR 2008-273 and in conjunction with other projects, while maintaining current failure rates.

4.3 Project/Program Justification

4.3.1 Alternatives Evaluation

4.3.1.1 *Alternatives Considered*

In order to address the drivers and achieve the performance objectives of the replacement program, HOL considered four alternatives for the replacement policy levels. Using the degradation model developed for polemounted transformers, HOL analyzed an impact of several replacement alternatives on the performance outcome. All of the alternatives, other than run-to-failure, stabilize the replacement amount beyond 2016-2020 rate filing period. The following scenarios were analyzed:

1. Run-to-Failure scenario with only reactive replacement of the transformers
2. Replace 200 polemounted transformers per year to maintain a mid-term reliability level
3. Replace 250 polemounted transformers per year to maintain a mid-term reliability level
4. Replace 550 polemounted transformers per year to maintain a mid-term reliability level

4.3.1.2 *Evaluation Criteria*

HOL evaluates all alternatives with consideration of the following criteria:

Criteria	Description
Failure / Reliability	The increased potential of failure posed by these aging assets will impact the organization's ability to guard worker and public safety. The selected alternative shall maintain or improve the reliability performance of the system.
Safety	HOL puts the safety of its employees and the public at the center of its decision-making process. The preferred alternative must not impose additional risks on the safety of HOL's employees and the public.
Resource	Unplanned and planned replacements utilize internal resources. Alternatives that incur more on-failure replacements are less favorable as it will be more challenging to gather resources on as needed basis.
Financial	Financial costs and benefits shall include all direct and indirect impact on the utility's performance and rates. The preferred alternative shall be at least cost or the most beneficial in the long-term to the stakeholder and to the customers.

Table 21 – Alternative Evaluation Criteria

4.3.1.3 *Preferred Alternative*

The preferred alternative is to target replacement of the worst conditioned polemounted transformers at a rate of 250 transformers annually. Since specific projects are not identified within the distribution polemounted transformer replacement program, except for the PCB removal projects, the 250 transformer annual replacement is the optimal replacement level that is completed in conjunction with other projects like pole replacement and voltage conversion projects.

Alternatives and their associated benefits with regards to reliability, safety, resources and finances, are discussed for each alternative below:

Failure / Reliability

HOL has analyzed the impact of several replacement policies using the failure rate model developed for polemounted transformers. Results of this analysis indicated that an optimal replacement rate of 250 transformers annually would be required to manage failures and keep them from increasing yearly.

Increasing the number of polemounted transformers replaced annually would minimize the number of transformers that are likely to fail. Installation of animal guards on all replaced transformers will also reduce the number of failures and impact on reliability.

Safety

Increasing the number of polemounted transformers replaced annually would minimize the risk to safety by reducing the number of transformers that are likely to fail based on age.

Resources

With assets in the system continuing to age and deteriorate, inadequate planned replacements of aging transformers will lead to accumulation of end of life assets. This has the potential to increase unplanned replacements that will stress the available resources of HOL at its current staffing level. Planned polemounted transformer replacements are much more easily handled due to the ability to schedule work rather than replacing upon failure which is done as soon as possible.

Financial

The cost associated with replacing polemounted transformers in an emergency situation has been estimated to be substantially higher than the cost of scheduled transformer replacements. This can be due to many factors including over time labour and express ordering equipment that was used as an emergency replacement. The do-nothing policy would see more frequent transformer failures resulting in a high cost impact of replacing unscheduled polemounted transformers. By increasing the replacement policy, the average costs to replace a transformer, scheduled and unscheduled, will be reduced and provide long-term financial benefit.

Replacing unscheduled polemounted transformers also affects HOL's ability to complete other planned projects throughout the year. With a do-nothing approach, both labour time and budget resources will be taken away from scheduled work throughout the year by focusing on replacing unscheduled failed transformers.

4.3.2 Project/Program Timing & Expenditure

Historically there have been no expenditures for proactive polemounted transformer replacement due to the assets being run-to-failure. However, from inspection information, transformers have been deemed end of life and scheduled for replacement when resources were available. As described in section 2.1, a project to replace the voltage regulators was completed in 2014 due to their condition. HOL has also complied with the federal regulation SOR 2008-273 of replacing equipment that contains greater than 50mg/kg of PCBs. The costs associated with the replacement of polemounted transformers are shown in below.

	Historical ($M)				Future ($M)					
	2011	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
End of life	$0.005	$0.001	$0.050	$0.024	-	-	-	-	-	-
PCBs	$0.124	$0.011	$0.002	$0.421	$0.615	$0.365	-	-	-	-

Table 22 – Polemounted Transformer Replacement Program Historical and Future Spending

Specific polemounted transformer replacements are coordinated to allow for optimal efficiency of crew resources by sub-dividing the work into suitable packages by geographic region or operational zones. To ensure cost-effectiveness, in conjunction with the pole replacement all pole fixtures are replaced and connecting transformers are reviewed and identified for replacement where required. In order to maximize system operation, phase balancing is also reviewed prior to pole replacement to see if any load connections should be relocated to a different phase during the work.

4.3.3 Benefits

Key benefits that will be achieved by implementing the distribution polemounted transformer replacement program are summarized in Table 23 below.

Benefits	Description
System Operation Efficiency and Cost-effectiveness	Costs associated with a failed transformer are significantly higher than planned replacement. Aging and deteriorating transformers increase the risk of failure and safety concerns. This alternative is the most effective means to minimize the potential safety and reliability risks associated with failed polemounted transformers.
Customer	System reliability will be preserved as the number of failed transformers will remain constant which will cause outages to very few customers annually.
Safety	Public safety is maintained as polemounted transformers are located above ground on poles; a falling transformer has the possibility of incurring serious injury to the public.
Cyber-Security, Privacy	N/A
Co-ordination, Interoperability	N/A
Economic Development	N/A
Environment	Transformers encase oil as a cooling medium and have the potential for oil leaks. These transformer cases are unable to contain oil if they have cracks or holes and oil will be spilt into the environment.

Table 23 - Polemounted Transformers Program Benefits

4.4 Prioritization

4.4.1 Consequences of Deferral

The run-to-failure replacement strategy is the ongoing directive of the program year after year. It cannot be deferred and therefore has no consequence of deferral. The preferred alternative of proactive replacement of 250 polemounted transformers annually would see an impact from deferral. The positive impacts discussed in section 3.3 would be neglected to the date at which the alternative began. This would also see a buildup of polemounted transformers at end of life condition.

4.4.2 Priority

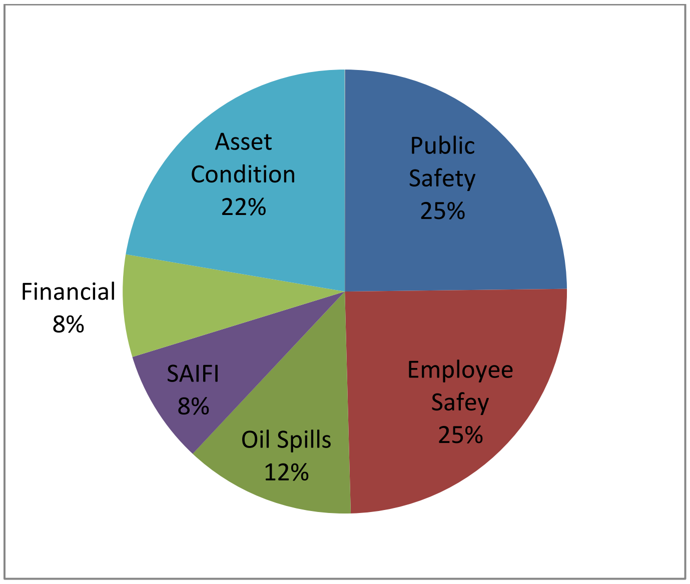


Figure 30 - Polemounted Transformer Replacement Avoided Risk

Project Score = 0.807

4.5 Execution Path

4.5.1 Implementation Plan

Polemounted transformers with issues that pose a risk to the safety of the public and the employees working in the vicinity are given a high priority. Transformers with a low health index score are being addressed next. The priority of the replacement of the deteriorating transformer also depends on whether or not the City of Ottawa or HOL has planned work in the area.

4.5.2 Risks to Completion and Risk Mitigation Strategies

Risk	Mitigation
Typical risks to completion include: • Coordinating activities in areas where multiple parties are working; • Getting approval for traffic plans where required • Priority changes as additional inspection results become available	HOL's mitigation strategy includes early planning with stakeholders, and coordination with the City of Ottawa to identify opportunities of resource use efficiency.

Figure 31 - Polemounted Transformer Program Risks and Mitigations

4.5.3 Timing Factors

Three year rotational visual and IR scan inspections identify polemounted transformers with poor conditions and expected to fail. Additional higher priority transformers might be identified prompting a reprioritization of the target transformers and will be scheduled as priorities are set.

4.5.4 Cost Factors
The final cost of the program is affected by the number of polemounted transformers that are identified as requiring replacement. Accessibility of the transformers can add significant costs to each replacement. In addition cost savings are available through planned scheduling with the City of Ottawa roadwork projects which require pole relocation. If a polemounted transformer fails before replacement is performed, the cost of replacing the failed transformer will be more than if the work is performed proactively.

4.5.5 Other Factors
Other factors to consider include possibility of project overlap with another planned program. Polemounted transformer may be replaced as part of pole replacement, line extension, or voltage conversion projects.

4.6 Renewable Energy Generation (if applicable)
Not Applicable.

4.7 Leave-To-Construct (if applicable)
Not Applicable.

4.8 Project Details and Justification

4.8.1 Overhead Transformer – PCB Regulatory Compliance

Project Name:	OH TXF- PCB Regulatory Compliance – Phase 3
Project Number:	92008627
Capital Cost:	$1,473,298
O&M:	N/A
Start Date:	2014 – Q1
In-Service Date:	2016 – Q1
Investment Category:	System Renewal
Main Driver:	Risk of Failure
Secondary Driver(s):	Reliability
Customer/Load Attachment	1038 customers/ 6210 kVA

Project Scope

This project entails HOL's PCB Regulatory Compliance Overhead Transformer Replacements. It involves the targeted removal of overhead transformers containing PCB's, replacement of brackets, switches and arrestors across the City of Ottawa. This project has been divided into 4 areas across the city with the amounts of transformers to be replace listed below

- 2014 - East – 45 Transformers
- 2015 - Core – 66 Transformers
- 2016 - South – 30 Transformers
- 2016 - West – 9 Transformers

Priority

Score: 0.03

Work Plan

Crews will be dispatched to the identified transformers throughout the city year round. Transformers to be replaced are de-energized, then replaced and re-energized. This project will continue through to Q1-2016

Customer Impact

Customers in the areas affected by this project may experience a sustained planned outage during replacement. This project will lead to an increase in reliability and decreased risk of asset failure and environmental risk.

5 Distribution Transformer Replacement - Padmounted

5.1 Project/Program Summary

HOL's underground transformer asset class includes a variety of transformers which are used in the delivery of power to customers. These transformers include submersible, padmounted, kiosk and vault transformers. While primarily oil filled, there is also a subset of solid dielectric transformers owned and operated by HOL. The underground distribution transformer replacement program focuses on the optimal time to replace an asset just before it fails. Inspections help identify the condition of the transformers so that they can be prioritized and replaced.

5.2 Project/Program Description

5.2.1 Assets in Scope

The HOL underground distribution system uses various types of underground transformers to convert electricity from medium voltage to low voltage. The low voltage power is used to supply residential, commercial, and industrial customers. The reliability of the underground distribution system is dependent on the performance of these underground transformers.

The underground transformer replacement program replaces submersible, padmounted, kiosk, and vault transformers connected to the underground cable network. These transformers are assessed based on their age which has a correlation to their condition. The exception is submersible transformers which are inspected for corrosion leading to leaking of oil due to their small population.

Underground transformers are replaced for numerous reasons including: asset failure, leaking oil, voltage conversion, insulator degradation identified by infrared scans, and in conjunction with cable replacement. The transformers that experience failure are replaced with a like-for-like transformer in order to provide electricity to the customer in a timely manner. Replacement completed during other projects will generally be like-for-like as well, however, the loading is assessed and there is the possibility for a smaller or larger capacity transformer to be used for economic or environmental benefits.

In addition, it is HOL's standard to replace live front transformers with dead front transformers. This is due to the safety benefits associated with having the cables insulated through the use of elbows. Padmounted and kiosk transformers and their concrete base have the potential to sink below grade. This poses a risk of flooding. This is flagged and remediated immediately to proactively avoid a failure.

Finally, federal regulation SOR 2008-273 dictates that all underground equipment with oil containing polychlorinated biphenyls (PCBs) in concentration of 50mg/kg or greater must be removed from service by 2025. The purpose of this is to improve protection of Canada's environment and the health of Canadians by minimizing the risks posed by the use, storage, and release of PCBs and by accelerating their elimination. HOL has been proactive with this replacement and all equipment that does not comply with this regulation will be removed by the end of 2016.

There have been field reports indicating that a high portion of submersible transformers are beginning to corrode. As a result, active replacement of all remaining submersible transformers has been scheduled for 2016.

HOL recommends a replacement rate on average of 300 to 400 padmounted and kiosk transformers per year and 60 to 80 vault transformers which represents 2.5% of the entire population of underground transformers. Under these scenarios transformers are still expected to fail, but the level of failures will be kept constant, if not reduced due to the proactive replacement.

5.2.2 Asset Life Cycle and Condition

HOL owns 19,189 underground transformers. These include roughly 29 submersible, 14,000 padmounted, 1,800 kiosk, and 3,500 vault transformers.

Currently, HOL has the installation or manufactured date information for approximately 98% of its kiosk and padmounted transformers. There is also data for 86% of the submersible transformers and 91% of the vault transformers on when they were installed or manufactured.

A typical lifecycle of an underground transformer is 30 years, with the exception of vault transformers which have a 35 year lifecycle. The overall age demographics of underground transformers in HOL's distribution system are shown in Figure 32. The percentage of underground transformers that have passed end of life criteria is 34%. In addition, in the next ten year period another 26% of underground transformers will reach the end of their useful life.

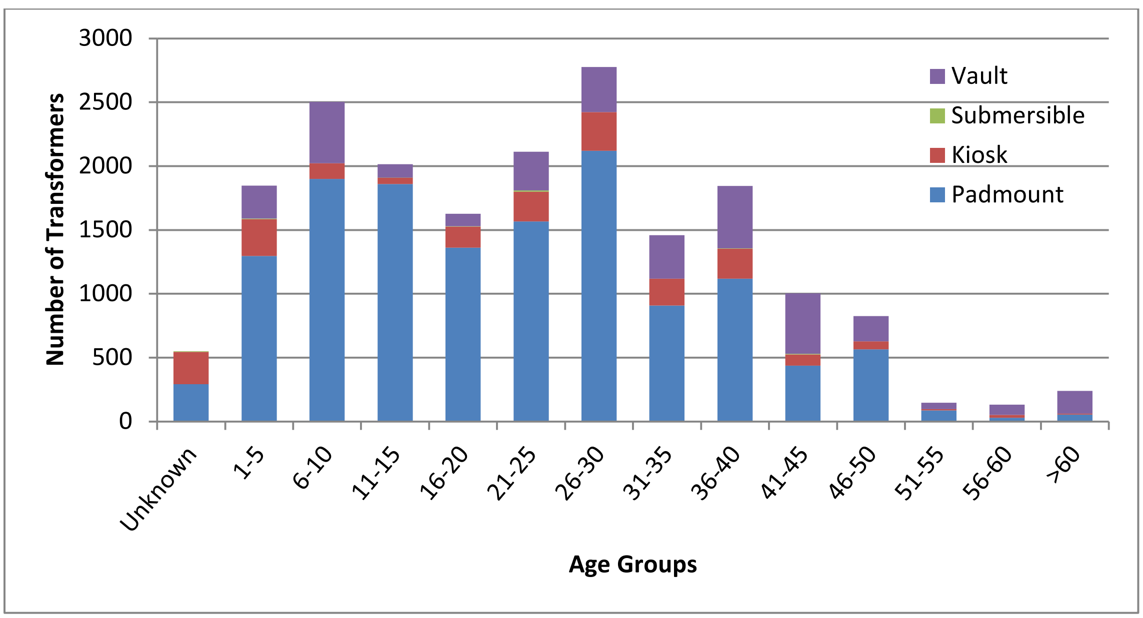


Figure 32 - Age Demographics of Underground Transformers

The current evaluation of underground transformers is based on the age of the asset. Underground transformers that have failed between 2011 and 2014 that had an associated year of installation or manufactured date can be seen below. There is a noticeable correlation between the age of the asset and the frequency of failure. The only exception to this is submersible transformers which are based on inspection due to the low number in the field and their primary mode of failure is corrosion leading to leaking of oil.

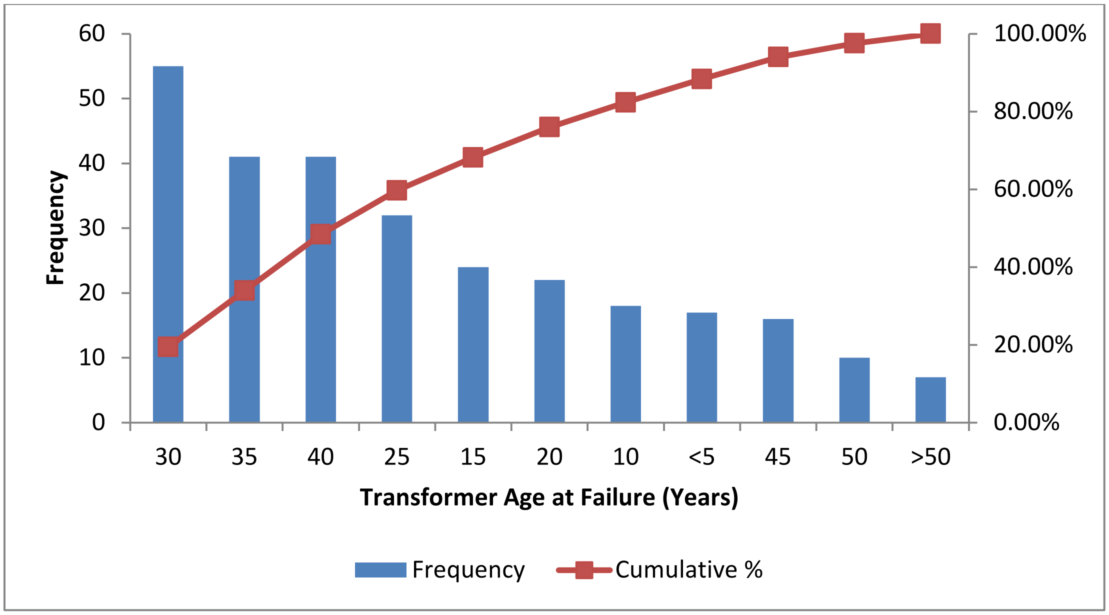


Figure 33 - Underground Transformer Age at Failure

Infrared (IR) tests and inspections are also carried out on padmounted and kiosk transformers. HOL attempts to inspect these transformers on a three year cycle. Most of the problems identified can be mitigated by cleaning connections, replacing minor components, or tightening connects, thus avoiding the need to replace the entire asset.

In order to effectively use the IR scanning information, an equipment health index was created for all IR scanned equipment. This can be seen below. The condition rating is based on the temperature difference between the reference temperature and the equipment's actual measured temperature.

Critical - (>75°C), immediate repair
Major Problem - (>36°C-75°C), repair as soon as possible
Intermediate - (>10°C- 36°C)
Minor - 10°C or less

Table 24 - Infrared Condition Rating

The records of underground transformer failures from 2009 to 2013, as shown below, indicate an upward trend in the number of failures per year. Based on the data, the number of underground transformer failures has increased by 52% in 2013 from 2009.

Increasing numbers of failures indicate an increasing condition deterioration of underground transformers. This trend is expected to continue due to the increasing number of transformers past their end of life. Therefore an aggressive replacement plan is required to maintain the number of failing transformers.

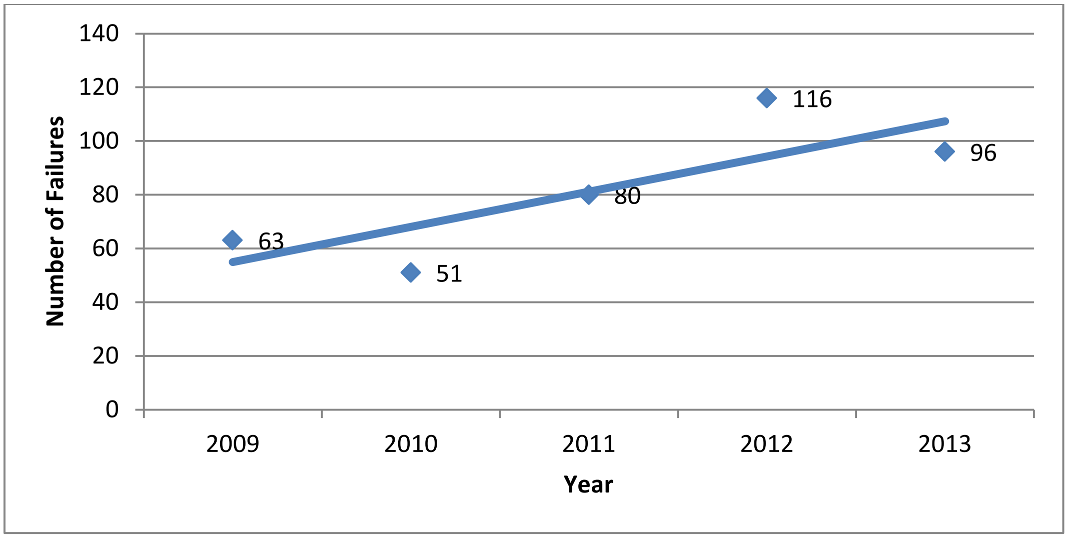


Figure 34 - Underground Transformer Failures

Underground transformers are typically run-to-failure or are replaced in concert with projects such as cable replacement or voltage conversion. However, they do from time to time require proactive replacement in response to known defects identified through IR and visual inspection. Issues have been encountered due to loose connections, equipment overload, swollen elbows, exposed electrical hazards, etc.

5.2.3 Consequence of Failure

In general, underground transformer failures will result in an outage affecting customers connected to that transformer. Outages as a result of underground transformer failures are typically limited in duration and customers impacted. However, as the amount of underground transformers progress past their end of life it is anticipated that annual failures will increase in the future. These events have a negative impact on overall system reliability. Figure 35 shows the contribution to the SAIFI and SAIDI metrics from failed underground transformers between 2009 and 2013.

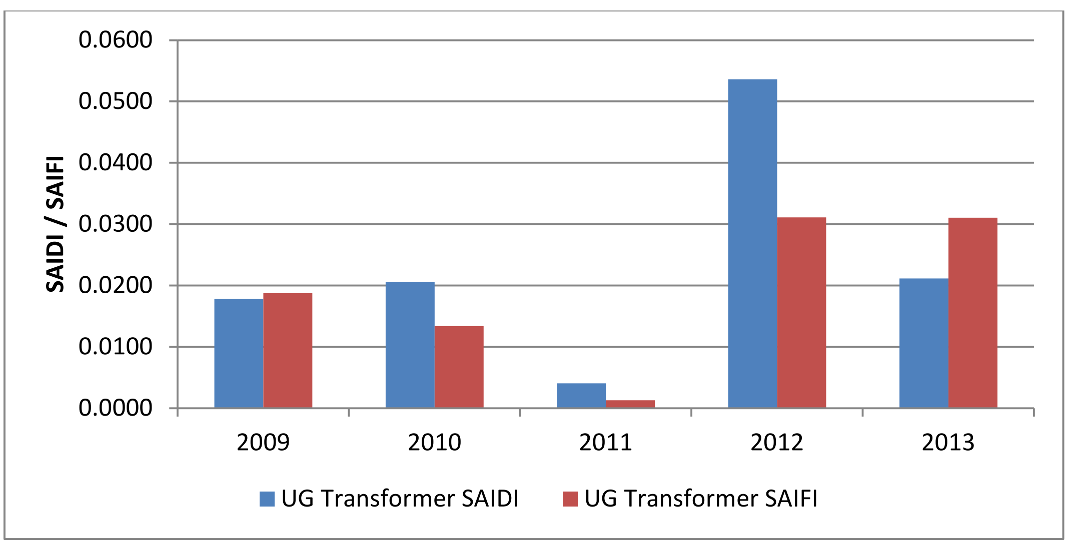


Figure 35 - Underground Transformer Failure Impact on System Reliability

When underground transformers fail, potentially pose a significant safety risk to the public, employees, and property. HOL mitigates the safety risks through the use of protection equipment such as fuses and appropriately rated enclosures.

In addition, when an underground transformer fails there is the chance of environmental impact due to the release of oil. HOL mitigates this risk through the use of appropriate enclosure and oil containment. HOL also historically replaced submersible transformers with solid dielectric models as opposed to oil filled models. As of 2010 HOL began replacing the transformers with stainless steel to protect from corrosion.

5.2.4 Main and Secondary Drivers

The drivers are represented in the Table 25 below.

Driver		Explanation
Primary	**Failure Risk**	Percentage of underground transformers that have passed end of life criteria is 34%. An additional 26% of transformers will reach their end of life criteria by 2024. Increasing number of underground transformer failures has an impact on SAIFI and SAIDI.
Secondary	**Safety**	Risks of underground transformers can lead to injuries of HOL employees and the public. The risks are mitigated through the use of protection equipment such as fuses and appropriately rated enclosures.
Secondary	**Environment**	Underground transformer failures can lead to oil leaks. HOL mitigates this risk through the use of appropriate enclosure and oil containment. In addition, submersible transformers are being replaced with solid dielectric models as opposed to oil filled models. As of 2010 HOL began replacing the transformers with stainless steel to protect from corrosion. Federal regulation also demanded the replacement of transformers containing PCBs of 50mg/kg or greater by 2025.

Table 25 - Underground Transformer Program Main Drivers

5.2.5 Performance Targets and Objectives

HOL employs key performance indicators for measuring and monitoring its performance. With the implementation of the underground transformer replacement program, improvements are expected in the following measurement:

- Defective Equipment SAIFI

HOL also expects to complete the replacement of all equipment that contains PCBs greater than 50mg/kg in accordance with federal regulation SOR 2008-273. This is anticipated to be met by the end of 2016.

5.3 Project/Program Justification

5.3.1 Alternatives Evaluation

5.3.1.1 *Alternatives Considered*

In order to address the drivers and achieve the performance objectives of the replacement program, HOL considered four alternatives for the replacement policy levels.

I. Underground Transformer Replacement Policy

Using the rate of failure model developed for underground transformers, HOL analyzed an impact of several replacement alternatives on the performance outcome. All of the alternatives, other than run-to-failure, stabilize the replacement amount beyond 2016-2020 rate filing period. The following scenarios were analyzed:

- Run-to-Failure scenario with only reactive replacement of the transformers
- Replace 300 padmounted/kiosk transformers and 60 vault transformers / year to maintain an mid-term reliability levels
- Replace 350 padmounted/kiosk transformers and 80 vault transformers / year to maintain long-term reliability levels
- Replace 520 padmounted/kiosk transformers and 120 vault transformers / year to improve mid and long-term reliability levels

5.3.1.2 *Alternatives Evaluation*

HOL evaluates all alternatives with consideration of the criteria below.

Criteria	Description
Failure / Reliability	The increased potential of failure posed by these aging assets will impact the organization's ability to guard worker and public safety. The selected alternative shall maintain or improve the reliability performance of the system.
Safety	HOL puts the safety of its employees and the public at the center of its decision-making process. The preferred alternative must not impose additional risks on the safety of HOL's employees and the public.
Resources	Unplanned replacements are usually carried out by HOL's own crews, whereas planned replacements can utilize both internal and external resources. Therefore, alternatives that incur more on-failure replacements are less favorable as it will be more challenging from a resource perspective.
Financial	Financial costs and benefits shall include all direct and indirect impact on the utility's performance and rates. The preferred alternative shall be at least cost or the most beneficial in the long-term to the stakeholder and to the customers.

Table 26 – Alternative Evaluation Criteria

5.3.1.3 *Preferred Alternative*

I. Underground Transformer Replacement Policy

The preferred alternative is replacing the oldest underground transformers at a rate of 350 padmounted/kiosk transformers and 80 vault transformers per year.

The 350 padmounted/kiosk transformers and 80 vault transformers replacement level is based on an assumed 100% program efficiency, that is to say only the oldest transformers are replaced first. This level of program efficiency does not always occur in practice. If a subset of transformers is known to be failing, then replacement of transformers with like qualities such as age and manufacturer will be replaced. These transformers may not always be the oldest transformers in the system.

Failure / Reliability

HOL has analyzed the impact of several replacement policies using the failure rate model developed for padmounted and kiosk transformers. A failure rate model was also developed for vault transformers. Results of this analysis indicated that an increase of replacements of kiosk and padmounted transformers to 350 and vault transformers to 80 annually would be required to manage failures and keep them from increasing yearly.

The impact of different replacement policies is shown below. The number of failed underground transformers indicated in the two graphs represents the number of transformers that have reached end of life based on their age. The actual failure of the transformer can occur prior or post to the 30 or 35 year age used for kiosk and padmounted transformers and vault transformers, respectively.

Actively replacing underground transformers also allows HOL to warn the customers of an outage. In addition, these outages can be planned during times that customers are not likely to be impacted. By not actively replacing these assets, increasing transformer outages will occur at unexpected and inconvenient times.

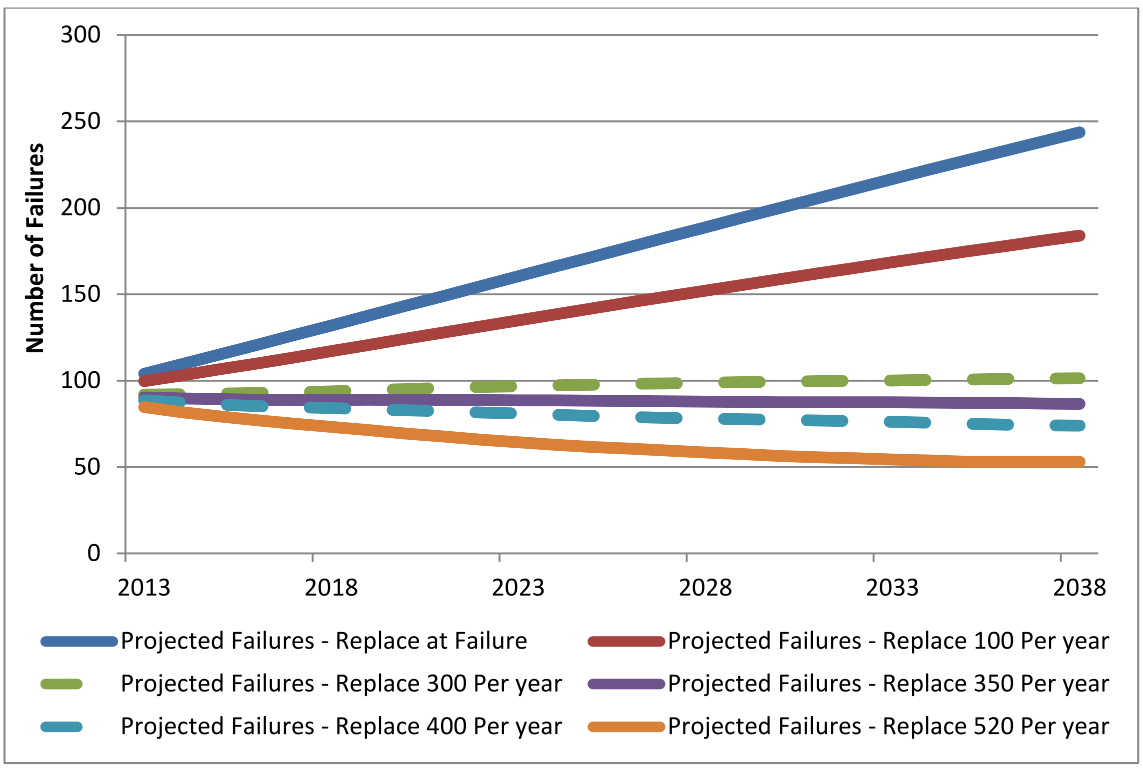


Figure 36 - Padmounted and Kiosk Transformers Recommended Replacement Rates

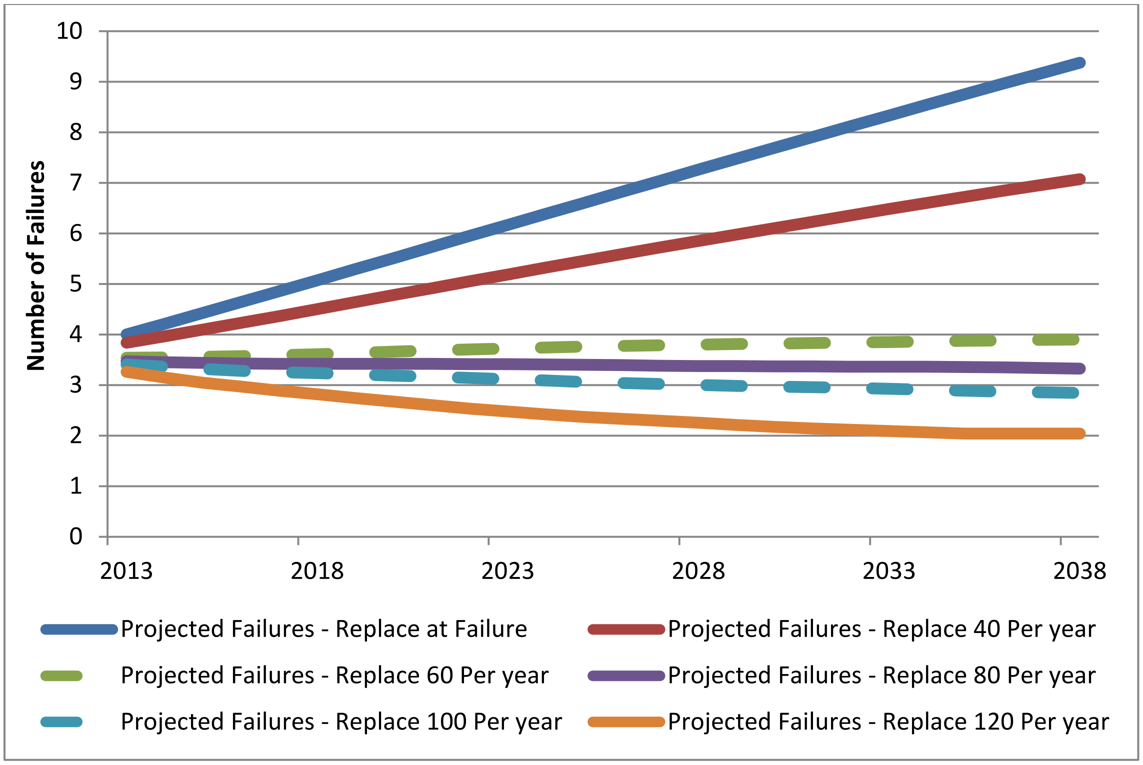


Figure 37 - Vault Transformer Projected Replacement Rates

Safety

An increased underground transformer replacement policy would minimize the risk to safety by reducing the number of transformers that are likely to fail based on age.

Resources

With assets on the system continuing to age and deteriorate, inadequate planned replacements of aging transformers will lead to accumulation of end of life assets. This has the potential to increase unplanned replacements that will stress the available resources of HOL at its current staffing level. Planned underground transformer replacements are much more easily handled due to the ability to schedule work rather than replacing upon failure which is done as soon as possible.

Financial

The cost associated with replacing underground transformers in an emergency situation has been estimated to be substantially higher than the cost of scheduled transformer replacements. This can be due to many factors including over time labour and express ordering equipment that was used as an emergency replacement. The do-nothing policy would see more frequent transformer failures resulting in a high cost impact of replacing unscheduled underground transformers. By increasing the replacement policy, the average costs to replace a transformer, scheduled and unscheduled, will be reduced and provide long-term financial benefit.

Replacing unscheduled underground transformers also affects HOL's ability to complete other planned projects throughout the year. With a do-nothing approach, both labour time and budget resources will be taken away from scheduled work throughout the year by focusing on replacing unscheduled failed transformers.

5.3.2 Project/Program Timing & Expenditure

Historically there have been no expenditures for proactive underground transformer replacement due to the assets being run-to-failure. However, from inspection information, transformers have been deemed end of life and scheduled for replacement when resources were available opposed to right away. As described in section 2.1, a project to replace submersible transformers is anticipated for 2016 due to their condition. HOL has also complied with the federal regulation SOR 2008-273 of replacing equipment that contains greater than 50mg/kg of PCBs.

	Historical ($M)					Future ($M)				
	2011	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
End of life	0.064	0.417	0.038	1.121	-	-	-	-	-	-
Submersible	0.07	-	-	-	-	0.439	-	-	-	-
PCBs	0.691	0.533	0.465	-	-	-	-	-	-	-

Table 27 - Historical and Future Spend on Transformer Replacement

5.3.3 Benefits

Key benefits that will be achieved by implementing the underground transformer replacement program are summarized below.

Benefits	Description
System Operation Efficiency and Cost-effectiveness	Costs associated with a failed transformer are significantly higher than planned replacement. Also, planned outages as opposed to unplanned are easier for HOL's system operators to handle and manage. Aging and deteriorating transformers increase the risk of failure and safety concerns. The alternative of replacing underground transformers at a rate of 350 padmounted/kiosk transformers and 80 vault transformers per year is the most effective means to minimize the potential safety and reliability risks associated with failed underground transformers.
Customer	System reliability will be preserved as the number of failed transformers will remain constant which will cause outages to fewer customers annually. Planned outages are resolved more quickly than unplanned. They can also be scheduled at times that would minimize the impact to our customers.
Safety	A failed transformer has the possibility of incurring serious injury to the public. HOL mitigates this possibility through the use of protection equipment and adequately rated enclosures. The preferred alternative will improve public safety by reducing the probability of a failed transformer.
Cyber-Security, Privacy	N/A
Co-ordination, Interoperability	N/A
Economic Development	N/A
Environment	Transformers utilize oil as a cooling medium and have the potential for oil leaks. Underground transformers are built with oil containment, but a failed transformer could lower the containments integrity. This could lead to an oil spill.

Table 28 - Underground Transformer Replacement Program Benefits

5.4 Prioritization

5.4.1 Consequences of Deferral

The run-to-failure replacement strategy is an ongoing program year after year. It cannot be deferred and therefore has no consequence of deferral. On the other hand, the preferred alternative of proactive replacement would see an impact from deferral. The positive impacts discussed in section 3.3 would be neglected to the date at which the alternative began. This would also see a buildup of underground transformers past their end of life.

5.4.2 Priority

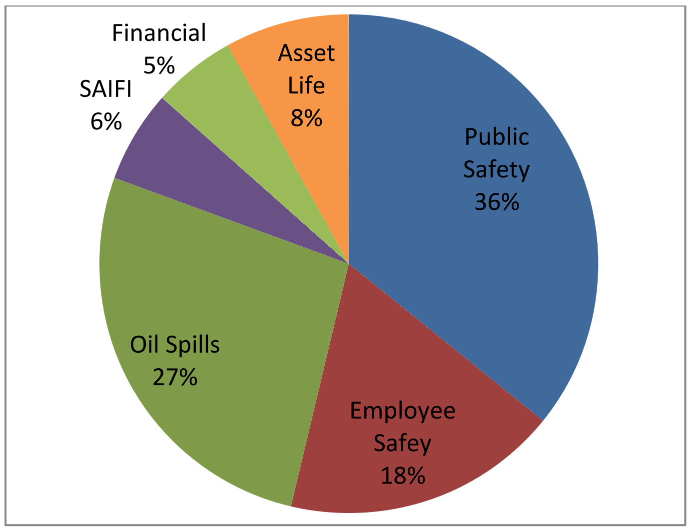


Figure 38 - Underground Transformer Replacement Avoided Risk

Score = 1.117

5.5 Execution Path

5.5.1 Implementation Plan

HOL currently evaluates its underground transformers based on their age demographics alone. This is likely to continue as a method of prioritization until a health index and supporting condition information is captured. Prioritization would then be based on both the transformers age and condition data.

5.5.2 Risks to Completion and Risk Mitigation Strategies

Risk	Mitigation
Typical risks to completion include: • Coordinating activities in areas where multiple parties are working; • Getting approval for traffic plans where required • Priority changes as additional inspection results become available	HOL’s mitigation strategy includes early planning with stakeholders, and coordination with the City of Ottawa to identify opportunities of resource use efficiency.

Table 29 - Underground Transformer Risks and Mitigation

5.5.3 Timing Factors

Three year rotational visual and IR scan inspections identify underground transformers with poor conditions and expected to fail. Additional higher priority transformers might be identified prompting a reprioritization of the target transformers and will be scheduled as priorities are set.

5.5.4 Cost Factors

The final cost of the program is affected by the number of underground transformers to be targeted for replacement. If a transformer fails before replacement is performed, the cost of replacing the failed transformer will be more than if the work is performed proactively. Failure of the transformer will also incur increased costs as it will experience customer outages if the electrical assets are damaged.

5.5.5 Other Factors

Other factors to consider include the possibility of project overlap with another planned program. Underground transformers may be replaced as part of cable replacement or voltage conversion projects.

5.6 Renewable Energy Generation

(Not applicable for this program)

5.7 Leave-To-Construct

(Not applicable for this program)

5.8 Project Details and Justification

5.8.1 Submersible Transformer Replacement

Project Name:	Submersible Transformer Replacement
Project Number:	92010279
Capital Cost:	$442,456
O&M:	N/A
Start Date:	2016 – Q1
In-Service Date:	2016 – Q4
Investment Category:	System Renewal
Main Driver:	Risk of Failure
Secondary Driver(s):	Reliability
Customer/Load Attachment	58 customers/ 167 kVA

Project Scope

This project involves the replacement of 14 solid-dielectric submersible transformers (Turtles) across the city. Typically submersible transformers are subject to salt contamination which can lead to corrosion and a diminished structural integrity. This can result in oil leaks. For this project, the solid-dielectric transformers will be replaced with either padmounted transformers or stainless steel submersible transformers to reduce the risk of damage due to corrosion and mitigate the risk of environmental hazards.

Priority

Score: 0.743

Work Plan

The following transformers identified below, will be replaced as part of this project and will be completed throughout 2016. Crews will be dispatched with appropriate equipment to perform the replacement. Where there is real estate, HOL will replace the submersible transformer with a padmounted transformer. If there is no available space the submersible will be replaced with a stainless steel type.

- TV113 @ 180 Beausoleil – Replace with Padmounted
- TV90 @ 115 Beausoleil – No real estate
- TV146 @ 75 Henry – Replace with Padmounted across the road
- TV144 @ 1 Rockwood – Replace with Padmounted on Laframboise
- TV179 @ 462 St. Patrick – Replace with Padmounted beside
- TV143 @ 106 Wurtemburg – Future Replacement by shared vault at 101 Wurtemburg
- TV114 @ 294 York – Replacement with Padmounted
- TV187 @ 260 Clarence – Replaced by shared vault at 333 King Edward
- TV139 @ 468 Clarence – No real estate
- TV91 @ 331 Clarence – No real estate
- TV141 @ 30 Desjardins – No real estate
- TV195 @ 292 St. Andrew – No real estate
- TV194 @ 260 St. Andrew – No real estate
- TV181 @ Murray Street – Repalce with Padmounted across the road

Customer Impact

During transformer replacement the customer may experience a planned sustained outage if not supplied by a backup circuit while crews are working. This project increases the distribution reliability and decreases the risk of asset failure in the areas affected.

6 Civil Structure Rehabilitation

6.1 Project/Program Summary

HOL's Underground Civil Structure asset class consists of underground duct banks, hand holes and various types of underground chambers forming a network through which cables may be installed. Distribution underground civil structures are used in areas where underground wiring is required for:

- aesthetics or clearances;
- to improve reliability;
- to reduce the time to access and correct faulty wiring;
- to permit access in congested areas; and
- to allow re-entry or expansion in areas where further excavation would be costly.

While duct structures are run to the unlikely event that they fail, underground chambers are maintained through a replacement and rehabilitation program based on regular condition assessment. Based on the currently available inspection data it is recommended that the program target a minimum of ten (10) underground chambers per year.

6.2 Project/Program Description

6.2.1 Assets in Scope

HOL's underground distribution system is supported by a vast network of underground civil structures ranging from cable chambers to duct banks. Generally, underground civil structures are divided into two groups: Duct structures and Underground Chambers.

The scope of this project is to rehabilitate or replace damaged underground cable chambers that are known to be in poor or critical condition which pose a safety risk to the public. As duct structures are run-to-failure, replacement is done reactively as asset condition cannot be assessed without excavation.

Manholes are proactively maintained through the current inspection program and work is coordinated with the City of Ottawa if possible to optimize resource usage. Based on the available inspection data, the program is to target a minimum of ten (10) underground chambers per year with a total of sixty (60) cable chambers to be replaced by 2020. These sixty (60) chamber rehabilitations will vary in complexity from roof replacements to complete chamber replacements. This number represents only 1.9% of a total population of the cable chambers in HOL's distribution system. Additional chamber rehabilitations may be completed over this time through the inclusion of other projects.

The cable chambers targeted for replacement are identified at the beginning of the specific budget year. The targeted chambers are based on the most up to date inspection results and are prioritized based on a condition assessment to identify the rehabilitation projects for the year. The projects are chosen to fit within the constraints of the annual budget, but are re-prioritized if during the annual inspection a chamber is identified to be in a worse condition than a scheduled project.

Chambers are typically repaired like-for-like, expect in cases where the chambers do not meet current HOL standards in which case these chambers will be repaired to meet these standards. In cases where an upcoming project has been identified, the chamber will be repaired to suit the needs of the upcoming project.

Each underground chamber costs an estimated $20,000 to repair or replace the structure roof, and $60,000 for a complete rebuild. Installation of new pads and vaults are also included in the scope of this project.

6.2.2 Asset Life Cycle and Condition

Underground civil structures include: Cable Chambers (Manholes), Ducts, Handholes, Sidewalk Vaults, and Equipment Pads. There are a total of 24,349 assets categorized as underground civil structures, including 3,174 manholes, 328 handholes, 34 sidewalk vaults, and 20,813 equipment pads. Before 1970, manholes were installed using cast-in-place construction. As standards became more stringent after 1970, precast manholes became favored as the structures can be made to exact specifications.

Civil Structure Type	Pre 1970	Post 1970	Unknown	Total
Cable Chambers	343	2,097	734	3,174
Handholes	8	238	82	328
Sidewalk Vaults	-	34	-	34
Equipment Pad	-	3,698	17,115	20,813

Table 30 - Civil Structures by Type

The typical lifecycle of civil structures is 40 years. The overall age demographics of civil structures are approximated based upon the age of the equipment utilizing the civil structure, but are not a reliable source of information. As a result the civil rehabilitation program is strictly based upon inspection and condition assessments.

The manhole inspection program targets 300 manholes annually as part of a 10 year inspection cycle. Underground chambers are also inspected through regular work activities when crews perform scheduled work in manholes and handholes. All of the manholes will have undergone inspection by 2017.

During manhole inspections the roof, collar, walls, and floor are examined to determine if there are cracks, concrete spalling, exposure and corrosion of the reinforcing steel rebar, and water entering cracks in the masonry. The table below summarizes the grade scale given to each part of the structure during the manhole inspection.

Condition	0	1	2	3	4	5
Description	**Very Good**	**Good**	**Fair**	**Poor**	**Very Poor**	**Critical**
Criteria	No significant deterioration	Minor hairline cracks or minor spalling	Large cracks and some spalling	Very large cracks and significant spalling	Major spalling and cracks reaching the steel rebar, concrete falling, some rusting	Concrete has deteriorated, large amounts of steel showing and strengths of rebar is questionable

Table 31 - Ratings for Underground Civil Structures

The manhole health index is formulated using the condition scoring above, which is then used to determine the remaining life of the structure. The table below summarizes the grade scale used to assess the asset health.

Overall Condition	Health Index
Very Good	90-100
Good	80-90
Fair	65-80
Poor	35-65
Very Poor	0-35

Table 32 - Asset Health Index condition rating

Of the inspected 1178 manholes for last three years, 1118 are in a fair and above condition and 60 are in a poor to very poor condition. The latter condition group will be targeted for rehabilitation or replacement during the length of the program in 2016-2020. The table below summarizes the condition of the manholes with inspection data organized by year inspected.

Health Index	Total Manholes Inspected			
	2012	2013	2014*	Total
>90%	348	404	61	813
80%-90%	95	110	25	230
65% - 80%	42	47	6	95
35% - 65%	29	24	3	56
<35%	3	3	0	6

Table 33 - Manhole health index by inspection year

***Note 2014 data only includes up to July 17, 2014**

Of the 3,174 in-service manholes, approximately 1,178 manholes have been inspected in the past three years and an approximately 538 additional manholes have been installed within the last 15 years. This leaves 46% of the 3,174 that have yet to be inspected; however, HOL aims to inspect 100% of the manhole population by the end of 2020 to better support the rehabilitation program. Extrapolating this data over the entire population would suggest that approximately 135 manholes have a poor to very poor condition. Annual prioritization of manhole inspection results will continue to address the most critical manholes and the program allocated budget will continue to be monitored to determine if it is sufficient based upon completing 100% of inspections.

6.2.3 Consequence of Failure

Underground civil structures have a low probability of failure, as issues leading to failure are addressed proactively. Proactive maintenance is the direct result of high consequence cost that could result from the collapse of underground civil structures. As the majority of underground civil structures are located in roadways and sidewalks, the health of the underground civil structure must be maintained to minimize the risk of injury to the public and employees, while preserving the corporate image of HOL.

Failure of underground civil structures are the result of deteriorating structural integrity from concrete breaks and corrosion of the metal rebar which will eventually lead to the collapse of the structure. Repair and replacement of structural components such as the walls, roof, and collar are vital to the mitigation of injury to the public and employees. In addition, a collapse of the underground civil structure can result in damage to electrical distribution assets located in the structure, and as a result customer interruptions can occur. The number of customers impacted by structure failures varies greatly depending on the asset that is housed in the structure; the number can vary from 1 customer to hundreds. Effected customers could expect to be without power for a minimum of four hours and up to twenty-four hours if it is not a redundant system.

There have been no failures of the cable chambers in HOL's distribution system that resulted in customer outages.

6.2.4 Main and Secondary Drivers

The drivers are represented in the table below.

Driver		Explanation
Primary	**Failure Risk**	1.9% of the inspected cable chambers are in Poor or Very Poor condition, totalling 60 chambers. It is estimated that the number will grow to 135 by the end of 2020 or completion of all inspections.
Secondary	**Safety**	Risks of the cable chamber collapse leading to potential injuries to the public as a result of being located on the roadways and sidewalks.

Table 34 - Civil Structure Rehabilitation Program Main Drivers

6.2.5 Performance Targets and Objectives

The target of the civil rehabilitation program is to continue on the current path of rehabilitating or replacing a minimum of 10 civil structures annually and maintaining the historical reliability trend of zero outages caused by a failed civil structure. Another target would be to have no injuries to the public or to employees as a result of a failed civil structure.

6.3 Project/Program Justification

6.3.1 Alternatives Evaluation

6.3.1.1 *Alternatives Considered*

The following alternatives have been analyzed:

1. Do nothing (Status-quo, Run-to-failure)
2. Increased Maintenance and Inspection with Run-to-failure
3. Replace all cable chambers that are currently in poor and very poor condition by the end of 2020 (60 units)
4. Replace all cable chambers that are estimated to be in poor and very poor condition by 2020 (135 units)

6.3.1.2 *Evaluation Criteria*

HOL evaluates all alternatives with consideration of the following criteria:

Criteria	Description
Failure / Reliability	The increased potential of failure posed by these aging assets will impact the organization's ability to guard worker and public safety. The selected alternative shall maintain or improve the reliability performance of the system.
Safety	HOL puts the safety of its employees and the public at the center of its decision-making process. The preferred alternative must not impose additional risks on the safety of HOL's employees and the public.
Resources	Unplanned and planned replacements utilize both internal and external resources. Alternatives that incur more on-failure replacements are less favorable as it will be more challenging to gather resources on as needed basis.
Financial	Financial costs and benefits shall include all direct and indirect impact on the utility's performance and rates. The preferred alternative shall be at least cost or the most beneficial in the long-term to the stakeholder and to the customers.

Table 35 – Alternative Evaluation Criteria

6.3.1.3 *Preferred Alternative*

The preferred alternative is to target a minimum of 10 civil structures per year in order to meet the target of 60 by the end of 2020. A run-to-failure approach would increase the safety risks to the public and employees as well as contribute to deteriorating condition which would lead to increased failures and unexpected costs. Rehabilitation versus replacement (Like for like or not-in-kind) is to be evaluated on a case by case basis.

Alternatives and their associated benefits with regards to reliability, safety, resources and Financial, are discussed for each criteria below:

Reliability

Alternative #1: increased levels of failing civil structures that would collapse on electrical equipment could cause outages that would increase SAIFI and have long duration outages increasing SAIDI.

Alternative #2: Reliability would be expected to remain consistent with the current situation – no outages caused by failing civil structures.

Alternative #3: Reliability would be expected to remain consistent with the current situation – no outages caused by failing civil structures.

Alternative #4: Reliability would be expected to remain consistent with the current situation – no outages caused by failing civil structures.

Safety

Increasing the number of civil structures rehabilitated or replaced annually would minimize the risk to safety by reducing the number that is likely to fail based on deterioration.

Resources

With assets in the system continuing to age and deteriorate, inadequate planned rehabilitation or replacements of aging civil structures will lead to accumulation of end of life assets. This has the potential to increase unplanned replacements that will stress the available resources of HOL at its current staffing level. Planned civil structure replacements are much more easily handled due to the ability to schedule work rather than replacing upon failure which is done as soon as possible.

Financial

The cost associated with replacing civil structures in an emergency situation has been estimated to be substantially higher than the cost of scheduled replacement. This can be due to many factors including over time labour and organizing civil contractors that are used for emergency replacement. The do-nothing policy would see more frequent failures resulting in a high cost impact of replacing unscheduled civil structures. By increasing the replacement policy, the average costs to replace a civil structure, scheduled and unscheduled, will be reduced and provide long-term financial benefit.

Replacing unscheduled civil structures also affects HOL's ability to complete other planned projects throughout the year. With a do-nothing approach, both labour time and budget resources will be taken away from scheduled work throughout the year by focusing on replacing unscheduled failed civil structures.

6.3.2 Project/Program Timing & Expenditure

The average cost to rehabilitate a manhole from 2010 to 2012 was $60,000. Budgets in 2011-2013 varied to be capable of completing other system improvement activities; however the budgeted amount was met each year. HOL plans to spend approximately $0.5M each year starting from 2014 and ending in 2020.

	Historical ($M)					Future ($M)				
	2011	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Total Expenditure	$0.4	$0.2	$0.3	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5

Table 36 - Civil Rehabilitation Program Expenditure

Spending for refurbishment and replacement of manholes is optimized by pre-planning the construction schedule and ensuring vehicles, staff, contractors and material are all available for start of construction. Where practical, manhole refurbishments and replacements are scheduled in conjunction with City of Ottawa roadwork.

6.3.3 Benefits

Key benefits that will be achieved by implementing the civil rehabilitation program are summarized below.

Benefits	Description
System Operation Efficiency and Cost-effectiveness	Costs associated with a collapsed chamber are significantly higher than planned rehabilitation or repair. Aging and deteriorating civil structures increase the risk of failure and safety concerns. This alternative is the most effective means to minimize the potential safety and reliability risks associated with collapsed

	structures.
Customer	Lower likelihood of a manhole collapsing and damaging cables if the structures are in good health. System reliability will be preserved as vital electrical assets are usually housed in underground civil structures. Failure of the structure results in damage to electrical assets, which will then impose customer outages.
Safety	Public safety is maintained as most manholes are located either on sidewalks or public roadways; a collapsing manhole has the possibility of incurring serious injury to the public.
Cyber-Security, Privacy	N/A
Co-ordination, Interoperability	N/A
Economic Development	HOL hires external third party contractors to complete the work in the Civil Rehabilitation program.
Environment	Transformer bases and switchgear manholes are intended to contain potential oil leaks. These structures are unable to contain oil if they have cracks or holes and oil will be spilt into the environment.

Table 37 - Civil Rehabilitation Benefits

6.4 Prioritization

6.4.1 Consequences of Deferral

Deferring the project will result in failure of rapidly deteriorating manholes. Public and worker safety will be compromised if a manhole collapses due to poor health. Operating and Maintenance costs will increase as it costs more to repair/replace a civil structure once it has failed, since the optimal intervention time is exceeded. Annual spending will also increase if the project is not performed in conjunction with City of Ottawa roadwork.

6.4.2 Priority

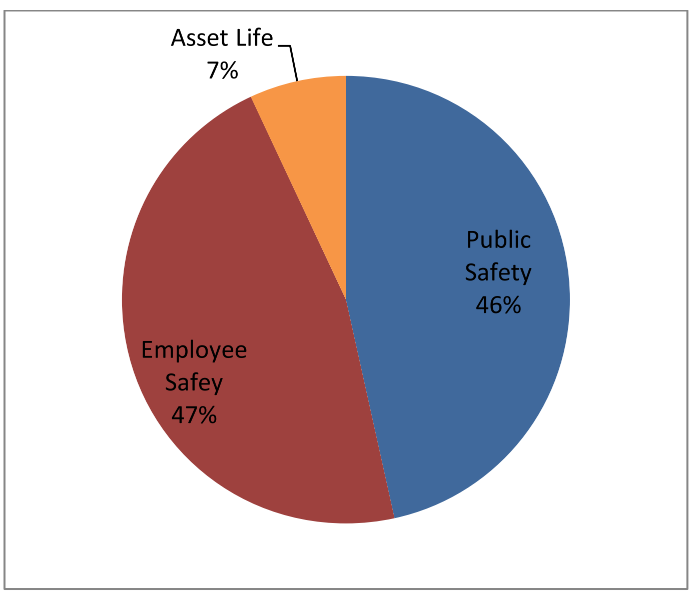


Figure 39 - Civil Rehabilitation Avoided Risk

Project Score = 0.92

6.5 Execution Path

6.5.1 Implementation Plan

Structures with issues that pose a risk to the safety of the public and the employees working in the vicinity are given a high priority. Manholes with a low health index score are being addressed next. The priority of the rehabilitation or replacement of the deteriorating manholes also depends on whether or not the City of Ottawa has planned work in the area.

6.5.2 Risks to Completion and Risk Mitigation Strategies

Risk	Mitigation
Typical risks to completion include: • Obtaining road cut permits from the City of Ottawa; • Coordinating activities in areas where multiple parties are working; • Getting approval for traffic plans where required • Priority changes as additional inspection results become available	HOL's mitigation strategy includes early planning with stakeholders, and coordination with the City of Ottawa to identify opportunities for efficient resource use Projects are chosen based on condition assessment and as new priorities arise, coordination can be adjusted with minimal impact to the program.

Table 38 - Civil Rehabilitation Risks and Mitigation

6.5.3 Timing Factors

As inspections are currently ongoing for manholes, additional higher priority structures might be identified prompting a reprioritization of the target manholes. If additional manholes are identified to be in poor or worse health, investment will have to be increased to allow for inclusion into the rehabilitation program.

6.5.4 Cost Factors

The final cost of the project is affected by the number of manholes to be targeted, and the type of rehabilitation or replacement work to be performed. In addition, cost savings are available through planned scheduling with the City of Ottawa roadwork projects. If a manhole fails before rehabilitation or replacement is performed, the cost of replacing the failed manhole will be more than if the work is performed proactively. Failure of the manhole will also increase costs as it will incur customer outages if the electrical assets are damaged. In addition, not-in-kind replacements will change the final cost of the project as it usually costs more to install a manhole with different specifications as it may require a redesign of the feeder section.

6.5.5 Other Factors

Other factors to consider include possibility of project overlap with another planned program. Civil structures may be rehabilitated or replaced as part of cable replacement, line extension, switchgear replacement or voltage conversion projects (transformer replacements).

6.6 Renewable Energy Generation (if applicable)

Not Applicable.

6.7 Leave-To-Construct (if applicable)

Not Applicable.

6.8 Project Details and Justification

6.8.1 2015 Manhole Rehabilitation

Project Name:	2015 Manhole Rehab
Project Number:	92008643
Capital Cost:	$540,897
O&M:	N/A
Start Date:	2015 – Q1
In-Service Date:	2015 – Q4
Investment Category:	System Renewal
Main Driver:	Risk of Failure
Secondary Driver(s):	Reliability
Customer/Load Attachment	13500 customers/ 27000 kVA

Project Scope

This manhole replacement/repair project occurs throughout the city through an inspection program that identifies deteriorating or damaged civil structures. When the manholes are inspected features such as the collars, roofs, walls, floors, and racks are ranked on a 0-5 scale and kept in a database. Manholes are then identified on a priority basis for rehabilitation and replacement.

Priority

Score: 0.53

Work Plan

- MH4422 – Rebuild
- MH299 – Roof
- MH507 – Rebuild
- MH1551 – Roof
- MH389 – Roof
- MH298 – Roof
- MH490 – Roof
- MH566 – Roof
- MH664 – Roof
- MH388 – Roof
- MH629 – Collar
- MH742 – Collar
- MH2766 – Collar
- MH795 – Collar
- MH2677 – Collar

Customer Impact

The project increases distribution reliability and decreases the risk of asset failure.

6.8.2 2016 Manhole Rehabilitation

Project Name:	2016 Manhole Rehab
Project Number:	92010285
Capital Cost:	$500,000
O&M:	N/A
Start Date:	2016 – Q1
In-Service Date:	2016 – Q4
Investment Category:	System Renewal
Main Driver:	Risk of Failure
Secondary Driver(s):	Reliability
Customer/Load Attachment	13500 customers/ 27000 kVA

Project Scope

This manhole replacement/repair project occurs throughout the city through an inspection program that identifies deteriorating or damaged civil structures. When the manholes are inspected features such as the collars, roofs, walls, floors and racks are ranked on a 0-5 scale and kept in a database. Manholes are then identified on a priority basis for rehabilitation and replacement.

Priority

Score: 0.53

Work Plan

The manhole rehabilitation and repair program for 2016 will become clearer as information is compiled during the 2015 inspection program and is used to identify manholes to be replaced and repaired. Typically manhole repairs will begin in Q2 when the weather becomes more favourable for working.

Customer Impact

This project increases the distribution reliability and decreases the risk of asset failure in the areas affected.

6.8.3 Civil Rehabilitation on Carling (Bronson to Sherwood)

Project Name:	Civil on Carling from Bronson to Sherwood
Project Number:	92010283
Capital Cost:	$2,602,393
O&M:	N/A
Start Date:	2016 – Q1
In-Service Date:	2016 – Q4
Investment Category:	System Renewal
Main Driver:	Risk of Failure
Secondary Driver(s):	Reliability
Customer/Load Attachment	27 customers/ 5700 kVA

Project Scope

The current unground duct banks along Carling Avenue are approaching their end of life. It is necessary to replace these civil structures to decrease the probability of failure. Also, new underground circuits from Bronson SB Substation to Sherwood Drive along Carling Avenue are required for future planned growth along the Preston Street area. Increased civil capacity is also required for the same reason. To date, LRT and planned bus lanes are changing the scope of this project and further meetings are required with the City of Ottawa to better align the project which was planned to occur simultaneously during road construction with the city in 2016.

Priority

Score: 1.17

Work Plan

At this point further meetings are required to take place with the City of Ottawa to better align the work plan for this project.

This project will involve civil duct work and electrical work.

Customer Impact

This project will increase the capacity and reliability in the Preston Street area and decrease the risk of asset failure.

7 Cable Replacement

7.1 Project/Program Summary

HOL's underground distribution system is fed using underground circuits running from distribution stations to overhead lines and from overhead lines to transformers and switches. This system is configured and connected through the use of underground cable. Distribution underground cables are used mainly in urban and newer residential areas where it is not feasible to build overhead lines due to aesthetic, legal, environmental or safety issues. The reliability of the overhead and underground distribution systems is contingent on the performance of this underground cable.

The cable replacement program manages HOL's underground replacement of polymer cable. All other cable types are run-to-failure. Underground cable is replaced on a like-for-like basis. In instances where cable is directly buried in a trench, the current standard is to bury the cable encased in a Poly Vinyl Chloride (PVC) duct in non-roadway applications. For roadway applications concrete encased PVC duct is used to reduce risk of physical factors such as dig-ins and vehicle weight.

Historically, HOL has replaced an average of 12km of cable per year. This cable replacement analysis is based on inspection information taken from known aged and problem areas in the system which may have biased the results. HOL will continue to do distributed inspections throughout the system to get a complete picture of the underground cable condition demographics. HOL's analysis recommends a replacement rate of 99km of underground cable per year over the 2016-2020 period to maintain the current fault levels. The equivalent estimated yearly cost of the proposed cable replacement program is $30 million dollars per year. Until confidence levels are more in-line, an average annual budget of $5.6 million will be spent replacing underground cable. This budget amount aligns with the available internal resources that have the qualification to complete this program.

7.2 Project/Program Description

7.2.1 Assets in Scope

Historically, cable replacements have been prioritized based on the number of faults, or the number of customer interruptions due to cable faults. Cables prioritized in the 2016-2020 period have been assessed using cable testing results in combination with cable age and inspection data. As such, poor and critical condition cable is scheduled for replacement first, while cable testing and condition assessments continue to identify high priority cables for future replacement.

HOL is also reviewing cable injection as a means of life extension in order to defer investments due to the large amount of assets approaching end of life. Targeted cable that meets a specific requirement will be identified for life extension. HOL is currently developing these criteria for identifying cables to be injected.

7.2.2 Asset Life Cycle and Condition

HOL owns and manages approximately 4,484 km of underground cable installed in its service territory. The breakdown between various types of cable is 92% cross-linked polyethylene (XLPE), 8% paper insulated lead covered (PILC), and <1% Butyl rubber (14 km installed in the Nepean area).

Demographic information for underground cables has been collected from HOL's Geographic Information System (GIS). When the installation date was not available, an estimated installation date has been used. The estimated installation date for the cable is based on the adjacent property legal records – i.e. date a subdivision was built. Proportional age demographics are illustrated by cable type in the figures below.

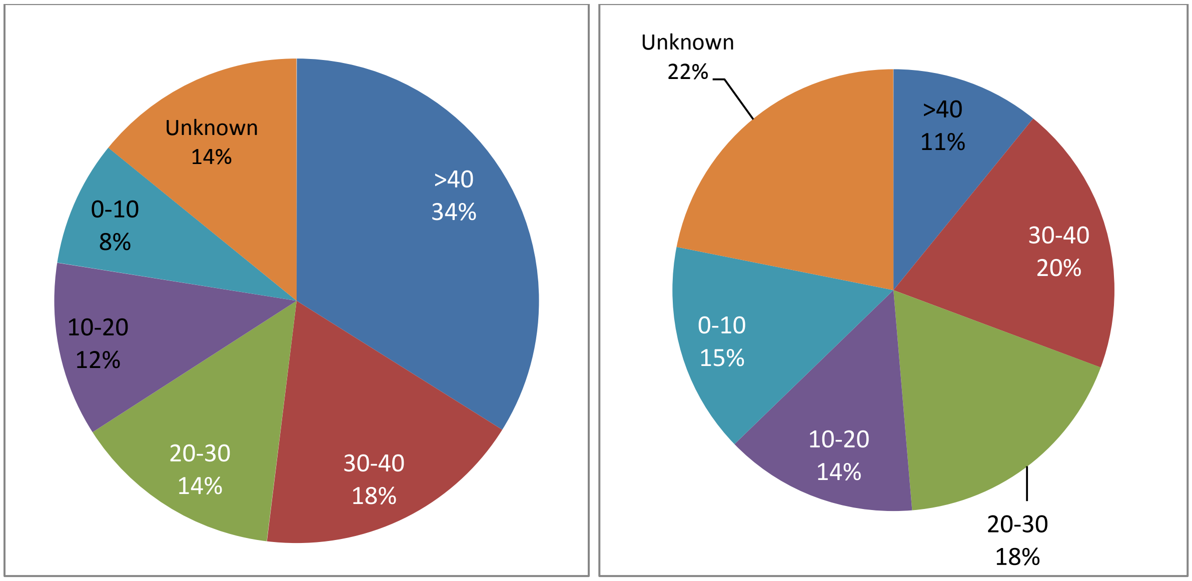


Figure 40 - Proportion of PILC (left) and XLPE (right) by age

The following table provides a breakdown of underground cables by voltage class and cable type (polymer or PILC).

Voltage Class	Polymer (km) (XLPE, EPR, Butyl Rubber)	PILC (km)
44kV	19	-
27.6kV	1,770	-
13.2kV	1,104	308
12.43kV	73	-
8.32kV	756	-
4.16kV	406	48
Total	4,128	356

Table 39 - Cable length by voltage class

Typical lifecycles of the various types of polymer and PILC cable is provided in the table below, based on the International Financial Reporting Standards (IFRS) Life.

Cable Type	IFRS Life
U/G Polymer Insulated cable	35
U/G PILC cable	60

Table 40 - IFRS Life for Underground Cable

Cable age is not the overarching factor in determining the insulation condition of in-service cable. Other factors such as soil condition, ground moisture, presence of a cable jacket, and operating condition play an important role in determining the rate of decay. Historically, cable replacements have been prioritized based on the number of faults, or the number of customer interruptions due to cable faults. While these reliability figures provide indication of cable health, they are lagging indicators. Replacement based on fault data may result in a cable in good health being replaced prematurely when the cable faults were the result of localized defects or damage.

An underground cable testing program was initiated in 2011 with The National Research Council of Canada (NRC). The testing method used by NRC determines the general condition of a polymer cable segment. Cable sites targeted for testing include ones scheduled for replacement in the next 2 to 5 years, high fault areas, and areas with known aged cable. In the 3 years of testing, 1.7% of the total polymer distribution cable has been tested. The following figure summarizes the results of the cable testing program.

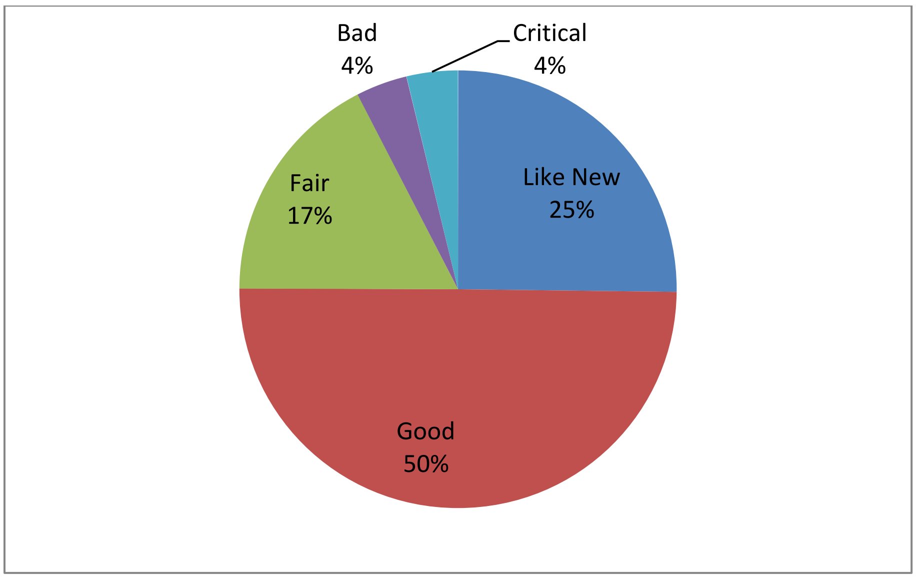


Figure 41 - Proportion of tested cable by condition

The NRC testing method assesses the progression of water-treeing in polymer cable to determine the relative condition of the entire segment. Water trees develop in the polymeric insulation due to the ingress of moisture and impurities from the soil which are driven into the dielectric by the electric field. Water trees cause the reduction of the insulation strength making the cable more prone to failure. While the testing procedure captures the general condition of the cable insulation, it does not capture issues such as neutral corrosion, accessory issues or local defects that also impact cable life. These other issues must be qualitatively assessed when reviewing and prioritizing potential cable replacement projects.

Although cable age is not the main factor in determining cable condition, it is currently the most reliable data source captured for the entire asset class. The cable tested was grouped into age ranges and fitted to normal distribution. The estimated distribution of cable age ranges, cable quality and percentage of the systems cable can be seen in Figure 42. These results were created by sorting the tested cable into age ranges and using their testing results, extrapolating it city wide based on the system's cable age.

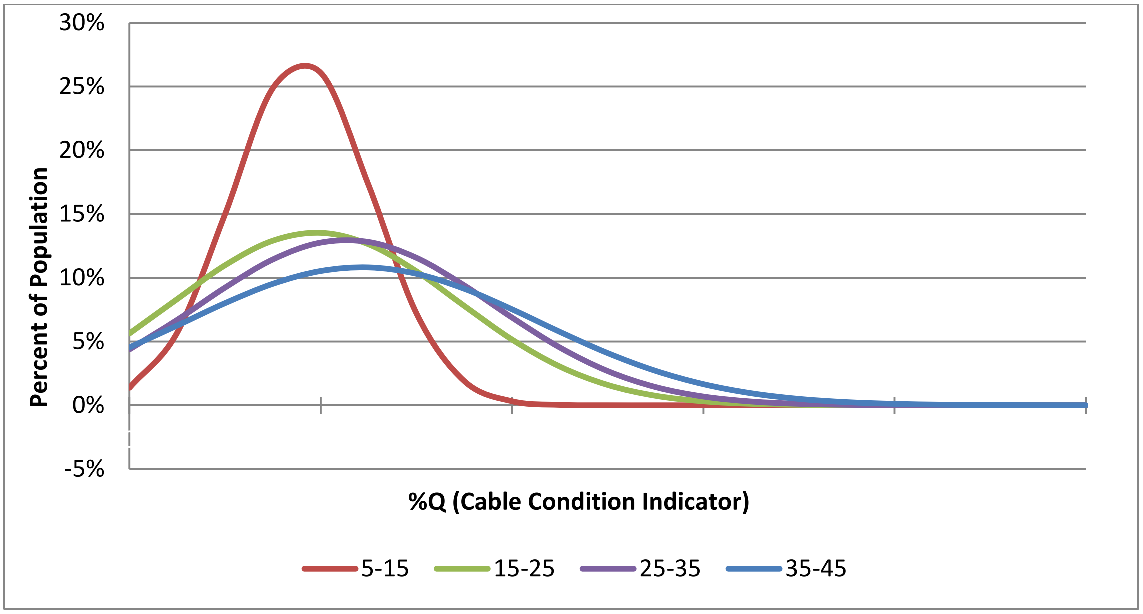


Figure 42 - Cable degradation model

Using the cable inspections and in service cable demographics, an overall HOL cable condition representation was created (see Figure 43). Further cable inspection will improve the accuracy of the estimated cable conditions. The graph indicates that 3% of the cable is in critical condition and 14% in poor condition. Areas with high percentages of this cable condition are the focus for cable injection and cable replacement projects.

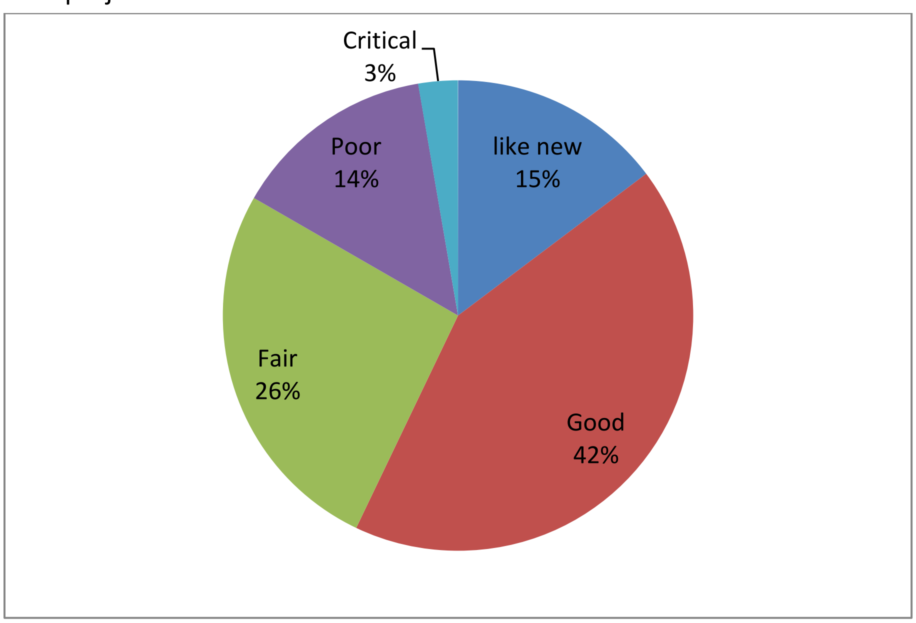


Figure 43 - Estimated condition of in service polymer cable

7.2.3 Consequence of Failure

The main impact of cable failures is on system reliability. Each cable fault will result in an outage to the customers fed by that circuit. Cable outages can have significant duration due to the time required to locate, isolate and repair the failed section. Failures will have increased impacts if they occur on the trunk of a circuit.

Much of HOL's underground distribution system is designed with a redundant loop to back-up the section of the feeder. A typical cable fault will result in an interruption for 2 to 4 hours depending on the availability of dispatch-able crews. Locating and isolating the faulted cable section is the most time consuming part of the interruption. The faulted section may remain in an isolated state for several days until a crew is available to repair the section. For direct buried cable, trenching is required to install the new section or splice the cable. For this time period, the looped segment has effectively lost its redundancy and could result in an outage of up to 8 hours or more if there are multiple failed sections.

Historical reliability for defective equipment XLPE cable is provided in the graph below.

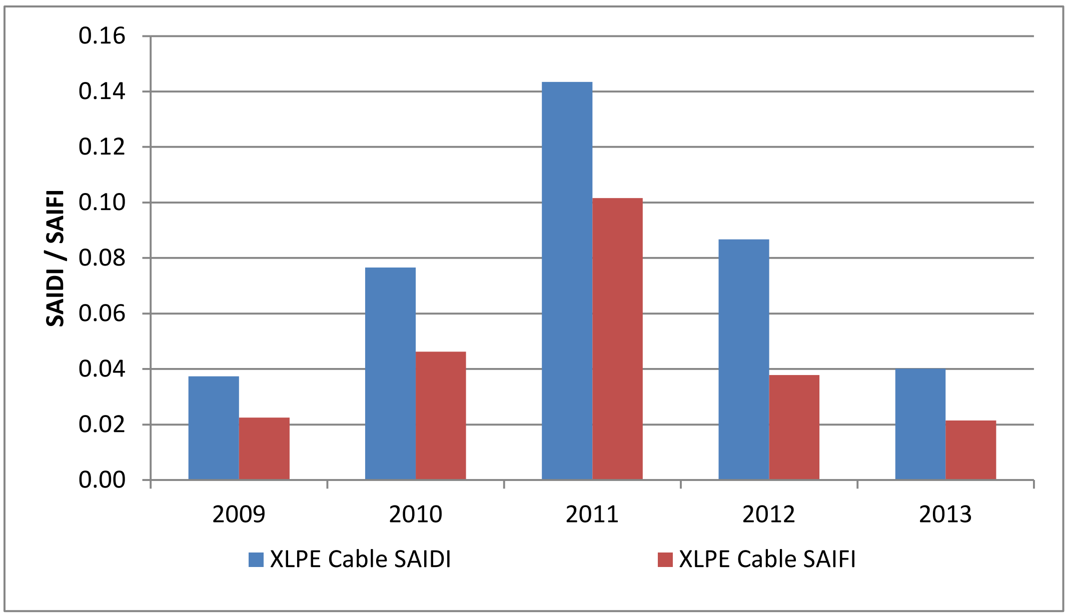


Figure 44 - Historical Impact on System SAIDI & SAIFI

7.2.4 Main and Secondary Drivers

The drivers are represented in the table below.

Driver		Explanation
Primary	**Failure Risk**	The percentage of cable that has passed end of life criteria is 22%. That will grow to 30% by the end of the rate filing period 2020. The number of cable faults is forecasted to increase at approximately 0.2% annually if the current level of investment is maintained.
Secondary	**Reliability**	Increasing number of cable failures have a negative impact on SAIFI and SAIDI

Table 41 – Cable Replacement Program Main Drivers

7.2.5 Performance Targets and Objectives

HOL employs key performance indicators for measuring and monitoring its performance. With the implementation of the cable replacement program, improvements are expected in the following measurements:

- Defective Equipment SAIDI
- Defective Equipment SAIFI

7.3 Project/Program Justification

7.3.1 Alternatives Evaluation

7.3.1.1 *Alternatives Considered*

In order to address the drivers and achieve the performance objectives of the program, HOL considered 3 alternatives for the replacement cable type to be used when replacing the underground cable as well as five alternatives for the replacement policy levels.

I. Cable Replacement Standard

1. Existing cable is replaced with tree-retardant crosslinked polyethylene (TR XLPE) cable which has proven to perform better than regular XLPE and butyl rubber cable which was installed in older areas of HOL service territory.
2. Where practical, cable will be installed in a direct buried duct for ease of installation and removal. Cable located in roadways or driveway will be installed in concrete encased ducts.
3. HOL is developing criteria for cable injection which is to extend the existing life of the cable section as an alternative to replacement.

II. Cable Replacement Policy

Using the condition model developed for underground cable, HOL analyzed an impact of several replacement alternatives on the performance outcomes. All the alternatives look to stabilize reliability levels beyond 2016-2020 rate filing period. The following scenarios were analyzed:

- Run-to-Failure scenario with only reactive replacement of cables
- Faults to increase at rate of 0.2 annually
- Status Quo: Maintain current fault level
- Faults to be reduced at rate of 0.2 annually
- Faults to be reduced at rate of 0.5 annually

7.3.1.2 *Alternatives Evaluation*

HOL evaluates all alternatives with consideration of the following criteria:

Criteria	Description
Failure / Reliability	The increased potential of failure posed by these aging assets will impact the organization’s ability to guard worker and public safety. The selected alternative shall maintain or improve the reliability performance of the system.
Safety	HOL puts the safety of its employees and the public at the center of its decision-making process. The preferred alternative must not impose additional risks on the

	safety of HOL's employees and the public.
Resources	Unplanned replacements are usually carried out by HOL's own crews, whereas planned replacements can utilize both internal and external resources. Therefore, alternatives that incur more on-failure replacements are less favourable as it will be more challenging from a resource perspective.
Financial	Financial costs and benefits shall include all direct and indirect impact on the utility's performance and rates. The preferred alternative shall be at least cost or the most beneficial in the long-term to the stakeholder and to the customers.

Table 42 – Alternative Evaluation Criteria

7.3.1.3 *Preferred Alternative*

I. Underground cable standard

Failure / Reliability

TR XLPE performs better than normal XLPE and butyl Rubber. Replacing existing cable with this type of cable will result in a longer service life for cable.

Cable injection effectively rejuvenates the cable to like-new, improving the condition and deferring the need for replacement to another date. Injecting the cables can only be performed once and will require replacement once the cable section had degraded.

Safety

Installing cables in direct buried or concrete encased ducts will help reduce accidental dig-ins with the possibility of electrification.

Resources

Installing ducts for cable requires greater upfront costs and labour time but will reduce future efforts when replacing cable.

Cable injection requires additional time isolating the section of cable so that it can be work on in a de-energized state.

Financial

Cable injection is much less costly than cable replacement however; cable injection is only deferring the replacement of the cable to a later date. Cable injections should be used strategically to levelize replacement costs.

II. Cable Replacement Policy

The preferred alternative is replacing cable to reduce faults at rate of 0.2 annually. This will be achieved through the replacement of, approximately 138,000m of cable per year.

The historical replacement level of 60,000m per year is not a feasible approach to replacement due to an increase in poor condition assets. This level of investment would see the annual fault rate increase at a rate of 0.2 annually. In order to maintain the current annual fault rate HOL forecasts that a level of replacement of approximately 98,000m of cable would have to be replaced annually. The investment policy alternatives are summarized in the table below.

Scenario		2013	2023	2033
Allow Faults to increase at a rate of 0.2 Annually	**Annual Cost**	$17,783,700	$17,667,300	$17,653,500
	Cable lengths replaced (m)	59,279	58,891	58,845
Maintain Current Fault Level	**Annual Cost**	$29,672,400	$29,555,700	$29,542,200
	Cable lengths replaced (m)	98,908	98,519	98,474
Reduce faults at a rate of 0.2 Annually	**Annual Cost**	$41,561,100	$41,444,400	$41,430,900
	Cable lengths replaced (m)	138,537	138,148	138,103
Reduce faults at a rate of 0.5 Annually	**Annual Cost**	$95,566,200	$75,388,200	$68,671,800
	Cable lengths replaced (m)	318,554	251,294	228,906
Reduce faults at a rate of 1 Annually	**Annual Cost**	$166,806,600	$146,628,600	$139,911,900
	Cable lengths replaced (m)	556,022	488,762	466,373

Table 43 - Cable Replacement Investment Scenarios

Failure / Reliability

HOL has analyzed the impact of several replacement policies using the degradation model developed for underground cables.

The average annual number of faults was calculated for the circuits which have had cable segments tested used by NRC (see Table below).

	Fault Rate (faults/100km/year)
Condition	Average
Like New	0.004
Good	0.012
Fair	0.018
Poor	0.021
Critical	0.039

Table 44 - Cable Failure Rates

As there have been several segments of cable tested on circuits, the result of the worst section was utilized to forecast overall condition of the segment. As cable segments selected for testing was based on the number of historic faults there was a bias towards cables representing poorer reliability than the system as a whole, which may have resulted in a higher fault rate than actual being forecasted.

Using the current age demographics for the cable, the cable condition distribution has been forecasted forward (neglecting the impact of new installations).

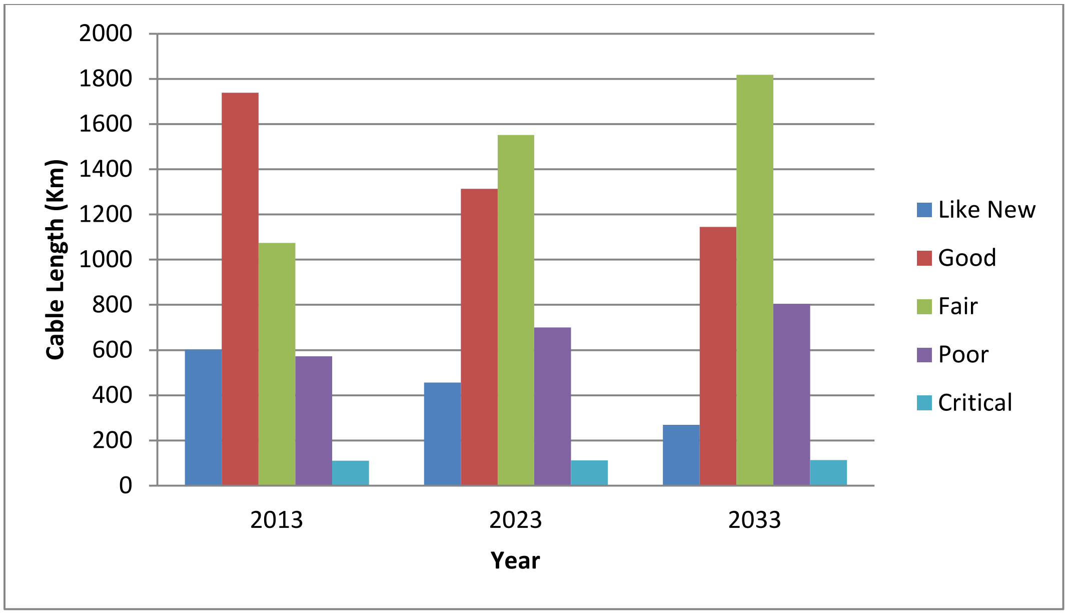


Figure 45 - Forecasted polymer cable condition

HOL has analyzed the impact of several replacement policies using the degradation model developed for underground cable. As previously outlined, in order to maintain a current fault rate for underground cable within the system a more aggressive replacement policy is required.

Safety

With a more aggressive approach to cable replacement direct buried installations will be reduced at an accelerated pace. In instances where risk to public is the exposure to trench cave-in exist this risk is reduced.

Resources

With assets on the system continuing to age and deteriorate, inadequate planned replacements of EOL assets will lead to the accumulation of poor/critical assets and potentially increase unplanned replacements that will stress the available resources of HOL at its current staffing level.

Financial

The costs associated with replacing cable in an emergency situation have been estimated to be upwards of double the cost of scheduled cable replacements. The do-nothing policy would see more frequent cable failures resulting in a high cost impact. By increasing the replacement policy, the average costs to replace cable, scheduled and unscheduled, will be reduced and provide long-term financial benefit.

Replacing unscheduled cable failures also affects HOL's ability to complete other planned projects throughout the year. With a do-nothing approach, both labour time and budget resources will be taken away from scheduled work throughout the year by focusing on replacing unscheduled failed cable.

7.3.2 Project/Program Timing & Expenditure

Information on the expenditures and length of cable replaced that was completed over the historical period is shown below. The average cost per meter of cable replaced in projects, historically, has been $350 per metre.

	Historical ($M)					Future ($M)				
	2011	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Total Expenditure	$2.26	$3.4	$5.12	$5.3	$5.4	$5.97	$5.26	$6.07	$5.5	$5.74
Km Replaced	6.15	15.64	14.57	12.9	15.4*	17.1*	15*	17.3*	15.7*	16.4*

Table 45 - Expenditure History of Comparative Projects

*Future kilometres replaced are approximate values

Specific Cable Replacement projects are coordinated to allow for optimal efficiency of crew resources by sub-dividing the work into suitable packages by geographic region or operational zones. To ensure cost-effectiveness, in conjunction with the cable replacement, all cable attachments are replaced and connecting transformers are reviewed and identified for replacement where required.

7.3.3 Benefits

Key benefits that will be achieved by implementing the cable replacement program are summarized in Table 46 below.

Benefits	Description
System Operation Efficiency and Cost-effectiveness	The costs associated with replacing cable in an emergency situation have been estimated to be upwards of double the cost of scheduled cable replacements. The do-nothing policy would see more frequent cable failures resulting in a high cost impact. By increasing the replacement policy, the average costs to replace cable, scheduled and unscheduled, will be reduced and provide long-term financial benefit.
Customer	Improvement to Defective Equipment related reliability statistics due to the decrease in underground cable failures: reduced failure rate.
Safety	Cable replacement reduces the risk of cave-ins where cables are not fed in a concrete encased duct, thereby reducing the health and safety risk to employees and the public.
Cyber-Security, Privacy	(Not applicable)
Co-ordination, Interoperability	(Not applicable)
Economic Development	HOL hires third party contractors to complete certain projects when the projects cannot be completed with our own internal resources.
Environment	(Not applicable)

Table 46 – Cable Replacement Program benefits

7.4 Prioritization

7.4.1 Consequences of Deferral

If this program is deferred to the next planning period or adequate replacement levels are not achieved this asset group will pose an increased risk to safety and reliability, as a result of the increase in cable failures per year.

Deferral of cable replacements will also create a backlog of poor condition cable that will require an increased level of investment in the future. As evident in the figure below, if increase in cable replacements is deferred until 2020 the cable demographics show a higher level of assets in poor condition.

7.4.2 Priority

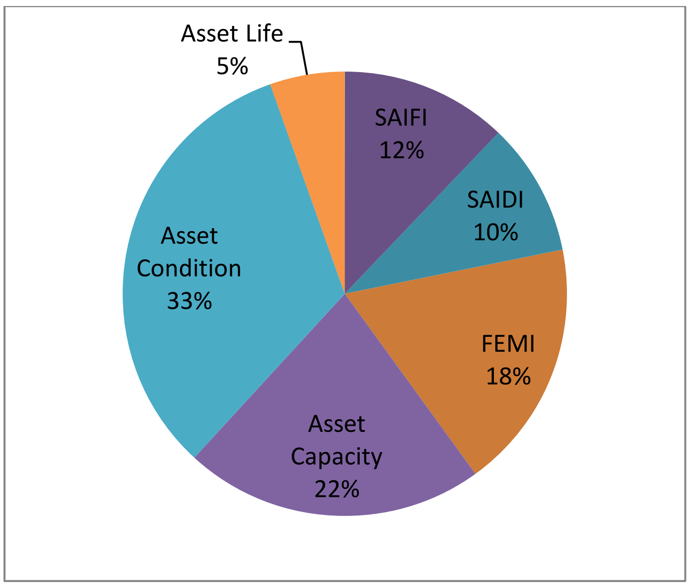


Figure 46 - Typical Cable Replacement Project Scoring Breakdown

Typical project score: 1.1

7.5 Execution Path

7.5.1 Implementation Plan

In 2014, HOL started proactively replacing the butyl rubber cable in Ottawa's Nepean community. The projects will span 2015 and 2016, effectively removing the majority of butyl rubber cable in the system.

In 2014, a project was initiated to replace and upgrade the underground cable along Stittsville Main Street which has seen poor reliability over the last few years. The cables will also be increased in size to accommodate increased capacity requirements. The project will continue until 2016.

The underground cable in the Blackburn community has had degrading reliability over the past years and will be replaced in a multi-phase project starting in 2015-2017.

The underground cable in the Beaconhill community has had degrading reliability over the past years and will be replaced in a project starting in 2016.

7.5.2 Risks to Completion and Risk Mitigation Strategies

Risk	Mitigation
Typical risks to completion include: • Obtaining road cut permits from the City of Ottawa; • Coordinating activities in areas where multiple parties are working; • Getting approval for traffic plans where required • Access to residential backyards and removal of customer installed structures	It is standard practice to engage early and communicate plans for future work with the City of Ottawa to coordinate effort and potential resources.

Table 47 - Cable Replacement Risks and Mitigation

7.5.3 Timing Factors

Cable replacements typically take place in the spring, summer, and fall months to avoid winter construction costs from contractors and the forming of concrete structures in cold temperatures.

7.5.4 Cost Factors

Cost factors that typically affect projects are:

- Requirement for direct buried ducts and concrete encased ducts
- Backyard cable installation
- Replacement of transformers and switchgear that have been deemed cost-effective to replace in conjunction with the cable.

7.5.5 Other Factors

N/A

7.6 Renewable Energy Generation

(Not applicable for this program)

7.7 Leave-To-Construct

(Not applicable for this program)

7.8 Project Details and Justification

7.8.1 2015 Cable Injection

Project Name:	Cable Injection 2015
Project Number:	92008682
Capital Cost:	$500,000
O&M:	N/A
Start Date:	2015 – Q1
In-Service Date:	2015 – Q4
Investment Category:	System Renewal
Main Driver:	Risk of Failure
Secondary Driver(s):	Reliability
Customer/Load Attachment	N/A

Project Scope

This is a cable injection project that is used to extend the life of direct buried cables that have been identified as successful candidates for this project. Cable Injection locations are identified through the results of a cable testing program carried out across the city in areas based on fault history and age. The life of a direct buried cable that has been injected can be extended by 40 years.

Priority

Score: 0.53

Work Plan

The project will begin in 2015, most likely in Q2/Q3 due to the weather. This project also identifies transformers, elbows and joints that are damaged and need to be replaced.

Customer Impact

This project increases the reliability to the customers in the areas identified, and also eliminates the need for cable replacement due to the extension of life of the buried cables.

7.8.2 Beaconhill Cable Replacement – Tisdale Crescent

Project Name:	Beaconhill Cable – Tisdale Crescent
Project Number:	92010259
Capital Cost:	$212,000
O&M:	N/A
Start Date:	2015 – Q1
In-Service Date:	2015 – Q4
Investment Category:	System Renewal
Main Driver:	Risk of Failure
Secondary Driver(s):	Reliability
Customer/Load Attachment	100 customers/ 500 kVA

Project Scope

This is the final phase of a cable replacement project in the Beaconhill Area. This is an area that was identified for a cable replacement as the cables were shown to test in poor condition and were also an older vintage.

Location: Beaconhill Area, Tisdale Crescent

Priority

Score: 1.093

Work Plan

For cable replacement projects the civil work will typically begin between April and July when the weather become more ideal for outdoor construction. The electrical work generally begins sometime after between August and October. In certain cases considerations of the customers must take place which adjusts the dates of the work plan.

Customer Impact

The customers in this area will experience increased reliability and decreased risk of interruptions due to asset failure.

7.8.3 48M4 & 48M5 Cable Replacement

Project Name:	48M4 & 48M5 Cable Replacement
Project Number:	92008700
Capital Cost:	$841,262
O&M:	N/A
Start Date:	2014 – Q1
In-Service Date:	2015 - Q4
Investment Category:	System Renewal
Main Driver:	Risk of Failure
Secondary Driver(s):	Reliability
Customer/Load Attachment	10 MVA

Project Scope

This is a cable replacement project which will replace the existing direct buried underground cables (3 circuits are left to transfer), which are currently located within a HOL easement. The duct structure is already in place, this will be used to pull in new cable.

Also this project includes the installation of 6 new 60' poles and finish construction on the concrete duct structure to each new pole (duct structure was installed during the summer/fall 2008 parallel to the existing cables) within our 20-meter easement. Upon completion of the concrete duct structure with the 6 new poles, new primary high voltage cables will be pulled into the duct structure.

Location: 48M5 crossing the 417 south of Cyrville Substation

Priority

Score: 0.69

Work Plan

Pending all permits and land access issues are resolved HOL would like to start civil construction after August 15, 2015
The electrical work will begin after civil work has been completed
Ground water testing will be required around the poles that are located on NCC property (4 poles west of Hwy 174, 2 poles east of Hwy 174)

Customer Impact

This project will increase the reliability and decrease the risk of asset failure in the area, also the ability of the system to operate through adverse weather without interruption is improved.

7.8.4 Butyl Rubber Cable Replacement – Craig Henry Drive

Project Name:	Butyl Rubber Rep. Craig Henry Drive
Project Number:	92008533
Capital Cost:	$1,604,722
O&M:	N/A
Start Date:	2015 – Q2
In-Service Date:	2015 – Q4
Investment Category:	System Renewal
Main Driver:	Asset Condition, Risk of Failure
Secondary Driver(s):	Reliability
Customer/Load Attachment	106 customers

Project Scope

The project involves replacement of approximately 3km of existing underground Butyl Rubber primary cable (direct buried cable) and 10 pad mounted transformers which are end of life.
This project will eliminate some of the last remaining butyl rubber cable in the South. Direct buried cable will be replaced with ducts, thus increasing reliability and decreasing restoration time. New transformer bases will be installed.

Priority

Score: 1.0133

Work Plan

Install new direct buried ducts and new cable.
Replace underground pad mounted transformers.
Routing options still being assessed.

Customer Impact

Reliability improvements due to new equipment and elimination of end of life assets.
Faster restoration time due to installation of direct buried ducts.
Multiple faults have occurred in this area already.
Possible routing alternatives to avoid disruption of customer backyards.

7.8.5 QCH Egress Cable Replacement

Project Name:	QCH Egress Cable Replacement
Project Number:	92010208
Capital Cost:	$333,578
O&M:	N/A
Start Date:	2015 – Q2
In-Service Date:	2015 - Q4
Investment Category:	System Renewal
Main Driver:	Asset Condition, Risk of Failure
Secondary Driver(s):	Reliability
Customer/Load Attachment	1160 customers/ 2363 kVA

Project Scope

This project involves the replacement of the 160F1, 160F2, 160F3 and 160F4 350MCM XLPE direct buried egress cable. These cables have reached end of life and in 2014 there was a cable fault on the 160F1. The 160F1 and 160F3 are the only back-ups to the Bayshore Mall.

Priority

Moved ahead from 2016 into 2015 due to concerns about cable condition.

Work Plan

New riser poles were installed within the past two years. New egress cable will be installed and placed into concrete encased duct. A small segment of direct buried duct (no concrete) will be installed at connection point from egress to station foundations, to allow for emergency access.

Customer Impact

Reliability improvements due to new equipment, reliable backup supply.
Mitigate risk of full feeder outages.

7.8.6 Stittsville Main Cable Replacement & Switchgear Upgrade

Project Name:	Stittsville Main Cable Replacement & SG Upgrade
Project Number:	92008567
Capital Cost:	$2,868,447
O&M:	$0
Start Date:	2014 – Q1
In-Service Date:	2016 – Q3
Investment Category:	System Renewal
Main Driver:	Reliability
Secondary Driver(s):	Risk of Failure
Customer/Load Attachment	4903 customers/ 11000 kVA

Project Scope

The driver of this project is to get a switchable trunk down Stittsville Main Street. Included is upgrading the 27.6kV cable to 1000MCM from S20 to S18 and will require 4 new Vista Switchgears. A separate distribution loop will be created to pick up all existing customers.

Also some reconfiguration of the customers around S20 will be required with some cost sharing from the commercial customers in the area. All 8.32kV supplied customers between S20 and S18 will be converted to be supplied by 27.6kV - allowing S17 primary pedestal to be removed.

The 8.32kV line is currently a mix of overhead and underground, which will all be switched to underground in the future.

Priority

Score: 1.2833 (2015), 1.76 (2016)

Work Plan

The work plan for this project is as follows:

- Design civil infrastructure for Stittsville Main (Ravenscroft Court to Abbott Street) to be completed with Poole Creek being the divider of 2014 and 2015 work.
- Limited electrical isolation by crews to occur throughout civil construction.
- Civil work is to prepare for complete cable replacement in Phase 3 - 2016
- Phase 3 – complete electrical primary cable replacement to be completed by HOL in 2016

Customer Impact

This project will increase capacity, reliability and switching capability in Stittsville as well as will set up the community for future voltage conversion to be solely supplied by 27.6kV.

7.8.7 2016 Cable Injection

Project Name:	Cable Injection 2016
Project Number:	92010229
Capital Cost:	$500,000
O&M:	N/A
Start Date:	2016 – Q1
In-Service Date:	2016 – Q4
Investment Category:	System Renewal
Main Driver:	Risk of Failure
Secondary Driver(s):	Reliability
Customer/Load Attachment	N/A

Project Scope

This is a cable injection project that is used to extend the life of direct buried cables that have been identified as successful candidates for this project. Cable Injection locations are identified through the results of a cable testing program carried out across the city in areas based on fault history and age. The life of a direct buried cable that has been injected can be extended by 40 years.

Priority

Score: 0.577

Work Plan

The project will begin in 2016, most likely in Q2/Q3 due to the weather. This project also identifies transformers, elbows and joints that are damaged and need to be replaced.

Customer Impact

This project increases the reliability to the customers in the areas identified, and also eliminates the need for cable replacement due to the extension of life of the buried cables.

7.8.8 Pothead Replacement – 470 Cambridge

Project Name:	Pothead Replacement at 470 Cambridge
Project Number:	92010289
Capital Cost:	$25,127
O&M:	N/A
Start Date:	2016 – Q1
In-Service Date:	2016 – Q4
Investment Category:	System Renewal
Main Driver:	Risk of Failure
Secondary Driver(s):	Reliability
Customer/Load Attachment	27 customers/ 550 kVA

Project Scope

This project will see the replacement of a pothead, leaning pole, broken pole lateral, and cables to the customer's vault. There is a broken concrete lateral at the base of the pole X25770 and it is putting strain on the lead primary cable going into vault V220 from the pole's pothead. The pole is beginning to slant which can add to the stress on the cables.

Priority

Score: 0.867

Work Plan

For this project a fleet will be dispatched to 470 Cambridge with appropriate equipment. They will install a new pole while replacing the pole top equipment. New cable will be installed into the customer's vault and a new concrete pole lateral will be installed.

Customer Impact

The customers at 470 Cambridge will experience a scheduled sustained outage while crews are undertaking the work. This outage will be coordinated with the customer. This is a benefit to the alternative which would be an unplanned sustained outage due to pole/lateral failure.

7.8.9 Blackburn 4F8 Cable Replacement – Phase 4

Project Name:	Blackburn 4F8 – Phase 4
Project Number:	92008609
Capital Cost:	$1,610,836
O&M:	N/A
Start Date:	2017 – Q1
In-Service Date:	2017 – Q4
Investment Category:	System Renewal
Main Driver:	Risk of Failure
Secondary Driver(s):	Reliability
Customer/Load Attachment	50 customers/ 300 kVA
Project Scope	
This reliability driven project replaces direct buried residential cable on the 4F8 circuit in Blackburn. This circuit has been prioritized due its significant fault history and poor results from cable testing. This is one of the three final phases in the Blackburn Cable Replacement Project.	
Priority	
Score: 0.62	
Work Plan	
For cable replacement projects the civil work will typically begin between April and July when the weather become more ideal for outdoor construction. The electrical work generally begins sometime after between August and October. In certain cases considerations of the customers must take place which adjusts the dates of the work plan.	
Customer Impact	
This project will increase the reliability and decrease the risk of failure in this neighbourhood.	

7.8.10 Butyl Rubber Cable Replacement – Tanglewood Subdivision

Project Name:	Butyl Rubber Replacement – Tanglewood Subdivision
Project Number:	92010206
Capital Cost:	$2,540,156
O&M:	N/A
Start Date:	2016 – Q1
In-Service Date:	2016 – Q4
Investment Category:	System Renewal
Main Driver:	Asset Condition, Risk of Failure
Secondary Driver(s):	Reliability
Customer/Load Attachment	386 customers/ 2421 kVA

Project Scope

This project involves the replacement of 2.7km of butyl rubber cable and the replacement of 16 end of life transformers.
This project will eliminate some of the last remaining butyl rubber cable in the South. Direct buried cable will be replaced with ducts, thus increasing reliability and decreasing restoration time. New transformer bases will be installed.

Location: Woodfield Drive, Downsview Crescent, Benlea Drive; Bordered by Hydro One Corridor and City of Ottawa Land.

Priority

Score: 1.0133

Work Plan

Install new direct buried ducts and new cable.
Replace underground pad mounted transformers.

Customer Impact

Reliability improvements due to new equipment and elimination of end of life assets.
Faster restoration time due to installation of direct buried ducts.
Multiple faults have occurred in this area already.

8 Underground Switchgear Replacement

8.1 Project/Program Summary

Underground distribution switchgear at HOL is used to provide switching and isolation points as well as overcurrent protection for loads on the underground distribution system. The underground switchgear replacement program targets the planned replacement of air-insulated padmounted switchgear and pedestal switches to maintain system reliability and safety in the most cost-effective manner.

8.2 Project/Program Description

8.2.1 Assets in Scope

The Underground Switchgear Replacement program scope encompasses the planned replacement of approaching end of life underground distribution air-insulated padmounted switchgear and pedestal switches due to functional and safety concerns. The switchgears identified for replacement present the highest failure rate and pose reliability issues due to environmental and operational factors.

Gas and oil operated padmounted switchgears and all vault switchgears including wall-mounted switches will not require proactive replacement in 2016-2020 as they are not approaching end of life and are, in general, in good condition.

Underground padmounted air-insulated switchgears will be replaced on a like-for-like basis in accordance with the current HOL practice using SF6 underground switchgear. New SF6 switches have sealed enclosures which are better protected against dirt or moisture, therefore are expected to provide longer life. The sealed enclosure also enables elbow operated operation of the switchgear which provides more operator safety when compared with air-insulated switchgear which has some live components exposed. In addition, this switchgear requires less maintenance costs over the life-cycle. Figure 47 and Figure 48 show the inside of air-insulated switchgear and SF6 switchgear, respectively.

Figure 47 – Inside of air-insulated switchgear

Figure 48 - Inside of SF6 underground switchgear

HOL plans to replace 20 primary pedestals in both the South and West ends of the city and on average 3 to 5 pieces of live front switchgear across the system to minimize reliability risks associated with these switchgears.

Section 8 of this business case lists specific projects for switchgears at their end of life targeted for replacement in 2016 and 2017.

8.2.2 Asset Life Cycle and Condition

Underground switchgears in HOL's distribution system include padmounted, vault, and submersible units. Based on the existing records, HOL owns 439 padmounted switchgears, 191 vault switchgears, and 2 submersible switchgears. Wall-mounted, stick-operated switches in the system have been included in the analysis with vault switchgear, although these are not strictly considered to be "switchgears".

Detailed records do not exist for the underground switchgear class and therefore the demographics have been estimated using available records. While these estimates provide an initial baseline for analysis, collection and consistent representation of switchgear information in a centralized repository is essential to enable accurate asset assessment in the future.

There are many sub-types of the switchgears with different insulating media and various interrupting styles. The distribution of sub-types is shown in Figure 49, which depicts the padmounted switchgear and Figure 50, which depicts the vault switchgear population by type.

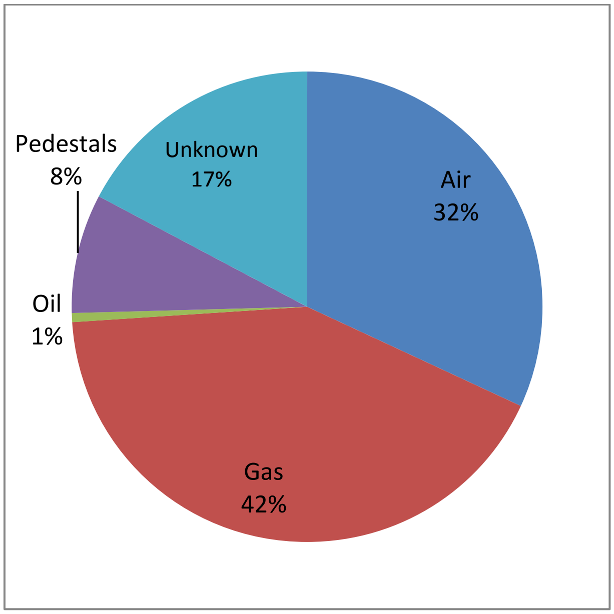


Figure 49 - Padmounted switchgear population by type

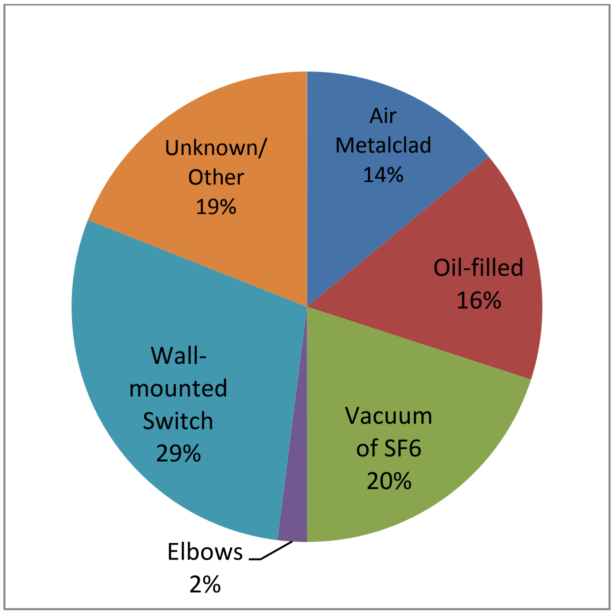


Figure 50 - Vault switchgear population by type

The life expectancy of padmounted switchgears is 25 years and is impacted by a number of factors including the frequency of switching operations, load dropped, the presence of a corrosive environment, and dampness at the installation site.

The life expectancy of vault switchgears is 30 years and may be affected by environmental factors; including salt water, pollutants, UV light, and frequent wet/dry cycles. The life expectancy may also be affected by electrical and mechanical stresses due to a high number of operations.

HOL follows industry standard practices of running switchgears to end of life, just short of failure. To extend the life of these assets, a number of intervention strategies are employed on a regular basis such as inspections with thermographic cameras and cleaning with CO_2 for air-insulated padmounted switchgears and inspection and cleaning for vault switchgear. If problems or defects are identified during inspection, often the affected component can be replaced or repaired without a total replacement of the switchgear.

Switchgear failures may not directly be linked to the age of the asset. Padmounted switchgears may fail due to dirt/contamination, vehicle accidents, rusting of the casing, and broken insulators caused by misalignment during switching. As such, HOL's padmounted switchgear inspection program seeks to identify and remediate certain degradation modes. Dirt and contaminant accumulation can often be removed by cleaning. Re-painting and touch-ups of the casing can delay the rusting process, but eventually a planned replacement of the unit is still required.

Moisture ingress into the insulation tank of a vault switchgear can lead to equipment failure by decreasing the insulation properties in an oil-immersed switchgear or form corrosive acids in an SF_6 switchgear. Breakdown of the switchgear's insulation due to electrical stress may also lead to asset failure on subsequent operations. The switchgear's operating mechanism and bearings and linkages wear out over time. Furthermore, the electrical contacts of the switchgear may degrade to the point that the units fails. HOL's maintenance program seeks to extend the life of its vault switchgears by cleaning dirt and contamination, maintaining bearings and linkages, and repairing defects.

Switchgears are identified and prioritized for replacement based on condition and consequence. Condition information is gathered through the three year cycle Padmounted Switchgear Infrared (IR) and Visual Inspection program. Consequence scoring is based on the number of customers that will be affected by the interruption, the duration of the interruption, the environmental risk and the health and safety risk.

The age demographics of the padmounted switchgears are presented in Figure 51.

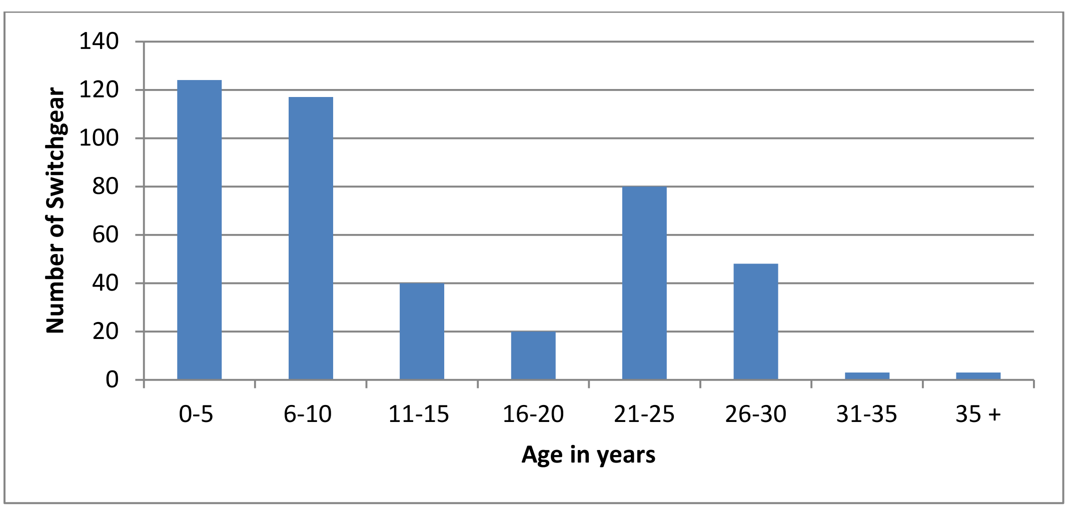


Figure 51 - Padmounted switchgear population by age group (in years)

8.2.3 Consequence of Failure

Although the effects are not as severe as station switchgear failures, underground switchgear failures diminish HOL's ability to provide reliable electricity service to its customers. A switchgear failure causes an outage, the severity of which depends on the number of affected customers and the duration of the outage.

Oil-immersed switchgears may leak oil into the environment upon failure. SF6 is a greenhouse gas, thus a gas leak due to failed SF6 switchgear is detrimental to the environment. Furthermore, SF6 may form corrosive acids when it reacts with water. SF6 is heavier than air and therefore may pose a suffocation danger if leaked into a contained area by displacing breathable oxygen from the air. Rusting on the casing of a padmounted switchgear can lead to perforation and is a public safety hazard.

HOL measures the defective equipment contribution to SAIFI in customer interruptions per 100 customers served. Figure 52 depicts the SAIFI contribution by defective underground switchgears for the years 2009 to 2013. The five-year average over this time period is 1.82 customer interruptions per 100 customers. Due to the small sample size in the number of underground switchgear, the effect on SAIFI varies between years and is not indicative of trends or patterns.

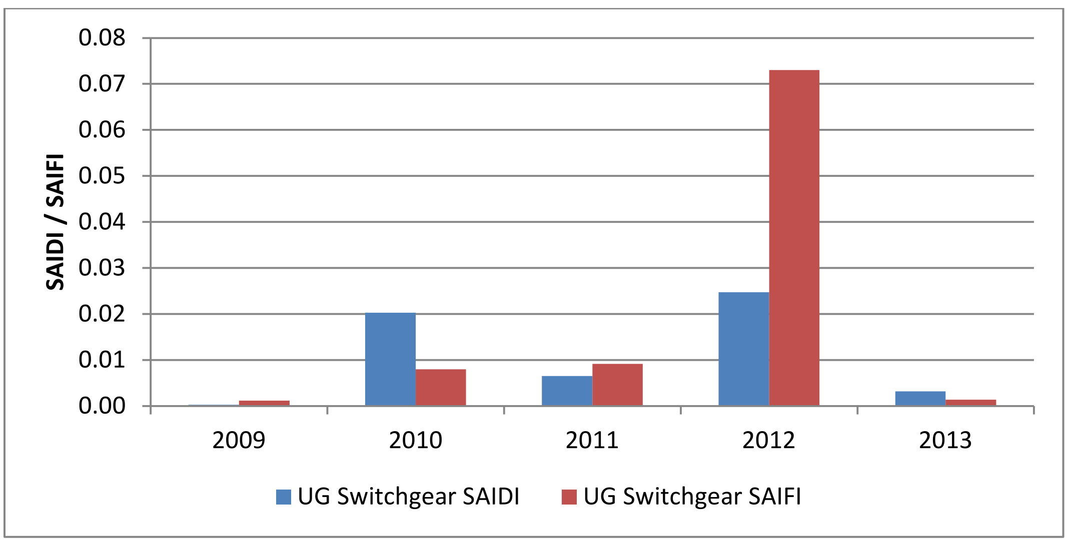


Figure 52: Defective underground switchgear on overall SAIDI/SAIFI

8.2.4 Main and Secondary Drivers

The drivers are represented below.

Driver		Explanation
Primary	**Failure Risk**	Air-insulated switchgears are reaching the end of life and are a critical part of the distribution system.
Secondary	**System Efficiency**	Newly installed styles of switchgears (SF6) require minimal maintenance in comparison with air-insulated switchgears.

Table 48 - Switchgear Replacement Program Drivers

8.2.5 Performance Targets and Objectives

HOL will minimize the number of underground switchgear failures through replacement of the worst condition end of life units. Another objective is to maximize operational efficiency by minimizing maintenance costs through replacement of switchgears with units that require less maintenance.

8.3 Project/Program Justification

8.3.1 Alternatives Evaluation

8.3.1.1 *Alternatives Considered*

The following alternatives have been considered:

- Run-to-Failure with only reactive replacement of the switchgears (Do-Nothing),
- Proactive replacement of all switchgear older than their 25 year life expectancy
- Proactive replacement of approximately three (3) to four (4) worst condition end of life switchgear annually while continuing maintenance and inspection program

8.3.1.2 *Evaluation Criteria*

HOL evaluates all alternatives with consideration of the criteria summarized below.

Criteria	Description
Failure / Reliability	The increased potential of failure posed by these aging assets will impact the organization's ability to guard worker and public safety. The selected alternative shall maintain or improve the reliability performance of the system.
Safety	HOL puts the safety of its employees and the public at the center of its decision-making process. The preferred alternative must not impose additional risks on the safety of HOL's employees and the public.
Resource	Unplanned replacements are usually carried out by HOL's own crews, whereas planned replacements can utilize both internal and external resources. Therefore, alternatives that incur more on-failure replacements are less favorable as it will be more challenging from a resource perspective.
Financial	Financial costs and benefits shall include all direct and indirect impact on the utility's performance and rates. The preferred alternative shall be at least cost or the most beneficial in the long-term to the stakeholder and to the customers.

Table 49 - Criteria used to evaluate alternatives

8.3.1.3 *Preferred Alternative*

The preferred alternative is the proactive replacement of approximately three (3) to four (4) worst condition, end of life switchgears annually while continuing maintenance and inspection programs.

	Do-Nothing	Replace All Switchgear older than 25 years	Proactively replace 3-5 switchgear and inspect and maintain
Failure / Reliability	Increased annual failures and worse reliability through unplanned failures	All older switchgear are replaced increasing reliability	Worst condition switchgear replaced – reliability maintained
Safety	Least safe option as switchgear is run-to-failure	All older switchgear are replaced increasing safety	Worst condition switchgear replaced increasing safety
Resource	Unplanned replacements are less efficient from a resource perspective	Large amount of resources required	Resourcing is levelized annually
Financial	Least expensive option at first, however unplanned replacement is more expensive than planned replacement	Most expensive solution	Most cost-effective solution as replacement is optimized

Table 50 - Switchgear Replacement Alternatives

Run-to-Failure with only reactive replacement of the switchgears (Do-Nothing)

This alternative involves ceasing the planned replacement of underground switchgear and allowing the assets to run-to-failure. This alternative is least costly at first. However, the cost associated with replacing switchgear in an unplanned emergency is substantially higher than the cost of planned replacement. This is due to many factors including over time labour and organizing civil contractors that are used for emergency replacement. Therefore, in the long term this alternative will be more expensive than a planned program. This alternative also inherently results in worse reliability and safety.

Proactive replacement of all switchgear older than their 25 year life expectancy

This alternative replaces all switchgears which have exceeded 25 years of age. This alternative should result in improved switchgear reliability and maintenance. However, large amounts of resources will be required at first to achieve this alternative. Additionally, this is the most expensive alternative and may result in unnecessary replacement of some switchgears which are still in good condition

Proactive replacement of approximately three (3) to four (4) worst condition end of life switchgear annually while continuing maintenance and inspection program

This alternative utilizes data collected from the annual 3 year rotational inspection program to identify the worst condition switchgear to be scheduled for replacement. This alternative maintains reliability and maintenance through inspection and targeted replacement. This is the most cost-effective of the three since it relies on planned replacement and levelized annual resourcing.

8.3.2 Project/Program Timing & Expenditure

The following table shows the historical and future capital expenditure in the underground switchgear replacement program and the number of units replaced each year.

	Historical						Future			
	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Expenditure ($M)	$1.14	$1.73	$1.09	$0.67	$0.16	$1.22	$0.38	$0.43	$0.39	$0.41
Units Replaced	5	10	7	5	2	8	4	4	4	4

Table 51 - Historical and forecast investments in underground switchgear replacements

8.3.3 Benefits

Benefits	Description
System Operation Efficiency and Cost-effectiveness	SF6-insulated switchgears require less maintenance than oil-immersed or air-insulated units, thus reducing O&M costs over the lifecycle of the asset. The proactive replacement of units at end of life but before failure results in labour cost savings compared to unplanned replacement of a failed unit.
Customer	The new SF6 switchgear units are relatively compact and provide an intangible benefit to customers since they are less intrusive than older, bulky units. The proactive replacement of an underground switchgear before failure prevents unplanned outages from occurring, improving system reliability for customers.
Safety	Underground switchgear replacements mitigate potential safety hazards due to leaking SF6 gas and live components exposed by rusting enclosures.
Cyber-Security, Privacy	N/A
Co-ordination, Interoperability	N/A
Economic Development	Improved system reliability has a subtle, yet direct impact on economic development, as local businesses and self-employed residents benefit.
Environment	Underground switchgear replacements mitigate potential environmental damage due to leaking oil or SF6 gas from units at their end of life.

Table 52 - Switchgear Replacement Benefits

8.4 Prioritization

8.4.1 Consequences of Deferral

The probability of failure of a distribution switchgear increases every year. The assets targeted in the replacement program are at end of life and will fail if not replaced, causing an outage and requiring the failed unit to be replaced at a higher cost than a planned replacement.

8.4.2 Priority

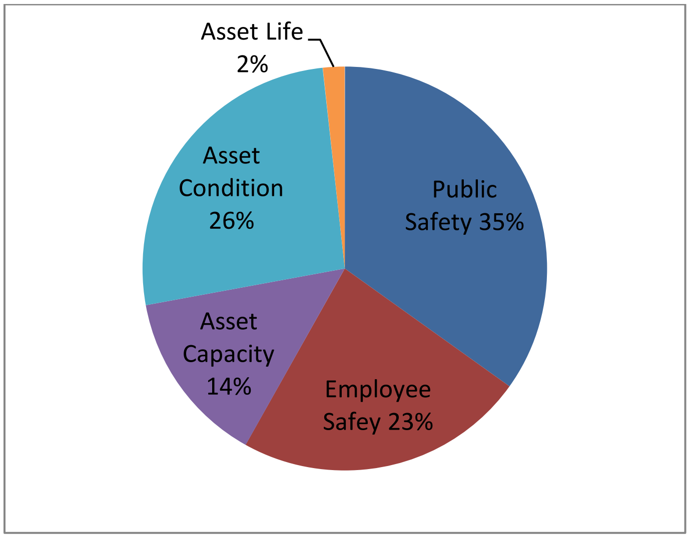


Figure 53 - Switchgear Replacement Avoided Risk

Project Score: 1.72

8.5 Execution Path

8.5.1 Implementation Plan

Replacement of distribution switchgear may occur year round. Old switchgear will be de-energized while crews remove the old switchgear and base. Civil contractors will then install a new switching manhole and the new switchgear will be installed on the new manhole and be commissioned.

8.5.2 Risks to Completion and Risk Mitigation Strategies

Risk	Mitigation
Typical risks to completion include: Project planning to minimize outages to customers and that coordinate with other planned work in the area.	It is HOL practice to schedule and coordinate all work (planned and emergency) through our System Office to ensure effective use of resourcing and ensure continued system operability and safety in areas where crews are working.

Table 53 - Switchgear Replacement Program Risks and Mitigation

8.5.3 Timing Factors

Work scheduling of resources in coordination with other HOL underground work is a timing risk.

8.5.4 Cost Factors

None identified.

8.5.5 Other Factors

None identified.

8.6 Renewable Energy Generation (if applicable)

N/A

8.7 Leave-To-Construct (if applicable)

N/A

8.8 Project Details and Justification

8.8.1 S124 Pedestal to Switch Replacement

Project Name:	S124 Pedestal to Switch
Project Number:	92008601
Capital Cost:	$166,395
O&M:	$0
Start Date:	2015 – Q2
In-Service Date:	2015 – Q4
Investment Category:	System Renewal
Main Driver:	Risk of Failure
Secondary Driver(s):	Reliability
Customer/Load Attachment	1953 customers/ 9131 kVA

Project Scope

This project involves the replacement of a primary pedestal S124 (MWDF2) due to EOL, with the installation of a new padmounted switchgear SC6881. The switch will be incorporated with future cable upgrades and will enable Katimavik voltage conversion from 12.43kV to 27.6kV.

Priority

Score: 0.15

Work Plan

A HOL Contractor will be responsible for supplying and installations of switching manhole and ducts. HOL will supply all material (primary cables, switchgear and splice kits) and will be responsible for primary cables installations, splicing and terminations/connections.

Civil and electrical work should be ready before the isolation of the single customer supplied by the pedestal - vault 4592.

HOL will replace existing SMD-20 switches with a new one inside vault 4592

Customer Impact

This project will help improve the reliability and power quality of the electrical system at 150 Katimavik Road.

8.8.2 SE20 Replacement & Relocation

Project Name:	SE20 Replacement & Relocation
Project Number:	92010212
Capital Cost:	$107,818
O&M:	N/A
Start Date:	2015 – Q1
In-Service Date:	2015 – Q4
Investment Category:	System Renewal
Main Driver:	Risk of Failure, Flooding Issues
Secondary Driver(s):	Reliability
Customer/Load Attachment	746 customers/ 2219 kVA
Project Scope	
This project includes the replacement and relocation of the SE20 switchgear based on inspection results and a history of flooding issues at this switchgear location. The switchgear will be relocated to higher ground, closer to the road and protected with bollards. Application to the MTO will be required. The attached transformer was recently replaced and will not be moved. The old switchgear location will become a splice pit. Location: West Hunt Club Road and Cedarview Road	
Priority	
Score: 1.20	
Work Plan	
MTO permit will be obtained before construction begins. SE20 will be replaced with a new SF6 switchgear including a new base and relocated to higher ground near the road. Old switchgear location will be used as splice pit. Bollards will be installed.	
Customer Impact	
Reliability improvement due to new equipment. No more flooding issues causing outages.	

8.8.3 SW89 Switchgear Replacement

Project Name:	SW89 S/G Replacement
Project Number:	92010261
Capital Cost:	$122,360
O&M:	N/A
Start Date:	2016 – Q2
In-Service Date:	2016 – Q4
Investment Category:	System Renewal
Main Driver:	Risk of Failure
Secondary Driver(s):	Reliability
Customer/Load Attachment	300 customers / 1000 kVA
Project Scope	
This project involves the replacement of an existing switchgear, SW89 near Thurston and Conroy, with a new S&C Vista switchgear. This project was identified through Siemens S/G inspection and IR scan. The age of the switchgear is 1986 vintage.	
Priority	
Score: 1.48	
Work Plan	
This civil and electrical work for this project is scheduled to being in Q2- 2016 and will be complete before then end of the year. In certain cases considerations of the customers must take place which may adjust the dates of the work plan.	
Customer Impact	
Customers in this area will experience increased reliability and power quality and decreased risk of asset failure	

8.8.4 SW190 Switchgear Replacement

Project Name:	SW190 S/G Replacement
Project Number:	92010263
Capital Cost:	$125,159
O&M:	N/A
Start Date:	2016 – Q2
In-Service Date:	2016 – Q2
Investment Category:	System Renewal
Main Driver:	Risk of Failure
Secondary Driver(s):	Reliability
Customer/Load Attachment	300 customers/ 1000 kVA

Project Scope

This project involves the replacement of an existing switchgear, SW190 located at 1051 Ages Drive, with a new S&C Vista switchgear.

This project was identified through Siemens S/G inspection and IR scan. The age of the switchgear is 1989 vintage.

Priority

Score: 1.39

Work Plan

This civil and electrical work for this project is scheduled to being in Q2- 2016 and will be complete before then end of the year. In certain cases considerations of the customers must take place which may adjust the dates of the work plan.

Customer Impact

Customers in this area will experience increased reliability and power quality and decreased risk of asset failure

8.8.5 S62 Switchgear Replacement

Project Name:	S62 Replacement
Project Number:	92010168
Capital Cost:	$170,666
O&M:	N/A
Start Date:	2016 – Q1
In-Service Date:	2016 – Q4
Investment Category:	System Renewal
Main Driver:	Risk of Failure
Secondary Driver(s):	Reliability
Customer/Load Attachment	3765 customers/ 24524 kVA

Project Scope

This project involves the replacement of switchgear S62, due to aging infrastructure, with an SEL automated Vista seitchgear. S62 is located at the corner of Kukulu Road and Pickford Drive.

Priority

Score: 1.72

Work Plan

This project is scheduled to start and be completed in 2016. To replace this switchgear it will be de-energized while crews remove the old switchgear and base. Civil contractors will then install a new switching manhole and the new automated switchgear will be installed on the new manhole and commissioned.

Customer Impact

Customers in this area will experience increased reliability and power quality and decreased risk of asset failure.

8.8.6 S98 Switchgear Replacement

Project Name:	S98 Replacement
Project Number:	92010160
Capital Cost:	$170,666
O&M:	$0
Start Date:	2016 – Q1
In-Service Date:	2016 – Q4
Investment Category:	System Renewal
Main Driver:	Risk of Failure
Secondary Driver(s):	Reliability
Customer/Load Attachment	857 customers/ 13481 kVA
Project Scope	
This project involves the replacement of switchgear S98, due to aging infrastructure, with an SEL automated Vista switchgear. The switchgear is located at Terry Fox and Mckinley.	
Priority	
Score: 1.72	
Work Plan	
This project is scheduled to start and be completed in 2016. To replace this switchgear it will be de-energized while crews remove the old switchgear and base. Civil contractors will then install a new switching manhole and the new automated switchgear will be installed on the new manhole and commissioned.	
Customer Impact	
Customers in this area will experience increased reliability and power quality and decreased risk of asset failure.	

8.8.7 S45 Switchgear Replacement

Project Name:	S45 Replacement
Project Number:	92010164
Capital Cost:	$170,666
O&M:	$0
Start Date:	2016 – Q1
In-Service Date:	2016 – Q4
Investment Category:	System Renewal
Main Driver:	Risk of Failure
Secondary Driver(s):	Reliability
Customer/Load Attachment	4097 customers/ 20508 kVA

Project Scope

This project involves the replacement of switchgear S45, due to aging infrastructure, with an SEL automated Vista switchgear. S45 is located at the intersection of Westlock Way and Knudson Drive.

Priority

Score: 1.72

Work Plan

This project is scheduled to start and be completed in 2016. To replace this switchgear it will be de-energized while crews remove the old switchgear and base. Civil contractors will then install a new switching manhole and the new automated switchgear will be installed on the new manhole and commissioned.

Customer Impact

Customers in this area will experience increased reliability and power quality and decreased risk of asset failure.

8.8.8 S54 Switchgear Replacement

Project Name:	S54 Replacement
Project Number:	92010162
Capital Cost:	$170,666
O&M:	$0
Start Date:	2016 – Q1
In-Service Date:	2016 – Q4
Investment Category:	System Renewal
Main Driver:	Risk of Failure
Secondary Driver(s):	Reliability
Customer/Load Attachment	1400 customers/ 800 kVA
Project Scope	
The project involves the replacement of switchgear S54, due to aging infrastructure, with an SEL automated Vista switchgear. S54 is located along Teron road, between Beaverbrook and The Parkway.	
Priority	
Score 1.72	
Work Plan	
This project is scheduled to start and be completed in 2016. To replace this switchgear it will be de-energized while crews remove the old switchgear and base. Civil contractors will then install a new switching manhole and the new automated switchgear will be installed on the new manhole and commissioned.	
Customer Impact	
Customers in this area will experience increased reliability and power quality and decreased risk of asset failure.	

8.8.9 S584 Switchgear Replacement

Project Name:	S584 Replacement
Project Number:	92010166
Capital Cost:	$170,666
O&M:	$0
Start Date:	2016 – Q1
In-Service Date:	2016 – Q4
Investment Category:	System Renewal
Main Driver:	Risk of Failure
Secondary Driver(s):	Reliability
Customer/Load Attachment	156 customers/ 17544 kVA

Project Scope

This project involves the replacement of switchgear S584, due to aging infrastructure, with an SEL automated Vista switchgear. S582 is located along Terry Fox Drive, close to the intersection with Helmsdale Drive.

Priority

Score: 1.72

Work Plan

This project is scheduled to start and be completed in 2016. To replace this switchgear it will be de-energized while crews remove the old switchgear and base. Civil contractors will then install a new switching manhole and the new automated switchgear will be installed on the new manhole and commissioned.

Customer Impact

Customers in this area will experience increased reliability and power quality and decreased risk of asset failure.

9 Overhead Distribution Switches & Reclosers

9.1 Project/Program Summary

Overhead distribution switches are used to isolate sections of the system for planned work or restoring customers from an interruption. They provide a means of protecting major system equipment as well as allowing circuits to be available for backup supply. The number of failures per year within this asset class is very minimal and as such, HOL employs a run-to-failure strategy for overhead switches. As an exception, there are three types of switches which have been identified as reaching end-of-life or defective presenting a safety concern.

9.2 Project/Program Description

9.2.1 Assets in Scope

HOL's overhead distribution switch and recloser asset class consists of all pole mounted load break switches, reclosers, fuse cut-outs and inline switches, with a primary voltage rating as high as 44kV. Equipment belonging to this asset class serves the main purpose of providing a means to isolate or re-route a section of overhead line due to a fault condition or planned work. Overhead switches and reclosers of varying size and type are located within all geographic areas covered by HOL's service territory and are found on all distribution feeders. The overhead switch and recloser program is typically a run-to-failure strategy, unless a technical or health and safety issue has been identified.

9.2.2 Asset Life Cycle and Condition

For the majority of this asset class, accurate demographic data exists within HOL's database. This includes known populations of reclosers, load break switches and inline switches. The number of fused cut-out switches in the system was estimated from the number of pole mounted transformer connections and fused switches in the database. Within these four switch types, there is a variety of switch sub-types that make up each category. The population distribution as of spring 2014 is shown in the following table, based on switch type and voltage class.

Switch Type	4.16kV	8.32kV	12.43kV	13.2kV	27.6kV	44kV	Total
Non-Load Break	1,610	2,293	39	1,342	1,467	483	7,234
Load Break	51	137	0	159	446	309	1,102
Cut-Outs	8,333	6,139	41	2,770	3,977	9	21,323
Reclosers	0	19	2	1	35	0	57

Table 54 - Overhead Switchgear Demographics

The typical useful life of the switches in the distribution system is 35 years.

There are two types of switches that have been identified as health and safety concerns. They are the 4.16kV rated porcelain box switches and the S&C Electric Company (S&C) 27.6kV SMD-20 porcelain and polymer fused cut-outs. Porcelain box switches have been identified as posing a safety and reliability risk due to issues of mechanical fracturing. There are four substations with a total of 28 sets of switches remaining that require porcelain box switch replacements. SMD-20 switches manufactured between 2004 and 2011 are reportedly experiencing failures when the switches are operated using a load break tool. There were approximately 2,800 S&C 27.6kV polymer and porcelain SMD-20 switches deployed in the system in 2013. HOL has initiated a replacement program for these switches. It is expected that the replacement of all porcelain box switches and SMD-20 switches will be completed in 2016.

HOL has started to experience failures on 13kV porcelain cut-out switches installed in areas that were converted from 4kV which have reduced spacing. Replacement of these switches has started in areas of concern and will increase into a larger program once the urgent safety concern switches are replaced. This program is expected to continue beyond the 2020 expenditure plan.

HOL employs a run-to-failure strategy for this asset class. Information regarding overhead switch and recloser failures has been collected to allow for predictive spending levels. Other than the three switches mentioned previously, failure rates for this asset group have been minimal in the past and do not require predictive analysis or active replacement programs. Recent performance does not suggest an accelerated deterioration of overhead switches and reclosers.

9.2.3 Consequence of Failure

It is important to distinguish between the failure of an overhead switch and the failure of other equipment that may lead to a blown fuse or open switch. In the case of a fault that causes a recloser to operate, this would not be considered a recloser failure. This is also applicable to fused switches in the sense that they are incorporated into the distribution system with the intention of breaking the circuit, should there be an electrical short circuit. Since switches and reclosers are installed as protective devices or for operational efficiency, the consequence of operation will not be heavily discussed.

HOL would be more concerned with the failure of a switch, fuse or recloser, to operate under a fault condition. Although unlikely, this would result in damage to other equipment and a larger outage. Any customers or assets upstream or downstream of the failed switch would be affected by the fault current. In other words, the fault would travel beyond the broken switch until it hit another switch. In some cases, this could mean that the fault current would travel back to the station, potentially causing a very large outage.

The scenario described above would present multiple consequences to HOL and its customers. Defective overhead switches in the system would have a negative impact on system reliability. Larger outages than necessary would occur and adversely affect SAIDI and SAIFI metrics. This effectively reduces the level of customer service that HOL strives to uphold. Defective protection could also lead to more equipment damage, which would increase the cost of repairs and require more time and labour efforts.

Certain switch types that exist in the current system have been identified for replacement due to manufacturer defects. These switches present a safety hazard to line crews when operated. A replacement program was initiated based on the large risk they posed compared to other proposed projects.

9.2.4 Main and Secondary Drivers

HOL's overhead switch and recloser program is a run-to-failure maintenance strategy for most switches. The main driver for this strategy is system reliability. Overhead switches have performed steadily in the past and there have been very few failures. For this reason, HOL sees more value in allocating resources towards the replacement of other assets which experience more failures. A secondary driver is operability. Time and labour is saved if a manual switch is replaced with an automated switch, for instance. An automated system will experience shorter restoration times.

In the case of switches that have been identified as defective and that pose a safety risk, the main driver for replacement is worker safety. Porcelain box switches and SMD-20 switches represented a large risk based on HOL's value scoring and a replacement program was immediately initiated. A secondary driver for the replacement of known defective equipment is system reliability. Defective equipment will likely cause outages and it is desired to remove any defective equipment from the system as soon as possible.

9.2.5 Performance Targets and Objectives

The objective of this program is to replace any failed or defective overhead switches effectively and efficiently. Where replacement is needed, HOL considers type, location and rating with the goal of optimizing the design of the system. Not every replacement is a like-for-like scenario. The main objective regarding defective switch types is to eliminate the safety risk they present by removing them completely from the system by the end of 2015.

9.3 Project/Program Justification

9.3.1 Alternatives Evaluation

9.3.1.1 *Alternatives Considered*

In general, there is only one alternative in the event of an overhead switch failure – replacement. The failure of a switch will likely cause an outage and customers will not be restored until the circuit is corrected and the switch replaced. Within the scope of replacing a failed switch, HOL considers various replacement options. In some cases, a different type of switch would be better suited to the location. In other cases, the rating or fuse size of the switch is upgraded to meet current standard or to prepare for upcoming development. For every replacement, the entire circuit is analyzed to increase system efficiency and to take full advantage of the replacement opportunity.

As for the switch types that have been identified for replacement, leaving them in the system to run-to-failure is not an option. They have been labeled as defective equipment and they present a safety hazard to crews. As such, they must be eliminated from the system as soon as possible.

9.3.1.2 *Evaluation Criteria*

Switches in the system that have failed must be replaced immediately to restore load. Porcelain box switches and S&C 27.6kV porcelain and polymer fused cut-outs are a known safety risk and must be replaced as soon as possible. Within the study for various replacement options, system planners and designers account for design standards, system protection, feeder expansion or development, past feeder performance, operability, and connectivity. The objective in any asset replacement scenario is to choose a replacement option that will optimize effective performance with cost efficiency.

9.3.1.3 *Preferred Alternative*

It is generally preferred to deploy a run-to-failure maintenance strategy for overhead switches and reclosers. Failure rates for this asset group have been minimal and do not require predictive analysis or active replacement programs, except in the case of identified defective switch types. Creating a program targeting overhead switch maintenance or replacement would not be cost or labour effective, due to their reliability and low failure rates. If the failure trend should increase, maintenance or replacement programs will be re-evaluated for effectiveness.

For the few failures that do occur, the replacement opportunity is used to optimize system design in that region. It is cost and labour efficient to account for system enhancements within a required asset replacement job. This also minimizes public disruption, as a second outage and crew along with potentially large vehicles would be required if an upgrade was planned for the same switch in the future. Blocking roads or entering private property reduces customer satisfaction. HOL attempts to address all issues within the scope of one construction period.

In response to the design flaw identified within the S&C 27.6kV polymer switches, a refurbishment program was initiated in which S&C will refurbish any affected switches at no cost. However, they will not cover any of the labour costs associated with the replacement or removal of these switches. HOL's multi-year replacement program began in 2013 targeting the defective polymer switches first, followed by the porcelain switches.

9.3.2 Project/Program Timing & Expenditure

HOL minimizes the controllable costs of its overhead switch replacement program by using a run-to-failure maintenance strategy. This asset class does not experience many failures so detailed predictive analysis and active replacement is not required. In the case of the defective S&C SMD-20 switches, S&C Electric Company will refurbish any affected switches at no cost. However, the labour costs associated with removing these switches is not covered, so HOL has divided the program across their planning regions. There are four different teams composed of planners, designers and field technicians who are responsible for SMD-20 removals in their areas – Central, East, South and West. This effectively saves the time and costs of individual field crews travelling all over the city. This also allows the program to proceed more rapidly, eliminating the inevitable future cost of equipment failures.

The costs associated with the replacement of a failed overhead switch are minimized by using the replacement opportunity to optimize system design in that region. It is cost and labour efficient to account for system enhancements within a required asset replacement job. HOL attempts to address all issues related to the switches within the scope of one construction period, rather than sending crews out for a second time in the future.

Historical ($M)					Future ($M)				
2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
0.314	0.199	0.422	1.54	1.02	0.785	0.902	1.04	0.942	0.983

Table 55 - Overhead Switchgear Expenditures

9.3.3 Benefits

Benefits	Description
System Operation Efficiency and Cost-effectiveness	System operation efficiency is achieved by accounting for system design when replacing a failed switch. Any upgrades to account for current standards or system expansion are considered. The run-to-failure strategy is cost-effective in that the minimal number of overhead switch failures every year does not justify an active replacement program. Eliminating known defective switches will save future failure costs and will contribute to a stronger electrical system. Reliability metrics such as SAIDI and SAIFI will improve.
Customer	Customers are benefitted by improved reliability associated with eliminating defective equipment from the system. Any safety risk is also mitigated. System enhancement is considered when replacement is required, which benefits both system reliability and customer disruption. HOL accounts for all known factors influencing replacement decisions to avoid any future work on the same piece of equipment.
Safety	Removing and replacing all overhead switch types that carry a health and safety hazard will eliminate this risk.
Cyber-Security, Privacy	(Not applicable)
Co-ordination, Interoperability	S&C Electric Company will refurbish all of their defective switches at no cost.
Economic Development	This program adds to the scope of work of HOL's field crews.
Environment	(Not applicable)

Table 56 - Overhead Switchgear Benefits

9.4 Prioritization

9.4.1 Consequences of Deferral

The run-to-failure maintenance strategy is an ongoing program year after year. It cannot be deferred and therefore has no consequence of deferral. On the other hand, the urgent replacement of defective switch types would carry potentially heavy consequences, were it to be deferred. These defective switches located throughout the system present a safety risk and do not function properly. In terms of safety, deferring their replacement could result in severe worker injury. In terms of system reliability, a defective switch could lead to the damage of equipment upstream or downstream of the switch, prolonging outages and increasing replacement costs.

9.4.2 Priority

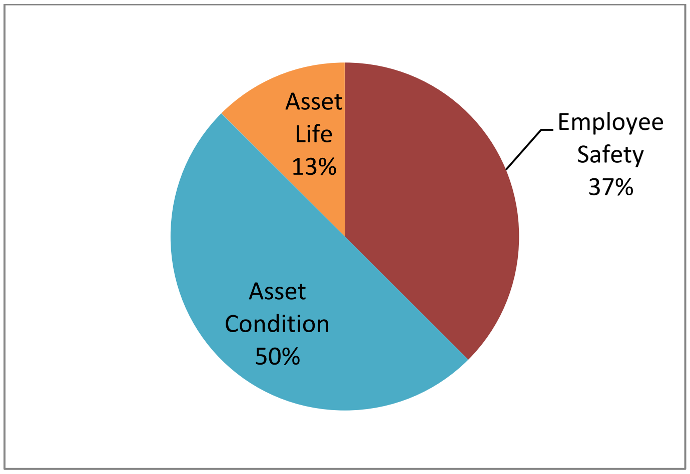


Figure 54 - Porcelain Box Switch Replacement Avoided Risk

Typical Project Score = 0.99

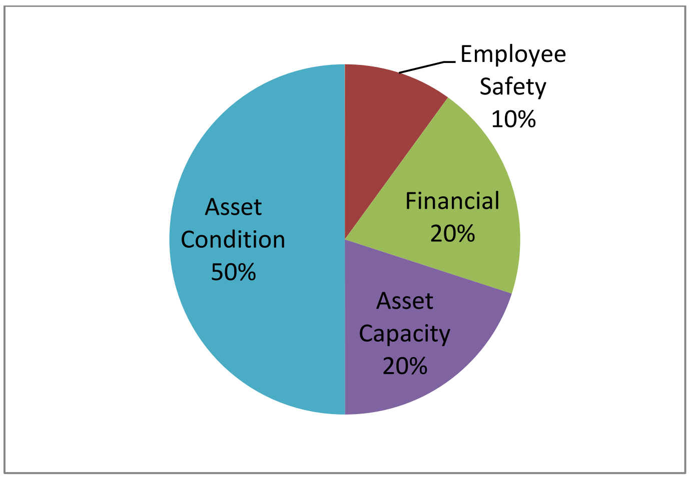


Figure 55 - SMD-20 Replacement Avoided Risk

Total 3-Year Program Project Score = 1.01

9.5 Execution Path

9.5.1 Implementation Plan

For most overhead switches and reclosers, HOL does reactive replacement on the few occasions that these assets experience failures every year. Overhead switches are generally in good condition and do not require an active replacement program.

For porcelain box switches, HOL has identified 28 remaining sets of switches located at 4 different substations that require porcelain box switch replacement. Individual projects for each of these switches have been created and budgeted for 2014 and 2015. By the end of 2015, it is expected that all porcelain box switches will be eliminated from the system.

For S&C 27.6kV SMD-20 switches, HOL has identified a total of 2,800 of these switches in the system. In 2013, a multiple-year replacement program was put into place which targeted the defective polymer switches first, followed by the porcelain switches. S&C will refurbish all of these switches at no cost. HOL's own crews have been actively replacing these switches with each crew focused on their respective planning region. The service territory is divided into four distinct planning regions – central, east, south and west. Crews incorporate this work into their schedules throughout the year.

Replacement of the 13kV porcelain cut-outs commenced in 2014 with the replacement of approximately 100 switches. This program will continue at this rate until the SMD-20 switches are all replaced after which the program replacement rate will be increased.

9.5.2 Risks to Completion and Risk Mitigation Strategies

It is possible that there are remaining S&C 27.6kV SMD-20 switches that are still unaccounted for, as some crews have found more in the system. It is possible that if any more of these switches are found past 2015, they will not be eliminated by the target date of 2016. However, the safety concern they present makes their replacement a priority and the budget will be adjusted if necessary to account for any remaining defective switches.

9.5.3 Timing Factors

The SMD-20 replacement program is scheduled to be completed in 2016 and the porcelain box switches in 2015.

9.5.4 Cost Factors

It is not expected that cost will be a problem in completing the replacement of defective SMD-20 switches. The budgeted amounts for this program have been increased in 2014 and 2015 in order to achieve the replacement target.

9.5.5 Other Factors

The location of the defective switches throughout the system can impact the replacement program. Some of these switches are located within customer backyards or on commercial property, making access more difficult. For switch replacements that will cause outages to commercial customers, crews work to minimize disruptions.

9.6 Renewable Energy Generation (if applicable)

N/A

9.7 Leave-To-Construct (if applicable)

N/A

9.8 Project Details and Justification

9.8.1 TH01 Porcelain Switch Replacement

Project Name:	TH01 Porcelain Switch Replacement
Project Number:	92008645
Capital Cost:	$249,513
O&M:	N/A
Start Date:	2015 – Q1
In-Service Date:	2015 – Q4
Investment Category:	System Renewal
Main Driver:	Risk of Failure
Secondary Driver(s):	Reliability
Customer/Load Attachment	450 customers/1250 kVA
Project Scope	
15kV porcelain switches have been failing and causing either pole fires, which are expensive to repair, or interrupting customers off a transformer. Areas where 13.2kV voltage conversion was done appear to be problem areas. This project will replace approximately 136 porcelain switches along the overhead of the TH01 circuit.	
Priority	
Safety issue	
Work Plan	
There are 136 locations on the TH01 to replace switches. HOL Limited design standards were reviewed, like-for-like replacement will apply in locations that cannot fit the new specifications. The project will begin in Q1 of 2015 and continue until completion within the same year. Isolation is required at every location for crew safety. Switches will be inspected before operating because cracked switches can be a dropping hazard.	
Customer Impact	
Customers will be given 48 hours of notice before isolation, with crews going door to door. Customers will gain a more reliable system from this replacement program because an overhead switch failure can result in outages affecting more customers and for a longer duration. Overhead switches are placed strategically in order to minimize outage impact and protect system equipment. Hence, this project will save reactive replacement costs and make better use of customer dollars.	

9.8.2 TH06 Porcelain Switch Replacement

Project Name:	TH06 Porcelain Switch Replacement
Project Number:	92008647
Capital Cost:	$145,902
O&M:	N/A
Start Date:	2015 – Q1
In-Service Date:	2015 – Q4
Investment Category:	System Renewal
Main Driver:	Risk of Failure
Secondary Driver(s):	Reliability
Customer/Load Attachment	250 customers/2200 kVA
Project Scope	
15kV porcelain switches have been failing and causing either pole fires, which are expensive to repair, or interrupting customers off a transformer. Areas where 13.2kV voltage conversion was done appear to be problem areas. This project will replace approximately 74 porcelain switches along the overhead of the TH06 circuit.	
Priority	
Safety issue	
Work Plan	
There are 74 locations on the TH06 to replace switches. HOL Limited design standards were reviewed, like-for-like replacement will apply in locations that cannot fit the new specifications. The project will begin in Q1 of 2015 and continue until completion within the same year. Isolation is required at every location for crew safety. Switches will be inspected before operating because cracked switches can be a dropping hazard.	
Customer Impact	
Customers will be given 48 hours of notice before isolation, with crews going door to door. Customers will gain a more reliable system from this replacement program because an overhead switch failure can result in outages affecting more customers and for a longer duration. Overhead switches are placed strategically in order to minimize outage impact and protect system equipment. Hence, this project will save reactive replacement costs and make better use of customer dollars.	

9.8.3 SMD-20 Switch Replacement

Project Name:	SMD-20 Switch Replacement (3 year program)
Project Number:	92007746
Capital Cost:	$1,250,000
O&M:	N/A
Start Date:	2013 – Q1
In-Service Date:	2015 – Q4
Investment Category:	System Renewal
Main Driver:	Health & Safety, Risk of Failure
Secondary Driver(s):	Reliability
Customer/Load Attachment	City-Wide

Project Scope

HOL was informed by S&C Electric Canada that their 27.6kV SMD-20 polymer and porcelain switches manufactured between 2004 and 2011 were defective and experienced failure when operated with a load break tool. In response to this identified design flaw, HOL Limited initiated a multi-year replacement program to replace these switches. S&C will refurbish any of these switches at no cost to HOL Limited, however they will not cover any of the labour costs associated with the replacement or removal of these switches.

Priority

Score = 1.23

Work Plan

The replacement program began in 2013 and targeted the defective polymer switches first, followed by the remaining porcelain switches. The 3-year program was limited by resources in the first year and only 80 switches were replaced. The budgeted amounts for this program were increased in 2014 and 2015 in order to achieve the 3 year replacement target.

Customer Impact

The defective SMD-20 switches present a safety hazard to HOL crews. This was the primary concern and the reason for immediate program implementation. Customers will gain a more reliable system from this replacement program because an overhead switch failure can result in outages affecting more customers and for a longer duration. Overhead switches are placed strategically in order to minimize outage impact and protect system equipment. Hence, this project will save reactive replacement costs and make better use of customer dollars.

9.8.4 Queens Sub Porcelain Box Switch Replacement

Project Name:	Queens Sub Porcelain Box Switch Replacement
Project Number:	92008663
Capital Cost:	$100,213
O&M:	N/A
Start Date:	2015 – Q1
In-Service Date:	2015 – Q4
Investment Category:	System Renewal
Main Driver:	Health & Safety, Risk of Failure
Secondary Driver(s):	Reliability
Customer/Load Attachment	1665 customers

Project Scope

Porcelain box switches have been identified for removal due to issues of mechanical fracturing. Existing porcelain box switches will be replaced with new 27.6kV “V Type” disconnect switches.

Priority

Score = 0.99

Work Plan

The original estimate included changing more porcelain box switches, however the on-going City of Ottawa project – Alta Vista Transit Corridor (OH removal) reduced and eliminated the switches on Old Riverside Drive near the Queens substation, as well crews where already working in the area on the Alta Vista Transit Corridor so doing these projects around the same time will reduce travel time and set-up costs.

Customer Impact

The defective porcelain box switches present a safety hazard to HOL crews. Customers will gain a more reliable system from this replacement program because an overhead switch failure can result in outages affecting more customers and for a longer duration. Overhead switches are placed strategically in order to minimize outage impact and protect system equipment. Hence, this project will save reactive replacement costs and make better use of customer dollars.

9.8.5 Fernbank Reclosers

Project Name:	Fernbank Reclosers
Project Number:	92010170
Capital Cost:	$165,000
O&M:	N/A
Start Date:	2016 – Q1
In-Service Date:	2016 – Q4
Investment Category:	System Renewal
Main Driver:	Risk of Failure
Secondary Driver(s):	Reliability
Customer/Load Attachment	5000 customers/4000 kVA
Project Scope	
The scope of the Fernbank Reclosers project is to install two three phase Cooper 27.6kV reclosers with SCADA communication and operation. One recloser will be installed on the TFXF4 and the other on the TFXF5 located on the pole line on Fernbank Road. The reclosers will help sectionalize these feeders as they grow in length and can sectionalize faults to limit the number of customers impacted.	
Priority	
Score = 0.52	
Work Plan	
Renewal construction of the pole line along Fernbank Road was completed in 2015 with provisions to allow for installation of these reclosers. Backup circuits are available so that the recloser and external power supply can be installed, tested, commissioned and put into service without an outage.	
Customer Impact	
Reliability is expected to improve in the Stittsville community, by the introduction of these two new feeders from Terry Fox MTS. The installation of these two reclosers will limit customers downstream to short interruptions during momentary faults and sectionalize sustained faults to limit as few customers as possible.	

9.8.6 TFXF1 Huntmar Recloser

Project Name:	TFXF1 Huntmar Recloser
Project Number:	92010172
Capital Cost:	$83,000
O&M:	N/A
Start Date:	2016 – Q1
In-Service Date:	2016 – Q4
Investment Category:	System Renewal
Main Driver:	Risk of Failure
Secondary Driver(s):	Reliability
Customer/Load Attachment	1960 customers/17.3 MVA

Project Scope

The scope of the TFXF1 Huntmar Recloser project is to install one three phase Cooper 27.6kV recloser with SCADA communication and operation on the TFXF1 on the pole line on Huntmar Road. The reclosers will help sectionalize this feeder as it grows in length and can sectionalize faults to limit the number of customers impacted.

Priority

Score = 0.52

Work Plan

Renewal construction of the Hydro One owned pole line along Huntmar Road to accommodate the addition of HOL's TFXF1 feeder was completed in 2015 with provisions to allow for installation of this recloser. A backup circuit is available so that the recloser and external power supply can be installed, tested, commissioned and put into service without an outage.

Customer Impact

Reliability is expected to improve in the Kanata North community, by the introduction of the TFXF1 feeder from Terry Fox MTS. The installation of this recloser will limit customers downstream to short interruptions during momentary faults and sectionalize sustained faults to limit as few customers as possible.

10 Metering

10.1 Project Details and Justification

10.1.1 Remote Disconnect Smart Meter

Project Name:	Remote Disconnect Smart Meter
Project Number:	92003564
Capital Cost:	2016 to 2020 - $6.8M
O&M:	N/A
Start Date:	2016
In-Service Date:	2016 to 2020 yearly individual in service dates
Investment Category:	System Renewal
Main Driver:	Assets at end of service life due to Functional Obsolescence
Secondary Driver(s):	N/A
Customer/Load Attachment	36,000 customers each with up to 50 KW
Project Scope	
This project will install approximately 36,000 remote disconnect meters over the 2016 to 2020 time period. This will provide the capability to turn power on and off at the service point remotely. This reduces the expense requirement as this will eliminate the requirement to send a meter technician to the premise to disconnect the meter as well as reconnect the meter when required. This will also eliminate the need to install power limiters based on timer functionality for non-payment during the winter months along with the associated expense of travelling to the premise.	
Priority	
Work Plan	
The work plan involves installing the remote disconnect meters on some of the locations that are required to be sampled according to Measurement Canada, new installations, inside meter locations and defective meter replacements. There will be approximately 3,000 to 8,000 meters installed per year.	
Customer Impact	
Remote disconnect meters reduce the expense requirements associated with travelling to the premise for disconnect and reconnect requirements. The meters can also be used as part of the collections processes when funds have not been received for past usage. The meters can reduce the time required to have the disconnect or reconnect function performed which can increase customer satisfaction. Eg For apartments where the power was turned off when previous customer moved out, the disconnect meter can be used to turn power on quicker when the customer requests power. The remote disconnect meter can also be used with the scheduled remote batch capability to emulate a physical timer on a service during winter months when permanently disconnecting power is not desirable. The remote capability also provides enhanced safety for the meter technician if it is in a difficult to access or dangerous location and a disconnect or reconnect function is required. The disconnect meters will have the normal verification periods as other meters as per Measurement Canada guidelines.	

System Service

1 Stations New Capacity

1.1 New South 27.6kV Substation

1.1.1 Project/Program Summary

With the south of Ottawa expanding rapidly, there is a need in the short term for additional distribution capacity. The purpose of this project is to supply the upcoming demand with the construction of a new 230kV to 27.6kV substation containing two 75MVA transformers. HOL, in conjunction with the Integrated Regional Resource Planning (IRRP) process, has deemed that a new station was the most feasible solution to address future capacity issues. The new station will also contribute to improving reliability by initiating a series of asset replacements and upgrades, and by eventually creating backup ties between the new station feeders and existing circuits. The total cost of this project is divided into phases over the next six years, with an anticipated commissioning date of December 2020. Hydro One Networks Inc. is involved in this project because the required 230kV transmission line extending into the South Nepean area does not currently exist.

1.1.2 Project/Program Description

1.1.2.1 *Current Issues*

There are many City of Ottawa development plans that have been reviewed to estimate the load demand over the next twenty years. The map below shows the major anticipated development projects in the South Nepean area, followed by brief descriptions of each project.

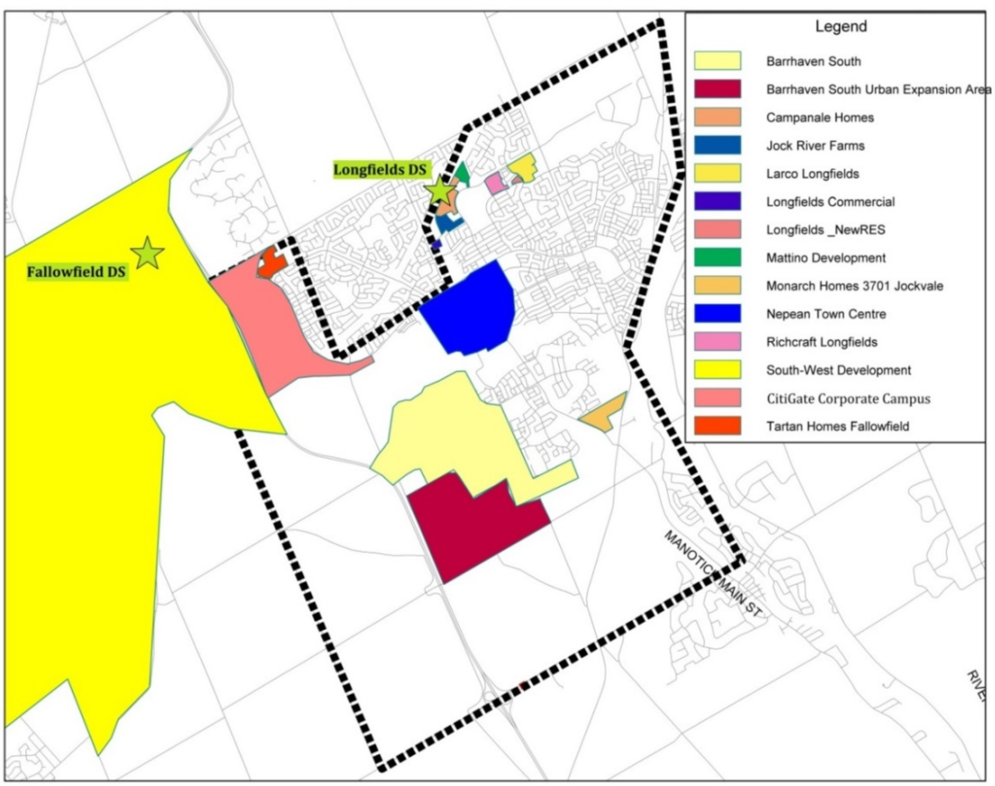


Figure 56 - Proposed Development Areas

Barrhaven South – The community design plan is to create a complete residential community containing a full range of housing choices and a broad complement of support services and facilities. This includes residential housing units, commercial buildings, community centres and schools. The expected load is 15.5MVA.

Barrhaven South Urban Expansion – The expected load is 12MVA by 2032.

Campanale Homes – This is a residential development for 136 residential units and 19 apartment units. The expected load is 6.2MVA in 2015.

Jock River Farms – This is a residential development for 186 units. The expected load is 476KVA in 2014.

Larco Longfields – This is a residential development for 220 units and two apartment buildings. The expected load is 863KVA in 2016.

Longfields Commercial – A church will be constructed with an expected load of 750KVA.

Longfields New Residential – This area is being rezoned from institutional to residential. Based on the area, the expected load is 50KVA.

Mattino Developments – This is a residential development for 126 units and four low density apartment buildings. The expected load is 722KVA in 2016.

Monarch Homes – This is a residential subdivision containing 194 single family homes, 73 street homes and 73 town homes. This is an extension to the Stonebridge Community. The expected load is 810KVA in 2015.

Nepean Town Centre – This development will require a significant load increase of 121MVA. It will include commercial buildings, office buildings, a shopping district and 18,300 residential units. The current feeder capacity supplying the area from Fallowfield DS will not be capable of sustaining the load throughout the duration of the project.

Richcraft Longfields – This is a residential development for 283 units. The expected load is 725KVA in 2015.

CitiGate Corporate Campus – This is an upcoming business park for 70 commercial buildings and office buildings. The expected load is 40MVA around 2020.

Tartan Homes Fallowfield – This project is the continuation of residential developments being constructed along Fallowfield and Strandherd Road. There are 250 homes for an expected load of 655KVA in 2015.

1.1.2.2 *Program/Project Scope*

This project is for the design and construction of a new 230kV to 27.6kV substation with two 45/60/75MVA transformers in the Barrhaven/Manotick area. The station will be designed to have 6-8 feeders and a breaker and a half configuration, however the planning and construction of the station feeders are out of the scope of this project. This project addresses the inability of HOL's distribution system to supply the expected load in five years and involves acquiring land, designing and constructing all civil and electrical components of the substation, and the tender of all equipment and services. The station will include two transformers, 230kV breakers, 230kV air break switches, switchgear, potential transformers, DC system, relay panels, transformer foundations with oil containment and civil structures. HOL is working closely with Hydro One and the Independent Electricity System Operator (IESO) in the IRRP process to plan a new 230kV transmission supply for Ottawa's south region, as currently none exists.

1.1.2.3 *Main and Secondary Drivers*

The main driver of this project is the need to supply the future expected load in this growing area. The forecasted load for the next 20 years in the South Nepean area indicates that the area's capacity limitations will be reached within the next five years. In the case of a single station contingency, the remaining capacity would not be enough to supply the required load in this area. Ongoing development worsens the situation which indicates why this project is required to meet the demand.

As a secondary driver for this project, reliability will be improved by eventually creating ties to other 27.6kV stations, specifically Fallowfield DS, Longfields DS, Limebank MS and the new 27.6kV Richmond South DS.

1.1.2.4 *Performance Targets and Objectives*

The primary objective of this project is to have the new station commissioned and on-line by December 2020. Within this goal, various milestones must be met including the procurement of land, environmental assessment and City of Ottawa approval, extension of a new transmission line, civil and electrical station design, tendering of all major equipment and services, and finally construction and commissioning. In conjunction with this new station, other projects are being planned and implemented in order to prepare the area for a 27.6kV voltage upgrade once the station has been constructed.

1.1.3 Project/Program Justification

1.1.3.1 *Alternatives Evaluation*

1.1.3.1.1 Alternatives Considered

Based on the forecasted load in the South Nepean area for the next 20 years, under normal operation, the stations in this area would reach their capacity limitations in the next five years. The impact of CDM was also considered to offset load. However, since most of the load is coming from new developments which already have many design efficiencies, CDM will have minimal effect. In the case of a single station contingency, the remaining capacity would not be adequate to supply the load. It was decided that the best solution was to build a new station in the Barrhaven/Manotick area.

The alternatives to this project would be to provide additional station capacity at either of the two existing 27.6kV stations in the area – Fallowfield DS and Longfields DS. The Fallowfield substation was recently upgraded from one 25MVA transformer supplying two circuits to two 25MVA transformers supplying four circuits in total. The capacity of the station was doubled and it is therefore not possible to add the needed capacity unless a new transmission line is extended to Fallowfield DS. Longfields DS is supplied by the 22M24 and 22M26 44kV circuits from Nepean TS. There is no capacity available to upgrade Longfields substation to satisfy the expected load.

1.1.3.1.2 Evaluation Criteria

The best alternative was chosen based on feasibility and location. The other option to increasing system capacity in a given area is to upgrade the capacity of existing stations. This is only possible if conductor thermal ratings and transmission supply constraints allow it. Location is also an important consideration, as the ideal solution is to provide capacity close by to the demand to minimize voltage drop and reliability risks.

1.1.3.1.3 Preferred Alternative

Due to the inability of the existing stations to be upgraded such that they may provide sufficient capacity, it is clear that constructing a new station is the preferred alternative.

The first reason is that it is a more feasible option. Upgrading Fallowfield DS would require another transmission line and since this station already supplies a heavy load, the outages that would be required to add capacity would disrupt many customers. Upgrading Longfields DS is not a feasible option since it is supplied by HOL’s 44kV system. The 44kV conductor supplying Longfields substation is the largest size available, 556 MCM, and the thermal capacity of these feeders would not allow a capacity upgrade large enough to meet the demand.

The second reason is that the location of the new station will be more central to the expected growth. Fallowfield DS and Longfields DS are currently much further north than the proposed developments, so feeders are currently travelling long distances to supply the few customers who are situated near the southern boundary of HOL’s service territory. The proposed location for the new station is closer to the upcoming developments which will minimize voltage drop and threats to reliability, such as lightning or pole damage.

1.1.3.2 *Project/Program Timing & Expenditure*

The total station construction project cost is expected to be $21,255,370 (does not include transimission lines). The yearly cost estimates in the table below extend into 2021, but the date range has been restricted to 2020 for the purpose of this business case. In general, HOL aims to minimize the costs associated with all projects. For station projects, this includes putting all equipment and work out for tender. Major station equipment is usually customized for each project and HOL considers the submitted bids from various equipment manufacturers. The same is true of contractor labour, with the lowest bid typically being chosen unless there are additional considerations, such as incompatible scheduling. The considered contractors and vendors are pre-screened to ensure that they have the abilities and expertise to meet the needs of HOL and are able to maintain required timelines.

Additionally, HOL minimizes the controllable costs of station projects in several other ways. For example, a competitive Request For Proposal (RFP) process is used to determine consulting resources. These consultants are retained for a minimum 3 year timeframe to ensure that they are able to efficiently meet HOL’s needs and have a good understanding of HOL’s internal processes and standards.

The use of in-house project management allows for the efficient use of resources and experience from similar past projects. Best practices for project management at HOL are based on the Project Management Institute (PMI) best practices.

Workforce planning is used to ensure that internal resource requirements are identified early. External resource requirements are identified early to ensure that the project runs smoothly and efficiently.

Historical ($M)				Future ($M)					
2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
-	-	-	-	0.06	0.14	1.50	5.54	6.67	5.84

Table 57 - Project Expenditures

1.1.3.3 *Benefits*

Benefits	Description
System Operation Efficiency and Cost-effectiveness	This project is required to satisfy the upcoming load growth in the South Nepean area. It is an essential system service project to supply the expected future capacity. System operation efficiency will be improved by the new station feeders' ability to connect with other 27.6kV feeders in the area. The backup ties will ensure faster restoration times in the event of an outage, as well as the capability to maintain adequate supply in a station contingency scenario. This should inevitably contribute to reducing SAIDI, which is important in an area where the overhead distribution system is subject to weather-related outages. Constructing a new station is the most cost-effective solution to provide the required demand. The other alternatives are not very feasible and the location of this new station will provide a better electrical and geographical balance between supply points.
Customer	This project will achieve two objectives: to supply future demand and to improve reliability in the south of the city. Not only will development projects be given adequate electrical supply, but the new station presents several opportunities to enhance the system. This project will contribute to a larger system plan to convert the entire south to a 27.6kV system, in order to keep up with city development. This larger system plan will provide enhanced capacity and improved reliability to customers in several communities including: Barrhaven, Manotick, Riverside South, Richmond and Kanata. The various upcoming ties between stations servicing this region will reduce outage durations and eliminate several radial segments that exist in the current distribution system. Other projects have been planned to prepare the South Nepean area for this voltage conversion, including project 92008686 Rideau Valley Voltage Conversion and project 92008543 Prince of Wales Voltage Conversion. These related projects involve asset replacements, which further improves system reliability.
Safety	Building a new station will address the predicted thermal overload of existing feeders and station transformers that will occur in the near future. Overloading the system can lead to equipment damage and safety hazards. This project will mitigate that risk.
Cyber-Security, Privacy	N/A
Co-ordination, Interoperability	The new station will be supplied on the high side by Hydro One Networks Inc.'s 230kV transmission line. The provincial utility has been heavily involved in the

	development of this project from the beginning, as it requires a new transmission line. Both utilities will coordinate to ensure the success of this project, although construction details have not yet been decided.
Economic Development	This project will facilitate the connection of new loads and future growth in this area of the city.
Environment	N/A

Table 58 - Project Benefits

1.1.4 Prioritization

1.1.4.1 *Consequences of Deferral*

The purpose of this project is to address an upcoming capacity issue; as a result the most important consequence of deferral would be the inability to service the required load in approximately five years. Allowing the system to experience thermal overload for an extended period of time would lead to equipment damage and customer outages. Customers working or living in the proposed developments would simply not have the electricity they require. The eventual failure of the system to keep up with demand validates the necessity of this project.

The new station feeders will create ties with other stations and backup other feeders. This presents an additional consequence of deferral, which is that the current radial segments of other feeders in the area will remain radial for a longer period of time. If an outage occurs on these segments, the affected customers will likely experience long outage times.

This project also promotes a series of equipment upgrade projects, to prepare the area for the larger 27.6kV voltage conversion. This involves replacing aging assets such as poles, conductors and transformers which inherently improves system reliability.

1.1.4.2 *Priority*

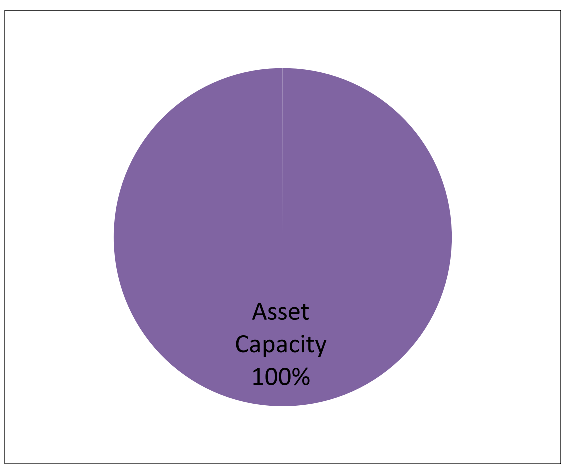


Figure 57 - Project Avoided Risk

Project Score = 0.72

1.1.5 Execution Path

1.1.5.1 *Implementation Plan*

Adherence to the implementation plan and key milestones for this project is necessary to ensure that sufficient capacity will be provided in this area when needed. The plan is typical of most new stations, with the exception of Hydro One Networks Inc.'s (HONI) involvement from the beginning. Hydro One is planning a new 230kV supply to the south of Ottawa, as no transmission lines currently exist. The success of Hydro One's transmission project is essential in achieving the objectives of this New South 27.6kV Substation project.

The schedule is as follows: The HONI study agreement will be completed and the Environmental Assessment process and preliminary design will be started in 2015. Land procurement and finalizing the Environmental Assessment is expected to take place by December 2015. Major material procurement and a detailed design will be started by December 2016. The detailed design should be completed by December 2017. Construction will follow and commissioning is planned by December 2020.

This project is coordinated with other asset replacement and upgrade projects, to prepare the entire area for a 27.6kV voltage conversion. These projects are all related and will involve making connections between feeders to achieve a more reliable system.

1.1.5.2 *Risks to Completion and Risk Mitigation Strategies*

The construction of HOL's new substation is dependent upon the availability of Hydro One Networks Inc.'s new transmission supply line. HOL cannot proceed with their project unless a 230kV supply is available. Due to this important requirement, HOL has maintained active communication with Hydro One in planning the new transmission line via the IRRP process.

This project must also gain Environmental Assessment approval and City of Ottawa consultation. The environmental assessment is not expected to be an issue as HOL's current station design standards minimize environmental risk with features such as oil containment. Through the environmental assessment process HOL will engage the community and work towards finding the most suitable location for the station. As the proposed area is more rural at this time, selection of a site should be well coordinated with development plans.

1.1.5.3 *Timing Factors*

Planned City development is the driver for this project, and it is unlikely that the timing and priority of this project will change. It is necessary to supply the proposed load and there are no other feasible solutions. If City development is delayed for any reason, it is possible that this project could be shifted slightly but this is unlikely, as site plans for new developments in the area have already begun to be submitted to HOL. For the timing and priority of this project to change, City development would have to be delayed and HOL would have to have a sudden change in priorities due to an unexpected requirement.

1.1.5.4 *Cost Factors*

The land acquisition process may affect the final cost of the project. The exact location of the new station remains undecided, but the cost of acquiring this land could vary according to the current ownership or any easements.

The tender process for major station equipment and labour services will also affect the final cost of the project.

1.1.5.5 *Other Factors*

While the main risk factors were identified previously, it should be noted that building a new station alone does not resolve any capacity issues. The station feeder routes must be planned, designed and constructed, which is not within the scope of this project. Due to the magnitude of the growing area, several smaller projects are being planned in conjunction with the new station project. These smaller projects involve upgrading current 8.32kV equipment to 27.6kV-rated equipment, building new line extensions for eventual ties, and existing station upgrades such as the Richmond South DS voltage conversion. HOL currently has projects underway to prepare for the larger voltage conversion, with the new station feeders to be planned in the short term.

1.1.6 Renewable Energy Generation (if applicable)

It is likely that there will be large customer generation projects in the South Nepean Area in the near future. These Feed-In-Tariff (FIT) projects currently have limited distribution feeders to connect to. This is because HOL only has confirmation of select station transformers being capable of handling reverse flow. For example, only one of the two transformers at Fallowfield DS is known to be capable of handling reverse flow, therefore generation potential is limited. It is planned that the new station will have reverse flow capability on both transformers, thus increasing the number of renewable energy generation projects possible.

1.1.7 Leave-To-Construct (if applicable)

N/A

1.1.8 Project Details and Justification

Project Name:	New South 27.6kV Substation
Capital Cost:	$21,255,370
O&M:	N/A
Start Date:	January 2015
In-Service Date:	December 2020
Investment Category:	System Service
Main Driver:	Capacity
Secondary Driver(s):	Reliability
Customer/Load Attachment	150 MVA
Project Scope	
Complete design and construction of a new 230kV to 27.6kV distribution substation 2 x 75MVA transformers, protection, oil containment New 230kV transmission supply Land acquisition and approvals required	
Work Plan	
Land procurement, Detailed Design, Tender of major equipment Station construction – Foundations, oil containment, transformer installation, switches, breakers, switchgear, relays, Protection & Control equipment Commissioning target date - December 2020	
Customer Impact	
Available distribution capacity to supply new loads for upcoming development Reliability improvement associated with replacement of aging assets and equipment upgrades Reduced outage durations with eventual backup supply	

1.2 Hinchey New Switchgear Lineup

1.2.1 Project/Program Summary

There are significant plans for growth in the downtown core of Ottawa. This is driven by both intensification and infill projects including the new proposed light rail transit system and the expansion of Tunney's Pasture. These projects will stress the available capacity in the area. Hinchey TH substation currently has two transformers; however, they each have an idle winding. This project will utilize these idle windings and connect them to two new switchgear lineups. This will increase the capacity at Hinchey TH substation from 37.5MVA to 75MVA.

1.2.2 Project/Program Description

1.2.2.1 *Current Issues*

Hinchey TH is a 13.2kV indoor substation located at the corner of Scott Street and Hinchey Avenue. Hinchey TH supplies electricity to the area North of Wellington Street W., East of Churchill Avenue, and West of Bronson Avenue. Hinchey TH currently has two transformers; however, they each have an idle winding. The anticipated load growth is expected to push the substation past its capacity.

1.2.2.2 *Program/Project Scope*

Due to the anticipated load growth in this area, the new switchgear lineups will be built utilizing the idle winding on both of the station's 115kV/13.2kV transformers. The installation configuration of the two switchgear lineups which make up the buss-pair is shown in Figure 58. This depicts where the proposed lineup will be compared to the existing one.

The new installation will include two transformer breakers, a buss tie breaker, two switchgear lineups complete with buss work, and 14 feeder breakers. These switchgears will be delivered and installed by a connection to the transformer's third winding. Four new protection and control panels will also be installed with protection and communication equipment. Once the switchgear has been completely installed, existing feeders connected to the current switchgears will be transferred in order to balance the load among the two buss pairs. This will also eliminate many hair pinned breakers. This increases reliability because it reduces the exposure of each of the hair pinned circuits to their customers by roughly 50%. Finally, relay settings will be updated in correspondence with the new configuration.

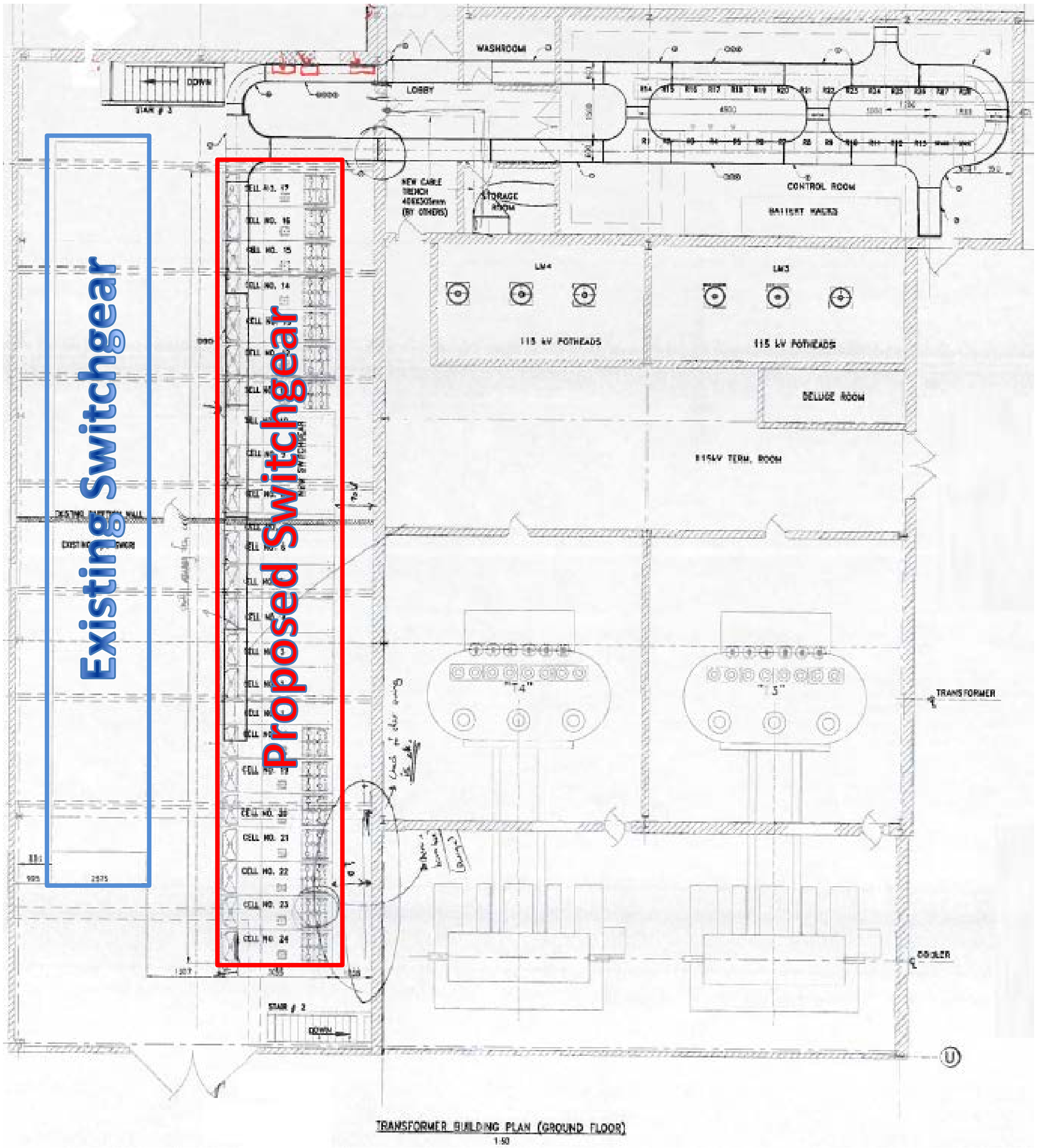


Figure 58 - Proposed Hinchey TH Substation Layout

1.2.2.3 *Main and Secondary Drivers*

The main driver for this project is the expected changes in load that will constrain this station's ability to provide consistent service delivery. It is anticipated that 33.7MVA of new load will be realized in the next ten years. The secondary driver for this project is that the current space for new feeders is limited. As of today all of the breaker positions are occupied by feeders and five out of the twelve positions contain hair pinned circuits. The addition of the new switchgear breaker positions will increase room for future supply and allow for the removal of the hair pinned circuits. This increases reliability because it reduces the exposure of each of the hair pinned circuits and their customers by 50%.

1.2.2.4 *Performance Targets and Objectives*

The main objective of this project is to increase the capacity at Hinchey TH substation. By utilizing the third winding of each of the two transformers the capacity will rise from 37.5MVA to 75MVA. This will allow Hinchey TH to continue to supply reliable power to the increasing demand in the region.

1.2.3 Project/Program Justification

1.2.3.1 *Alternatives Evaluation*

1.2.3.1.1 Alternatives Considered

In order to meet the increasing load in the downtown Ottawa area, specifically the geographical area surrounding Hinchey TH substation, two alternatives were considered:

1) Feeder extension: Under this scenario Hinchey TH substation will be at capacity and unable to supply new loads. In order to supply the increasing demand, numerous circuits would be required from Lisgar TL, Carling TM, or Lincoln Heights TD substations. A large amount of infrastructure is necessary to supply the demand from these other stations which are a minimum of 2.3km away.
2) Utilize idle third winding: This alternative involves the installation of the new switchgear lineups. Hinchey TH substation was built with two three winding transformers and enough room for 4 switchgear lineups. Due to the loading in the area at the time, only one of the two free windings from each transformer were utilized and two switchgear lineups were installed creating one buss-pair. The area around Hinchey TH substation has since grown and the future load has been forecasted to increase above the current station’s limited time rating. This option will see two new switchgear lineups installed and connected using the idle third winding of the two transformers.

Figure 59 - Existing Switchgear Lineup

1.2.3.1.2 Evaluation Criteria

The main evaluation criteria used to determine the best option were the cost between the two projects and the practicality. Both costs associated with the alternatives are those that will enable 37.5MVA of new capacity. The estimated net present values of revenue requirements for each option are:

Alternative 1: $13,682,919

Alternative 2: $11,282,899

Further criteria that were used to evaluate the alternatives are timing of the project, safety, and future planning.

1.2.3.1.3 Preferred Alternative

Due to the evaluation criteria, Alternative 2 is the preferred alternative. Alternative 2, which involves utilizing the third winding of the transformers and constructing two new switchgear lineups with accompanying protection and control, is $2.4M cheaper than Alternative 1 which involves extending circuits from the nearest stations. The costs associated with both alternatives are that which will bring 37.5MVA of capacity to the area. Therefore Alternative 1 costs $364,878/MVA and option 2 costs $300,877/MVA.

Alternative 2 is also the more practical option. It is HOL's ideology that each substation is to supply customers within its geographic area. Extending circuits from other stations to areas outside of their ideal boundaries would defeat this strategy as well as increase the exposure for outages on the circuits. Alternative 2 also allows for the removal of hair pinned circuits at Hinchey TH substation. This increases reliability because it reduces the exposure of each of the hair pinned circuits and their customers by 50%. Alternative 1 does not improve the spare feeder positions at Hinchey. It also will take numerous feeder positions at other stations and is likely to result in hair pinned breakers.

Furthermore, the need for the additional capacity has been forecasted for 2015. Due to the scope of work involved, Alternative 1 is likely to demand more time and resources which could prolong the project past the needed time frame. It is also more disruptive to the public as civil duct structures will require sidewalk excavation. This also poses safety risks to the general public. While HOL has excellent safety mitigation practices, Alternative 2 does not contribute to the safety risk to the public.

1.2.3.2 *Project/Program Timing & Expenditure*

As shown in Table 59, the bulk of the costs associated with this project have already been incurred. Hydro One requires a connection and cost recovery agreement for any capacity work they are asked to do. This payment outlines the work that is necessary for Hydro One to complete the request to extend the third winding of the transformers. It also covers the installation cost of the switchgear lineups (not the cost of the switchgears themselves). Moving forward costs for this project include the switchgear lineups, as well as the costs of the protection and control panels and their installation.

As a strategy to minimize expenditures within the project, HOL tenders for all equipment such as switchgears and relays. In addition, HOL completes all feasible installations in house which are done using industry best practices. However, since the substation's transformers are owned by Hydro One, they are the only ones that can complete specific parts of the scope of work and therefore, these costs are not in HOL's control.

Historical ($M)					Future ($M)				
2011	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
	1.141	6.162	2.555	0.969					

Table 59 - Project Expenditures

1.2.3.3 *Benefits*

Benefits	Description
System Operation Efficiency and Cost-effectiveness	By eliminating the hair pinned breakers, System Operations will be able to identify which circuit had a fault if it tripped the breaker more easily. This will result in a faster location of the fault and therefore a quicker restoration.
Customer	This investment is the most cost-effective option. Therefore the customer, as a ratepayer, is less impacted than they would be if another alternative was chosen. Customers being supplied by hair pinned circuits will also have a decreased number of outages due to the circuits transitioning to a single breaker. This reduces the exposure of each hair pinned circuit by 50%. Finally, the project will benefit future customers in this area by increasing the available capacity in the area to supply the new load.
Safety	The new switchgear has an explosion resistant design which will protect the worker in the event of a failure.
Cyber-Security, Privacy	N/A
Co-ordination, Interoperability	In order to accomplish this project on a specified time frame, HOL and Hydro One must coordinate with respect to the installation of the joint-purchased switchgear.
Economic Development	This project allows for future development to have sufficient capacity in place to acquire a timely connection. This will be important with the development of Bayview yards and the expansion of Tunney's Pasture. In addition to these large load areas, intensification is occurring along neighbouring properties.
Environment	N/A

Table 60 - Project Benefits

1.2.4 Prioritization

1.2.4.1 *Consequences of Deferral*

The deferral of this project would lead to difficulty to serve the increase in load that is expected. New load would have to be supplied from adjacent stations which are a considerable distance from the load center requiring long circuit extensions. Expensive civil infrastructure upgrades may be required to accommodate this alternative.

1.2.4.2 *Priority*

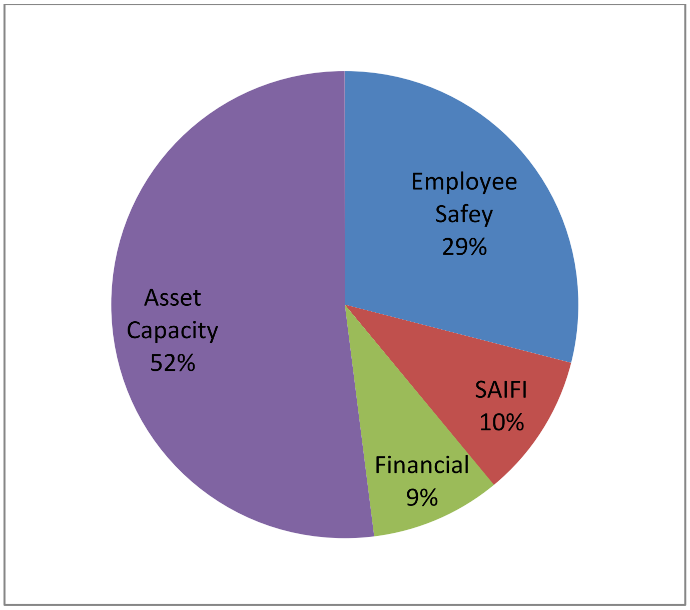


Figure 60 - Project Avoided Risk

Score = 1.373

1.2.5 Execution Path

1.2.5.1 *Implementation Plan*

The design and estimates for this project have already been completed. Currently Hydro One is working on the replacement of the two transformers at Hinchey TH substation. This work is scheduled to be complete in 2015. Once the work is complete the implementation of the new switchgears will commence. This coordination with Hydro One is essential as the switchgears cannot begin to be installed until the transformers are replaced.

The construction of the switchgears will begin with Hydro One installing the first new switchgear lineup. These breakers will allow for the installation of seven HOL feeder cells, to be installed by HOL. Hydro One will then install the tie breaker which will allow for the isolation between the two new switchgear lineups. The second new switchgear lineup will then be installed by Hydro One. These breakers will allow again, for the installation of additional feeder cells. Finally HOL will install the protection and control panels and program the relays for feeder protection and switchgear operation.

Furthermore, under Hydro One's scope of work they will have to upgrade the high side protection and control due to the increased capacity at the station, replace the fire suppression system, replace the heating, ventilating, and air conditioning system, and replace the station service.

Currently there are no foreseen internal resource constraints. However, when dealing with external parties there is always a risk. Timely procurement of the equipment, contract negotiations, and agreement on design is essential for the project to be completed on time and on budget.

1.2.5.2 *Risks to Completion and Risk Mitigation Strategies*
This installation of the switchgears will be occurring in 2015. There are currently no foreseeable risks that will cause this project not to be completed. There are, however, risks that could affect this projects timeline and cost. These are further explained in the sections below.

1.2.5.3 *Timing Factors*
Currently Hydro One is completing work inside Hinchey TH substation in order to facilitate the installation of the switchgears. This work has delayed the project and the switchgear installation has been pushed from 2014 to 2015. HOL has little control over the timeline of this work.

Further delays could arise from untimely procurement of the assets. This risk is mitigated by early planning and ordering equipment in advance. However, if upon delivery the assets are found to be faulty or damaged they will need to be reordered. This will add significant delay to the project. This risk is mitigated by taking into consideration the experience with various venders while making a decision on which vendor to use.

1.2.5.4 *Cost Factors*
The project delays mentioned above could have an economic impact on this project if it is not completed in time for the increase in load. In this case interim solutions will be required. This will either be in the form of constructing new circuits to the load area or operating equipment above their ratings which degrades their life expectancy. Both of these options will incur increased project costs.

1.2.6 Renewable Energy Generation
N/A

1.2.7 Leave-To-Construct
N/A

1.2.8 Project Details and Justification

Project Name:	Hinchey New Switchgear
Capital Cost:	$11.28M
O&M:	N/A
Start Date:	Q2 2012
In-Service Date:	Q4 2015
Investment Category:	System Service
Main Driver:	Need for additional capacity
Secondary Driver(s):	Additional breaker positions needed
Customer/Load Attachment	Future customers will benefit from the capacity upgrade (33.7MVA by 2024)
Project Scope	
The new installation will include two transformer breakers, a buss tie breaker, two switchgear lineups complete with buss work, and 14 feeder breakers. These switchgears will be delivered and installed by a connection to the transformer's third winding. Four new protection and control panels will also be installed with protection and communication equipment.	
Work Plan	
The design and estimates for this project have already been completed. Currently Hydro One is working on the replacement of the two transformers at Hinchey TH substation. This work should be done Q1 2015. Once the work is complete the implementation of the new switchgears will commence. The switchgears will then be installed, along with the feeder cells. Finally, the protection and control panels will be built.	
Customer Impact	
This project will allow for future customers to be connected due to the increase in capacity. It will also see a number of current customer's reliability improve because the exposure of the hair pinned circuits will be reduced. The customers fed from a circuit that is transferred to one of the new busses may experience a temporary outage while switching is completed. The alternative chosen is also expected to be the most cost-effective. Therefore, having the lowest effect on ratepayers.	

1.3 Lisgar Transformation Upgrade

1.3.1 Project/Program Summary

There are significant plans for growth in the City of Ottawa's downtown core. The growing load is being driven by both intensification and infill projects including the new proposed light rail transit. These projects will push the available capacity in the area to its limit. It is anticipated that Lisgar TL will experience 30MVA of new load within the next ten years. Currently the substation does not have the transformer capability to supply this increase in demand. This need is expected to occur by 2016 and has been identified through the integrated regional planning process led by the IESO.

HOL also expects there to be an increase in embedded generation that will be connected to Lisgar TL. The existing transformer's reverse power flow capability is limiting and inadequate to allow for a large amount of additional generation. An upgrade of the transformers will allow for reverse power flow to be utilized.

1.3.2 Project/Program Description

1.3.2.1 *Current Issues*

There are currently two transformers at Lisgar TL. These transformers are both owned by Hydro One and are rated at 45/60/75MVA. Currently one of the transformers is approaching its end of life. However, the other transformer is relatively new because of an electrical failure that caused the need for its replacement. Due to the level of expected load growth from projects such as the Light Rail Transit and Lebreton Flats development and the anticipated embedded generation, HOL will be requesting Hydro One to complete a transformation upgrade. These discussions have already begun.

1.3.2.2 *Project/Program Scope*

HOL has identified a need for capacity upgrade in its downtown service territory. This need has also been identified by the IESO as part of the integrated regional resource plan for the Ottawa area. HOL has requested Hydro One to commence a study on a detailed analysis indicating the work that will be implemented, the associated work schedule, and a Class B estimate (+/-25%) for upgrading both transformers at Lisgar TL substation to a rating of 60/80/100MVA. Currently, it is not anticipated that upgrades to the buss work will be part of this project's scope.

1.3.2.3 *Main and Secondary Drivers*

The main driver for this project is the expected increase in load that will constrain the ability of this substation to provide adequate power to customers. It is anticipated that 30MVA of new load will be realized in the next 10 years and this is above Lisgar TL substation's capacity. A secondary driver for this project is that HOL anticipates a large amount of embedded generation in the near term. Currently Lisgar TL substation is limited by the reverse power flow capability of its transformers. The upgrade will see this limitation removed.

1.3.2.4 *Performance Targets and Objectives*

The objectives of this project are to allow HOL to adequately supply the growing load within downtown Ottawa and connect future embedded generation. These objectives will be accomplished by upgrading the transformers to increase their capacity and allow reverse power flow.

1.3.3 Project/Program Justification

1.3.3.1 *Alternatives Evaluation*

1.3.3.1.1 Alternatives Considered

In order to meet the objectives mentioned in section 1.3.2.4 above, several alternatives were considered:

1) Line extensions: This option would see the current transformers at Lisgar TL substation not upgraded and left as is with a limited time rating of 83MVA. Under this alternative the substation will be loaded to its capacity. Circuits from nearby stations would then be extended into the Lisgar TL substation geographic area to supply the additional load. There are three substations that have been identified as being able to supply this additional capacity due to their location. However, due to the expected load growth, this solution is only anticipated to be sufficient for 5-8 years at which time a station capacity upgrade will be required. Furthermore, this alternative does not provide Lisgar TL substation with reverse power flow capabilities.
2) Upgrade one transformer: This option would see the current 40 year old transformer upgraded. This would lead to a mismatch in transformer ratings, but due to the age of the non-upgraded transformer the substation's limited time rating will be increased to 96MVA. Based on the expected load growth, this solution is anticipated to be sufficient for 4-5 years. At this time line extensions or the upgrade of the second transformer will be needed due to Lisgar TL substation being at capacity. This option will allow up to 30MW of generation to be connected due to reverse power flow capability. In addition, by allowing more load capacity at Lisgar TL substation, further embedded generation can be connected due to the minimum station loading having increased.
3) Upgrade both transformers: This alternative would see both of the transformers at Lisgar TL upgraded. This would increase the substation's limited time rating to 144MVA, however due to the rating of the buss, the station would be operated to a rating of 115MVA. This option is sufficient to supply the increasing load growth around Lisgar TL substation for the foreseeable future. By replacing both of the transformers, the reverse flow capability will be increased to 40MW. In addition, by allowing more load capacity at Lisgar TL substation, further embedded generation can be connected due to the minimum station loading having increased.

1.3.3.1.2 Evaluation Criteria

The evaluation criteria used to determine the best option was based on meeting the aforementioned objectives. While meeting these objectives is the primary focus, cost is also a factor that was largely considered.

1.3.3.1.3 Preferred Alternative

The preliminary preferred alternative is option 3 which will see both of the current 45/60/75MVA transformers upgraded to a rating of 60/80/100MVA. However, this decision will be re-evaluated after the study that Hydro One is currently performing has concluded.

Upon the completion of Hydro One's study, it is likely that either alternative 2 or 3 will be chosen. This is due to the forecasted load growth and the ability to connect embedded generation. It is also HOL's preferred planning method to supply an area by the closest geographical station if possible. This limits the exposure of the circuits feeding our customers. Alternative 1 does not provide a solution to the objective of adding embedded generation at Lisgar TL substation. The decision on whether to implement alternative 2 or 3 will be largely driven by cost differences and the feasible timing of the upgrade.

1.3.3.2 *Project/Program Timing & Expenditure*

Hydro One is currently developing a study on the work that will be needed for the project of upgrading two transformers at Lisgar TL substation. This will include the schedule of work and a cost estimate. This study will be completed in 2015. It is currently planned that in order to meet the anticipated load forecast this project should be implemented in 2016. Therefore, it is expected that if the decision to replace both transformers is chosen then they will be upgraded in 2016 and 2017.

Due to the substation being owned by Hydro One, all work will be sole sourced through them. Therefore HOL does not have much control over the costs associated with the transformation upgrade. However, HOL has requested Hydro One to complete a study on the alternative of upgrading both transformers in order to identify the work needed and the estimated cost so that the best decision can be made.

1.3.3.3 *Benefits*

Benefits	Description
System Operation Efficiency and Cost-effectiveness	The increase in capacity at Lisgar TL substation will allow for easier operations during high demand periods. Without the upgrade, any demand that would put Lisgar TL substation over its limited time rating would need to be shifted to stations that it is interconnected with to safely operate the station's transformers. This will not be necessary once the transformers have been upgraded.
Customer	The benefit to customers that is likely to come from this project is that the most cost-effective option to meet the increase in load will be chosen. This will be done by considering each option and making an informed decision based on meeting the needs.
Safety	N/A
Cyber-Security, Privacy	N/A
Co-ordination, Interoperability	The need for increased capacity in this area has been identified within the integrated regional resource plan working group led by the IESO. However, due to the timeline of the plan, HOL has had to pursue this option before its release.
Economic Development	One of the drivers for this project is to allow for the anticipated development in downtown Ottawa. This includes the development of Lebreton Flats, a light rail transit station, and future expansions. This project also looked to allow for the connection of embedded generation. All of these projects lead to economic growth for Ottawa by allowing their

	connection.
Environment	Much of the generation being contracted by the IESO in Ontario is of the renewable fuel type. By allowing for an increased amount of generation at Lisgar TL substation, more renewable generation can be connected. This generation can be used to offset other forms of electrical production that utilize harmful fossil fuels.

Table 61 - Project Benefits

1.3.4 Prioritization

1.3.4.1 *Consequences of Deferral*

If this project is deferred, HOL risks not having enough capacity to supply the requested load. This will lead to either HOL's assets being over loaded or the installation of new circuits from other substations. Neither of these options is preferred as the former reduces the life of HOL's assets and the latter will have a large impact on the customers financially.

1.3.4.2 *Priority*

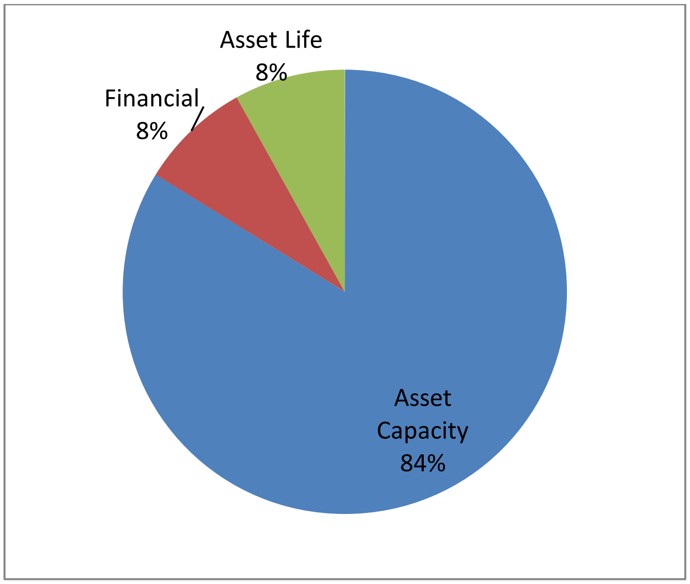


Table 62 - Project Avoided Risk

Score = 0.72

1.3.5 Execution Path

1.3.5.1 *Implementation Plan*

Hydro One is currently undergoing a detailed study on the work that will be required to upgrade both transformers at Lisgar TL substation. This report will also specify the schedule of work and a cost estimate. Upon receiving the completed study in 2015, HOL will make a decision to ask Hydro One to upgrade either one or both of the transformers. The implementation of this project will then be carried out by Hydro One at the request of HOL as they are the owner of Lisgar TL substation's transformers. The current plan is to have one transformer upgraded by the end of 2016 and if the option of upgrading both transformers is chosen, then the second transformer will be upgraded in 2017.

1.3.5.2 *Risks to Completion and Risk Mitigation Strategies*
This project is currently in the beginning phases of planning. The need is known, but the optimal solution is still being determined. The result of Hydro One's study on upgrading both transformers could enlighten the need for various upgrades at Lisgar TL substation that have not been identified. Based on the costs associated with this upgrade a more feasible alternative may be chosen and this project will not be completed. However, there are also risks that could affect this projects timeline and cost. These are further explained in the sections below.

1.3.5.3 *Timing Factors*
There are several factors that can affect the timing of this project. First is the completion of Hydro One's study on the alternative to replace both transformers at Lisgar TL substation. This is currently limiting the progress of the project since HOL's final decision will come after reviewing the study.

The timely procurement of equipment is also a major factor that can cause delays in the project. Transformers can take over a year to procure and therefore must be ordered as soon as possible from the manufacturer. Any delay in delivery will directly result in a prolonged schedule of work. In order to mitigate this risk HOL will request Hydro One to procure transformers once the final decision has been made.

1.3.5.4 *Cost Factors*
Due to the fact the Hydro One owns the transformers at Lisgar TL substation all work will be sole sourced through them. Therefore HOL has little control in the costs associated with the project's work. HOL has mitigated this risk by requesting a study to be completed by Hydro One in order to determine the costs associated with upgrading both transformers. This is an attempt to make an informed decision about which alternative to pursue.

1.3.6 Renewable Energy Generation
This project is mainly being driven due to the lack of capacity to connect new load at Lisgar TL substation. However, by upgrading the transformers at the substation there is an additional benefit from their ability to accept reverse power flow. This increases the amount of embedded generation that can be connected. Hydro One has specified that the alternative of upgrading the transformer that is near end of life will achieve 30MW of reverse power flow. The alternative to upgrade both transformers allows for 40MW of reverse power flow to be achieved.

1.3.7 Leave-To-Construct
N/A

1.3.8 Project Details and Justification

Project Name:	Lisgar Transformation Upgrade
Capital Cost:	Awaiting outcome of Hydro One study
O&M:	N/A
Start Date:	Q1 2014
In-Service Date:	Q4 2017
Investment Category:	System Service
Main Driver:	Capacity need
Secondary Driver(s):	Renewable energy generation connection
Customer/Load Attachment	Future customers will be affected (30MVA by 2024)

Project Scope

HOL has identified a need for capacity upgrade in its downtown service territory. This need has also been identified by the IESO as part of the integrated regional resource plan for the Ottawa area. HOL has requested Hydro One to commence a study on a detailed analysis indicating the work that will be implemented, the associated work schedule, and a Class B estimate (+/-25%) for upgrading both transformers at Lisgar TL substation to a rating of 60/80/100MVA. Currently, it is not anticipated that upgrades to the buss work will be part of this project's scope.

Work Plan

Hydro One is currently undergoing a detailed study on the work that will be required to upgrade both transformers at Lisgar TL substation. This report will also specify the schedule of work and a cost estimate. Upon receiving the completed study in 2015, HOL will make a decision to either ask Hydro One to upgrade one or both of the transformers. The implementation of this project will then be carried out by Hydro One at the request of HOL as they are the owner of Lisgar TL substation's transformers. The current plan is to have one transformer upgraded by the end of 2016 and if the option of upgrading both transformers is chosen, then the second transformer will be upgraded in 2017.

Customer Impact

The impact to customers will be those that come in the future. It is expected that 30MVA of demand will be required over the next ten years. These customers will need the ability to be supplied with reliable power.

1.4 Limebank Transformer Upgrade

1.4.1 Project/Program Summary

The Limebank Transformer Upgrade project involves the installation of a new station transformer with protection and new distribution feeders to meet the growing capacity requirements close to the station. In addition to the capacity driver, there are also reliability benefits gained by completing this project through the splitting of existing circuits and ties to other substations.

1.4.2 Project/Program Description

1.4.2.1 *Current Issues*

Limebank MS is currently at its planning capacity limit. Large increases in load are forecasted in the area directly adjacent to the substation. In particular, the Riverside South Community Design Plan encompasses an area of 1,800 hectares around the substation and involves the development of a rapid transit corridor, residential areas, and an employment area.

1.4.2.2 *Program/Project Scope*

The project is located in the south part of the City of Ottawa at 4389 Limebank Road at HOL's Limebank MS substation. The existing substation consists of two 33MVA station transformers. This project will be adding another station transformer to the station with provisions for a fourth transformer in the future.

The assets in scope for this project include the following:

- A new third 115KV to 27kV 33MVA station transformer with an online tap changer
- Installation of a 115kV high voltage disconnect switch
- Installation of 115kV high side SF6 breaker
- Protection upgrade including Potential Transformers, Current Transformers, Protection & Control Relays, Protection & Control Building
- New 27.6kV Switchgear and Switchgear Building
- Four new distribution circuits
- Ground grid installation
- Noise abatement and oil containment
- Oil containment for existing station transformers T1 and T2 (required by the Ministry of Environment)

1.4.2.3 *Main and Secondary Drivers*

The primary driver for this project is capacity. There is significant load growth forecasted in the ideal supply range of Limebank substation. In particular, the Riverside South Community Design Plan (CDP) is forecasting load which exceeds the planning capacity of Limebank substation. The Riverside South CDP encompasses an area of 1,800 hectares and involves the development of a rapid transit corridor, residential areas, and an employment area. The geographic plan of the Riverside South CDP is shown in Figure 61.

A secondary driver for the Limebank Transformer Upgrade is reliability. Along with the new station transformer, additional breaker positions will be available for new circuits coming out of Limebank station. These new circuits will split existing circuits coming out of Limebank MS, reducing customer exposure to outages, as well as making ties with circuits from nearby stations including Uplands MS, Longfields DS, Fallowfield DS, and Leitrim MS.

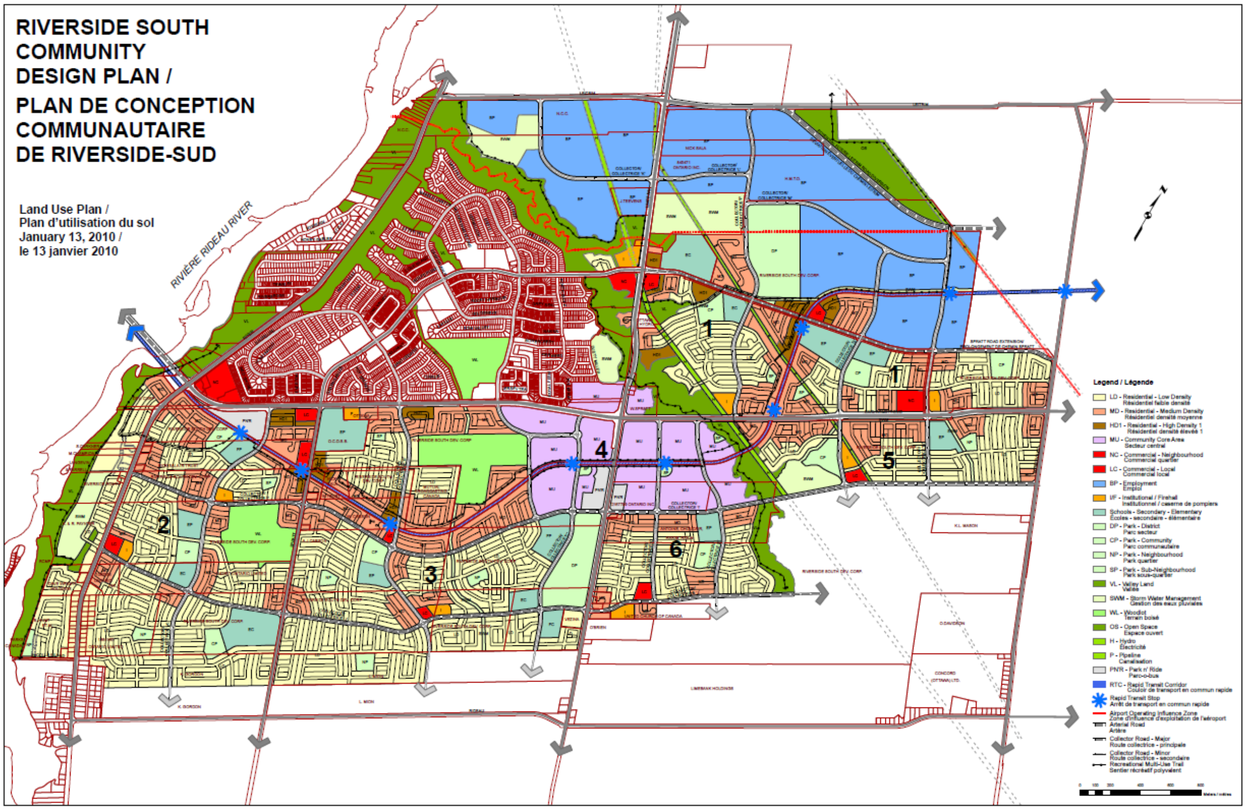


Figure 61 - Riverside South Community Design Plan

1.4.2.4 *Performance Targets and Objectives*

The primary objective of implementing this project is to increase the planning supply capacity in the surrounding area of the substation by 33MVA.

Additional planning objectives that are met by this project include:

- Planning for the long term dependence of the new station assets through the implementation of proper protection
- Increasing the contingency within the station by installing the new transformer lineup sufficiently far away from the existing line up in case of failure
- Increasing the contingency of existing Limebank circuits and ties with other substation circuits through additional new feeders
- Planning for environmental concerns by installing proper oil containment for the new transformer and upgrading the oil containment of the existing transformers

1.4.3 Project/Program Justification

1.4.3.1 *Alternatives Evaluation*

The primary objective of this project is to increase the planned supply capacity in the area surrounding the substation.

1.4.3.1.1 Alternatives Considered

Feeder ties with other stations

Limebank substation has existing feeder ties with the surrounding 27.6kV substations Leitrim MS, Uplands MS, Longfields DS, and Fallowfields MTS. Figure 62 below shows a map of the area surrounding Limebank MS along with the Limebank feeders, other 27.6kV substations, and the Riverside Community area highlighted. In order to meet the capacity needs of the Limebank Station area, feeder ties with other stations are being considered.

Limebank Transformer Upgrade with provision for future transformer

The upgrade of a new 33 MVA transformer with feeders at Limebank MS substation is considered.

Limebank Transformer Upgrade with two additional transformers

The upgrade of two new 33 MVA transformers with feeders at Limebank MS substation is considered.

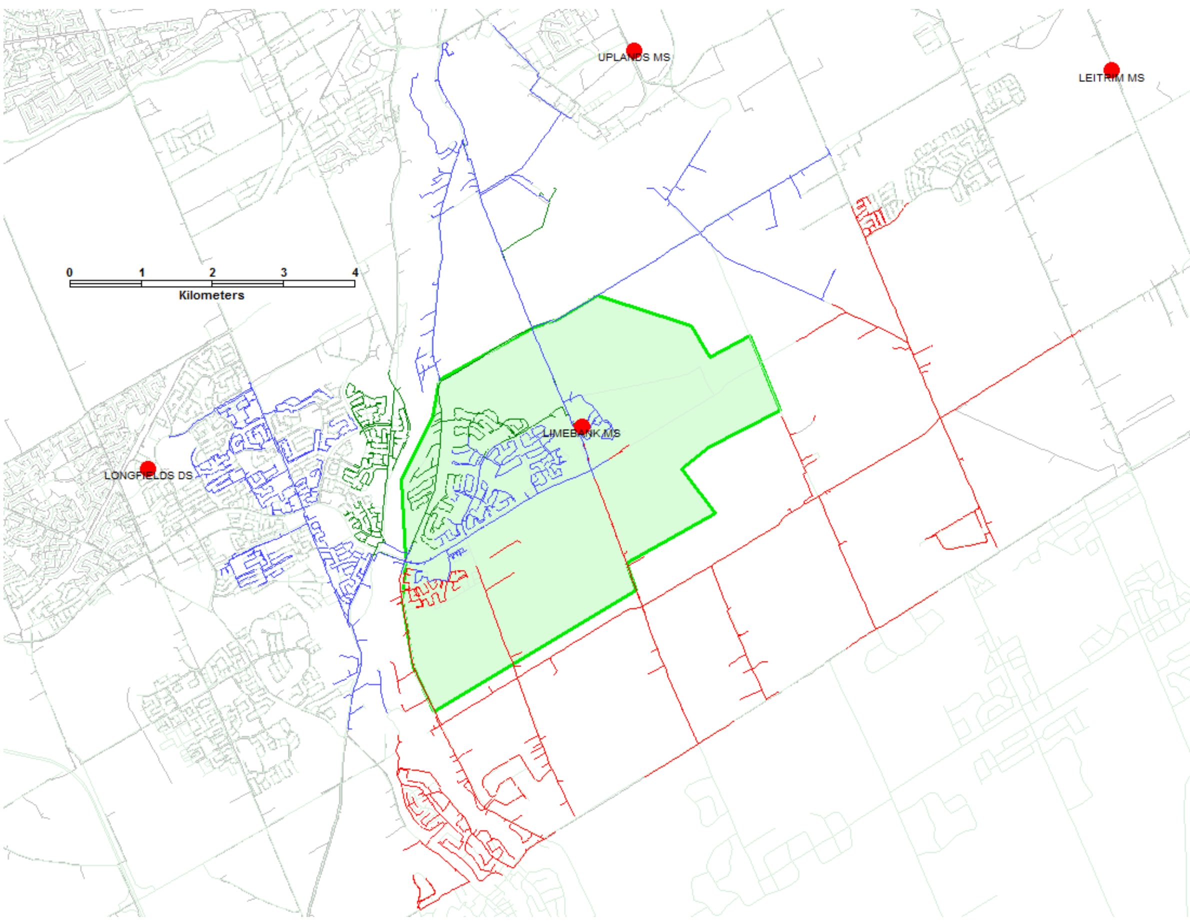


Figure 62 - Riverside South Community Design Plan are (light green area) shown in reference to surrounding substations. Existing Limebank circuits are also shown.

1.4.3.1.2 Evaluation Criteria

The criteria used to evaluate the alternatives are reliability, cost, and long term capacity sustainability.

1.4.3.1.3 Preferred Alternative

The preferred alternative is the Limebank transformer upgrade with provision for future transformer.

The full ranking of alternatives is:

1. Limebank transformer upgrade with provision for future transformer
2. Limebank transformer upgrade with two additional transformers
3. Feeder ties with other stations

	Reliability	Cost	Long Term Capacity Sustainability
Limebank transformer upgrade with provision for future transformer	Ideal – splitting of feeders at Limebank MS substation is simple and feeder length to load centers is minimized	Upgrade cost of new transformer line-up and feeders with provision for future transformer	Ideal – load growth is located near Limebank MS substation and there is provision for future growth
Limebank transformer upgrade with two additional transformers	Ideal – splitting of feeders at Limebank MS substation is simple and feeder length to load centers is minimized	Upgrade cost of two new transformer line-ups and feeders	Ideal – load growth is located near Limebank MS substation and long term capacity exists
Feeder ties with other stations	Splitting of feeders at Limebank MS is more complex and feeder length to load centers is longer	Upgrade cost of new transformer line-ups and feeders at other stations	Non-ideal – load growth near Limebank MS substation would be supplied by stations geographically further away

Table 63 - Alternatives Comparison

Feeder ties with other stations

Both Leitrim MS and Uplands MS have reached their supply planning capacities and would require upgrades to supply new load around the Limebank substation area. Both these substations currently have a single transformer and therefore are not ideal for contingency planning.

Longfields DS has reached its supply planning capacity and would require transformer upgrades to supply additional feeder capacity to the Limebank substation area.

Fallowfield MTS has reached its supply planning capacity in addition to being 13km west from the Limebank substation area.

Limebank MS substation is ideally situated to supply the load growth as it is located within the Riverside Community Design Plan.

Limebank Transformer Upgrade with two additional transformers
Upgrading capacity at Limebank MS substation is ideal for both long term sustainability and reliability. Locating new capacity beside the future load growth center allows for minimized feeder lengths and for simple splitting of existing feeders from Limebank MS substation.

It has been determined that the upgrade of a single 33MVA transformer at Limebank MS will suffice planning capacity until at least 2024.

Upgrading the station with a second new transformer would provide long term capacity benefits. However, this second new transformer would not be required until approximately 2024 and would incur additional costs to the project in 2014 and 2015.

Limebank transformer upgrade with provision for future transformer
Upgrading capacity at Limebank MS substation is ideal for both long term sustainability and reliability. Locating new capacity beside the future load growth center allows for minimized feeder lengths and for simple splitting of existing feeders from Limebank MS substation.

It has been determined that the upgrade of a single 33MVA transformer at Limebank MS will be sufficient for planning capacity until at least 2024.

As there is capacity forecasted beyond 2024, it is rational to make provisions for a second future new transformer. This alternative also ensures that risk is minimized in the case that load is not realized. The costs of this second transformer are out of scope for this alternative.

1.4.3.2 *Project/Program Timing & Expenditure*

Historical ($M)					Future ($M)				
2011	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
	1.04	5.47	1.62	0.23					

Table 64 - Project Expenditure

HOL has minimized the controllable costs of this project by implementing a number of measures.

- A competitive Request for Proposal (RFP) process was used for determining consulting resources. These consultants are retained for a minimum 3 year timeframe to ensure that they are able to efficiently meet our needs and have a good understanding of HOL's internal processes and standards.
- All contractors and vendors are selected through a competitive RFP process. These contractors and vendors are pre-screened to ensure that they have the abilities and expertise to meet the needs of HOL and are able to maintain timelines required.

- The use of in house project management allowed for efficient use of resources and experience from past projects within HOL. Project management best practices at HOL are based on PMI (Project Management Institute).
- Workforce planning is used to ensure internal resources requirements are identified early. If outside resources are required this is identified early in the project to ensure the roll out is implemented smoothly and efficiently.

1.4.3.3 *Benefits*

Benefits	Description
System Operation Efficiency and Cost-effectiveness	This project improves the reliability of the station assets by installing contingent assets through a new transformer lineup. The contingency is improved by installing the new transformer lineup sufficiently far away from the existing line up in case of failure. Additionally, more available feeder positions are introduced by this project, allowing for the splitting of load for customers and more ties between feeders for contingent switching.
Customer	This project gives future customers the station capacity to be able to connect new load in the future. Additionally, this project should increase reliability in the area through new feeder positions.
Safety	Building a new transformer will address the predicted thermal overload of the existing station transformer that would occur in the future. Overloading the system can lead to risks such as equipment damage and safety hazards which this project will mitigate Proper protection coordination in the station improves the safety of employees and the public.
Cyber-Security, Privacy	Not Applicable
Co-ordination, Interoperability	Not Applicable
Economic Development	This project enables infrastructure for economic growth in the area. In particular Riverside South Community Development Plan, which includes lands reserved for employment blocks.
Environment	This project includes oil containment for the new transformer along with refurbished oil containment for the existing transformers. This protects oil from seeping into the environment in case of oil leaks or catastrophic failure. It is no longer acceptable to use Polychlorinated Biphenyl (PCBs) oil in transformer insulation, and the new transformer will use a safer chemical. Oil containment will be included to minimize environmental damage, should a transformer leak.

Table 65 - Project Benefits

1.4.4 Prioritization

1.4.4.1 *Consequences of Deferral*

Since the purpose of this project is to address an upcoming capacity issue, the most important consequence of deferral would be the inability to service the required load in the near future. Deferring capacity upgrades risks thermal overload for an extended period of time which could lead to equipment damage and customer outages.

This project will enable the creation of ties with other stations and backup other feeders. This presents an additional consequence of deferral, which is that reduced contingency and therefore reliability in the case of an outage.

1.4.4.2 *Priority*

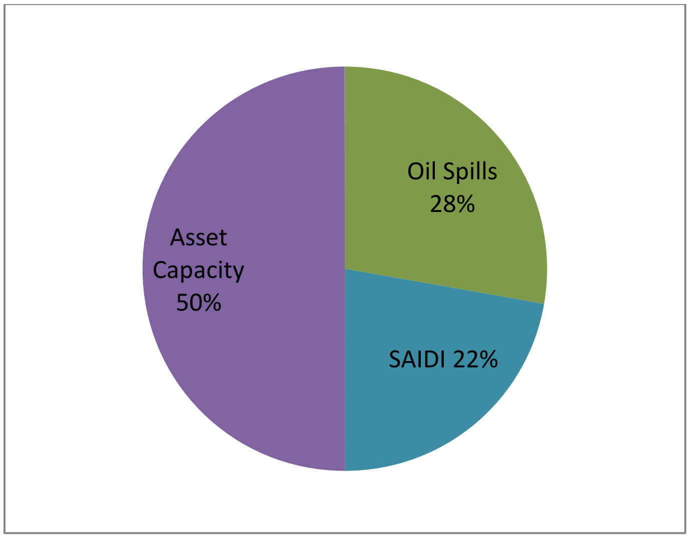


Figure 63 - Project Avoided Risk

Project Score: 1.44

1.4.5 Execution Path

1.4.5.1 *Implementation Plan*

The implementation plan for the Limebank Transformer Upgrade is as follows:

- The design and major equipment for this project were procured in 2012 and 2013.
- The first phase of civil construction was completed in 2013 by contractors
- The second phase of civil construction was completed in 2014 by contractors
- Electrical construction began in 2014 by HOL station electricians and technicians
- The new transformer is to be energized by end of 2014
- New feeders will be egressed by end of 2014 and Q1 of 2015
- Oil containment refurbishment for existing station transformers will occur in Q3 of 2015

1.4.5.2 *Risks to Completion and Risk Mitigation Strategies*

The construction of a substation transformer is dependent upon the availability of Hydro One Networks Inc.'s transmission supply line. HOL cannot proceed with their project unless supply is available. Due to this important requirement, HOL has maintained heavy communication with Hydro One.

This project must also gain Environmental Assessment approval and City of Ottawa approval.

1.4.5.3 *Timing Factors*

Coordination with Hydro One is required for transmission connection for the new transformer lineup.

1.4.5.4 *Cost Factors*

In order to gain Environmental Assessment approval, additional refurbishment of the oil containment for the existing transformer at Limebank MS was required.

1.4.5.5 *Other Factors*

Noise abatement was introduced as part of the scope of this project due to the stations close proximity to a residential neighbourhood.

1.4.5.6 *Renewable Energy Generation (if applicable)*

Not applicable.

1.4.6 Leave-To-Construct (if applicable)

Not applicable.

1.4.7 Project Details and Justification

Project Name:	Limebank Transformer Upgrade
Capital Cost:	$8.36 M
O&M:	$0
Start Date:	2012
In-Service Date:	2014
Investment Category:	System Service
Main Driver:	Capacity
Secondary Driver(s):	Reliability
Customer/Load Attachment	33MVA

Project Scope

The project is located in the south part of the City of Ottawa at 4389 Limebank Road at HOL's Limebank MS substation. The existing substation consists of two 33MVA station transformers. This project will be adding another station transformer to the station with provisions for a fourth transformer in the future. The assets in scope for this project include the following:

- A new third 115KV to 27kV 33MVA station transformer with an online tap changer
- Installation of a 115kV high voltage disconnect switch
- Installation of 115kV high side SF6 breaker
- Protection upgrade including Potential Transformers, Current Transformers, Protection & Control Relays, Protection & Control Building
- New 27.6kV Switchgear and Switchgear Building
- Four new distribution circuits
- Ground grid installation
- Noise abatement and oil containment
- Oil containment for existing station transformers T1 and T2 (required by the Ministry of Environment)

Work Plan

The work plan for the Limebank Transformer Upgrade is as follows:

- The design and major equipment for this project were procured in 2012 and 2013.
- The first phase of civil construction was completed in 2013 by contractors
- The second phase of civil construction was completed in 2014 by contractors
- Electrical construction began in 2014 by HOL station electricians and technicians
- The new transformer is to be energized by end of 2014
- New feeders will be egressed by end of 2014 and Q1 of 2015
- Oil containment refurbishment for existing station transformers will occur in Q3 of 2015

Customer Impact

This project gives existing and future customers the station capacity to be able to connect new load. Additionally, this project will increase reliability in the area through new feeders which allow for splitting of customer load and more ties between feeders for contingent switching. The contingency of the station is improved by installing the new transformer lineup sufficiently far away from the existing line up in case of failure.

1.5 Leitrim T1

1.5.1 Project/Program Summary

The core purpose of the Leitrim T1 project is to add 25MVA of transformation capacity and one additional circuit egress to the single transformer substation Leitrim MS. This project will bring additional and contingent transformation to Leitrim MS Substation, potentially allowing for either T1 or T2 to be brought out of service without impacting the customers it serves.

1.5.2 Project/Program Description

1.5.2.1 *Current Issues*

Leitrim MS is currently a single transformer substation. This results in operational difficulties whenever servicing or maintenance of station equipment is required. Additionally, in the event of a transformer or station feeder interruption, there is no redundancy within the station for contingency.

The circuits at Leitrim MS, the 249F1 and 249F2, have also consistently been HOL's worst performing feeders. The primary issue with these feeders are overhead exposure over long feeder lengths.

Capacity is forecasted to increase with the realization of the Leitrim Community Design Plan.

1.5.2.2 *Program/Project Scope*

This project is located at 4294 Hawthorne Road in the former municipality of Gloucester, at Leitrim MS substation. This project will bring additional and redundant transformation to Leitrim MS Substation, potentially allowing for either T1 or T2 to be brought out of service without impacting the customers it serves.

The scope of this project includes: the relocation of the incoming 44kV supply; installation of a motorized high side air break switch; high side breaker; high side PT feeding the transformer; and a new 25MVA transformer complete with a seismically rated foundation and full oil containment. On the low side, a circuit switcher and structure mounted Current Transformers (CTs) will feed back into the existing low side bus. In addition, a secondary tie breaker will be installed in between the two existing buses. On the P&C/SCADA side, the new transformer will be protected by differential protective relaying and the secondary bus will be protected by overcurrent relaying. The scope also includes the construction of an additional recloser (249F3) bringing the total number of circuits fed by the station to four (4). The load side of this new egress feeder is out of scope and will be taken care of by a distribution project. Further, the scope includes the installation of an automatic transfer switch capable of feeding the station's AC service from the low-side bus of either T1 or T2, serving the new standard P&C "house" containing most of the protective relaying, power supplies, and communications gear. Lastly, the service road used to access the substation will also require minor modifications to accommodate the finished substation.

The ground grid and fencing will be upgraded as well.

1.5.2.3 *Main and Secondary Drivers*

The primary driver for this project is reliability. In its current state, Leitrim MS only has a single transformer. In the event of a transformer or station feeder interruption, there is no redundancy within the station for contingency. Restoration of load in the event of a prolonged outage is dependent on feeder ties with either Uplands MS or Limebank MS, which may be constrained in their loading during peak times and require lengthy switching. Additionally, this project introduces another station feeder position. A new circuit will allow for the potential to split existing circuits coming out of Leitrim MS, reducing customer exposure to outages, as well as make ties with circuits from nearby stations such as Uplands MS and Limebank MS.

Secondary drivers include the ability to maintain either transformer at the station as well as an increase in available capacity at Leitrim MS.

1.5.2.4 *Performance Targets and Objectives*

The primary objective of implementing this project is to achieve the station contingency realized by a second 25MVA transformer lineup.

Additional planning objectives that are met by this project include:

- Planning for the long term dependence of the new station assets through the implementation of proper protection
- Increasing the contingency of existing Leitrim circuits and ties with other substation circuits through an additional feeder
- Planning for environmental concerns by installing proper oil containment
- Additional available transformation capacity at the station

1.5.3 Project/Program Justification

1.5.3.1 *Alternatives Evaluation*

The primary driver of this project is providing more contingency to Leitrim MS with a secondary driver of increasing capacity.

1.5.3.1.1 Alternatives Considered

Feeder Ties with Other Stations

Leitrim MS substation has existing feeder ties with the surrounding 27.6kV substations Limebank MS and Uplands MS. Figure 64 below shows the trunk circuitry of each station in the area and ties. In order to meet the reliability needs and capacity needs of Leitrim MS, feeder ties with other stations are considered as an alternative.

Second Transformer and Feeder (Leitrim T1)

The addition of a new 25MVA transformer and additional egress feeder out of Leitrim MS substation is considered as an alternative.

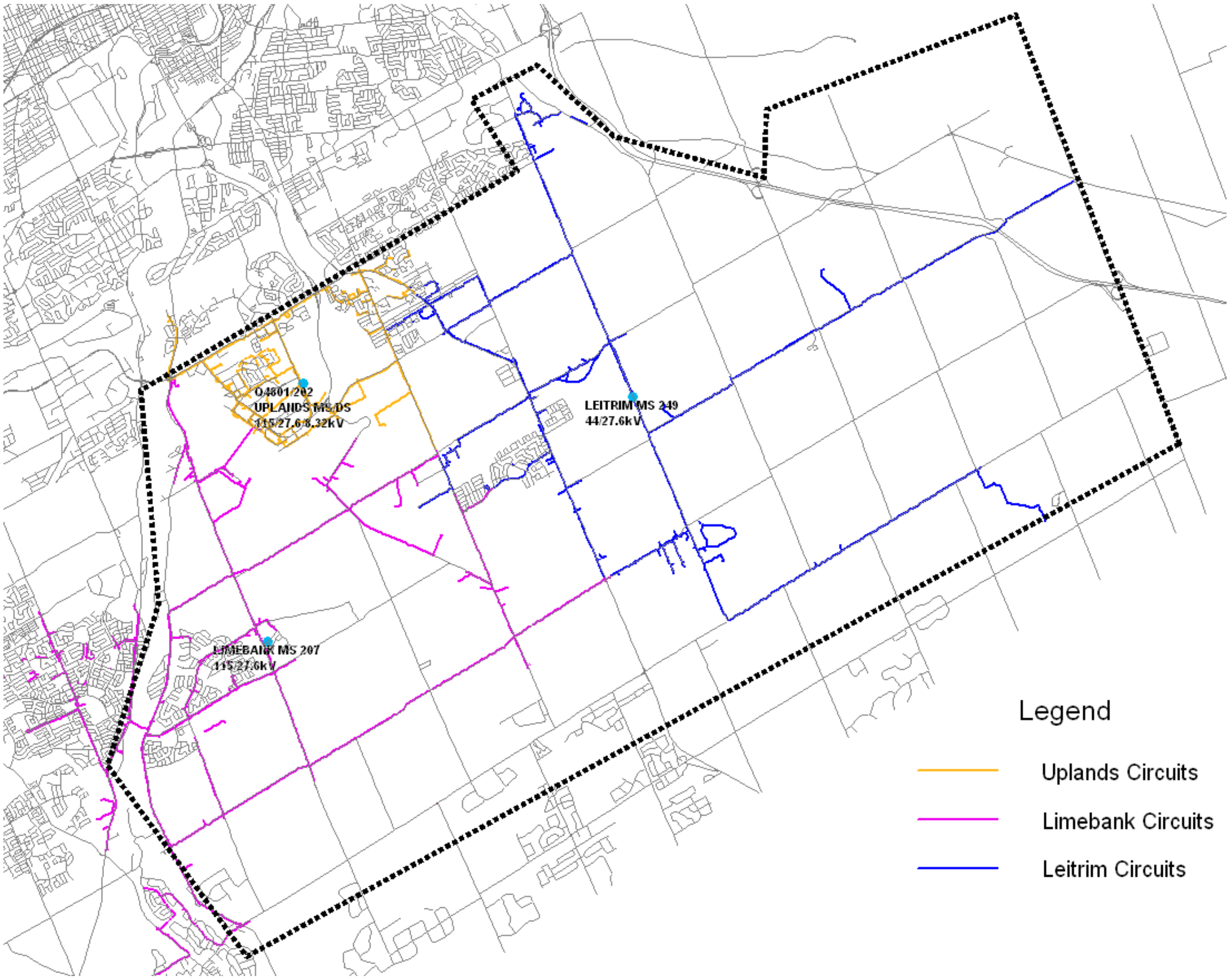


Figure 64 - Leitrim MS in relation to tie stations Uplands MS and Limebank MS

1.5.3.1.2 Evaluation Criteria

The criteria used to evaluate the alternatives are reliability, capacity, cost, and power quality.

1.5.3.1.3 Preferred Alternative

The preferred alternative is the upgrade of Second Transformer and Feeder (Leitrim T1).

The full ranking of alternatives is:

1. Second Transformer and Feeder (Leitrim T1).
2. Feeder Ties with Other Stations

	Second Transformer and Feeder (Leitrim T1)	Feeder Ties with Other Stations
Reliability	Improved reliability compared to feeder solution	Worse reliability compared to Leitrim station solution
Capacity	Meets capacity requirements	Meets capacity requirements
Power Quality	No power quality issues	Possibility of voltage sags at end of line trunk customers
Cost	$3.05M	$5.33M

Table 66 - Project Alternatives

Second Transformer and Feeder (Leitrim T1)
Adding a second transformer and new feeder at Leitrim MS substation improves reliability through transformer lineup contingency, new feeder splitting and tie potential. Leitrim MS would be self-sufficient as a station for restoration in the case of a single transformer trip or station feeder trip.

The new transformer would also provide additional capacity planning in the area.

Power quality issues such as voltage sag should not be an issue in the case of contingent feeding with the second transformer as the existing distance from station to end-of-line would not change.

The total cost of this alternative is approximately $3.05M.

Feeder Ties with Other Stations
Leitrim MS substation has existing feeder ties with the surrounding 27.6kV substations Limebank MS and Uplands MS. In order to accommodate an equivalent of 25MVA of contingency capacity, upgrades would be required at either Uplands MS or Limebank MS. Uplands MS is a single transformer station and scheduled to have a second transformer installed in 2018 for its own capacity forecast and reliability needs. Limebank MS will have provisions to install a fourth 33MVA transformer lineup with an estimated need install date of 2024.

This alternate involves the option of installing the fourth transformer at Limebank MS in order to meet the reliability and capacity needs of Leitrim MS, prior to the original planned install date of 2024. In addition to a new transformer at Limebank MS, a dedicated feeder would be required to egress from the station and tie to Leitrim MS.

Estimation of the cost of this alternative is based on installing a new dedicated pole line with a single three phase circuit a distance of 10km from Limebank station to tie into the nearest existing Leitrim 249F2 circuit at Bank Street and Rideau Road. The cost per kilometer of an overhead dedicated circuit is estimated to be $333,000 based on $20,000 per pole and 60m between poles. Therefore, for 10km of circuit, it is estimated the cost is $3.33M. The cost of the breaker position at Limebank MS has not been considered. An estimated preliminary cost of the new transformer at Limebank MS is $2.0M. Therefore the total cost of this alternate is approximately $5.33M.

From a capacity standpoint, this alternative will provide the same benefits as adding new transformer capacity at Leitrim MS since 25MVA amounts to one fully dedicated, fully loaded circuit.

From a reliability perspective, this option is not as preferable as upgrading at Leitrim MS. This is because no new feeder positions are added at Leitrim MS itself, where new load growth is forecasted. Additionally, there is more exposure on supply coming from long overhead feeders compared with local station supply.

A dedicated backup supply line from Limebank MS to Leitrim MS may result in power quality issues for some customers due to long feeder lengths. The distance from Limebank MS to end-of-line trunk Leitrim MS customers is approximately 20km. This could result in voltage sag issues.

1.5.3.2 *Project/Program Timing & Expenditure*

Historical ($M)						Future ($M)			
2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
				0.84	2.21				

Table 67 - Project Expenditures

HOL has minimized the controllable costs of this project by implementing the following measures:

- A competitive Request For Proposal (RFP) process was used for determining consulting resources. These consultants are retained for a minimum 3 year timeframe to ensure that they are able to efficiently meet our needs and have a good understanding of HOL's internal processes and standards.
- All contractors and vendors are selected through a competitive RFP process. These contractors and vendors are pre-screened to ensure that they have the abilities and expertise to meeting the needs of HOL and are able to maintain timelines required.
- The use of in house project management allowed for efficient use of resources and experience from past projects within HOL. Project management best practices at HOL are based on PMI (Project Management Institute).
- Workforce planning is used to ensure internal resource requirements are identified early. If outside resources are required this is identified early in the project to ensure the roll out is implemented smoothly and efficiently.

1.5.3.3 *Benefits*

Benefits	Description
System Operation Efficiency and Cost-effectiveness	This project improves the reliability of the station assets by installing contingent assets through a new transformer lineup. Additionally, another feeder position is introduced by this project, allowing the potential for splitting of load for customers and more ties between feeders for contingent switching.
Customer	This project increases station reliability through a new transformer line up. A new feeder position enables increasing distribution reliability in the area as well. Additionally, this project provides capacity to be able to connect customers and future load.
Safety	Building a new transformer will lineup will allow for more accessible maintenance on transformer lineups as well as a sharing of load on each transformer to avoid thermal overload. Overloading the system can lead to equipment damage and safety hazards. This project will mitigate that risk. Proper protection coordination in the station improves the safety of employees and the public.
Cyber-Security, Privacy	Not Applicable
Co-ordination, Interoperability	Not Applicable
Economic Development	This project enables electrical capacity infrastructure for economic growth in the area.
Environment	This project includes oil containment for the new transformer. This keeps oil from seeping into the environment in case of oil leaks or catastrophic failure. Oil containment will be included to minimize environmental damage, should the transformer leak.

Table 68 - Project Benefits

1.5.4 Prioritization

1.5.4.1 *Consequences of Deferral*

Since the purpose of this project is to address the issue of station transformer reliability as well as capacity at Leitrim MS, the most important consequence of deferral would be outage risks and the inability to service future load.

This project will enable the potential creation of ties with other stations and backup other feeders. This presents an additional consequence of deferral, which results in reduced contingency and therefore reliability in the case of an outage.

1.5.4.2 *Priority*

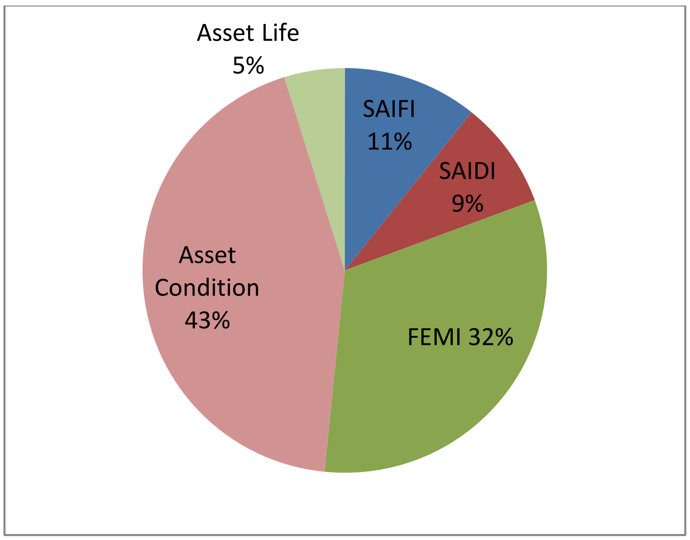


Table 69 - Project Avoided Risk

Project score: 0.62.

1.5.5 Execution Path

1.5.5.1 *Implementation Plan*

The implementation plan for the Leitrim T1 project is as follows:

- The design and major equipment procurement is to occur in 2015.
- The delivery of equipment and construction is to begin in 2016.
- The project is to be completed by Q2 2018.

1.5.5.2 *Risks to Completion and Risk Mitigation Strategies*

This project may require the clearance of some trees on the north side of the existing property of Leitrim MS. Consequently, it will require an Environmental Assessment approval. Consultants will be engaged in early assessment to mitigate this risk.

1.5.5.3 *Timing Factors*
The final design of this project will occur in 2015 although possible changes in design may affect project timing. Work scheduling of internal station resources in coordination with other HOL station work is a timing risk.

1.5.5.4 *Cost Factors*
The final design of this project will occur in 2015. Possible changes in design may affect final project cost.

1.5.5.5 *Other Factors*
None identified.

1.5.6 Renewable Energy Generation (if applicable)
Not applicable.

1.5.7 Leave-To-Construct (if applicable)
Not applicable.

1.5.8 Project Details and Justification

Project Name:	Leitrim T1
Capital Cost:	$3.05 M
O&M:	$0
Start Date:	2015
In-Service Date:	2018
Investment Category:	System Service
Main Driver:	Reliability
Secondary Driver(s):	Capacity
Customer/Load Attachment	25MVA

Project Scope

The scope of this project includes the relocation of the incoming 44kV supply, installation of a motorized high side air break switch, high side breaker, high side PT feeding the transformer, a new 25MVA transformer, complete with a seismically rated foundation and full oil containment. On the low side, a circuit switcher and structure mounted CTs will feed back into the existing low side bus. In addition, a secondary tie breaker will be installed in between the two existing buses. On The P&C/SCADA side, the new transformer will be protected by differential protective relaying and the secondary bus will be protected by overcurrent relaying. The scope also includes the construction of an additional recloser (249F3) bringing the total number of circuits fed by the station to four (4). The load side of this new egress feeder is out of scope and will be taken care of by a distribution project. Further, the scope includes the installation of an automatic transfer switch capable of feeding the station's AC service from the low-side bus of either T1 or T2, serving the new standard P&C "house" containing most of the protective relaying, power supplies, and communications gear. Lastly, the service road used to access the substation will also require minor modifications to accommodate the finished substation.
The ground grid and fencing will be upgraded as well.

Work Plan

The implementation plan for the Leitrim T1 project is as follows:

- The design and major equipment procurement to occur in 2015.
- The delivery of equipment and construction to begin in 2016.
- The project to be completed by Q2 2018.

Customer Impact

This project improves the reliability of the station assets by installing contingent assets through a new transformer lineup. Additionally, another feeder position is introduced by this project, allowing the potential for splitting of load for customers and more ties between feeders for contingent switching. Building a new transformer will lineup will allow for more accessible maintenance on transformer lineups as well as a sharing of load on each transformer to avoid thermal overload. Finally, this project provides capacity to be able to connect customers and future load.

1.6 Casselman T1

1.6.1 Project/Program Summary

Originally Casselman MS substation was made up of a single transformer lineup.

There are two phases to the Casselman T1 project. The first phase involves adding a new 44-8.32kV 16.6MVA transformer lineup to provide additional and contingent transformation to Casselman MS. The second phase involves replacing and upgrading the existing transformer line up to achieve a reliable distribution supply from two transformers along with proper protection coordination. Three additional three phase reclosers are also part of phase two of the project, which will enable more reliable distribution in the area.

1.6.2 Project/Program Description

1.6.2.1 *Current Issues*

Casselman MS was originally a single transformer substation. This configuration results in operational difficulties whenever servicing or maintenance of station equipment is required. Casselman MS is physically isolated from other HOL distribution lines. The original distribution contingency at HOL's Casselman MS was through a connection with Hydro One's Casselman DS substation. Casselman MS substation is located approximately 50km east of HOL's closest operational facility. Furthermore, in late 2011, the single transformer experienced an oil leak leading to an emergency replacement.

1.6.2.2 *Program/Project Scope*

The project is located in the village of Casselman at 29 Racine Street at HOL's Casselman MS substation. The original substation consisted of a single 10MVA transformer lineup.

The scope of Phase 1 of the project includes:

- Addition of new refurbished 44-8.32kV 16.6MVA transformer
- New transformer foundation and containment
- Addition of 44kV SF6 breaker and disconnect switch
- New 15kV outdoor secondary bus breaker and tie breaker with disconnect switches
- New P&C panels including new Remote Terminal Unit (RTU) and high side, transformer and bus relays.
- New 8.32kV overhead bus with 3 recloser feeder positions for future

The scope of Phase 2 of the project includes:

- Purchase new 44-8.32kV 12MVA transformer
- New transformer foundation and containment
- Addition of 44kV SF6 breaker and disconnect switch
- New 15kV outdoor secondary bus breaker and disconnect switch
- New P&C panel including new high side transformer and bus relays.

1.6.2.3 *Main and Secondary Drivers*

The primary driver for this project is reliability. In its original state, Casselman MS only has a single transformer. In the event of a transformer or station feeder interruption, there is no redundancy within the station for contingency. Restoration of load in the event of a prolonged outage, as well as offloading for maintenance activities, is dependent on feeder ties with Hydro One's Casselman DS. This project removes the dependence on another distribution company. Additionally, this project introduces three additional recloser positions. New circuits will allow for the potential to split existing circuits coming out of Casselman MS, reducing customer exposure to outages, as well as make ties with existing circuits.

Secondary drivers include the ability to maintain either transformer at the station as well as an increase in the available capacity at Casselman MS.

1.6.2.4 *Performance Targets and Objectives*

The primary objective of implementing this project is to achieve the station contingency realized by a second transformer lineup.

Additional planning objectives that are met by this project include:

- Planning for the long term dependence of the new station assets through the implementation of proper protection
- Increasing the contingency of existing Casselman circuits and ties with other substation circuits through additional feeder positions
- Planning for environmental concerns by installing proper oil containment
- Additional available transformation capacity at the station

1.6.3 Project/Program Justification

The primary driver of this project is to provide long term increased reliability through HOL station or distribution assets that have proper protection coordination.

1.6.3.1 *Alternatives Evaluation*

1.6.3.1.1 Alternatives Considered

Second Transformer Lineup and Provision for Three Reclosers (Casselman T1)

This alternative includes the installation of a second transformer lineup along with protection for station assets and the provision for three future reclosers.

Do-Nothing (Remain Single Transformer Lineup)

This alternative involves keeping Casselman MS station as a single transformer lineup configuration.

1.6.3.1.2 Evaluation Criteria

The criteria used to evaluate the alternatives are reliability, long term sustainability, and cost.

1.6.3.1.3 Preferred Alternative

The preferred alternative is the Second Transformer Lineup and Provision for Three Reclosers (Casselman T1).

The second preferred alternative is Do-Nothing (Remain Single Transformer Lineup).

	Second Transformer Lineup and Provision for Three Reclosers (Casselman T1)	Do-Nothing (Remain Single Phase Transformer Lineup)
Reliability	Second station transformer lineup available for contingency. Provision for future feeders allows for splitting of customers and load and ability to make new feeder ties. Proper station protection and coordination.	Reliability is impacted as a result of dependency on distribution tie with separate utility. No provision for future feeders. Fused station protection puts station assets at higher risk.
Long Term Sustainability	HOL contingency assets. Ability to transfer load between station transformers and schedule station maintenance and upgrades. Additional capacity for future load growth.	Dependency on Hydro One distribution for maintenance, contingency, and scheduling.
Cost	$4.74M	Ongoing costs associated with coordination with Hydro One for maintenance and lost revenue during contingency will continue indefinitely into the future.

Table 70 - Project Alternatives

Second Transformer Lineup and Provision for Three Reclosers (Casselman T1)
Adding a second transformer and provision for future feeder at Casselman MS station improves reliability through transformer lineup contingency and new feeder splitting and tie potential. Casselman MS would be self-sufficient as a station in the case of a single transformer trip or station feeder trip.

This project includes protection and control coordination to ensure the safety of the station assets.

The new transformer would also provide additional capacity planning in the area.

The total cost of this alternative is approximately $4.74M.

Do-Nothing (Remain Single Transformer Lineup)
This option would have Casselman MS station stay with a single transformer lineup configuration. This option would result in a continued dependence on Hydro One distribution for maintenance, contingency, and scheduling whenever work is required at Casselman MS. No provisions for new circuits are included in this alternative and the protection of the lineup will remain fused. Ongoing costs associated with coordination with Hydro One for maintenance and lost revenue during contingency will continue indefinitely into the future.

1.6.3.2 *Project/Program Timing & Expenditure*

Historical ($M)					Future ($M)				
2011	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
	0.60	2.21	1.93						

Table 71 - Project Expenditures

HOL has minimized the controllable costs of this project by implementing a number of measures:

- A competitive Request For Proposal (RFP) process was used for determining consulting resources. These consultants are retained for a minimum 3 year timeframe to ensure that they are able to efficiently meet our needs and have a good understanding of HOL's internal processes and standards.
- All contractors and vendors are selected through a competitive RFP process. These contractors and vendors are pre-screened to ensure that they have the abilities and expertise to meeting the needs of HOL and are able to maintain timelines required.
- The use of in house project management allowed for efficient use of resources and experience from past projects within HOL. Project management best practices at HOL are based on PMI (Project Management Institute).
- Workforce planning is used to ensure internal resources requirements are identified early. If outside resources are required this is identified early in the project to ensure the roll out is implemented smoothly and efficiently.

1.6.3.3 *Benefits*

Benefits	Description
System Operation Efficiency and Cost-effectiveness	This project enables HOL to have backup station assets in contingency situations. This will create the ability to transfer load between station transformers and schedule station maintenance and upgrades. Additionally, provision for new recloser positions is introduced by this project, allowing the potential for splitting of load for customers and more ties between feeders for contingent switching. Both the new transformer lineup and the provision for future feeders will improve reliability.
Customer	This project will increase station reliability in the area through a new transformer line up. Provision for new recloser positions enables increasing distribution reliability in the area as well. Additionally, this project provides capacity to be able to connect customers and future load.
Safety	Building a new transformer lineup will allow for more accessible maintenance on transformer lineups as well as a sharing of load on each transformer to avoid thermal overload. Overloading the system can lead to equipment damage and safety hazards. This project will mitigate that risk. Proper protection coordination in the station improves the safety of employees and the public.
Cyber-Security, Privacy	Not Applicable
Co-ordination, Interoperability	Not Applicable
Economic Development	This project enables electrical capacity infrastructure for economic growth in the area.
Environment	This project includes oil containment for both transformers. This protects oil from seeping into the environment in case of oil leaks or catastrophic failure. Oil containment will be included to minimize environmental damage, should a transformer leak.

Table 72 - Project Benefits

1.6.4 Prioritization

1.6.4.1 *Consequences of Deferral*

Since the purpose of this project is to address the issue of station transformer reliability at Casselman MS, the most important consequence of deferral would be outage risks and the indefinite dependence of the station on another distribution utility.

This project will enable the potential creation of ties with other stations and backup other feeders. This presents an additional consequence of deferral, which is that potential reduced contingency and therefore reliability in the case of an outage.

1.6.4.2 *Priority*

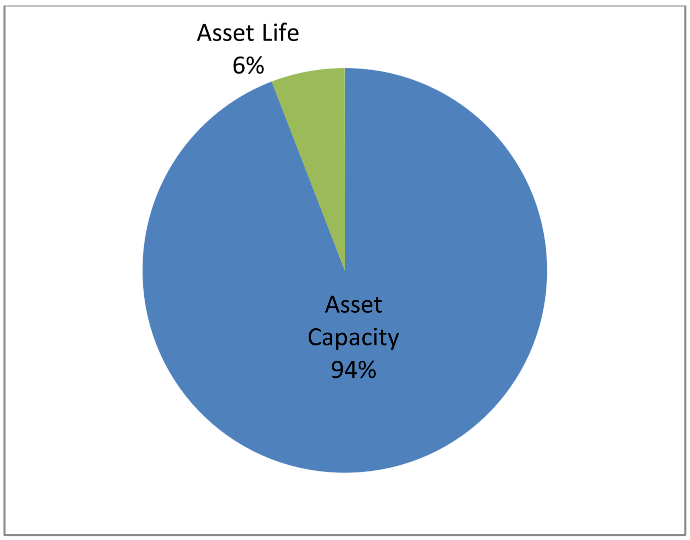


Figure 65 - Project Avoided Risk

Project Score: 0.510

1.6.5 Execution Path

1.6.5.1 *Implementation Plan*

The implementation plan for phase one of the Casselman T1 project is as follows:

- Design and major equipment procurement began in 2012
- Delivery of equipment, and construction to begin in 2013
- Project to be completed by Q2 2014

The implementation plan for phase two of Casselman T1 project is as follows:

- Design and major equipment procurement occurring in 2014
- Delivery of equipment, and construction to begin in 2014
- Project to be completed by Q4 2015

1.6.5.2 *Risks to Completion and Risk Mitigation Strategies*
Construction work is scheduled during the winter of 2015. This represents a risk as winter work may be slower and faces additional weather challenges. This risk is mitigated through awareness and planning for winter work.

1.6.5.3 *Timing Factors*
Work scheduling of internal station resources in coordination with other HOL station work is a timing risk.

1.6.5.4 *Cost Factors*
None identified.

1.6.5.5 *Other Factors*
None identified.

1.6.6 Renewable Energy Generation (if applicable)
Not applicable.

1.6.7 Leave-To-Construct (if applicable)
Not applicable.

1.6.8 Project Details and Justification

Project Name:	Casselman T1
Capital Cost:	$4.74M
O&M:	$0
Start Date:	2012
In-Service Date:	2015
Investment Category:	System Service
Main Driver:	Reliability
Secondary Driver(s):	Capacity
Customer/Load Attachment	16.6MVA

Project Scope

The scope of Phase 1 of the project includes:

- Addition of new refurbished 44-8.32kV 16.6MVA transformer
- New transformer foundation and containment
- Addition of 44kV SF6 breaker and disconnect switch
- New 15kV outdoor secondary bus breaker and tie breaker with disconnect switches
- New P&C panels including new RTU and high side, transformer and bus relays.
- New 8.32kV OH bus with 3 recloser feeder positions for future

The scope of Phase 2 of the project includes:

- Purchase new 44-8.32kV 12MVA transformer
- New transformer foundation and containment
- Addition of 44kV SF6 breaker and disconnect switch
- New 15kV outdoor secondary bus breaker and disconnect switch
- New P&C panel including new high side, transformer and bus relays.

Work Plan

The implementation plan for phase one of Casselman T1 project is as follows:

- Design and major equipment procurement began in 2012
- Delivery of equipment, and construction to begin in 2013
- Project to be completed by Q2 2014

The implementation plan for phase two of Casselman T1 project is as follows:

- Design and major equipment procurement occurring in 2014
- Delivery of equipment, and construction to begin in 2014
- Project to be completed by Q4 2015

Customer Impact

This project enables HOL to have backup station assets in contingency situations. There will be the ability to transfer load between station transformers and schedule station maintenance and upgrades. Additionally, provision for new recloser positions is introduced by this project, allowing the potential for splitting of load for customers and more ties between feeders for contingent switching. Both the new transformer lineup and the provision for future feeders will improve reliability. Building a new transformer will lineup will allow for more accessible maintenance on transformer lineups as well as a sharing of load on each transformer to avoid thermal overload. Overloading the system can lead to equipment damage and safety hazards. This project will mitigate that risk. Proper protection coordination in the station improves the safety of employees and the public.

1.7 Richmond South DS

1.7.1 Project/Program Summary

In the West 8.32kV Regional Planning Study, the projected developments were assessed for construction timing and associated load. Anticipated developments in the Richmond village area include commercial, light industrial and residential developments. In 2012, Richmond was identified to increase in size by 600% over a 20 year horizon. The two substations that supply Richmond and the surrounding area with 8.32kV are Richmond North DS and Richmond South DS which have a combined capacity of 11.72MVA. These two stations would not be capable of supplying the 20 year, 45MVA load forecast and as Richmond North DS is limited by its 44kV supply, Richmond South DS was identified for transformation upgrade. The decision for a 27.6kV voltage conversion was driven by the limitation of the 8.32kV lines to extend long distances and maintain adequate voltage levels, increased operability to transfer load to neighboring 27.6kV stations. The conversion is also driven by a single customer, Trans Canada, who is requesting a dedicated feeder to supply them 20MVA for their Energy East Pumping Station, located in the Richmond area.

1.7.2 Project/Program Description

1.7.2.1 *Current Issues*

Current issues of Richmond South DS include deteriorating reliability due to failure of aging infrastructure and power quality issues which can be attributed to the length of the feeders and the limitation of 8.32kV to supply the distances without a significant voltage drop. The projected load growth in the area supplied from Richmond South DS will become an issue for the 8.32kV system within a five-year timeframe.

1.7.2.2 *Program/Project Scope*

The Richmond South DS project will encompass the complete removal of all existing 8.32kV equipment from the site and will add two (2) taps off the S7M 115kV transmission line, six (6) primary disconnect switches, two (2) primary circuit breakers, two (2) 115/27.6kV 45/60/75MVA transformers, metal clad switchgear lineup adequate for six (6) feeders, a protection and control building with associated equipment to monitor and protect all station equipment and two (2) 28/8.32kV 4MVA transformers. The two 8.32kV transformers will maintain the existing 8.32kV load until all distribution conversion to 27.6kV is complete, as well as provide backup support for Richmond North DS and Munster DS until adequate ties between these two stations can be installed.

Phase 1, which will include all work and expenses to occur within 2015, includes preliminary design as well as Hydro One and IESO consultations.

Phase 2, which will include all work and expenses to occur within 2016, includes design completion and first progress payments for major equipment.

Phase 3, which will include all work and expenses to occur within 2017, includes the start of construction and arrival of major equipment. The 2017 construction will incorporate Hydro One requiring re-construction of their dead-end structures within the station yard to allow for two taps to two

115/27.6/8.32kV lineups, which includes all infrastructure required from the transmission tap to the distribution egress. All major civil work for one complete 115/27.6/8.32kV lineup will be completed as the existing 115/8.32kV lineup will be maintained until energization of the first 115/27.6/8.32kV lineup.

Phase 4, which will include all work and expenses to occur within 2018, includes construction of the protection and control building, installation of switchgear in the building, electrical construction and commissioning of the first 115/27.6/8.32kV lineup, removal of the existing 115/8.32kV lineup and completion of civil work and start of electrical construction for the second 115/27.6/8.32kV lineup.

Phase 5, which will include all work and expenses to occur within 2019, includes final commissioning of the second 115/27.6/8.32kV lineup, clean-up and issuance of the final drawings and completion of all project closure procedures.

1.7.2.3 *Main and Secondary Drivers*

The main driver of this project is to supply the future expected load in this growing area. The forecasted load for the next 20 years in the Richmond area indicates that its capacity limitations will be reached within the next five years. In the case of a single station contingency, the remaining capacity would not be enough to supply the required load in this area. Ongoing development worsens the situation which is why this project is required to meet the demand.

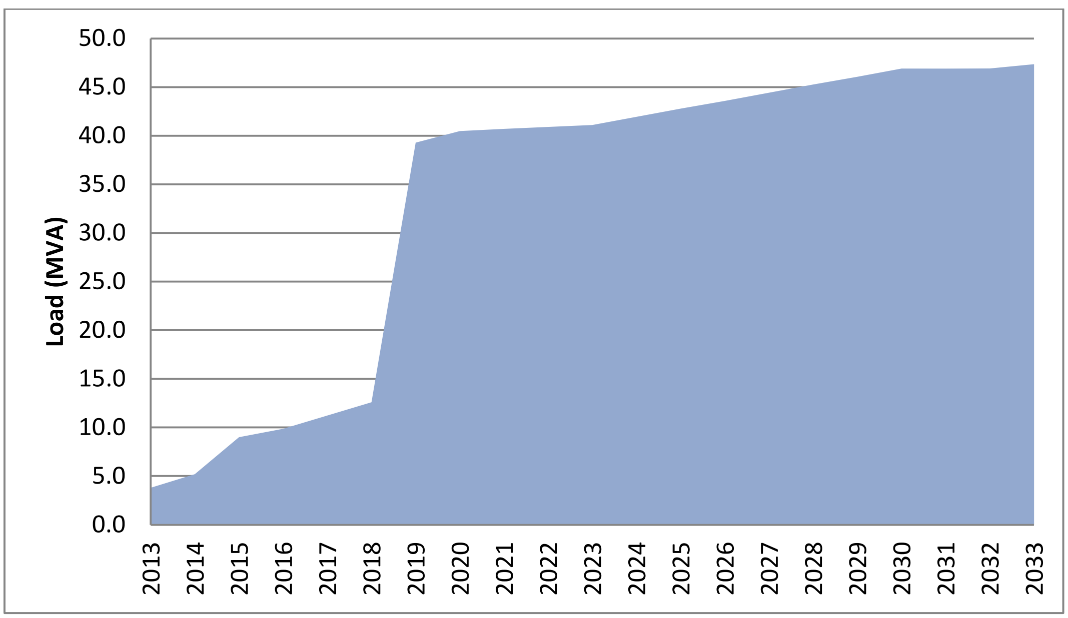


Figure 66 - Richmond South Load Profile

There are many City of Ottawa development plans that have been reviewed to estimate the load demand over the next twenty years. The following outlines the development projects in the Richmond area.

Richmond Community Design Plan (CDP)

The Village of Richmond CDP was initiated in 2008 and covers a planning period from 2010 to 2030. Based on this plan the residential capacity is planned to increase from approximately 1,550 dwelling units to between 4,400 and 5,500 units (including existing), for an increase of 2,850 – 3,950 which accounts for a load increase of 7.3 MVA – 10.1 MVA (using an estimate of 2.56 kVA/unit).

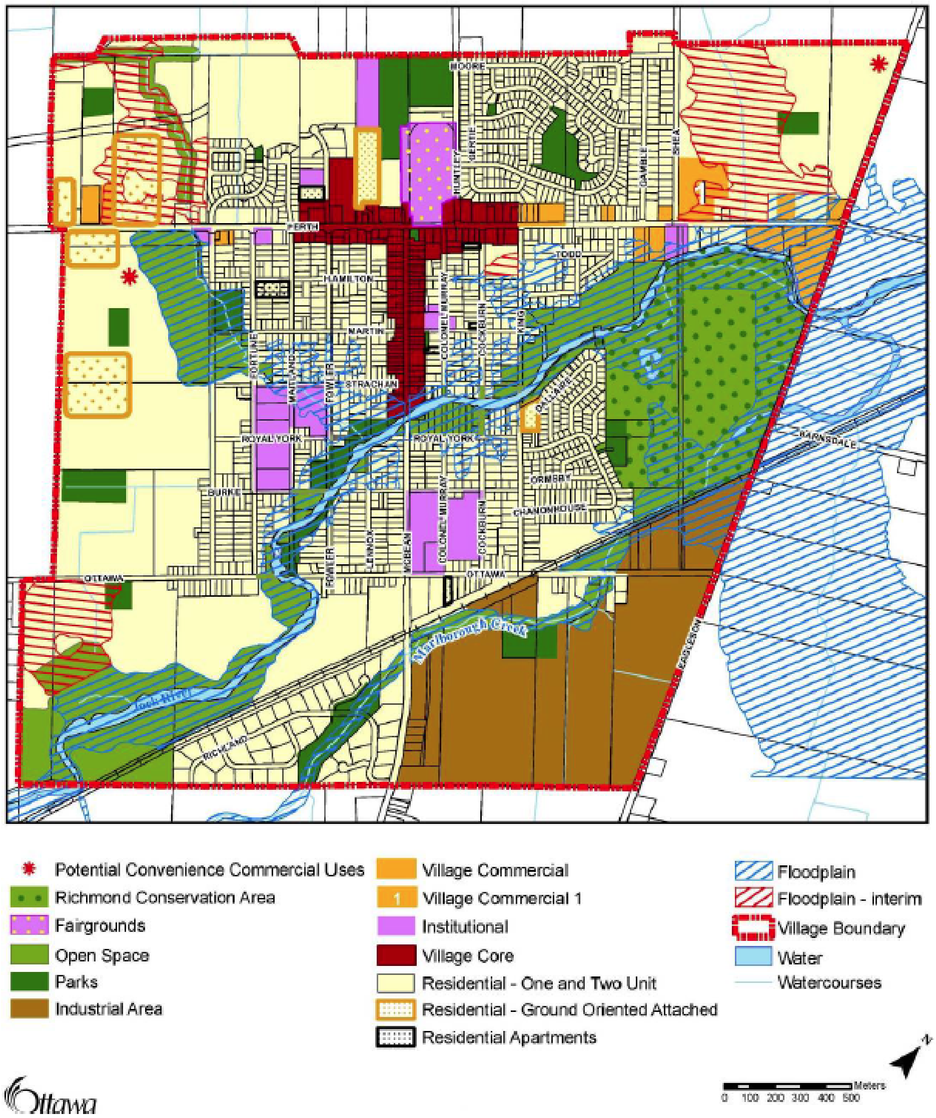


Figure 67 - Richmond CDP Proposed Land Use

Industrial Lands

The Richmond CDP describes the Industrial Lands as providing "an opportunity for industrial and employment-generating uses that require large parcels of land and that are not always compatible with residential uses". The maximum building height in this area is restricted to the equivalent of three or four storeys with the following permitted uses: light industrial, office, printing plant, service and repair shop, small batch brewery, warehouse and heavy equipment and vehicle sales, rental and servicing, research, technology, nurseries, greenhouses, catering, places of assembly, broadcasting and training. Existing areas with a similar profile have a load estimate within the range of 10 – 20 MVA/km^2 depending on particular uses. The proposed industrial lands cover approximately 0.9 km^2 which would predict a load profile within the range of 9 – 18 MVA. For planning purposes the low end, 9 MVA, will be used, assuming that no large industrial plants will be developed on these lands.

Figure 68 - Industrial Lands Demonstration Plan

Western Development Lands

Growth in the Western Development Lands will primarily consist of detached dwellings, townhouses, parks, open space, a school and a pathway system. The density and unit mix provisions for this area are shown in the chart below.

Dwelling Type	Max Density Units/Net Ha	Unit Mix (% of Total)
One & Two Units Large Lots	17	2-7% Minimum
One & Two Units Small Lots	30	58-78% Maximum
Townhouses	45	20-35% Minimum
Townhouses with Rear Lanes	80	
Back-to-Back Townhouses	99	

Table 73 - Proposed Density

Figure 69 - Western Development Lands Demonstration Plan

The Western Development Lands Demonstration Plan was developed through a workshop hosted by Mattamy Homes in December 2008. Since that time, Mattamy has developed a plan for a section of the western area, which is described below.

Mattamy Homes Residential

The Mattamy development covers the southern portion of the Western Development Lands and will account for approximately 1000 units, or 2.5 MVA of load. They will be submitting the Draft Plan of Subdivision to the City of Ottawa in 2013 with closings to begin around 2017 since it is currently outside of their five year plan.

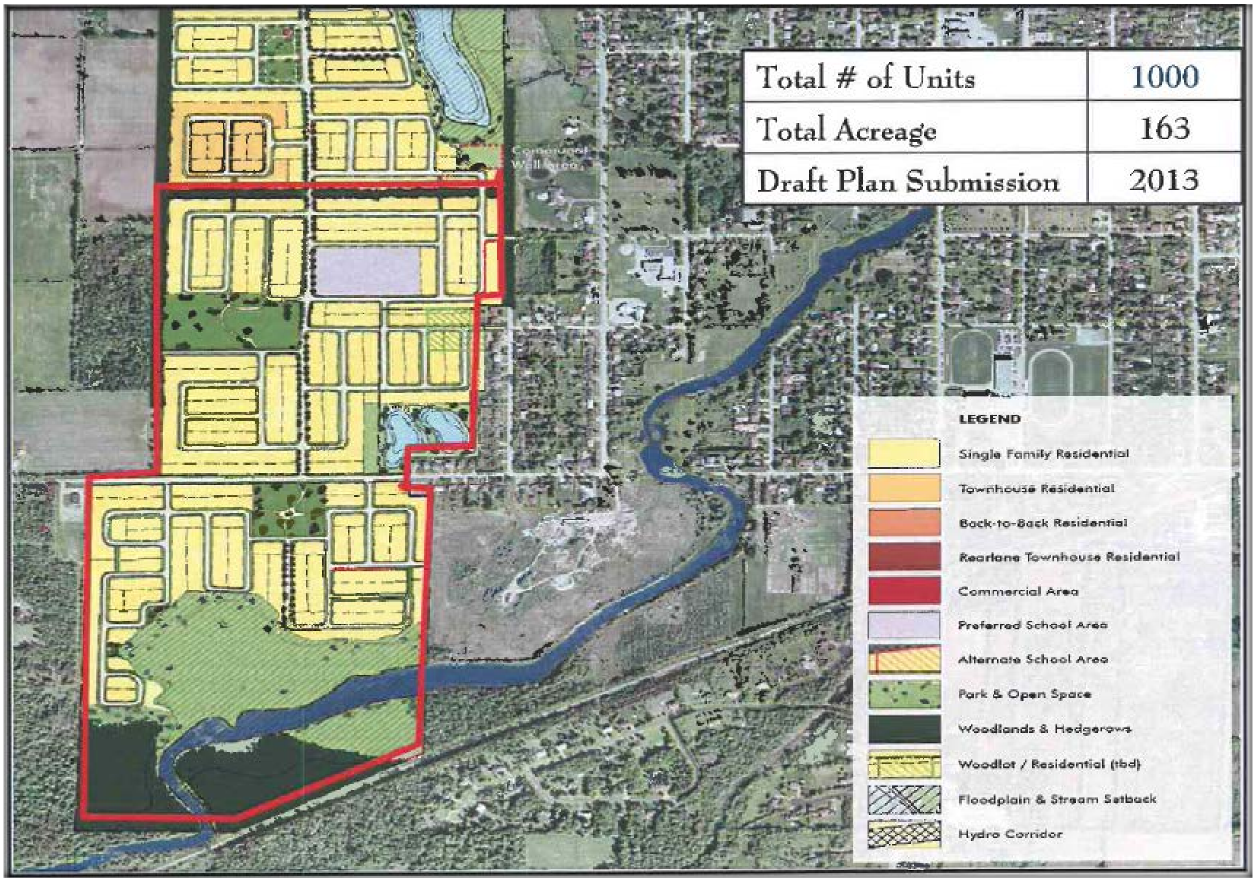


Figure 70 - Mattamy's Richmond West Development

Northeast Development Lands

The Demonstration plan for the Northeast Development Lands is show below. The plans for this area follow the same general outline as the Western Development Lands.

Figure 71 - Northeast Development Lands Demonstration Plan

Richmond Village Square

The development known as Richmond Village Square is a commercial plaza that will consist of six single storey buildings for a total of 7,039 m^2. Using an estimate of 75.38 W/m^2 gives a load estimate of 590 kVA. The servicing for this site will consist of 3 x 1000 kVA transformers, and using an estimate of 60% connected capacity provides a load estimate of 1.8 MVA. A load estimate of 1.0 MVA will be used for planning purposes.

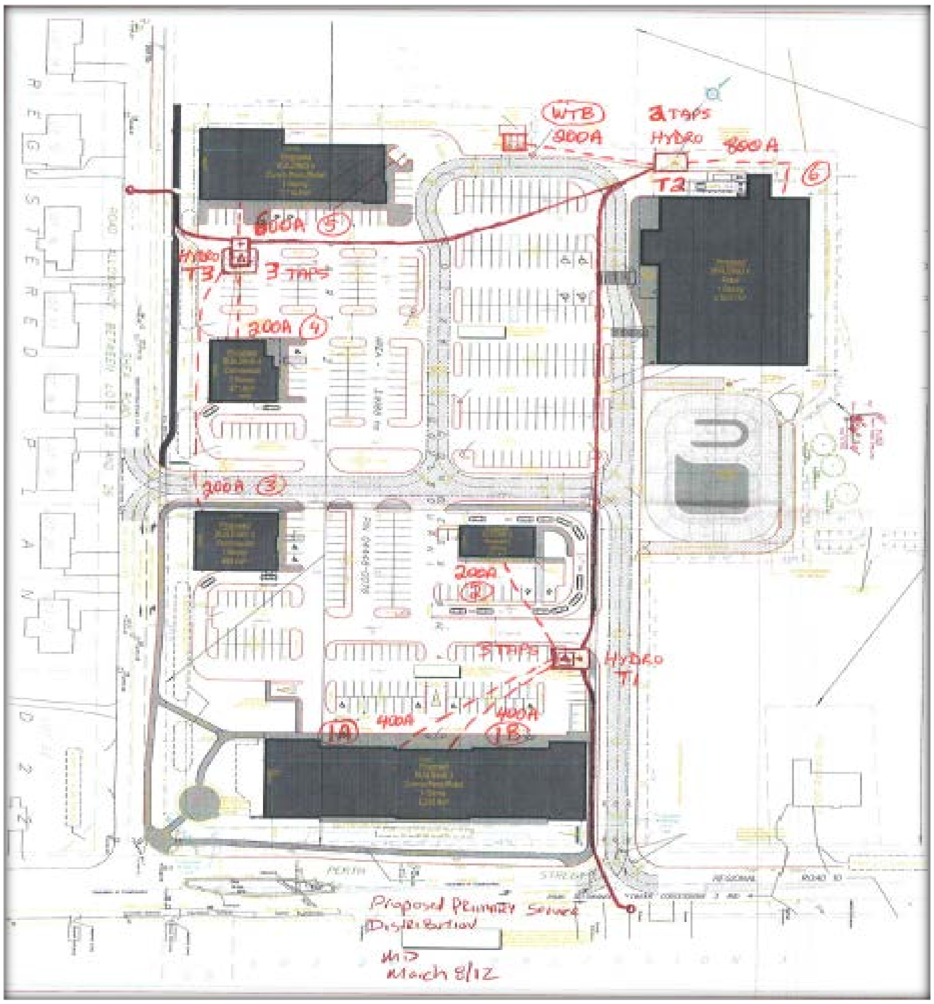


Figure 72 - Richmond Village Square Layout

Trans Canada's Energy East Pumping Station

Trans Canada's Energy East Pumping Station is an oil pumping station that is being constructed approximately 3km outside the village of Richmond. Trans Canada has requested a dedicated supply feeder as they are anticipating a load requirement of 11MVA in 2017 and 20MVA in 2018 onward. As required by the Distribution System Code, a customer requiring this amount of capacity will contribute financially to the required distribution and station upgrades. It is anticipated that Trans Canada will be contributing $3M towards the Richmond South DS project.

As a secondary driver for this project, reliability will be improved by eventually creating ties to other 27.6kV stations, specifically Janet King DS, Bridlewood DS, Terry Fox MTS, Fallowfield DS and the New South 27.6kV Substation.

1.7.2.4 *Performance Targets and Objectives*

The primary objective of this project is to have the first line-up at Richmond South DS constructed and commissioned supplying load by Q4 of 2018, following with the completion of the second line-up in Q3 2019. Within this goal, various milestones must be met including: an environmental assessment, IESO System Impact Assessment approval, City of Ottawa approval, Hydro One Transmission upgrades, civil and electrical station design, tendering of all major equipment and services, and finally construction and commissioning. In conjunction with this station rebuild, other projects are being planned and implemented in order to prepare the area for a 27.6kV voltage upgrade once the station has been constructed.

1.7.3 Project/Program Justification

1.7.3.1 *Alternatives Evaluation*

1.7.3.1.1 Alternatives Considered

Due to the timing requirements of this project, alternatives are limited. Surrounding stations do not have the station nor feeder capacity to support the load being anticipated for the village of Richmond and the Trans Canada Energy East Pumping Station. Feeder extensions from the newly constructed Terry Fox TS station will help with temporary supply of load growth, however due to increasing load requirements in Stittsville that will require the capacity from Terry Fox MTS, upgrading Richmond South DS is the only feasible option.

Alternative #1: Upgrading Richmond South DS will encompass the complete removal of all existing 8.32kV equipment from the site and will add two (2) taps off the S7M 115kV transmission line, six (6) primary disconnect switches, two (2) primary circuit breakers, two (2) 115/27.6kV 45/60/75MVA transformers, metal clad switchgear lineup adequate for six (6) feeders, a protection and control building with associated equipment to monitor and protect all station equipment and two (2) 28/8.32kV 4MVA transformers.

This option is the most direct route to supply the load growth expected in the Richmond area for the long term future.

Alternative #2: In order to achieve the capacity requirements in the Richmond area the following projects would need to be undertaken:

1. 44kV line extension from South March for dual supplies for Richmond North DS and Munster DS
2. One (1) 15MVA 44/8.32kV transformer installed at Richmond North DS and infrastructure to support Two (2) new feeders
3. One (1) 15MVA 44/8.32kV transformer installed at Munster DS and infrastructure to support two (2) new feeders

4. Two (2) 15MVA 115/8.32kV transformers installed at Richmond South DS and infrastructure to support four (4) feeders
5. Line extensions along Franktown Road, Shea Road, Huntley Road, Perth Road, Bleeks Road Garvin Road and Brownlee Road in order to meet the anticipated development areas.

1.7.3.1.2 Evaluation Criteria

Costs:
Alternative #1: $17.543M with a $3M contribution from Trans Canada

Alternative #2: $31.44M

Ability to supply load:
Both alternatives offer the ability to supply existing and future load, however HOL does not possess the manpower required to complete all work associated with Alternative #2 in time to meet the load development requirements.

Reliability Benefits:
Both alternatives would offer significant increases in reliability. However with the direction of the surrounding communities including Kanata, Stittsville and Barrhaven, proceeding with 27.6kV, Alternative #1 would offer the greatest reliability benefits as this would allow for an increased number of feeders ties.

1.7.3.1.3 Preferred Alternative

Due to the reliability benefit, alternative costs and limited time before capacity is required, Alternative #1 is the preferred alternative.

1.7.3.2 *Project/Program Timing & Expenditure*

The total project cost is $17,543,000 and the project is anticipated to be completed in 2019. HOL has minimized the controllable costs of this project by implementing a number of measures:

- A competitive Request For Proposal (RFP) process was used for determining consulting resources. These consultants are retained for a minimum 3 year timeframe to ensure that they are able to efficiently meet our needs and have a good understanding of HOL's internal processes and standards.
- All contractors and vendors are selected through a competitive RFP process. These contractors and vendors are pre-screened to ensure that they have the abilities and expertise to meeting the needs of HOL and are able to maintain timelines required.
- The use of in house project management allowed for efficient use of resources and experience from past projects within HOL. Project management best practices at HOL are based on PMI (Project Management Institute).
- Workforce planning is used to ensure internal resources requirements are identified early. If outside resources are required this is identified early in the project to ensure the roll out is implemented smoothly and efficiently.

Historical ($M)					Future ($M)				
2010	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
$0	$0	$0	$0	$0	$0.139	$3.315	$10.42	$2.269	$1.40

Table 74 - Project Expenditures

1.7.3.3 *Benefits*

Key benefits that will be achieved by implementing the Richmond South DS project are summarized below.

Benefits	Description
System Operation Efficiency and Cost-effectiveness	This project is required to satisfy the upcoming load growth in the Richmond area. It is an essential system service project to supply the needed capacity. System operation efficiency will be improved by the new station feeders' ability to connect with other 27.6kV feeders in the area. The backup ties will ensure faster restoration times in the event of an outage, as well as the capability to maintain adequate supply in a station contingency scenario. This should inevitably contribute to reducing SAIDI, which is important in an area where the overhead distribution system is subject to weather-related outages. Re-constructing the station is the most cost-effective solution for supplying the required demand.
Customer	This project will achieve two objectives: to supply future demand and to improve reliability in the south-west of the city. Not only will development projects be given adequate electrical supply, but the upgraded station presents several opportunities to improve the system. This project will contribute to a larger system plan to convert the entire west area to a 27.6kV system, in order to keep up with city development. This larger system plan will provide enhanced capacity and improved reliability to customers in several communities: Richmond, Munster, Kanata, Stittsville and Barrhaven. The various upcoming ties between stations servicing this region will reduce outage durations and eliminate several radial segments that exist in the current distribution system. Other projects have been planned to prepare the West area for this voltage conversion, including project 92010186 Richmond South Voltage Conversion – McBean, 92010188 Richmond South Voltage Conversion – Shea, 92010920 Richmond South Egress – Garvin East, 92010922 Richmond South Voltage Conversion – Perth East, 92010924 Richmond South Voltage Conversion – Perth West, 92010926 Richmond South Voltage Conversion – Huntley, 92010954 Richmond South Voltage Conversion – King, 92010956 Richmond South Voltage Conversion – Fortune, 92010958 Richmond South Voltage Conversion – Ottawa, 92010960 Richmond South Voltage Conversion – Burke, and 92010962 Richmond South Voltage Conversion – Eagleson. These related projects involve asset replacement, which further improves system reliability.
Safety	Upgrading the station will address the predicted thermal overload of existing feeders and station transformers that will occur in the near future. Overloading the system can lead to equipment damage and safety hazards. This project will mitigate that risk. Protection and control relays will be brought up to current HOL standards that reduce safety concerns as much as possible.
Cyber-Security, Privacy	N/A

Co-ordination, Interoperability	The new station will be supplied on the high side by Hydro One Networks Inc.'s 115kV transmission line, with provisions that this line may be upgraded to 230kV. The provincial utility has been heavily involved in the development of this project from the beginning, as it requires an upgraded transmission line. Both utilities will coordinate to ensure the success of this project, although construction details have not yet been decided.
Economic Development	This project will enable ongoing growth and development in the city as it will provide the necessary electrical supply.
Environment	The environmental impacts of a distribution station revolve around the station transformers. Oil containment will be included to eliminate environmental damage, should a transformer leak.

Table 75 - Project Benefits

1.7.4 Prioritization

1.7.4.1 *Consequences of Deferral*

Since the purpose of this project is to address an upcoming capacity issue, the most important consequence of deferral would be the inability to service the required load by 2019. Allowing the system to experience thermal overload for an extended period of time would lead to equipment damage and customer outages. Customers working or living in the proposed developments would simply not have the electricity they require. The eventual failure of the system to keep up with demand validates the necessity of this project.

The new station feeders will create ties with other stations and backup other feeders. This presents an additional consequence of deferral, which is that the current radial segments of other feeders in the area will remain radial for a longer period of time. If an outage occurs on these segments, the affected customers will likely experience longer outage times.

This project also promotes a series of equipment upgrade projects, to prepare the area for the larger 27.6kV voltage conversion. This involves replacing aging assets such as poles, conductors and transformers which inherently improves system reliability.

1.7.4.2 *Priority*

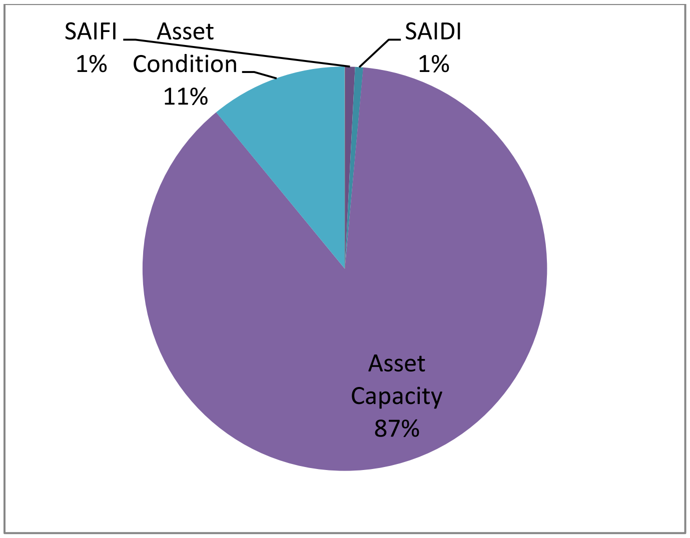


Figure 73 - Project Avoided Risk

Project Score = 0.822

1.7.5 Execution Path

1.7.5.1 *Implementation Plan*

Phase 1, which will include all work and expenses to occur within 2015, includes preliminary design as well as Hydro One and IESO consultations.

Phase 2, which will include all work and expenses to occur within 2016, includes design completion and first progress payments for major equipment.

Phase 3, which will include all work and expenses to occur within 2017, includes the start of construction and arrival of major equipment. The 2017 construction will incorporate Hydro One re-constructing their dead-end structures within the station yard to allow for two taps to two 115/28/8.32kV lineups; all infrastructure required from the transmission tap to the distribution egress. All major civil work for one complete 115/28/8.32kV lineup will be completed as the existing 115/8.32kV lineup will be maintained until energization of the first 115/28/8.32kV lineup.

Phase 4, which will include all work and expenses to occur within 2018, includes construction of the protection and control building, installation of switchgear in the building, electrical construction and commissioning of the first 115/28/8.32kV lineup, removal of the existing 115/8.32kV lineup and completion of civil work and start of electrical construction for the second 115/28/8.32kV lineup.

Phase 5, which will include all work and expenses to occur within 2019, includes final commissioning of the second 115/28/8.32kV lineup, clean-up and issuance of the final drawings and completion of all project closure procedures.

1.7.5.2 *Risks to Completion and Risk Mitigation Strategies*

Risks include failing to get the following approvals: environmental assessment, IESO System Impact Assessment approval and City of Ottawa approval. Any delay from Hydro One Transmission upgrades, civil and electrical station design, delivery of all major equipment and completion of services would also be a risk to the ability to supply of the new growth. HOL will engage the stakeholders that could have an impact on these associated risks on a consistent basis to ensure that project milestones are met. Adjustments will be made as needed throughout the project to ensure timely completion to prevent thermal overloading of equipment.

1.7.5.3 *Timing Factors*

Planned City development and Trans Canada's Energy East Pumping Station are the drivers for this project, and it is unlikely that the timing and priority of this project will change. It is necessary to supply the proposed load and there are no other feasible solutions to supply this load otherwise. If City or Trans Canada's developments are delayed for any reason, it is possible that this project could be shifted slightly but this is unlikely, as site plans for new developments in the area have already begun to be submitted to HOL. For the timing and priority of this project to change, these developments would have to be delayed and HOL would have to have a sudden change in priorities due to an unexpected requirement.

1.7.5.4 *Cost Factors*

The tender process for major station equipment and labour services will also affect the final cost of the project. HOL typically takes the lowest bid and these costs will remain unknown until 2016.

1.7.5.5 *Other Factors*

Trans Canada has recently filed their application with the National Energy Board for approval to construct their oil pipeline and pumping stations. There exists a risk that they will not be granted this approval and as a result HOL will require a letter of credit to ensure that the work required to supply them is paid for if they cannot meet their load expectations.

1.7.6 Renewable Energy Generation (if applicable)

While it is not expected that Richmond South DS itself will directly connect to any renewable energy generation sources, the transformers and station infrastructure will be purchased with reverse flow capability so that renewable energy generations can be connected to Richmond South DS feeders.

1.7.7 Leave-To-Construct (if applicable)

Not applicable.

1.7.8 Project Details and Justification

Project Name:	Richmond South DS
Capital Cost:	$17.657M
O&M:	$0
Start Date:	2015 – Q1
In-Service Date:	2019 – Q3
Investment Category:	System Service
Main Driver:	Capacity
Secondary Driver(s):	Reliability
Customer/Load Attachment	3,069 Customers/16,500kVA
Project Scope	
In the West 8.32kV Regional Planning Study, the projected developments were assessed for construction timing and associated load. Anticipated developments in the Richmond village area include commercial, light industrial and residential developments. In 2012, Richmond was identified to increase in size by 600% over a 20 year horizon. The two substations that supply Richmond and the surrounding area with 8.32kV are Richmond North DS and Richmond South DS which have a combined capacity of 11.72MVA. These two stations would not be capable of supplying the 20 year, 45MVA load forecast and as Richmond North DS is limited by its 44kV supply, Richmond South DS was identified for transformation upgrade. The decision for 27.6kV voltage conversion was driven by the limitation of 8.32kV to extend long distances and maintain adequate voltage levels, increased operability to transfer load to neighboring 27.6kV stations and by a single customer, Trans Canada, who are requesting a dedicated feeder to supply them 20MVA for their Energy East Pumping Station, located in the Richmond area.	
Work Plan	
Phase 1, to be complete in 2015, includes preliminary design as well as Hydro One and IESO consultations. Phase 2, to be complete in 2016, includes design completion and first progress payments for major equipment. Phase 3, to be complete in 2017, includes the start of construction and arrival of major equipment. Phase 4, to be completed in 2018, includes construction of the protection and control building, installation of switchgear in the building, electrical construction and commissioning of the first 115/28/8.32kV lineup. Phase 5, to be completed in 2019, includes final commissioning of the second 115/28/8.32kV lineup, clean-up and issuance of the final drawings and completion of all project closure procedures.	
Customer Impact	
Available distribution capacity to supply new loads for upcoming development Reliability improvement associated with replacement of aging assets and equipment upgrades Reduced outage durations with eventual backup supply	

2 Line Extensions

2.1 TM1AH Capacity Upgrade

2.1.1 Project/Program Summary

HOL expects an increase in demand along Richmond Road and in the Westboro neighbourhood in the near future. This is due to the expected intensification along Richmond Road as described in the Richmond Road/Westboro Community Design Plan. In order to supply this new load, HOL has planned an underground line extension project in order to maximize the usefulness of an overhead circuit feeding this area.

2.1.2 Project/Program Description

2.1.2.1 *Current Issues*

Currently, the existing circuit (TM1AH) consists of a section of underground cable which transitions to overhead for the remainder of the circuit. As of today the underground section is the limiting factor with a design capacity limit of 425 amps. However, the overhead circuit has a design rating of 600 amps. By installing a parallel underground cable and connecting it to the existing overhead circuit the full capacity of the circuit can be realized. Figure 74 below shows the load growth area (blue), the existing TM1AH circuit (red), the proposed parallel circuit (green), and the point of connection (yellow).

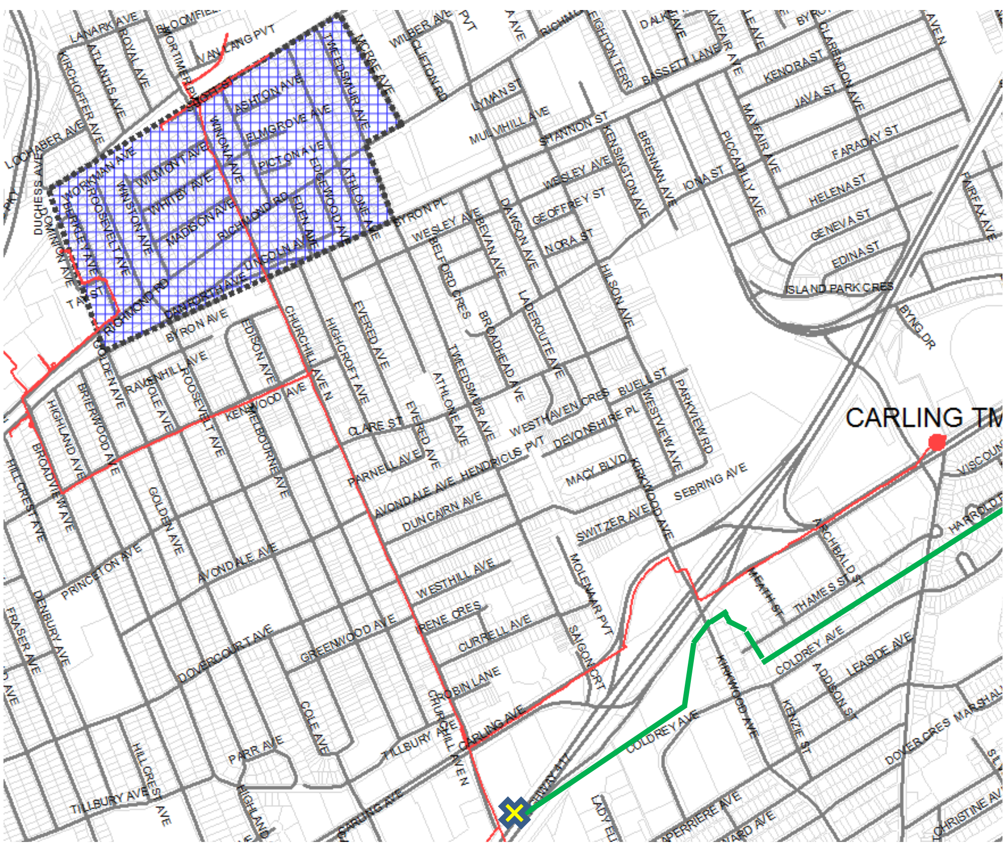


Figure 74 - Proposed Parallel Circuit

2.1.2.2 *Project/Program Scope*
There is a currently existing civil structure installed along the desired route which is along Carling Avenue from Merivale Road (Carling TM Station) to Churchill Avenue North. The required material will consists of 1800 meters of 500MCM EPR cable, three overhead switches, and a new pole to be able to accommodate the cable`s transition from underground to overhead.

2.1.2.3 *Main and Secondary Drivers*
The main driver behind this project is the anticipated load growth in the area fed by this circuit. Currently the existing circuits in the area are at their planned capacity. Therefore additional capability is needed.

2.1.2.4 *Performance Targets and Objectives*
The main objective of this project is to increase the capacity in the Richmond Road/Westboro area. By installing a parallel cable from Carling TM substation to Churchill Avenue North and connecting into the existing overhead circuit an additional 175 amps (4MVA) of capacity can be realized.

2.1.3 Project/Program Justification

2.1.3.1 *Alternatives Evaluation*

2.1.3.1.1 Alternatives Considered
In order to meet the increasing demand along Richmond Road and in the Westboro area, two alternatives were considered:

1) Install parallel egress: In this scenario HOL will install 1800 meters of underground cable in parallel with the existing cable (TM1AH) to maximize the usefulness of the overhead portion of the circuit. This scenario will add 4MVA of capacity to the area at a relatively low cost due to the existing infrastructure.
2) Install a new looped circuit: In this scenario HOL will construct a new looped circuit to the area of demand which will provide 9.5MVA of capacity. This work would consist of installing ~7200 meters of conductor. Due to the limited civil structure in the area, ~1800 meters of duct bank would need to be installed; however, it is much more likely that this distance would be supplied via overhead circuitry. This in itself introduces new challenges such as upgrading current poles to account for the new load or acquiring easements for the installation of new poles.

2.1.3.1.2 Evaluation Criteria
The main evaluation criteria used was the cost between the projects. However, disruption and safety concerns to the public and environmental impact were also considered. To ensure the alternatives were being evaluated equally the cost per MVA was calculated. The total project cost and cost per MVA are:

Alternative 1: $888,216 & $222,054/MVA

Alternative 2: $3,728,501 & $392,474/MVA

2.1.3.1.3 Preferred Alternative

Due to the costs of the two options, Alternative 1 is more preferable than Alternative 2. By having the electrical capacity in the area, customer developments will be more likely to happen since there will not be a large system expansion cost associated with their project. The benefits of this project are explained in section 3.3. Alternative 1 also requires no civil work to be done. Therefore there is no need to dig up the sidewalk which on top of disturbing the environment creates a safety hazard. HOL mitigates these risks by applying best practices, but the ultimate mitigation technique is avoiding the risk altogether.

2.1.3.2 *Project/Program Timing & Expenditure*

This project is scheduled for implementation in 2016. However, there is the potential for demand work to advance the need date. At this point the cost will be transferred from the sustainment budget to the demand budget and an economic evaluation will be assessed. The expected timeline for the project will be six weeks to pull the cable through the existing duct structures and complete connections. Additionally, two weeks have been estimated for the work associated with a new pole.

In order to minimize costs HOL will tender for all necessary equipment. HOL will complete all labour required for the project in house, however, if resources are not available the work will be tendered.

Historical ($M)					Future ($M)				
2011	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
					0.998				

Table 76 - Project Expenditures

2.1.3.3 *Benefits*

The main benefit of this project is the ability to supply a further 4MVA to the Richmond Road/Westboro area. This capacity will serve the anticipated near term future growth. By having the ability to supply load in this area it is expected to increase the likelihood of economic development. Finally, the operators will be able to load this circuit to a higher amount to serve other customers in the case of a fault on an interconnected circuit.

Benefits	Description
System Operation Efficiency and Cost-effectiveness	This project allows HOL operators to more effectively use the circuit TM1AH to backup interconnected circuits if there is a fault on those circuits.
Customer	Due to the planning and proactive action taken by HOL through this project, future customers will have the electrical supply available within a timely manner up to the identified 4MVA.
Safety	N/A
Cyber-Security, Privacy	N/A
Co-ordination, Interoperability	N/A
Economic Development	As a result of electrical capacity in the anticipated future customer's area, it is more likely that load will be willing to connect since there are no extensive costs for electrical supply. When there is a large cost to developers due to system expansion it can slow the willing connections and stall projects. This project will

	eliminate that problem.
Environment	N/A

Table 77 - Project Benefits

2.1.4 Prioritization

2.1.4.1 *Consequences of Deferral*

If this project is deferred it is expected that there will be insufficient capacity to supply new load in the area. Once a request for connection has been made HOL will be under a time constraint to provide power. The shortened time frame typically leads to increased costs. Also, due to the lack of current capacity and the cost of connection it is likely that a small demand customer will be unable to connect. This project will drive economic development in the Richmond Road/Westboro area.

2.1.4.2 *Priority*

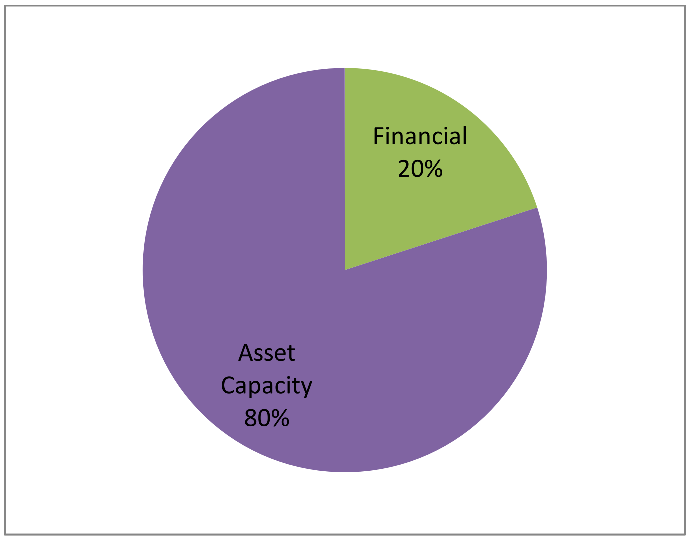


Figure 75 - Project Avoided Risk

Score = 0.3

2.1.5 Execution Path

2.1.5.1 *Implementation Plan*

Due to the existing underground infrastructure there will be no need for additional easements or permits. The 1800 meters of 500 MCM EPR cable will be pulled through the duct bank from Carling substation to Churchill Avenue North by HOL underground crews. A new pole is required to install the additional equipment needed to connect this circuit. The stronger pole as well as the riser equipment and switch will be installed and the necessary plant will be transferred. Finally the cable will be terminated at the station. Currently, there are no open breakers at Carling substation which means the new cable will be hair pinned with an existing circuit. Therefore the relay protection for the chosen breaker will need to be updated. A scheduled outage will be necessary in order to safely connect the cable at the substation

2.1.5.2 *Risks to Completion and Risk Mitigation Strategies*

This project's objective is to provide additional capacity to the Richmond Road/Westboro area. However, there is the risk that more than 4MVA of capacity will be needed in the near term. If this is the case it may be necessary to install a new circuit to the area and this project will be put on hold. HOL will continue to monitor the area plans in order to quantify the need. There are, however, other risks that could affect this projects timeline and cost. These are further explained in the sections below.

2.1.5.3 *Timing Factors*

This project is currently planned to be completed in 2016. However, if the demand materializes before that date it will need to be done earlier to meet the need.

There are not any foreseeable timing risks associated with the project work as the infrastructure is already in place.

2.1.5.4 *Cost Factors*

If the project must be completed sooner than planned, due to demand, the cost could rise. This is the typical case due to resource constraints.

2.1.6 Renewable Energy Generation

N/A

2.1.7 Leave-To-Construct

N/A

2.1.8 Project Details and Justification

Project Name:	TM1AH Capacity Upgrade
Capital Cost:	$0.88M
O&M:	N/A
Start Date:	Q1 2016
In-Service Date:	Q4 2016
Investment Category:	System Service
Main Driver:	Additional capacity need
Secondary Driver(s):	N/A
Customer/Load Attachment	Future customers will be affected by having the capacity to connect/ 4MVA worth of load

Project Scope

There is a currently existing civil structure installed along the desired route which is along Carling Avenue from Merivale Road (Carling TM Station) to Churchill Avenue North. The required material will consists of 1800 meters of 500MCM EPR cable, three overhead switches, and a new pole to be able to accommodate the cable`s transition from underground to overhead.

Work Plan

Due to the existing underground infrastructure there will be no need for additional easements or permits. The 1800 meters of 500 MCM EPR cable will be pulled through the duct bank from Carling substation to Churchill Avenue North by HOL underground crews. A new pole is required to install the additional equipment needed to connect this circuit. The stronger pole will be installed and the necessary plant will be transferred as well as the ne riser equipment and switch installed. Finally the cable will be terminated at the station. Currently there are no open breakers at Carling substation which will cause the new cable to be hair pinned with an existing circuit. Therefore the relay protection for the chosen breaker will need to be updated. A scheduled outage will be necessary in order to safely connect the cable at the substation

Customer Impact

This project will allow for future customers to be connected due to the increase in capacity. The parallel cable will allow for an additional 4MVA of load to be supplied.

2.2 Alta Vista Tie

2.2.1 Project/Program Summary

This project will facilitate the interconnection of Overbrook TS, Russell TS and Riverdale TS in order to increase the flexibility of the system. It will allow the transfer of load from Overbrook TS and Russell TS which are approaching their maximum load capacity at peak.

This business case will describe the project, look at the alternatives considered to meet its objectives and provide an overview of the execution plan.

2.2.2 Project/Program Description

2.2.2.1 *Current Issues*

Overbrook TS, Riverdale TS and Russell TS substations are currently poorly interconnected limiting the ability to provide system backup and transfer load. Overbrook TS and Russell TS are approaching their maximum load capacity at peak and will require capacity upgrades if load continues to grow.

Intensification with the development in the Terminal Lands will continue to grow, pushing the load capacity limit of Overbrook TS and Riverdale TS.

2.2.2.2 *Assets in Scope*

The Riverdale TS feeder TR3UQ will then be extended 1.5km from Queens DS, along Riverside Drive to the intersection of Alta Vista Drive and Industrial Ave, terminating at a 4-way 3 position switch. The interconnecting circuits, Overbrook TS feeder 1802 and Russell TS feeder 5306, are located in close proximity to this intersection and will only require a minor extension to connect to the switchgear. The extension along Riverside Drive will require 480m of new concrete encased ducts and two (2) new manholes. The project will utilize existing duct structures where available.

2.2.2.3 *Main and Secondary Drivers*

The main driver of this project is to support the expected changes in load to maintain the system's ability to provide consistent service delivery. This project will facilitate the transfer of load between Riverdale TS, Overbrook TS and Russell TS. This will enable the deferral of a station capacity upgrade by transferring the load to a station with available capacity.

As a secondary driver, this project will provide reliability benefits by allowing more flexibility when restoring customers from an interruption by interconnecting the circuits.

2.2.2.4 *Performance Targets and Objectives*

The objective of this project will be to facilitate the transfer of load between the three (3) stations for reliability improvements and capacity planning to help defer investments.

2.2.3 Project/Program Justification

2.2.3.1 *Alternatives Evaluation*

2.2.3.1.1 Alternatives Considered

Riverdale TS, Overbrook TS and Russell TS are physically separated by the Rideau River and Highway 417 which limit the ability to create inter-station ties.

Alternative #1: Use existing feeders from Riverdale TS, Overbrook TS and Russell TS to connect to a common switching point.

Overbrook TS feeder 1802 and Russell TS feeder 5306 are located in close proximity at Industrial Ave and Sandford Fleming Ave.

Alternative #2: Use a new feeder from Riverdale TS or Russell TS to tie with an existing feeder from Overbrook TS.

2.2.3.1.2 Evaluation Criteria

Cost:

Alternative #1: $1.658M

Alternative #2: $2.1M

Ability to supply load:

Alternative #1: The current circuit loading of all three circuits is such that any one (1) can take the entire loading of one (1) other circuit. This will provide the ability to off-load 3.4MVA from Overbrook TS or 2.7MVA from Russell TS onto Riverdale TS.

Alternative #2: With the extension of a new feeder from Riverdale TS, both Overbrook TS and Russell TS feeders can be supplied from Riverdale TS. This would result in the ability to transfer 6.1MVA to Riverdale TS. This alternative does not provide the opportunity to off-load from Riverdale TS.

Reliability Benefits:

Both options will provide the same interconnection between the stations in the area improving system flexibility to manage load and quickly restore power from unplanned outages.

2.2.3.1.3 Preferred Alternative

Alternative #1 is the preferred alternative as it will meet the short-term needs of transferring load from Overbrook TS or Russell TS to Riverdale TS and will also allow flexibility with long-term load forecasts by transferring load away from Riverdale TS.

2.2.3.2 *Project/Program Timing & Expenditure*

Historical ($k)						Future ($k)			
2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
				$929	$729				

Table 78 - Project Expenditures

2.2.3.3 *Benefits*

Benefits	Description
System Operation Efficiency and Cost-effectiveness	This project will improve system operations by interconnecting the 3 stations and provide the flexibility to transfer load between stations.
Customer	The customers connected to these circuits, which includes the Riverside Hospital, will see a reduction in time to restore power and also increased redundancy by being connected to multiple sources.
Safety	N/A
Cyber-Security, Privacy	N/A
Co-ordination, Interoperability	HOL will coordinate part of this project with the City of Ottawa's Alta Vista Transportation Corridor (AVTC) project which affects the area around Queens DS.
Economic Development	N/A
Environment	N/A

Table 79 - Project Benefits

2.2.4 Prioritization

2.2.4.1 *Consequences of Deferral*

If this project is deferred, it may result in the inability of the system to manage new load effectively and create overload conditions.

2.2.4.2 *Priority*

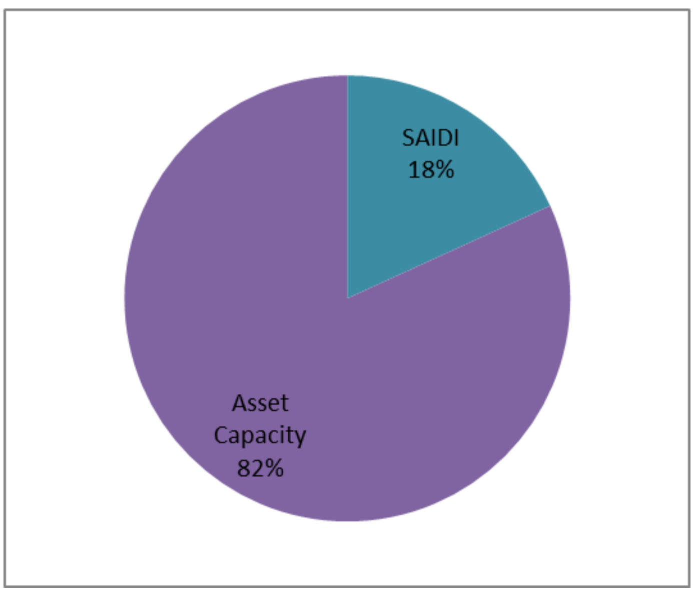


Figure 76 - Project Avoided Risk

Project Score: 0.88

2.2.5 Execution Path

2.2.5.1 *Implementation Plan*

This project will begin in 2014 with the installation of civil works along Riverside Drive, Industrial Avenue, and Sandford Fleming Avenue. Civil works include the installation of 480m of new concrete encased ducts and two manholes. The purchase of the switchgear will also take place this year.

In 2015, feeder TR3AQ from Riverdale TS will be extended 1.5 km from Queens DS to Alta Vista Drive and connect to the newly installed switchgear. Lie-along feeders 5306 and 1802 from Russell TS and Overbrook TS will also be terminated to this switchgear.

2.2.5.2 *Risks to Completion and Risk Mitigation Strategies*

Typical risks to completion include:

- Obtaining road cut permits from the City of Ottawa;
- Coordinating activities in areas where multiple parties are working;
- Getting approval for traffic plans where required

It is standard practice to engage early and communicate plans for future work with the City of Ottawa and residence to coordinate effort and potential resources.

2.2.5.3 *Timing Factors*

Coordination with the City of Ottawa's Alta Vista Transportation Corridor (AVTC) project required that the civil structures around Queens DS be in place in order to remove the overhead structures by 2015.

2.2.5.4 *Cost Factors*

A large part of the cost savings on this project is reliant on the use of existing duct structures along Riverside Drive. HOL will mitigate this risk by inspecting the duct structures well in advance of the cable installation to ensure the availability of ducts. If there is insufficient duct capacity, additional excavation and civil works will need to be completed prior to the cable installation.

2.2.5.5 *Other Factors*

Not applicable.

2.2.6 Renewable Energy Generation (if applicable)

Not applicable.

2.2.7 Leave-To-Construct (if applicable)

Not applicable.

2.2.8 Project Details and Justification

Project Name:	Alta Vista Tie
Capital Cost:	$1.658M
O&M:	N/A
Start Date:	2014 – Q1
In-Service Date:	2015 – Q4
Investment Category:	System Service
Main Driver:	Capacity
Secondary Driver(s):	Reliability
Customer/Load Attachment	11.2 MVA

Project Scope

This project will facilitate the interconnection of Overbrook TS, Russell TS and Riverdale TS in order to increase the flexibility of the system to transfer of load from Overbrook TS and Russell TS which are approaching their maximum load capacity at peak.

The Riverdale TS feeder TR3UQ will then be extended 1.5km from Queens DS, along Riverside Drive to the intersection of Alta Vista Drive and Industrial Ave, and terminating at a 4-way 3 position switch. The interconnecting circuits, Overbrook TS feeder 1802 and Russell TS feeder 5306, are located in close proximity to this intersection and will only require a minor extension to connect to the switchgear. The extension along Riverside Drive will require 480m of new concrete encased ducts and two (2) new manholes. The project will utilize existing duct structures where available.

Work Plan

This project will begin in 2014 with the installation of civil works along Riverside Drive, Industrial Avenue, and Sandford Fleming Avenue. Civil works include the installation of 480m of new concrete encased ducts and two manholes. The purchase of the switchgear will also proceed this year.
In 2015, feeder TR3AQ from Riverdale TS will be extended 1.5 km from Queens DS to Alta Vista Drive and connect to the newly installed switchgear. Lie-along feeders 5306 and 1802 from Russell TS and Overbrook TS will also be terminated to this switchgear.

Customer Impact

The customers connected to these circuits, which includes the Riverside Hospital, will see a reduction in time to restore and also increased redundancy by being connected to multiple sources.

2.3 Orleans TS Feeder

2.3.1 Project/Program Summary

Hydro One is constructing the new Orleans TS station. HOL has purchased one of the breakers at this station and will use this feeder to interconnect with Cyrville MTS and Bilberry TS to improve reliability and service new load from the development of the East Urban Community.

This business case will describe the project, look at the alternatives considered to meet objectives, and provide an overview of the execution plan.

2.3.2 Project/Program Description

2.3.2.1 *Current Issues*

Bilberry TS feeders 77F2 & 77F6 are on HOL's worst feeders list for impact on reliability.

Cyrville MTS feeder CYRF3 has a long radial section extending out Renaud Road and Mer Bleue Road with no backup on this section.

The City of Ottawa has approved the development of the East Urban Community which expands North and South of Renaud Road and West of Mer Bleue Road.

2.3.2.2 *Program/Project Scope*

This project will extend out a new feeder 2.3km from Hydro One's new Orleans TS along Mer Bleue Road to connect with Cyrville MTS feeder CYRF3 at Renaud Road and Bilberry TS feeder 77M2 North on Mer Bleue Road.

The project involves the installation of 500m of concrete encased ducts and XLPE cable, two (2) padmounted switchgear, 28 wood poles, and 1.8km of overhead conductor.

Also included in the cost of the project is the purchase of a breaker position at Hydro One's Orleans TS.

2.3.2.3 *Main and Secondary Drivers*

The main driver of this project is to improve reliability. Bilberry TS feeder 77M2 is one of HOL's worst performing feeders. Cyrville feeder CYRF3 is a long radial feeder in this area. This new feeder from Orleans TS will provide an integral backup to both these circuits.

The secondary driver is to provide the ability to service new customers in the East-Urban Development lands.

2.3.2.4 *Performance Targets and Objectives*

The objectives of this project are to improve reliability on Bilberry TS feeder 77M2 as one of HOL's worst performing feeders and to prevent Cyrville MTS feeder CYRF3 from getting worse.

It's expected that these two feeders will see a significant reduction in interruption durations.

2.3.3 Project/Program Justification

2.3.3.1 *Alternatives Evaluation*

2.3.3.1.1 Alternatives Considered

Alternative #1:

Extend a new feeder from Orleans TS to connect with Cyrville MTS feeder CYRF3 and Bilberry TS feeder 77M2. This alternative would require the construction of the egress from Orleans TS and the infrastructure required to extend South on Mer Bleue Road.

This option would enable use of the new capacity available at Orleans TS.

Alternative #2:

Extend Cyrville MTS feeder CYRF3 North along Mer Bleue Road to connect with Bilberry feeder 77M2. This alternative will require the construction of infrastructure required to extend North on Mer Bleue Road to connect CYRF3 to 77M2.

This option would limit the available capacity for new load as both feeders are already loaded.

2.3.3.1.2 Evaluation Criteria

Costs:

Alternative #1: $4,546,000

Alternative #2: $800,000

Ability to service new load:

Alternative #1: The connection of the Bilberry TS and Cyrville MTS feeders to the new Hydro One Orleans TS will allow for an additional 16MVA of capacity to supply new load.

Alternative #2: The connection of the Cyrville MTS and Bilberry TS feeders will only provide the ability to add 4MVA of new capacity to service new load which is insufficient for the projected 6MVA load required to service phase 1 of the East Urban community. To meet this loading requirement another line extension from Cyrville MTS would be required.

Reliability:

Alternative #1: Customer outage duration and frequency will be improved by having three (3) stations interconnected from multiple sources.

Alternative #2: Customer outage duration will be reduced by having two (2) stations connected together.

2.3.3.1.3 Preferred Alternative

Alternative #1 is the preferred option as it will provide added reliability benefits to HOL's feeders. Orleans TS is ideally located to service the load growth in this area and will reduce the overall exposure to unplanned interruptions.

This option also meets the secondary objective which is to have a long-term service plan for the new growth in the area.

2.3.3.2 *Project/Program Timing & Expenditure*

Historical ($M)						Future ($M)			
2010	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
				1.709	2.837				

Table 80 - Project Expenditures

2.3.3.3 *Benefits*

Benefits	Description
System Operation Efficiency and Cost-effectiveness	This project will improve system operation efficiency by interconnecting the new Orleans TS to Cyrville MTS and Bilberry TS which will provide an alternative source when restoring outages.
Customer	By integrating Orleans TS into the distribution system in South Orleans, it will improve the flexibility of the system. The average number of customer hours per interruption should diminish significantly. This project will also increase the available capacity in the area of Renaud Road and Mer Bleue Road for the upcoming developments to the North.
Safety	N/A
Cyber-Security, Privacy	N/A
Co-ordination, Interoperability	This project will coordinate with the proposed City road alignment of Mer Bleue Road.
Economic Development	N/A
Environment	N/A

Table 81 - Project Benefits

2.3.4 Prioritization

2.3.4.1 *Consequences of Deferral*

The deferral of this project would limit HOL's ability to purchase a breaker position in Hydro One's new Orleans TS and would necessitate looking at other alternatives to meet the objectives.

2.3.4.2 *Priority*

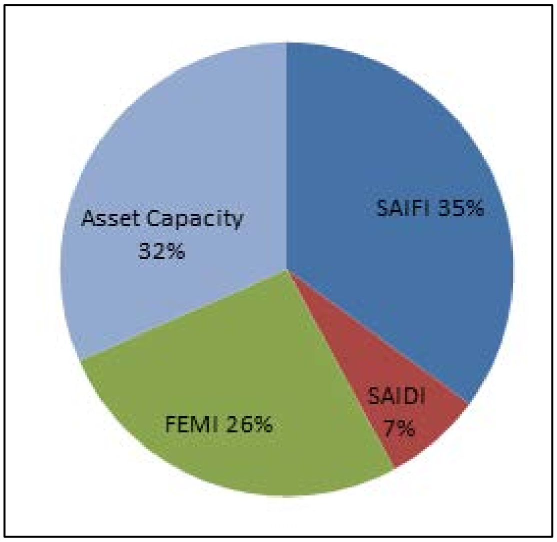


Figure 77 - Project Avoided Risk

Project Score: 0.76

2.3.5 Execution Path

2.3.5.1 *Implementation Plan*

The project will begin with the purchase of the breaker position from Hydro One. Construction of the egress from the station will begin in 2014.

In 2015, the pole line will be extended South from Orleans TS, down Mer Bleue Road to Renaud Road. to make connection with CYRF3. The connection to 77M3 to the North of the station egress will also be completed.

2.3.5.2 *Risks to Completion and Risk Mitigation Strategies*

Risks that may affect this project are easement acquisition, existing location of trees, and bedrock. HOL takes many steps in the design phase of the project to minimize these risks by investigating them early on.

2.3.5.3 *Timing Factors*

This project is dependent on Hydro One completing the construction of Orleans TS.

2.3.5.4 *Cost Factors*

Factors that can affect the costs of this project:

- Existing trees on the proposed feeder alignment,
- Finding rock when excavating pole holes,
- Acquiring easements on private property.

2.3.5.5 *Other Factors*

Not applicable.

2.3.6 Renewable Energy Generation (if applicable)

Not applicable.

2.3.7 Leave-To-Construct (if applicable)

Not applicable.

2.3.8 Project Details and Justification

Project Name:	92009734 - Orleans TS Feeder
Capital Cost:	$4,546,000
O&M:	$0
Start Date:	2014 – Q1
In-Service Date:	2015 – Q4
Investment Category:	System Service
Main Driver:	Reliability
Secondary Driver(s):	Capacity
Customer/Load Attachment	28MVA

Project Scope

This project will extend out a new feeder 2.3km from Hydro One's new Orleans TS along Mer Bleue Road to connect with Cyrville MTS feeder CYRF3 at Renaud Road and Bilberry TS feeder 77M2 North on Mer Bleue Road.
The project involves the installation of 500m of concrete encased ducts and XLPE cable, two (2) padmounted switchgear, 28 wood poles, and 1.8km of overhead conductor.
Also included in the cost of the project is the purchase of a breaker position at Hydro One's Orleans TS

Work Plan

The project will begin with the purchase of the breaker position from Hydro One. Construction of the egress from the station will begin in 2014.
In 2015, the pole line will be extended South from Orleans TS, down Mer Bleue Road to Renaud Road to make connection with CYRF3. The connection to 77M3 to the North of the station egress will also be completed.

Customer Impact

By integrating Orleans TS into the distribution system in South Orleans, it will improve the flexibility of the system. The average number of customer hours per interruption should diminish significantly.

This project will also increase the available capacity in the area of Renaud Road and Mer Bleue Road for the upcoming developments to the North.

2.4 Fernbank Road Line Extension

2.4.1 Project/Program Summary

This project is to extend two feeders from Terry Fox MTS along Fernbank Road in order to facilitate the transfer of load from Hydro One's Alexander DS feeder ALEXF3 by 2016, support future growth along Fernbank Road, and support the connection of the TransCanada Ottawa East pumping station in 2017.

This business case will describe the project, look at the alternatives considered to meet objectives and provide an overview of the execution plan.

2.4.2 Project/Program Description

2.4.2.1 *Current Issues*

Hydro One has requested that HOL transfer load from Hydro One's Alexander DS feeder ALEXF3 by 2016 in order for them to service upcoming developments to the North of Stittsville. The closest station that HOL could possibly transfer the load to is Janet King DS however this station does not have the capacity to support the load transfer.

The TransCanada Ottawa East pumping station is planned to be constructed in the South of Stittsville by 2017 and has requested HOL for a 10MW connection.

HOL's new Terry Fox MTS will be in service in 2014 and is well situated to support load growth in the South of Kanata and Stittsville. A line extension from this station would be ideal to support the short-term load transfer and future growth planned on the North side of Fernbank Road.

2.4.2.2 *Project Scope*

The scope of this project is to extend two (2) 27.6kV feeders from Terry Fox Drive to Stittsville Main Street. The project will make use of the existing 8.32kV feeder where applicable by converting to 27.6kV to reduce cost.

Phase 1 includes a 1.7km line extension of two (2) circuits from Terry Fox Drive to Founder Road. This includes the installation of thirty (30) poles and the replacement of four (4) transformers to accommodate the change in voltage.

Phase 2 includes a 1.3km line extension of two (2) circuits from Founder Road to Shea Road. This included the installation of 21 poles and the replacement of six (6) transformers to accommodate the change in voltage.

Phase 3 includes a 1.5km line extension of two (2) circuits from Shea Road to Stittsville Main Street. This will include the installation of 4 new poles, reframing 25 poles to accommodate another circuit and replacing 11 transformers to accommodate the change in voltage.

2.4.2.3 *Main and Secondary Drivers*

The main driver of this project is to support the expected changes in load to maintain the system's ability to provide consistent service delivery. Hydro One is requesting that HOL offload the Alexander DS ALEXF3 feeder by 2016 because of load growth in their service territory at the North end of Stittsville.

This project will also support upcoming load growth with the construction of the TransCanada Ottawa East pumping station in 2017.

The secondary driver of this project is to provide reliability benefits to the system in Kanata and Stittsville. These two new circuits will provide backup to four (4) other circuits in order to improve the flexibility of the system to quickly restore power.

2.4.2.4 *Performance Targets and Objectives*

The main objectives of this project are to be in a position to offload Hydro One's feeder ALEXF3 by 2016 and support the upcoming development of the TransCanada Ottawa East pumping station in 2017.

Secondary objectives are to align with future City of Ottawa road widening of Fernbank Road to prevent the need to relocate poles at a future date and to improve system ties by connecting feeders between stations.

2.4.3 Project/Program Justification

2.4.3.1 *Alternatives Evaluation*

2.4.3.1.1 Alternatives Considered

Due to the timing requirements of this project, alternatives are limited. Surrounding stations do not have the station nor feeder capacity to support the load being added to the HOL system. A feeder extension from the newly constructed Terry Fox MTS station is the only feasible option.

Alternative #1: Routing considered is along Fernbank Road. This route would extend two feeders from Terry Fox Drive east along Fernbank Road to Stittsville Main Street.

This option is the most direct route to make feeder connection to offload ALEXF3. It would make use of the existing 8.32kV feeders along Fernbank Road by converting the services fed from it to 27.6kV and upgrading pole structures where necessary to allow for two feeder pole framing.

Alternative #2: Routing considered is along Flewellyn Road. This route would extend two feeders south on Terry Fox Drive from Fernbank Road to Flewellyn Road, west on Flewellyn Road to Stittsville Main Street, and then north on Stittsville Main Street.

This option would make use of the existing 8.32kV feeders along Flewellyn Road by converting the services fed from it to 27.6kV and upgrading pole structures where necessary to allow for two feeders. Many of the existing 8.32kV poles are undersized and will require upgrade to support two feeder pole framing.

2.4.3.1.2 Evaluation Criteria

Costs:

Alternative #1: $1.533M

Alternative #2: $4.633M

Ability to supply load:
Alternative #1: Feeders will allow for the off-loading of ALEXF3, be in a good position to extend to the TransCanada pumping station, and support new growth on the North side of Fernbank Road.

Alternative #2: Feeders will allow for the off-loading of ALEXF3 and be in a good position to extend to the TransCanada pumping station. The City of Ottawa's urban boundary is Fernbank Road with upcoming planned developments on the north side of Fernbank Road it would be difficult to service this load with this route option.

Reliability Benefits:
Both options will provide the same interconnection between stations in the area improving system flexibility to manage load and quickly restore unplanned outages.

2.4.3.1.3 Preferred Alternative

Alternative #1 is the preferred feeder route due to lower costs and the ability to supply future load developments.

Alternative #2 would allow for better expansion to the TransCanada pumping station however it involves a much larger scope than alternative #1 due the number poles that would require upgrading to support the two new feeders and the number of transformers that would to be converted to 27.6kV.

2.4.3.2 *Project/Program Timing & Expenditure*

This project will start in 2012 and continue over 3 years.

Historical ($k)						Future ($k)			
2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
		473	23	530	507				

Table 82 - Project Expenditures

2.4.3.3 *Benefits*

Benefits	Description
System Operation Efficiency and Cost-effectiveness	This project will improve system operation efficiency by interconnecting the new Terry Fox MTS to the distribution system in Stittsville and provide an alternative source when restoring outages.
Customer	By integrating Terry Fox MTS into the distribution system in Stittsville, it will improve the flexibility of the system. The average number of customer hours per interruption should diminish significantly. This project will also increase the available capacity in the area of Fernbank Road for the upcoming developments to the North.
Safety	N/A
Cyber-Security, Privacy	N/A
Co-ordination, Interoperability	This project will coordinate with the City of Ottawa's plans to widen Fernbank Road. Poles will be set referencing the proposed plans so as to not interfere with the future road widening.
Economic	This project supports the connections to the TransCanada East Pipeline by

Development	servicing the Ottawa East pumping station.
Environment	N/A

Table 83 - Project Benefits

2.4.4 Prioritization

2.4.4.1 *Consequences of Deferral*

Deferring this project will result in the inability to transfer load from Hydro One's Alexander DS feeder ALEXF3 in 2016 which will in turn affect Hydro One's ability to utilize this feeder to connect future customers.

Another consequence of deferral is that it will delay the line extension needed to connect the TransCanada Ottawa East pumping station which is scheduled to be connected in 2017.

2.4.4.2 *Priority*

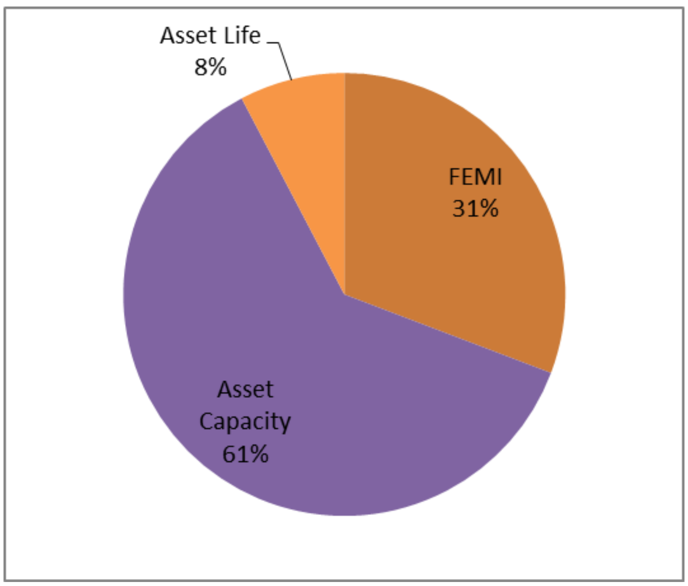


Figure 78 - Project Avoided Risk

Project Score: 0.39

2.4.5 Execution Path

2.4.5.1 *Implementation Plan*

Phase 1 in 2012 included a 1.7km line extension of two (2) circuits from Terry Fox Drive to Founder Road. This includes the installation of thirty (30) poles and the replacement of four (4) transformers to accommodate the change in voltage. This will be coordinated to align with the City's proposed road widening.

Phase 2 in 2014 includes a 1.3km line extension of two (2) circuits from Founder Road to Shea Road. This included the installation of twenty-one (21) poles and the replacement of six (6) transformers to accommodate the change in voltage.

Phase 3 in 2015 includes a 1.5km line extension of two (2) circuits from Shea Road to Stittsville Main Street. This will include the installation of four (4) new poles, reframing twenty-five (25) poles to accommodate another circuit and the replacement of eleven (11) transformers to accommodate the change in voltage.

2.4.5.2 *Risks to Completion and Risk Mitigation Strategies*

Risks that may affect this project are easement acquisition, existing location of trees, and bedrock. HOL takes many steps in the design phase of the project to minimize these risks by investigating them early on.

2.4.5.3 *Timing Factors*

This project was dependent on the in-service date of Terry Fox MTS. With Terry Fox MTS now being complete and in-service, there are no more timing factors from this project.

The timing of the project is being driven by the requirement from HONI to offload Hydro One's Alexander DS feeder ALEXF3 by 2016 and the requirement to have a line in place to service the TransCanada Ottawa East pumping station by 2017.

2.4.5.4 *Cost Factors*

Factors that can affect the costs of this project:

- Existing trees on the proposed feeder alignment,
- Finding rock when excavating pole holes,
- Acquiring easements on private property.

2.4.5.5 *Other Factors*

Not applicable.

2.4.6 Renewable Energy Generation (if applicable)

Not applicable.

2.4.7 Leave-To-Construct (if applicable)

Not Applicable.

2.4.8 Project Details and Justification

Project Name:	92006253 - Fernbank Road Line Extension
Capital Cost:	$1.533M
O&M:	$0
Start Date:	2012 – Q1
In-Service Date:	2015 – Q4
Investment Category:	System Service
Main Driver:	Capacity Upgrade
Secondary Driver(s):	Reliability
Customer/Load Attachment	2779 Customers

Project Scope

The scope of this project is to extend two (2) 27.6kV feeders from Terry Fox Drive to Stittsville Main Road. The project will make use of the existing 8.32kV feeder where applicable by converting to 27kV to reduce cost.

Work Plan

2012 – Phase 1: Starting from Terry Fox Drive to Founder Road
2014 – Phase 2: Founder Road to Shea Road
2015 – Phase 3: Shea Road to Stittsville Main Street

Customer Impact

By integrating Terry Fox TS into the distribution system in Stittsville, it will improve the flexibility of the system. The average number of customer hours per interruption should diminish significantly.

This project will also increase the available capacity in the area of Fernbank Road for the upcoming developments to the North.

2.5 West 44kV Line Extension

2.5.1 Project/Program Summary

The West 44kV Line Extension project is to extend the 22M25 Nepean TS 44kV feeder a distance of 20km to tie into the A9M3 South March TS 44kV feeder. The A9M3 sub-transmission line supplies 4 substations and does not have an alternate tie outside of the South March TS substation. The conductor and insulators of the 47F6 Belles Corners DS 8.32kV feeder along West Hunt Club Road and the 145F3 Jockvale DS 8.32kV feeder along Old Richmond Road will be upgraded to allow for increased capacity and provide renewed infrastructure. Services in the village of Fallowfield along Old Richmond Road will be replaced and amalgamated where possible to improve street aesthetics. The BRDF2 Bridlewood MS 27.6kV feeder will be extended starting from the corner of Hope Side Road and Old Richmond Road along Old Richmond Road and then along Fallowfield Road to Shea Road.

2.5.2 Project/Program Description

2.5.2.1 *Current Issues*

Current issues in the West service territory include deteriorating reliability due to failure of aging infrastructure of the A9M3 44kV sub-transmission line. The A9M3 supplies two customers and four substations that account for 9500 customers and 33MVA peak load. The A9M3 has been identified as one of the top ten worst performing feeders in 2013 and in 2014. This feeder radially supplies these customers with no source of back-up, which prevents sectionalisation of line segments for routine maintenance and asset replacements. This has led to aging infrastructure that, upon failure, has no source of back-up which leads to prolonged outages.

2.5.2.2 *Program/Project Scope*

The scope of this project is to extend one (1) 44kV circuit to tie Nepean TS to South March TS. This includes extending the 22M25 feeder from the corner of Moodie Drive and West Hunt Club Road to the corner of Fallowfield Road and Shea Road to tie with the A9M3 via West Hunt Club Road, Old Richmond Road and then Fallowfield Road. The conductor and insulators of the 47F6 Belles Corners DS 8.32kV feeder along West Hunt Club Road and the 145F3 Jockvale DS 8.32kV feeder along Old Richmond Road will be upgraded to allow for increased capacity and provide renewed infrastructure. Services in the village of Fallowfield along Old Richmond Road will be replaced and amalgamated where possible to improve street aesthetics. The BRDF2 Bridlewood MS 27.6kV feeder will be extended starting from the corner of Hope Side Road and Old Richmond Road along Old Richmond Road to Fallowfield Road. The 8.32kV line along Fallowfield Road will be constructed to allow for future voltage conversion to 27.6kV.

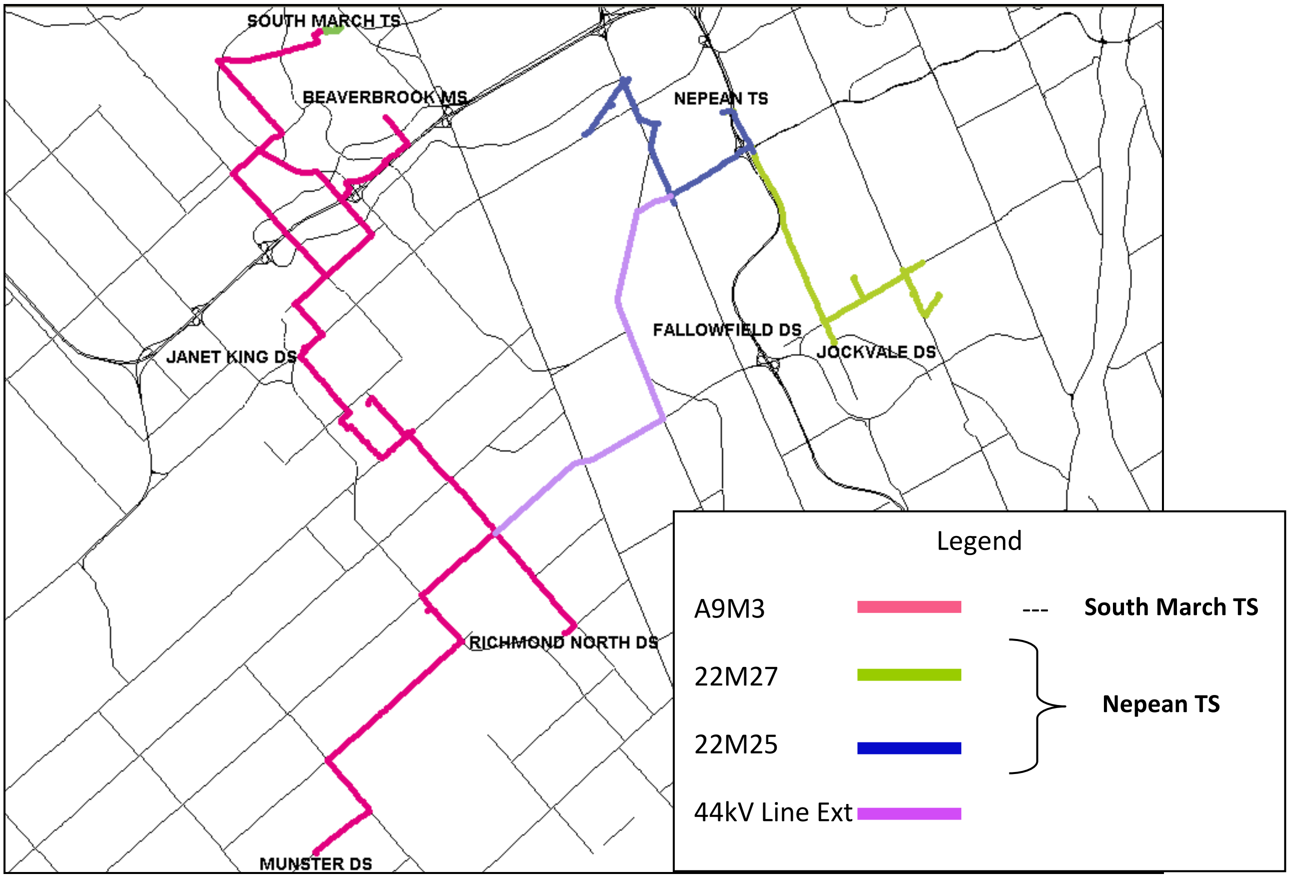


Figure 79 - 44kV Line Extension Route

Phase 1, which will include all work and expenses to occur within 2015, includes 3.6km line extension from the intersection of Moodie Drive and West Hunt Club Road to the intersection of Old Richmond Road and Hope Side Road. Extension of the 22M25 44kV feeder is the main focus of Phase 1, but the existing 8.32kV 47F6 and 145F3 feeders on the effected poles will have the conductor and insulators upgraded to allow for future capacity increases. Seventy-one (71) poles need to be replaced with taller poles in order to meet HOL standard clearances between circuits and road grade. A 44kV air break switch will be installed at the beginning of the line extension at the corner of Moodie Drive and West Hunt Club Road that will allow for circuit sectionalisation when required. Six (6) 8.32kV overhead transformers that are located along the affected pole line will be replaced to renew equipment approaching end of life condition. HOL anticipates clearance limitations when crossing beneath Hydro One's 500kV corridor along Old Richmond Road and has proposed shorter poles to accommodate the 22M25 44kV circuit and an underground concrete encased duct system to accommodate the 145F3 8.32kV circuit.

Phase 2, which will include all work and expenses to occur within 2016, includes a 2.1km line extension from the intersection of Hope Side Road and Old Richmond Road to the intersection of Old Richmond Road and Fallowfield Road. Extension of the 22M25 44kV feeder is the main focus of Phase 2, but the existing 145F3 8.32kV feeder on the effected poles will have the conductor and insulators upgraded to allow for future capacity increases. Also included on this pole line is an extension of the BRDF2 27.6kV circuit starting from Hope Side Road. A future project will extend FAL02 to the corner of Fallowfield Road and Old Richmond Road that will create a tie between Bridlewood MS and Fallowfield MTS. Seventy-two (72) poles require replacement with taller poles in order to meet HOL standard clearances between circuits and road grade. Fifteen (15) 8.32kV overhead transformers that are located along the effected pole line will be replaced to renew equipment approaching end of life condition. Within the village of Fallowfield these 15 transformers are located within proximity that amalgamation may be possible to reduce the number of transformers required. HOL anticipates that substantial tree trimming will be required in order to meet HOL conductor to tree clearance standards.

Phase 3, which will include all work and expenses to occur within 2017, includes a 4.7km line extension from the intersection of Old Richmond Road and Fallowfield Road to the intersection of Fallowfield Road and Shea Road. Extension of the 22M25 44kV feeder is the main focus of Phase 2, but the existing 145F3 8.32kV feeder on the effected poles will have the conductor and insulators upgraded to allow for future voltage conversion to 27.6kV and capacity increases. A future project will extend TFXF5 to the corner of Fallowfield Road and Eagleson Road that will create a tie between Terry Fox MTS and Fallowfield MTS. Seventy-five (75) poles require replacement with taller poles in order to meet HOL standard clearances between circuits and road grade. Eleven (11) 8.32kV overhead transformers that are located along the effected pole line will be replaced to renew equipment approaching end of life condition. The transformers will contain dual winding primaries that will allow them to be transferred to 27.6kV supply voltage. A 44kV Joslyn VBM automated switch will be installed at the connection point between the A9M3 and the 22M25 at the corner of Fallowfield Road and Shea Road that will allow for circuit transferability when required.

2.5.2.3 *Main and Secondary Drivers*

The primary driver of this project is to provide an alternate sub-transmission supply to customers and substations supplied by A9M3. Reliability on this line has been deteriorating because there is no alternate source to facilitate maintenance and repairs. The A9M3 has been identified as one the top ten worst performing feeders in both 2013 and 2014. The completion of this project will provide a tie between the A9M3 and the 22M25, which will allow for sectionalization so that future work can be done on this line targeted to improve the feeder’s reliability.

2.5.2.4 *Performance Targets and Objectives*

The main objective of this project is to improve reliability on the A9M3. The alternate supply point will provide switchable means of supply during emergency situations that will directly improve SAIDI, but will also allow for sectionalization of sections with failing assets for replacement that will improve SAIFI.

Secondary objectives are to align with future City of Ottawa road widening of Old Richmond Road to prevent the need to relocate poles at a future date and to improve system ties by connecting feeders between stations.

2.5.3 Project/Program Justification

2.5.3.1 *Alternatives Evaluation*

2.5.3.1.1 Alternatives Considered

Capacity on the A9M3 exceeds the asset planning rating for circuits with an approximate load of 430 amps. There are limited alternative circuits that are loaded lightly enough to support the A9M3 circuit for contingency circumstances. The A9M4 from South March TS and 22M25 from Nepean TS are the only two circuits loaded lightly enough to support the A9M3. The cost implications of extending the A9M4 from its existing location would require extensive asset upgrades and re-routing of other circuits along the existing route. The cost analysis alone suggests the 22M25 circuit tie is the preferred alternative.

Alternative #1: Routing considered is along West Hunt Club Road, Old Richmond Road and Fallowfield Road. This route would extend the 22M25 from Nepean TS to tie the A9M3 South March TS.

This option is the most direct route to make feeder connections to improve reliability of the A9M3. It would make use of the existing 8.32kV routing along West Hunt Club Road, Old Richmond Road and Fallowfield Road that have assets approaching end of life condition.

Alternative #2: Routing considered is along Station Road, March Road, Eagleson Road and Fallowfield Road. This route would extend the A9M4 feeder east on Station Road, south on March Road and Eagleson Road and then west on Fallowfield Road to tie with the A9M3 at Shea Road.

This option would make use of the existing 44kV, 27.6kV and 8.32kV feeders along these routes and would require re-routing of 27.6kV and 8.32kV feeders to an underground system. This would be required to remain in compliance with HOL standards which limits the number of feeders on a pole to three (3) and dictates that 44kV remain overhead.

2.5.3.1.2 Evaluation Criteria

Costs:
Alternative #1: $6.243M

Alternative #2: $7.880M

Ability to supply load:
Alternative #1: The 22M25 is loaded lightly enough to support the A9M3 for load transferability for construction and emergency circumstances.

Alternative #2: The A9M4 is loaded lightly enough to support the A9M3 for load transferability for construction and emergency circumstances.

Reliability Benefits:
Both options will provide improved reliability, however Alternative #1 allows for interconnection ties between South March TS and Nepean TS, whereas Alternative #2 allows for interconnections between two (2) feeders from the same substation.

2.5.3.1.3 Preferred Alternative

Alternative #1 is the preferred feeder route due to lower costs and the ability to support the A9M3 load. The interconnection ties between South March TS and Nepean TS will provide an improved level of reliability.

Alternative #2 would have the ability to support the A9M3 load, but expansion costs of the A9M4 comparatively to Alternative #1 are too expensive.

2.5.3.2 *Project/Program Timing & Expenditure*

The total project cost is $6,243,000 and the project is anticipated to start in 2015 and conclude in 2017. HOL aims to minimize the costs and meet the deadlines associated with all projects, by completing pre-planning of the construction schedule and ensuring vehicles, staff and material are all available for start of construction.

Historical ($M)					Future ($M)				
2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
$0	$0	$0	$0	$0	$2.141	$1.995	$2.107	$0	$0

Table 84 - Project Expenditures

2.5.3.3 *Benefits*

Key benefits that will be achieved by implementing the West 44kV Line Extension project are summarized below.

Benefits	Description
System Operation Efficiency and Cost-effectiveness	This project is required to improve the reliability of the A9M3 and creates an additional tie between South March TS and Nepean TS. It is an essential system service project needed to be capable of isolating sections of the A9M3 for asset replacement. System operation efficiency will be improved by the new automated switch that will allow for quick transferability from System Office during contingency circumstances. This should inevitably contribute to reducing SAIDI, which is important in an area where the overhead distribution system is subject to weather-related outages. The construction of this line is the most cost-effective solution capable of improving the reliability of the A9M3 feeder.
Customer	This project will achieve reliability improvements for customers supplied by the A9M3 sub-transmission line. The alternate supply will allow for sectionalisation that had been previously not been available, in order to complete routine maintenance and asset replacements. The alternate supply and automated switches will directly help to improve the impact on SAIDI and future projects that will be permitted as a result of completion of this project will allow for renewed infrastructure that will ultimately improve SAIFI.
Safety	The infrastructure in place today is beginning to approach end of life and poses a small risk of failure and safety concern. By renewing the infrastructure, the safety risk is significantly reduced.
Cyber-Security, Privacy	Not Applicable.
Co-ordination, Interoperability	This project will coordinate with the City of Ottawa's plans to widen Old Richmond Road. Poles will be set referencing the proposed plans as to not

	interfere with the future road widening.
Economic Development	This project is not expected to contribute directly to economic growth or job creation, but due to the number of assets being replaced in this project, it will inevitably require operation and maintenance. Contractor labour will be used extensively to complete the project.
Environment	Not Applicable.

Table 85 - Project Benefits

2.5.4 Prioritization

2.5.4.1 *Consequences of Deferral*

Deferring this project will result in further deterioration of infrastructure that currently supports the A9M3. The reliability of this feeder can be expected to continue to deteriorate, which contributes highly to the total system reliability statistics due to the number of customers the A9M3 supplies.

2.5.4.2 *Priority*

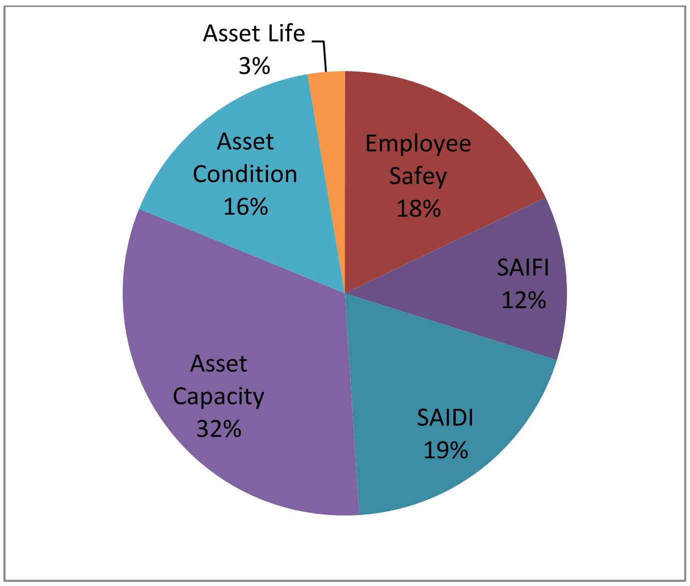


Figure 80 - Project Avoided Risk

Project Score: 1.117

2.5.5 Execution Path

2.5.5.1 *Implementation Plan*

Phase 1 in 2015 includes a 3.6km line extension of the 22M25 feeder from Moodie Drive to Hope Side Road via West Hunt Club Road and Old Richmond Road. This includes the replacement of seventy-one (71) poles, six (6) transformers and installation of 120m of underground infrastructure to accommodate the 8.32kV circuit in order to meet the clearances required under the Hydro One 500kV tower line. This will be coordinated to align with the City's proposed road widening.

Phase 2 in 2016 includes a 2.1km line extension of the 22M25 and BRDF2 feeders from Hope Side Road to Fallowfield Road. This includes the replacement of seventy-two (72) poles and fifteen (15) transformers.

Phase 3 in 2017 includes a 4.7km line extension of the 22M25 and BRDF2 feeders from Old Richmond Road to Shea Road. This will include the replacement of seventy-five (75) poles, and eleven (11) transformers to accommodate the change in voltage.

2.5.5.2 *Risks to Completion and Risk Mitigation Strategies*

Risks that may affect this project are easement acquisition, existing location of trees, and bedrock. HOL takes many steps in the design phase of the project to minimize these risks by investigating them early on.

2.5.5.3 *Timing Factors*

Factors affecting the timing of this project include easement acquisition, City of Ottawa Municipal Consent, customer outage limitations and weather conditions. Other factors that may affect the timing of this project include on-going work with the City of Ottawa to establish the future road cross sections and roundabouts expected to be installed along West Hunt Club Road and Old Richmond Road in 2015/2016.

2.5.5.4 *Cost Factors*

Factors that may affect costs of the project include costs associated with digging through rock and delays due to weather conditions.

2.5.5.5 *Other Factors*

Not applicable.

2.5.6 Renewable Energy Generation (if applicable)

Not applicable.

2.5.7 Leave-To-Construct (if applicable)

Not applicable.

2.5.8 Project Details and Justification

Project Name:	92008531 – West 44kV Line Extension
Capital Cost:	$6.243M
O&M:	$0
Start Date:	2015 – Q3
In-Service Date:	2017 – Q4
Investment Category:	System Service
Main Driver:	Reliability
Secondary Driver(s):	Aging Infrastructure
Customer/Load Attachment	9500 Customers/33,000kVA

Project Scope

The West 44kV Line Extension project is to extend the 22M25 Nepean TS 44kV feeder a distance of 20km to tie into the A9M3 South March TS 44kV feeder. The A9M3 sub-transmission line supplies 4 substations and does not have an alternate tie outside of the South March TS substation. The conductor and insulators of the 47F6 Belles Corners DS 8.32kV feeder along West Hunt Club Road and the 145F3 Jockvale DS 8.32kV feeder along Old Richmond Road will be upgraded to allow for increased capacity and provide renewed infrastructure. Services in the village of Fallowfield along Old Richmond Road will be replaced and amalgamated where possible to improve street aesthetics. The BRDF2 Bridlewood MS 27.6kV feeder will be extended starting from the corner of Hope Side Road and Old Richmond Road along Old Richmond Road and then along Fallowfield Road to Shea Road.

Work Plan

Phase 1, to be complete in 2015, includes a 3.6km line extension of the 22M25 feeder by replacement of seventy-one (71) poles, six (6) transformers and installation of 120m of underground infrastructure to accommodate the 8.32kV circuit in order to meet the clearances required under the Hydro One 500kV tower line. Phase 2, to be completed in 2016, includes a 2.1km line extension of the 22M25 and BRDF2 feeders by replacement of seventy-two (72) poles and fifteen (15) transformers. Phase 3, to be completed in 2017, includes 4.7km line extension of the 22M25 and BRDF2 feeders by replacement of seventy-five (75) poles, and eleven (11) transformers to accommodate the change in voltage.

Customer Impact

By integrating 22M25 and A9M3 feeders with automated switches into the distribution system, it will improve the flexibility of the system and improve reliability. The average number of customer hours per interruption should diminish significantly. This project will also increase the available capacity in the Richmond, Stittsville and Kanata areas for the upcoming developments.

2.6 Springbrook Drive Trunk

2.6.1 Project/Program Summary

The Springbrook Drive Trunk project is intended to extend an underground trunk system along Springbrook Drive from Hazeldean Road to Abbott Street. The exiting trunk system that supplies this neighbourhood is located in areas inaccessible for the majority of the year and has not received adequate required maintenance and has resulted in a number of outages due to failed equipment, which was ranked in the top ten of worst performing feeders in 2014. The intent is to remove the existing pole line upon completion of the underground trunk system. Changes from the distribution layout are expected to improve operability through improved trunk ties and by isolation of three-phase customers from single-phase customers onto separate loop systems. The conclusion of the Springbrook Drive Trunk project will directly connect to 92010176 – Abbott Street Trunk project for the purposes of improved system operability.

2.6.2 Project/Program Description

2.6.2.1 *Current Issues*

Current issues in the Stittsville community include deteriorating reliability due to failure of aging infrastructure. The community supply design was not constructed with adequate means of a trunk system that would allow for transferability amongst feeders. The duration of outages (SAIDI) has been greatly impacted as a result. Distribution loops in this area contain single phase and three phase transformers, which have required single phase switching to be completed and has resulted in three phase transformer failures due to ferroresonce.

2.6.2.2 *Program/Project Scope*

The scope of this project is illustrated below, which is to extend one (1) 27.6kV circuit from to tie JKGF5 to JKGF4 and incorporate changes to the distribution layout to enhance operability. This includes extension through the use of a concrete duct system to encase trunk cables and through the use of two (2) switchgears, separate the three-phase customers, from single-phase customers, onto a dedicated three-phase loop. The trunk system will start at Hazeldean Road; continue south along Springbrook Drive and Moss Hill Trail to Abbott Street where the trunk will tie in with the Abbott Street Trunk project, which will be completed in 2016. As part of this project the old trunk system which is inaccessible for the majority of the year will be removed. This pole line contains seventeen (17) poles that will be removed upon completion of the underground system. Also being removed is a switchgear supplied off of the overhead system, which can be removed through minor cable work and single-phase transformer phase changes.

Phase 1, which will include all work and expenses to occur within 2016, includes 0.9km of concrete encased cable extensions from the intersection of Hazeldean Road and Springbrook Drive to approximately the intersection of Springbrook Drive and Earl Rock Way. The extent of Phase 1 is at the installation of the second switchgear and an isolated loop will be created between switchgears for the two (2) three-phase customers. Two (2) primary pedestals are located within the distribution along Springbrook Drive and their locations will be used to locate switchgears.

Phase 2, which will include all work and expenses to occur within 2017, includes 1.0km of concrete encased cable extension from the intersection of Springbrook Drive and Earl Rock Way to the intersection of Moss Hill Trail and Abbott Street. The concrete duct will commence at the location of the second switchgear from Phase 1 and extend to tie in on Abbott Street with the Abbott Street Trunk project. Approximately 730m of direct buried duct and cable will be required which will allow for the removal of 2 primary pedestals that do not provide adequate switching and protection capability and have also reached end of life condition. A change of phase for nine (9) transformers will enable the removal of a switchgear, which will no longer serve a purpose and contribute to saving in operating and maintenance costs. Seventeen (17) poles from the aging pole line will be removed upon completion of the underground trunk system.

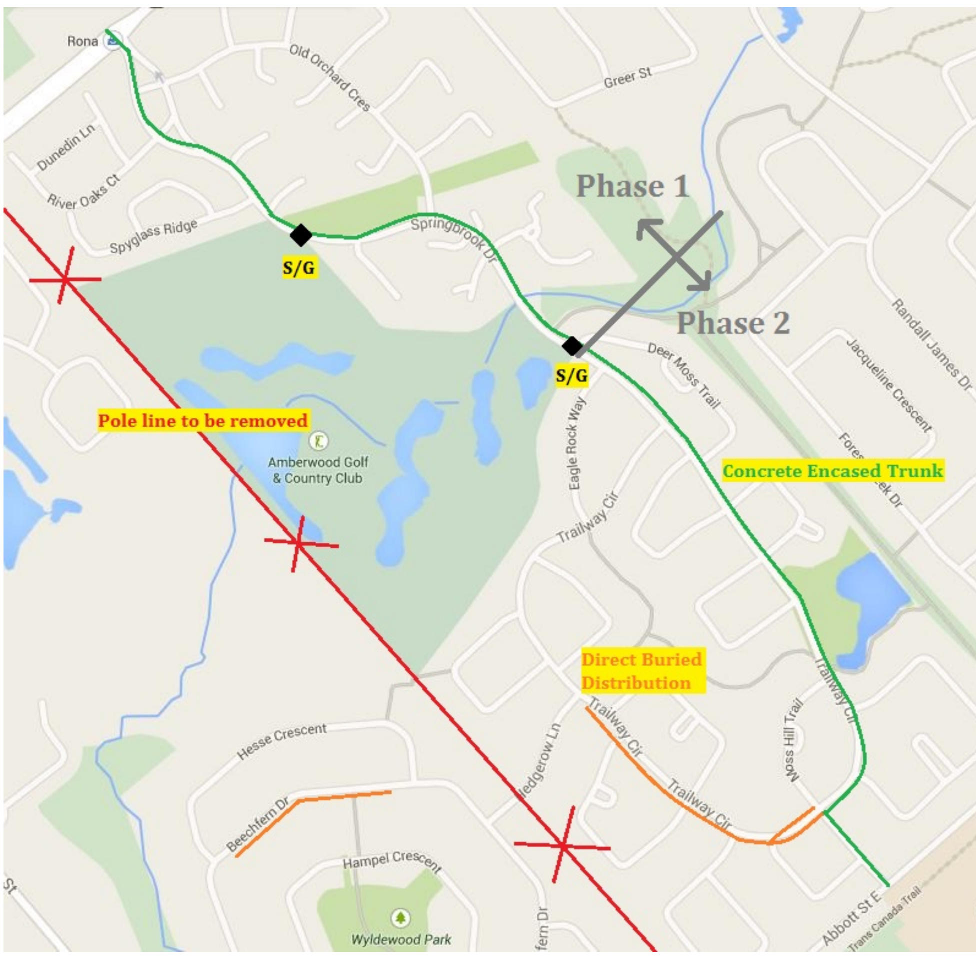


Figure 81 - Springbrook Drive Trunk Scope

2.6.2.3 *Main and Secondary Drivers*

The main driver of this project is the improvement of reliability in the Amberwood community. The ALXF3 which is the main supply system for this community is from an overhead pole line that is inaccessible for the majority of the year and has been accountable for a number of outages caused by defective equipment. The ALXF3 has been identified as one of the top ten worst performing feeders in 2014. Renewed infrastructure will directly improve SAIFI and automated switchgear will allow for monitoring and control that will directly reduce the impact on SAIDI.

The secondary driver of this project is the improvement of system operability by separating the three phase transformers from the single phase transformers. When required, isolation becomes simple and eliminates the possible impacts of ferroresonce.

2.6.2.4 *Performance Targets and Objectives*

The main objective of this project is to improve reliability in the Amberwood community. New infrastructure will directly improve SAIFI and automated switchgear will allow for monitoring and control that will directly reduce the impact on SAIDI.

A secondary objective is to remove an overhead pole line that supports the ALXF3 feeder which has proven to be historically unreliable.

2.6.3 Project/Program Justification

2.6.3.1 *Alternatives Evaluation*

2.6.3.1.1 Alternatives Considered

Reliability in the Amberwood community has been greatly impacted by the aging infrastructure of the existing pole line and the inaccessibility of the lines has contributed to deteriorating levels of SAIDI. New accessible infrastructure on the street boulevard is the most effective means of improving reliability.

Alternative #1: Routing considered is along Springbrook Drive. This route would extend the JKGF5 from Hazeldean Road to Abbott Street. This option is the most direct route to make feeder connection to improve reliability in the Amberwood community. New infrastructure will directly improve SAIFI and automated switchgear will allow for monitoring and control that will directly reduce the impact on SAIDI.

Alternative #2: Routing considered is along the existing pole line route. This route would replace the existing poles and infrastructure through the backyards and swamp from Hazeldean Road to Abbott Street. Renewed infrastructure would immediately improve SAIFI however due to the inaccessibility of the pole line throughout much of the year any outage would contribute greatly to increased SAIDI. Aging infrastructure and system operability would continue to be an issue.

2.6.3.1.2 Evaluation Criteria

Costs:

Alternative #1: $2.363M

Alternative #2: $1.360M

Ability to supply load:

Both alternatives will make it possible to continue to supply load, however system operability will be enhanced by Alternative #1.

Reliability Benefits:

Alternative #1: New infrastructure will directly improve SAIFI and automated switchgear will allow for monitoring and control that will directly reduce the impact on SAIDI.

Alternative #2: Renewed infrastructure would immediately improve SAIFI however due to inaccessibility of the pole line throughout much of the year any outage would contribute greatly to increased SAIDI.

2.6.3.1.3 Preferred Alternative

Alternative #1 is the preferred feeder route due to reliability benefits associated with this alternative. The costs associated with Alternative #2 are considerably cheaper however the reliability of the Amberwood community is the primary driver of this project and would be better served by Alternative #1.

2.6.3.2 *Project/Program Timing & Expenditure*

The total project cost is $2,363,000 and construction is anticipated to start in 2016 and conclude in 2017. HOL aims to minimize the costs and meet the deadlines associated with all projects, by completing pre-planning of the construction schedule and ensuring vehicles, staff and material are all available for start of construction.

Historical ($M)						Future ($M)			
2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
$0	$0	$0	$0	$0	$0	$0.99	$1.373	$0	$0

Table 86 - Project Expenditures

2.6.3.3 *Benefits*

Key benefits that will be achieved by implementing the Springbrook Drive Trunk project are summarized below.

Benefits	Description
System Operation Efficiency and Cost-effectiveness	This project is a necessary step to improve reliability in the Amberwood community. It is an essential system service project needed in order to improve system operation efficiency by constructing a trunk system with automated switchgear that will provide alternative sources when restoring outages. This should inevitably contribute to reducing SAIDI. Construction of the Springbrook Drive Trunk system is not the most cost-effective solution; however, it has the greatest benefit for improving the reliability in the Amberwood community.
Customer	This project will achieve reliability improvement for customers in the Amberwood community. The trunk extension and connection with 92010176 - Abbott Street Trunk created a four (4) feeder tie from Terry Fox MTS and Janet King DS which will directly help to improve the impact on SAIDI and renewed infrastructure that will ultimately improve SAIFI.
Safety	The infrastructure in place today has begun approaching end of life and poses a small risk of failure and safety concern. By removing the failing infrastructure, the safety risk is eliminated.
Cyber-Security, Privacy	Not Applicable.
Co-ordination, Interoperability	Not Applicable.
Economic Development	This project is not expected to contribute directly to economic growth or job creation, but due to the number of assets being replaced in this project, will inevitably require operation and maintenance. Contractor labour will be used

	extensively to complete the project.
Environment	Not Applicable.

Table 87 - Project Benefits

2.6.4 Prioritization

2.6.4.1 *Consequences of Deferral*

Deferring this project will result in further deterioration of infrastructure that currently supports the ALXF3 circuit. The reliability of this feeder can be expected to continue to degrade, which contributes highly to the total system reliability statistics due to the number of customers the ALXF3 circuit supplies.

2.6.4.2 *Priority*

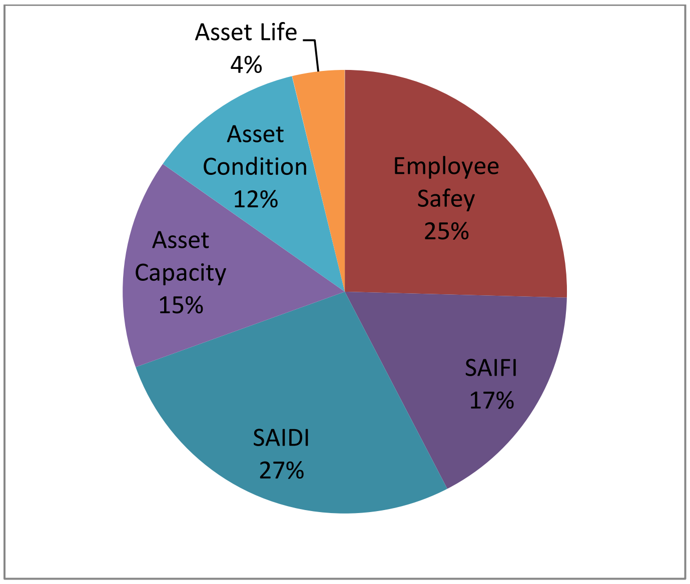


Figure 82 - Project Avoided Risk

Project Score: 0.997

2.6.5 Execution Path

2.6.5.1 *Implementation Plan*

Phase 1 in 2016 includes a 0.9km line extension of the JKGF5 feeder from Hazeldean Road to Earl Rock Way via Springbrook Drive. This includes 900m of concrete duct encased cable, two (2) new automated switchgears and removal of two (2) end of life condition primary pedestals.

Phase 2 in 2017 includes a 1.0km line extension of the JKGF5 feeder from Earl Rock Way to Abbott Street via Springbrook Drive and Moss Hill Trail. This includes 1000m of concrete encased cable, 730m of direct buried duct encased cable, changing the phase configuration of nine (9) transformers, removal of one (1) switchgear and removal of seventeen (17) poles that are at end of life condition.

2.6.5.2 *Risks to Completion and Risk Mitigation Strategies*

Risks that may affect this project are easement acquisition, existing location of trees, and bedrock. HOL takes many steps in the design phase of the project to minimize these risks by investigating them early on.

2.6.5.3 *Timing Factors*
Factors affecting the timing of this project include easement acquisition, City of Ottawa Municipal Consent, customer outage limitations and weather conditions.

2.6.5.4 *Cost Factors*
Factors that may affect costs of the project include costs associated with digging through rock and delays due to weather conditions.

2.6.5.5 *Other Factors*
Not applicable.

2.6.6 Renewable Energy Generation (if applicable)
Not applicable.

2.6.7 Leave-To-Construct (if applicable)
Not applicable.

2.6.8 Project Details and Justification

Project Name:	92010174 – Springbrook Drive Trunk
Capital Cost:	$2.363M
O&M:	$0
Start Date:	2016 – Q2
In-Service Date:	2017 – Q3
Investment Category:	System Service
Main Driver:	Reliability
Secondary Driver(s):	System Operability
Customer/Load Attachment	2779 Customers/11,187kVA

Project Scope

The Springbrook Drive Trunk project is intended to extend an underground trunk system along Springbrook Drive from Hazeldean Road to Abbott Street. The exiting trunk system that supplies this neighbourhood is located in areas inaccessible for the majority of the year and has not received adequate required maintenance and has resulted in a number of outages due to failed equipment, which was ranked in the top ten of worst performing feeders in 2014. The intent is to remove the existing pole line upon completion of the underground trunk system. Changes from the distribution layout are expected to improve operability through improved trunk ties and by isolation of three-phase customers from single-phase customers onto separate loop systems. The conclusion of the Springbrook Drive Trunk project will directly connect to 92010176 – Abbott Street Trunk project for the purposes of improved system operability.

Work Plan

Phase 1, to be completed in 2016, includes 0.9km of concrete encased cable extension, installation of two (2) automated switchgears and an isolated loop will be created between switchgears for the two (2) three-phase customers. Phase 2, to be completed in 2017, includes 1.0km of concrete encased cable extension, approximately 730m of direct buried duct and cable, removal of 2 primary pedestals, a change of phase for nine (9) transformers and removal of seventeen (17) poles and a switchgear upon completion of the underground trunk system.

Customer Impact

By integrating new infrastructure and automated switchgear into the distribution system in Stittsville, it will improve the flexibility of the system and improve reliability. The average number of customer hours per interruption should diminish significantly. This project will also increase the available capacity in the Stittsville area for the upcoming developments.

2.7 Abbott Street Trunk

2.7.1 Project/Program Summary

The Abbott Street Trunk project is intended to extend a part overhead and part underground trunk system along Abbott Street from Stittsville Main Street to Shea Road. This project will tie together four (4) projects that are targeted specifically to improve reliability in the Stittsville community. These four projects include:

- 92008567 – Stittsville Main Cable Replacement & S/G Upgrades,
- 92010174 – Springbrook Drive Trunk,
- 92008535 – GRC 44 to 27,
- 92010178 – Granite Ridge Trunk

Through the completion of the Abbott Street Trunk and tying of these four (4) projects, the Stittsville community will have a mesh network trunk system that will reduce the number of customers between protective devices (SAIFI) and provide improved system operability that will allow for a reduction to the duration of outages (SAIDI). This will strengthen ties between Janet King DS and Terry Fox MTS which includes connections amongst four (4) feeders: JKGF4, JKGF5, TFXF1 and TFXF5.

2.7.2 Project/Program Description

2.7.2.1 *Current Issues*

Current issues in the Stittsville community include deteriorating reliability due to failure of aging infrastructure. The community supply design was not constructed with adequate means of a trunk system that would allow for transferability amongst feeders. The duration of outages (SAIDI) has been greatly impacted as a result.

2.7.2.2 *Program/Project Scope*

The scope of this project is illustrated below in Figure 83, which is to extend one (1) 27.6kV circuit from to tie Stittsville Main Street to Shea Road which will tie together four (4) feeders JKGF4, JKGF5, TFXF1 and TFXF5. This includes extension through use of existing 8.32kV routing by replacing nine (9) poles and two (2) transformers while converting the voltage to 27.6kV and installing six (6) new poles along Abbott Street. Further extension through a concrete duct system to encase 660m of trunk cable and through the use of two (2) automated switchgears will allow for ties to be made to Springbrook Drive Trunk, GRC 44 to 27 and Granite Ridge Trunk.

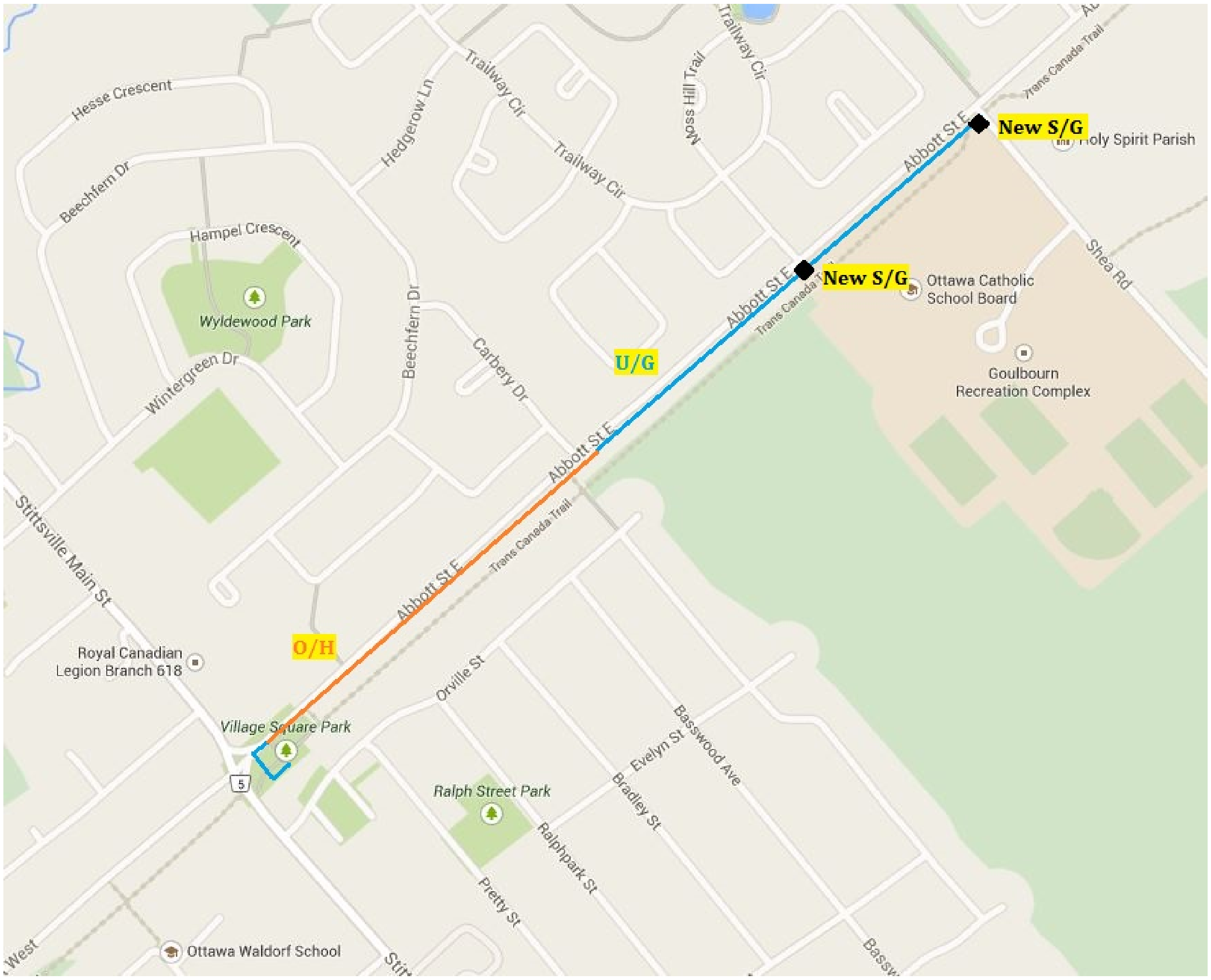


Figure 83 - Abbott Street Trunk Scope

2.7.2.3 *Main and Secondary Drivers*

The main driver of this project is to improve reliability in the Stittsville community. Through various trunk extension projects and tying them all together via the Abbott Street Trunk project, extensive trunk ties will be created between four (4) feeders from Janet King DS and Terry Fox. Renewed infrastructure will directly improve SAIFI and automated switchgears will allow for monitoring and control that will directly reduce the impact on SAIDI.

2.7.2.4 *Performance Targets and Objectives*

The main objective of this project is to improve reliability in the Stittsville community. New infrastructure will directly improve SAIFI and automated switchgear will allow for monitoring and control that will directly reduce the impact on SAIDI.

2.7.3 Project/Program Justification

2.7.3.1 *Alternatives Evaluation*

2.7.3.1.1 Alternatives Considered

Reliability in the Stittsville community has been greatly impacted by the aging infrastructure. On-going trunk upgrades have been initiated to improve the service the customers have historically experienced.

Alternative #1: Routing considered is along Abbott Street. This route would extend the JKGF4 feeder from Stittsville Main Street to Shea Road. This option is the most direct route to make a feeder connection to improve reliability in the Stittsville community. New infrastructure will directly improve SAIFI and automated switchgear will allow for monitoring and control that will allow for fast transferability amongst four (4) feeders which directly reduces the impact on SAIDI.

Alternative #2: This alternative is to not proceed with the project. By not proceeding with this project there are no costs however reliability will be greatly impacted by leaving Stittsville Main Cable Replacement & S/G Upgrades, Springbrook Drive Trunk, GRC 44 to 27, and Granite Ridge Trunk as radially complete projects with no interconnection ties.

2.7.3.1.2 Evaluation Criteria

Costs:
Alternative #1: $1.023M

Alternative #2: $0.00

Ability to supply load:
The area surrounding Abbott Street has been fully developed and has adequate means of supplying the existing load.

Reliability Benefits:
Alternative #1: Tying together Stittsville Main Cable Replacement & S/G Upgrades, Springbrook Drive Trunk, GRC 44 to 27, and Granite Ridge Trunk projects will directly improve SAIFI. Automated switchgear will allow for monitoring and control that will allow for fast transferability amongst four (4) feeders directly reducing the impact on SAIDI.

Alternative #2: This alternative has no reliability benefits.

2.7.3.1.3 Preferred Alternative

Alternative #1 is the preferred feeder route due to reliability benefits associated with this alternative. The costs associated with Alternative #2 are considerably less costly; however, the reliability of the Stittsville community is the primary driver of this project and would be better served by Alternative #1.

2.7.3.2 *Project/Program Timing & Expenditure*

The total project cost is $1,023,000 and it is anticipated to be completed in 2016. HOL aims to minimize the costs and meet the deadlines associated with all projects, by completing pre-planning of the construction schedule and ensuring vehicles, staff and material are all available for start of construction.

Historical ($M)						Future ($M)			
2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
$0	$0	$0	$0	$0	$0	$1.023	$0	$0	$0

Table 88 - Project Expenditures

2.7.3.3 *Benefits*

Key benefits that will be achieved by implementing the Abbott Street Trunk project are summarized below.

Benefits	Description
System Operation Efficiency and Cost-effectiveness	This project is required to improve reliability in the Stittsville community. It is an essential system service project needed in order to improve system operation efficiency by interconnecting the new Terry Fox TS to the distribution system in Stittsville and provide an alternative source when restoring outages. This should inevitably contribute to reducing SAIDI. Construction of the Abbott Street Trunk system is not the most cost-effective solution; however, it has the greatest benefit for improving the reliability in the Stittsville community.
Customer	This project will achieve reliability improvements for customers in the Stittsville community. The trunk extension and tying together of four (4) feeders from Terry Fox MTS and Janet King DS will directly help to improve the impact on SAIDI and renewed infrastructure that will ultimately improve SAIFI.
Safety	The infrastructure in place today has begun approaching end of life and poses a small risk of failure and safety concern. By replacing the infrastructure, the safety risk is significantly reduced.
Cyber-Security, Privacy	Not Applicable.
Co-ordination, Interoperability	Not Applicable.
Economic Development	This project is not expected to contribute directly to economic growth or job creation, but due to the number of assets being replaced in this project, will inevitably require operation and maintenance. Contractor labour will be used extensively to complete the project.
Environment	Not Applicable.

Table 89 - Project Benefits

2.7.4 Prioritization

2.7.4.1 *Consequences of Deferral*

The consequence of deferring this project is the further deterioration of infrastructure that currently supplies the Stittsville community. Reliability for this area can be expected to continue to deteriorate, which contributes highly to the total system reliability statistics due to the number of customers in the community.

2.7.4.2 *Priority*

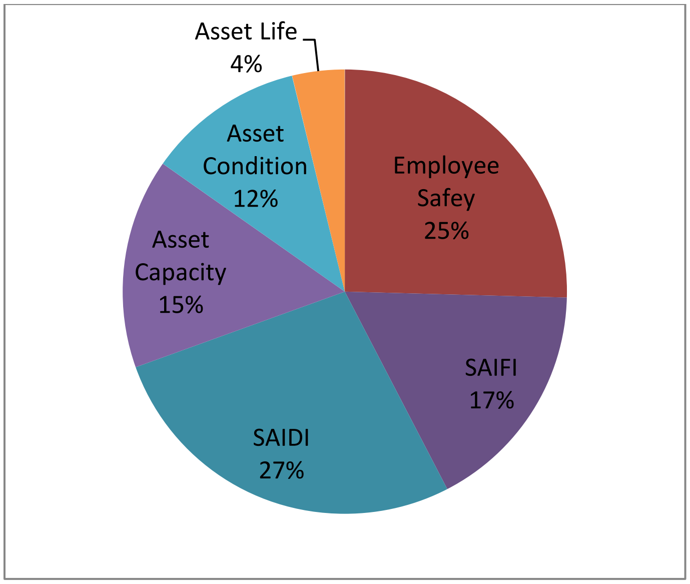


Figure 84 - Project Avoided Risk

Project Score: 0.787

2.7.5 Execution Path

2.7.5.1 *Implementation Plan*

This project is to be entirely completed in 2016 and includes the extension of the JKGF4 from Stittsville Main Street to Shea Road which will tie together four (4) feeders JKGF4, JKGF5, TFXF1 and TFXF5. This includes extension through use of existing 8.32kV routing by replacing nine (9) poles and two (2) transformers while converting the voltage to 27.6kV and installing six (6) new poles along Abbott Street. Further extension through a concrete duct system to encase 660m of trunk cable and through the use of two (2) automated switchgears will allow for ties to be made to Springbrook Drive Trunk, GRC 44 to 27 and Granite Ridge Trunk.

2.7.5.2 *Risks to Completion and Risk Mitigation Strategies*

Risks that may affect this project are easement acquisition, existing location of trees, and bedrock. HOL takes many steps in the design phase of the project to minimize these risks by investigating them early on.

2.7.5.3 *Timing Factors*

Factors affecting the timing of this project include easement acquisition, City of Ottawa Municipal Consent, customer outage limitations and weather conditions.

2.7.5.4 *Cost Factors*

Factors that may affect costs of the project include costs associated with digging through rock and delays due to weather conditions.

2.7.5.5 *Other Factors*

Not applicable.

2.7.6 Renewable Energy Generation (if applicable)

Not applicable.

2.7.7 Leave-To-Construct (if applicable)

Not applicable.

2.7.8 Project Details and Justification

Project Name:	92010176 – Abbot Street Trunk
Capital Cost:	$1.023M
O&M:	$0
Start Date:	2016 – Q2
In-Service Date:	2016 – Q3
Investment Category:	System Service
Main Driver:	Reliability
Secondary Driver(s):	N/A
Customer/Load Attachment	4903 Customers/21,321kVA

Project Scope

The Abbott Street Trunk project is intended to extend part overhead and part underground trunk system along Abbott Street from Stittsville Main Street to Shea Road. This project will tie together four (4) projects that are targeted specifically to improve reliability in the Stittsville community. These four projects include:

- 92008567 – Stittsville Main Cable Replacement & S/G Upgrades,
- 92010174 – Springbrook Drive Trunk,
- 92008535 – GRC 44 to 27,
- 92010178 – Granite Ridge Trunk

Through the completion of Abbott Street Trunk and tying of these four (4) projects, the Stittsville community will have a mesh network trunk system that will reduces the number of customers between protective devices (SAIFI) and provides improved system operability that will allow for reduced duration of outages (SAIDI). This will strengthen ties between Janet King DS and Terry Fox MTS which includes connections amongst four (4) feeders: JKGF4, JKGF5, TFXF1 and TFXF5.

Work Plan

The scope of this project, to be completed entirely in 2016, is to extend one (1) 27.6kV circuit from to tie Stittsville Main Street to Shea Road which will tie together four (4) feeders JKGF4, JKGF5, TFXF1 and TFXF5. This includes extension through use of existing 8.32kV routing by replacing nine (9) poles, two (2) transformers while converting the voltage to 27.6kV and installing six (6) new poles along Abbott Street. Further extension through concrete duct system to encase 660m of trunk cable and through the use of two (2) automated switchgears, will allow for ties to be made to Springbrook Drive Trunk, GRC 44 to 27 and Granite Ridge Trunk.

Customer Impact

By integrating Terry Fox MTS feeders and automated switchgear into the distribution system in Stittsville, it will improve the flexibility of the system and improve reliability. The average number of customer hours per interruption should diminish significantly. This project will also increase the available capacity in the Stittsville area for the upcoming developments.

3 System Voltage Conversion

3.1 Woodroffe UW Voltage Conversion

3.1.1 Project/Program Summary

HOL's 4.16kV substations are experiencing a decrease in demand as larger developments convert existing 4.16kV supplies to a 13.2kV supply. This decreases the financial usefulness of the 4.16kV substation. Coupled with the need to replace infrastructure and equipment, a voltage conversion project has the potential to make economic sense. The Woodroffe UW voltage conversion is a prime example of this. The Woodroffe UW 4.16kV substation's structures and equipment were identified as nearing end of life and due for replacement. The option of maintaining the 4.16kV system and replacing the necessary equipment was compared to the option of upgrading the area's distribution system to be operated at 13.2kV and supplied by Woodroffe TW located at the same address. Based on a financial evaluation completed in 2011 it was recommended to pursue the latter option. Physical construction for this project started in 2013 and is on schedule to be complete in 2015.

3.1.2 Project/Program Description

3.1.2.1 *Current Issues*

Currently much of the residential and small commercial loads North of Baseline Road from Clyde Avenue to Pinecrest Park are supplied by the 4.16kV system from the Woodroffe UW susbstation. The switchgear and transformers are approaching their end of life and a solution is required. In addition the neighbourhood was constructed circa 1957 and most of the poles and distribution equipment are nearing their end of life.

3.1.2.2 *Program/Project Scope*

The voltage conversion requires the replacement and upgrade of existing equipment in order to be operated at the increased voltage. In addition, equipment is upgraded to meet current HOL standards that may have been developed after their original installation. In total, by the projects closing 9 4.16kV circuits will be replaced by 3 13.2kV circuits, over 600 poles will have been replaced or upgraded, and over 200 transformers will have been replaced. Most of the work needed for the conversion (pole, transformer, conductor, and insulator upgrades) is able to be done while the load remains supplied by the 4.16kV system through communicated outages. However, due to the change in voltages, transformer protection and settings will need to be updated once the supply is connected to the 13.2kV system.

Neither the decommissioning of the Woodroffe UW switchgear and transformers nor the replacement of the Woodroffe TW switchgear is in scope for this project.

3.1.2.3 *Main and Secondary Drivers*

The main driver for this project is the anticipated end of life of the Woodroffe UW switchgear (~2016) and the near term end of life of the 13.2kV/4.16kV station transformers (2021-2026). A secondary driver for this project is that various distribution assets are also nearing their end of life. These include poles and the Woodroffe TW switchgear. In order to complete the necessary stations work the 4.16kV system equipment must be retrofitted in order to be able to accommodate the 13.2kV supply.

3.1.2.4 *Performance Targets and Objectives*

The main objective of this project is to identify and pursue the most cost-effective option to remedy the end of life assets associated with the 4.16kV system at Woodroffe UW substation. This is accomplished by taking a detailed look at potential alternatives and developing a cost estimate.

This project also has the potential to complete work that would be scheduled as separate projects at a future date. This includes pole replacement and replacement of the porcelain box switches on the Woodroffe UW system. The replacement of these assets will improve the reliability to the customers in this area.

3.1.3 Project/Program Justification

3.1.3.1 *Alternatives Evaluation*

3.1.3.1.1 Alternatives Considered

There were two options evaluated in order to deal with the main drivers:

1) Asset replacement: This scenario would involve replacing the Woodroffe UW 4.16kV switchgear and transformers as they approached their end of life. It would also encompass the replacement of all distribution equipment and structures when required. All of these assets would be due for replacement by 2026.
2) Voltage conversion: This scenario involves the conversion of the existing 4.16kV supply from Woodroffe UW substation to the 13.2kV supply from Woodroffe TW. This requires the replacement and upgrade of existing equipment in order to be operated at the increased voltage. In addition, equipment will be upgraded to meet current HOL standards that may have been developed after their original installation. In total, by the project’s closing over 600 poles and over 200 transformers will have been upgraded or replaced.

3.1.3.1.2 Evaluation Criteria

The main evaluation criteria used to assess the alternatives was cost which can be seen below in Table 90. These costs represent initial estimates for the project and were completed in 2011. Either option presented adequate solutions to the ageing infrastructure which is why cost is the core evaluation metric. In addition, future costs and man hours associated with maintaining the equipment were considered.

Additionally, reliability was evaluated between having the equipment upgraded today as opposed to being replaced at their respective end of life.

Revenue Requirements	Alternative 1 - Asset Replacement	Alternative 2 - Voltage Conversion
Annual Operation Expenses	$401,403	$0.00
Net Income	$3,222,849	$1,960,926
Debt Interest Recovery	$2,937,418	$1,787,257
Depreciation Expense	$2,968,750	$1,866,798
Income Tax	$2,431,272	$1,479,295
Net Present Value of Revenue Requirements	**$11,961,692**	**$7,094,275**

Table 90 - Alternatives Cost Analysis

3.1.3.1.3 Preferred Alternative

Based on the cost estimates developed in 2011 the preferred alternative to overcome the main driver is Alternative 2 which is the conversion of the 4.16kV system to 13.2kV. This alternative was chosen due to the estimate being $4.9M less than the cost to replace all of the aging equipment and infrastructure. The decommissioning of the 4.16kV switchgear also eliminates the need for equipment maintenance. This results in a savings of both future costs and resources.

Additionally, the voltage conversion will implement new equipment in the very near term. This will provide increased reliability to the customers served previously by the Woodroffe UW substation. Alternative 1 would have seen the assets replaced as they met their end of life. Therefore there is a greater chance of that option seeing reduced reliability by comparison.

3.1.3.2 *Project/Program Timing & Expenditure*

Due to the amount of scope associated with this project work is carried out year round. The project was broken up into three phases and it is crucial that each phase is done on time because of the switchgear replacement project that is planned for 2016. The actual and anticipated costs associated with this project are shown in the table below.

HOL attempts to reduce project costs by tendering out all work that is unable to be done in house due to the type of work and resource constraints. HOL also tenders the equipment and infrastructure that will be installed. Furthermore, with respect to this project, commercial services have been transitioned from vault transformers to padmounted transformers. This reduces the amount of transformers on the system and eliminates maintenance and replacement costs in the future. Also due to the increased capacity of 13.2kV circuits compared to 4.16kV circuits, single phase feeders can support areas that used to be fed by three phases. This reduces equipment costs by decreasing the number of circuits and material needed.

As explained in section 5.4 below, unexpected rock that was discovered when drilling pole holes caused an increase in work time. However, this project has a specific deadline it is required to meet due to the switchgear replacement project slated for 2016. In order to stay on schedule more resources were deployed which elevated the price of the project.

Historical ($M)					Future ($M)				
2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
	0.038	4.384	6.081	5.368					

Table 91 - Project Expenditures

3.1.3.3 *Benefits*

Benefits	Description
System Operation Efficiency and Cost-effectiveness	The decommissioning of the Woodroffe UW substation will make operation measures simpler. This is because there are fewer devices that need to be coordinated during any switching operation or outages.
Customer	The main benefit to customers that were specifically fed by the Woodroffe UW substation is an increase in reliability. Many assets that were replaced as a result of this project were nearing their end of life. The new equipment that has been installed has a higher reliability compared to the older equipment. Additionally, HOL chose the cheapest option known at the time in order to pass the least cost on to the ratepayers. The additional costs that came through unpredicted ground conditions are likely to have been incurred if the other alternative was chosen. Therefore, there are still overall cost savings with this project.
Safety	As a result of the conversion project, many assets that were approaching end of life in the near term were replaced. These assets have a lower likelihood of failing. This results in a safer and higher performing system.
Cyber-Security, Privacy	N/A
Co-ordination, Interoperability	Coordination with telecommunication companies was essential in this project as they had plant on the poles that were being replaced. Bell Canada also owned 30% of the poles that were being replaced or worked on. Early communication with the telecommunication companies has led to an easier execution of the project.
Economic Development	N/A
Environment	An outcome from converting the 4.16kV system to 13.2kV is the reduction in the number and size of transformers. This is because more power can be supplied from the increased voltage. Due to the reduced number of transformers, it is less likely that there will be an oil leak. Also due to the reduction in size of the transformers there is a lower volume of oil at risk.

Table 92 - Project Benefits

3.1.4 Prioritization

3.1.4.1 *Consequences of Deferral*

This project needs to be completed in order to prepare for a subsequent project, which will initially see the 4.16kV switchgear decommissioned and the 13.2kV switchgear replaced. Any delay in completing the voltage conversion will carry over to the project of replacing the switchgear. This will lead to increased costs due to resource rescheduling. It will also carry the risk of the switchgear failing due to its end of life state.

3.1.4.2 *Priority*

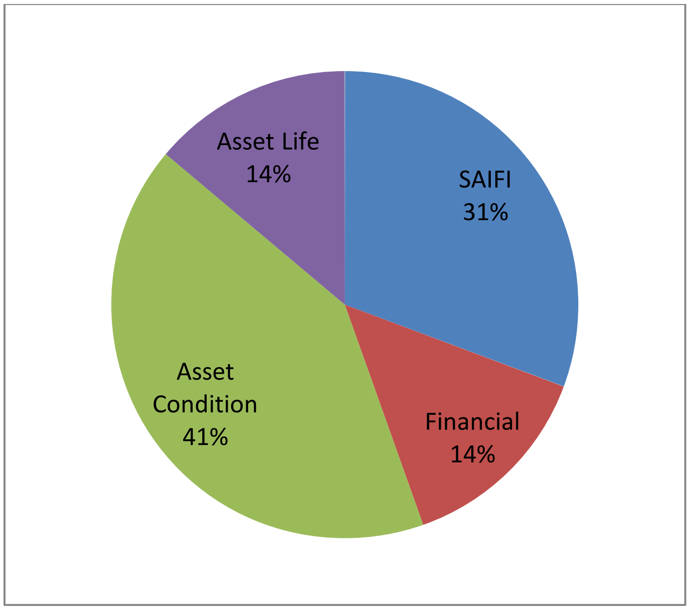


Figure 85 - Project Avoided Risk

Score = 0.343

3.1.5 Execution Path

3.1.5.1 *Implementation Plan*

Due to the size of this project, the implementation plan spans three years. Each year three 4.16kV circuits are converted into one 13.2kV circuit. This is further broken down into approximately 16 phases which group together numerous streets. This allows work to be done in a planned and methodical fashion. To take advantage of work efficiencies and cost benefits, all pole equipment was replaced or upgraded at the same time the pole was replaced. This includes the installation of pole mount transformers, insulators, fused switches, etc.

The first phase involves the transition of the 4.16kV circuits UW04, UW13, and UW14. These circuits supply the area West of Woodroffe Avenue. The second phase involves the transition of the 4.16kV circuits UW03, UW05, and UW07. Finally, the third phase involves the transition of the 4.16kV circuits UW01, UW02, and UW06. These circuits supply the area East of Agincourt Road and West of Maitland Avenue. In total more than 600 poles and 200 transformers were replaced/ installed.

Currently HOL is implementing projects to replace porcelain switches due to their historical failures. These have the potential to cause either pole fires, which are dangerous and expensive, or interrupting customers. The Woodroffe UW system had 42 switches which are being replaced as part of the voltage conversion project.

3.1.5.2 *Risks to Completion and Risk Mitigation Strategies*

This project is nearing the completion of its second phase. The third and final phase will be completed in 2015. There are currently no foreseeable risks that will jeopardize this project. There are, however, risks that could affect this projects timeline and cost. These are further explained in the sections below.

3.1.5.3 *Timing Factors*

There are several factors that have been identified as having the potential to delay this project. Firstly, around 30% of the poles being replaced or worked on are owned by Bell Canada. Therefore a joint collaboration is required for timely completion of pole work. Telecommunication plant needs to be transferred to new poles so that the former poles can be removed. This can greatly delay the process. HOL has mitigated this measure by involving Bell Canada early on in discussions about the work that is involved.

Secondly, due to the amount of work involved with this project there is the risk of being limited by resources. HOL has mitigated this risk by tendering out work to K-Line who is an approved contractor. K-Line offers a sizeable crew and equipment that will minimize the risk of delay due to a lack of resources.

Finally, in phase two and expected in phase three there has been a larger than expected amount of rock in the ground. This affects the installations of poles due to the hole needing to be drilled. HOL has mitigated the delay this might have on timing by allowing the contractor to employ more resources into the work. This mitigation step was taken due to the timing of the switchgear replacement project.

3.1.5.4 *Cost Factors*

As mentioned above, in phase two and expected in phase three there has been a larger than expected amount of rock in the ground. In order to stay within the time frame of this project HOL has requested the contractor to spend more resources which will increase costs to the project.

Also, during this project, ageing equipment was replaced that may not have fallen into the original scope. This was due to the cost efficiency of having crews, equipment, and vehicles working in the area. Although these assets may not have been at their end of life, it was deemed that they were old enough to justify replacement in parallel with the voltage conversion project.

3.1.6 Renewable Energy Generation

N/A

3.1.7 Leave-To-Construct

N/A

3.1.8 Project Details and Justification

Project Name:	Woodroffe UW Voltage Conversion
Capital Cost:	$15.835M
O&M:	N/A
Start Date:	Q4 2012
In-Service Date:	Q4 2015
Investment Category:	System Service
Main Driver:	Woodroffe UW switchgear and transformers approaching end of life
Secondary Driver(s):	Increased reliability by replacing old distribution equipment and poles
Customer/Load Attachment	1500 customers/ 4.5MVA of load
Project Scope	
The Woodroffe UW 4.16kV substation's structures and equipment were identified as nearing end of life and due for replacement. It was estimated that a more cost-effective solution would be to convert the 4.16kV loads to 13.2kV. The voltage conversion requires the replacement and upgrade of existing equipment in order to be operated at the increased voltage. In addition, equipment is upgraded to meet current HOL standards that may have been developed after their original installation. In total, by the projects closing 9 4.16kV circuits will be replaced by 3 13.2kV circuits, over 600 poles will have been replaced or upgraded, and over 200 transformers will have been replaced.	
Work Plan	
The three year project is broken into three phases. Each phase involves three 4.16kV circuits which are converted into one 13.2kV circuit. This is further broken down into approximately 16 phases which group together streets by proximity. This allows work to be done in a planned and methodical fashion. To take advantage of work efficiencies and cost benefits, all pole equipment was replaced or upgraded at the same time the pole was replaced. This includes the installation of pole mount transformers, insulators, fused switches, etc.	
Customer Impact	
The main benefit to the ~1500 customers that were specifically fed by the Woodroffe UW substation is an increase in reliability. Many assets that were replaced as a result of this project were nearing their end of life. The new equipment that has been installed has a higher reliability compared to the older equipment. Additionally, HOL chose the cheapest option known at the time in order to pass the least cost on to the ratepayers. The additional costs that came through unpredicted ground conditions are likely to have been incurred if the other alternative was chosen. Therefore, there are still overall cost savings to the rate payer with this project.	

3.2 Prince of Wales Voltage Conversion

3.2.1 Project/Program Summary

This project is a line upgrade along Prince of Wales Drive in the preparation of a future voltage conversion from 8.32kV to 27.6kV. This project will address the upcoming load growth while improving system reliability. 70 customers will be affected on the 8.32kV FAL03 circuit from Fallowfield DS along Prince of Wales Drive, between Woodroffe Avenue and Barnsdale Road. The project will upgrade the existing 8.32kV overhead line with new poles, conductors and transformers which will be rated for 27.6kV. No voltage conversion will take place yet. A second 27.6kV-carrying circuit will be extended along Prince of Wales Drive. Although independent from each other, this project is being done for the same purpose as the Rideau Valley Voltage Conversion (92008686), to prepare the area for the increased capacity that will accompany the New South 27.6kV Substation (92008537).

3.2.2 Project/Program Description

3.2.2.1 *Current Issues*

The south region of Ottawa is expected to develop and expand rapidly over the next few years. It is estimated that HOL's current distribution system will not be fully capable of supporting the load growth. Expansion based on city plans in the South Nepean area is shown below.

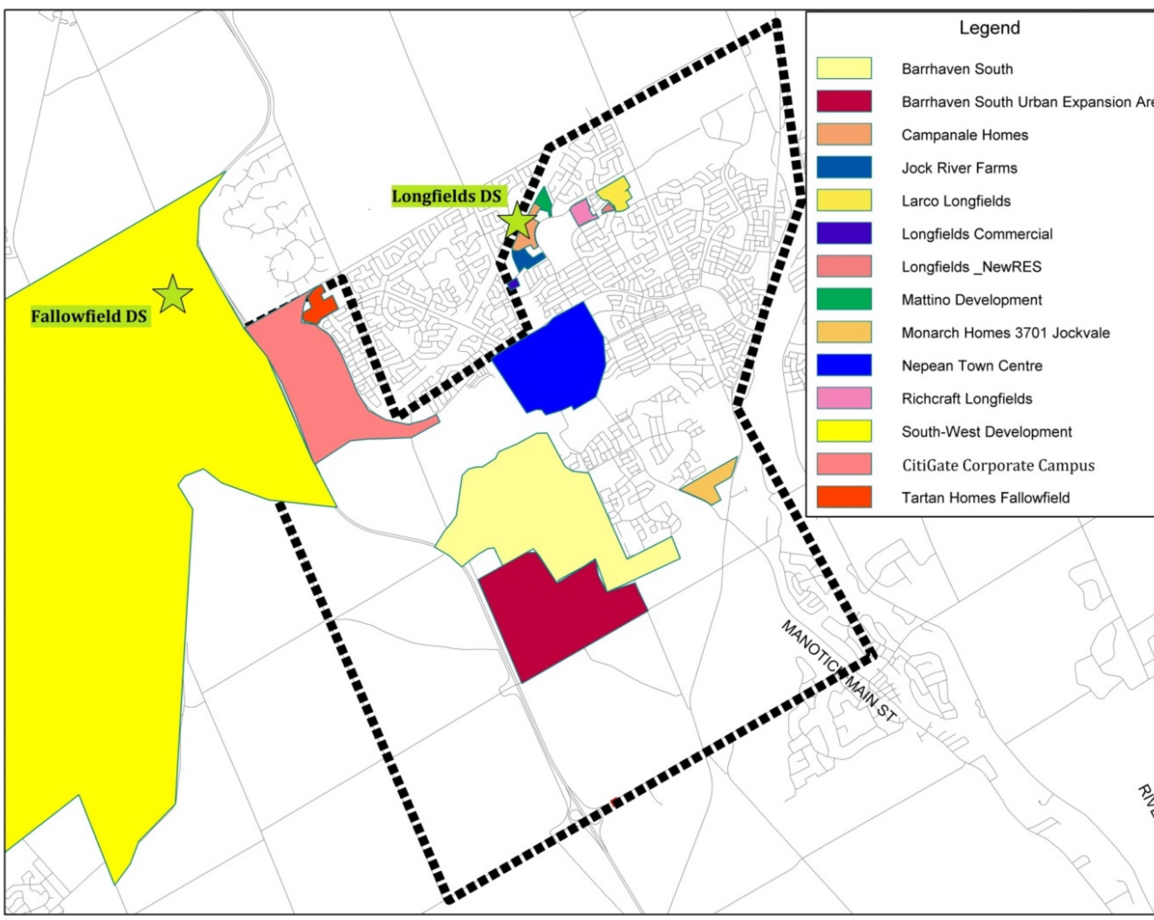


Figure 86 – Proposed Developments

In order to meet demand, the distribution system must be upgraded to a higher voltage. Although some portions of the south are supplied by a 27.6kV system, many areas still only have an 8.32kV supply. The overall goal is to convert the entire south area to a 27.6kV voltage supply, to support upcoming development while maintaining a reliable system.

In order to achieve the overall goal, a new 27.6kV distribution station with 6-8 feeders will be constructed to provide additional capacity to the area, as described in the business case for the New South 27.6kV Substation (92008537) project. The new station feeders will create ties with existing feeders, which will be upgraded in voltage rating. Converting the majority of the supply in the area to 27.6kV will enable backup connections between stations and feeders. Hence, reliability will be improved while anticipated capacity issues are resolved. Other major projects that have contributed or will contribute to the overall goal for the area include: Richmond South DS voltage conversion to 27.6kV, Limebank MS transformer upgrade, Fallowfield DS capacity upgrade and the transformer protection and base replacement at Longfields DS.

It can be seen in the above figures that there is proposed development on the east side of Highway 416, which is currently supplied by 8.32kV feeders. There are multiple projects taking place in the short term to prepare this section for a voltage upgrade. This includes both the Prince of Wales Voltage Conversion and the Rideau Valley Voltage Conversion projects. Another project is planned for 2016, to extend the voltage conversion preparation from where the Prince of Wales Voltage Conversion project left off. This 2016 project will bring two circuits further south along Prince of Wales Drive and then north on Greenbank Road.

The purpose of the Prince of Wales Voltage Conversion project is to prepare Prince of Wales Drive for a 27.6kV voltage conversion of the existing line, while a second 27.6kV line is extended from Woodroffe Avenue to Barnsdale Road. Although the current 8.32kV line is being upgraded to 27.6kV-rated equipment, no voltage conversion will take place within the scope of this project. After construction, Prince of Wales Drive will have a single pole line carrying two circuits – one carrying 27.6kV and the other rated for 27.6kV, but carrying 8.32kV. This project will begin construction in March 2015, following the work for the Rideau Valley Voltage Conversion, and is expected to be completed before the end of 2015.

3.2.2.2 *Program/Project Scope*

This project involves the replacement of 72 poles which are currently in poor condition. New poles, conductors, 16/4.8kV dual rated overhead transformers and all related equipment will be installed to carry two 27.6kV rated circuits. Further, customer-owned insulators will be replaced on existing customer-owned poles. Secondary services will be transferred and the existing pole line, transformers and associated hardware will be removed. Tree trimming and the transfer of communication lines is also included. As an addition to the original project scope, step-down transformers will be installed at the radial supply to Nicolls Island.

At the intersection of Woodroffe Avenue and Prince of Wales Drive, there currently exist two circuits at different voltages – an 8.32kV and a 27.6kV 7F2 circuit from Limebank MS. Only the 8.32kV circuit currently continues south along Prince of Wales Drive. This project will upgrade the existing 8.32kV circuit to be rated for 27.6kV, but the voltage will remain at 8.32kV until conversion is needed. This project will also extend the 27.6kV circuit from Woodroffe Avenue to Barnsdale Road. The plan is illustrated on the following map.

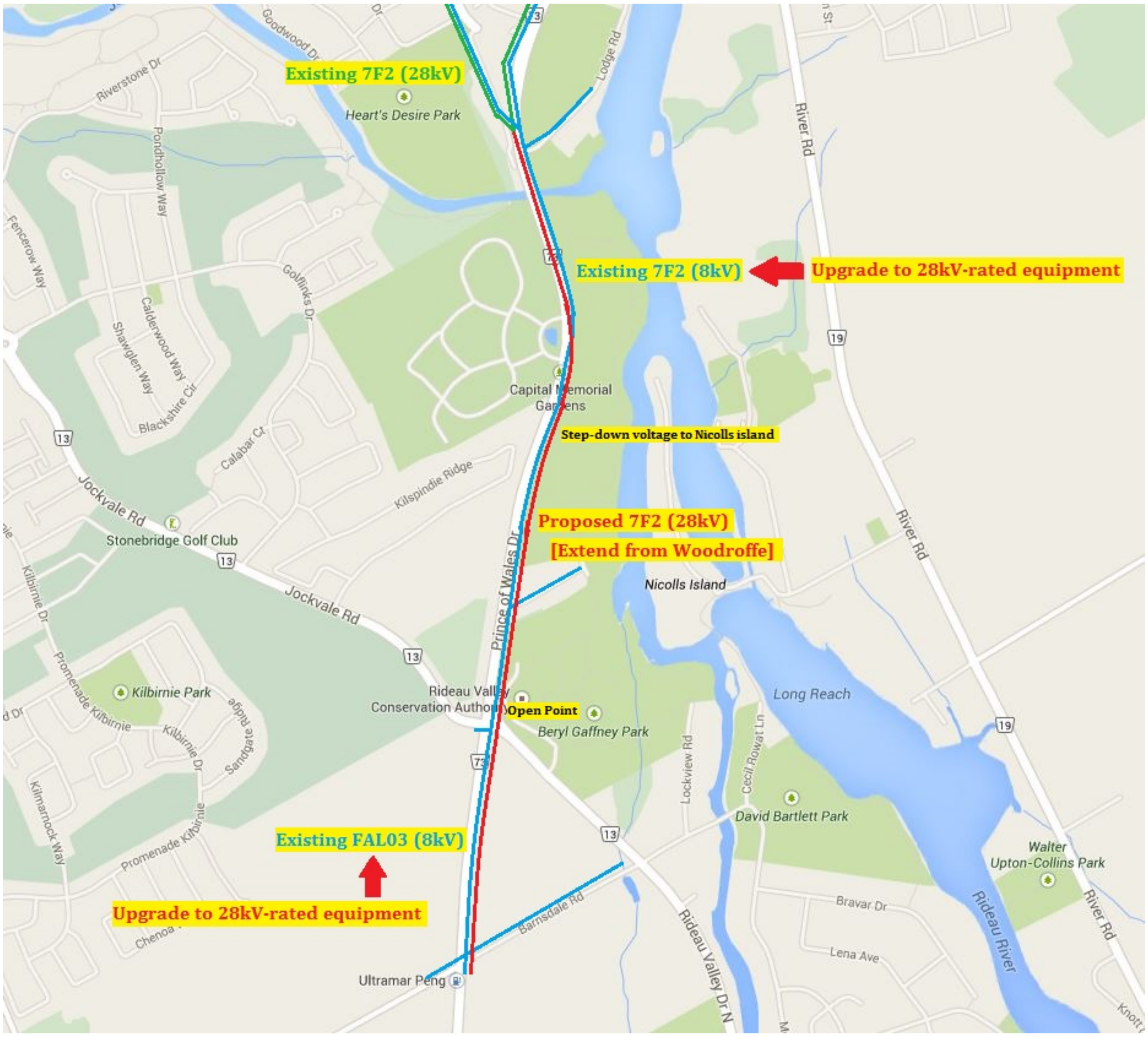


Figure 87 - Proposed Conversion Plan

It is important to note that no voltage conversion will take place within the scope of this project, only the preparation for it because of capacity restrictions at the stations. The upgraded existing line will have capacity for 27.6kV but will remain at 8.32kV for now, until more capacity becomes available. The 27.6kV line will be extended to Barnsdale Road and will continue to carry a voltage of 27.6kV.

3.2.2.3 *Main and Secondary Drivers*

The main driver of this project is the upcoming load growth in the area. It is expected that the area's capacity limitations will be reached within the next five years. The 8.32kV circuits in the south of

Barrhaven are being prepared for a conversion to 27.6kV, which will be needed to satisfy the demand. As a secondary driver for this project, reliability will be improved with the replacement of aging assets. The poles along Prince of Wales Drive are in bad condition and the installation of new poles and related equipment will decrease the likelihood of failure. Additionally, when the New South 27.6kV Substation is complete, the two circuits along Prince of Wales Drive will be prepared to accept ties with the new substation feeders, thus improving reliability by creating backup loops to decrease restoration time in the event of an outage.

With the additional station capacity underway at Limebank MS, two circuits from this station are planned to be dedicated to supplying the south region. It is expected that this additional capacity will be available by 2016, therefore it is worth preparing Prince of Wales Drive for this upgrade. Furthermore, there is an asset replacement project planned for 2016 in which the two circuits on Prince of Wales Drive will extend further south along the same road, then north on Greenbank Road.

This will enable the new developments around the Barnsdale/Greenbank intersection to receive adequate supply in 2016. In this sense, the Prince of Wales Voltage Conversion project is important in providing a tie for the 2016 asset replacement project, while continuing to work towards the overall goal of upgrading the South to a 27.6kV system.

3.2.2.4 *Performance Targets and Objectives*

The primary objective of this project is to prepare Prince of Wales Drive for an upcoming voltage conversion. This involves the replacement of all utility poles, overhead transformers, primary conductors and related assets, as well as the extension of a 27.6kV circuit from Woodroffe Avenue. The replacement of aging assets will contribute to improving reliability in the area. The upgrade will allow a voltage conversion within the next few years as needed and will create the possibility for eventual backup ties with the New South 27.6kV Substation feeders and existing lines. The project will be deemed a success if all of the core objectives are met in a timely manner while minimizing the impact to HOL's customers.

3.2.3 Project/Program Justification

3.2.3.1 *Alternatives Evaluation*

3.2.3.1.1 Alternatives Considered

Due to the nature of this project and its contribution to the overall goal of upgrading the supply voltage in the south, there were no specific alternatives to upgrading and expanding the system along Prince of Wales Drive.

Circuits from Limebank MS on the east side of the Rideau River are needed to help fulfill the future capacity requirements in the south. These circuits only cross the river at two locations, Manotick Island and the new Strandherd Bridge. Manotick Island currently carries the 27.6kV 7F4 circuit but a large portion of the conductor is undersized and would therefore require a major upgrade to be capable of supplying the south. This was not a feasible option. Thus, the only other option was to utilize the 7F2 circuits to the north of Prince of Wales Drive, at Woodroffe Avenue.

Although there were limited options in extending circuits from Limebank MS to the south, there were several alternatives which were considered in planning the scope of this project. They were: Creating a single-circuit tie at the intersection of Prince of Wales Drive and Jockvale Road; Servicing a portion of Barnsdale Road from either Prince of Wales Drive or from Rideau Valley Drive (thus including in the scope of one project or the other); Cancelling the Nicolls Island project and accounting for the island within the scope of the Prince of Wales Voltage Conversion project.

3.2.3.1.2 Evaluation Criteria

The evaluation criteria for alternatives to the project itself are based on feasibility and cost. A utility must anticipate and provide the needed services in an efficient manner. The evaluation criteria for alternatives to the project scope are based on minimizing cost, reliability considerations and external influences. HOL strives to minimize cost and customer interruptions. This involves planning ahead for future work that is expected to occur in the same area as the project in question.

3.2.3.1.3 Preferred Alternative

Due to the need for Limebank MS to contribute to the south supply, it was determined that upgrading and extending the circuits along Prince of Wales Drive was the only feasible solution to prepare for upcoming capacity requirements. That being said, there were several preferred alternatives found within the scope of this project.

First, it is desired to connect the existing circuit along Jockvale Road to one of the circuits on Prince of Wales Drive. This would create an additional backup loop to improve reliability and enable reduced outage durations.

Approximately 515m of existing single-phase conductor at the end of Jockvale Road would be upgraded to a 3-phase line. Then a 250m line extension would be needed to connect the two segments. This connection was planned, however it was learned that the City of Ottawa is planning a road widening for Jockvale Road. This means that any new pole line extension would be relocated in two years, so HOL decided to postpone this connection until the road widening is completed. That being said, the scope of this project was altered to include bringing a circuit across Prince of Wales Drive, to be used in the future connection with Jockvale Road. Crossing the street now and installing a switch will avoid a second traffic disruption and customer outage later.

Secondly, it was decided to supply the customers on Barnsdale Road (between Prince of Wales Drive and Rideau Valley Drive) from Prince of Wales Drive as opposed to Rideau Valley Drive. Since the supply originates from Fallowfield DS, it is better planning to supply the customers from a point closer upstream to the source. Rideau Valley Drive is supplied radially so reliability will be improved for customers residing on that section of Barnsdale Road.

Finally, supplying customers on Nicolls Island from a step-down transformer on Prince of Wales Drive was added to the scope of this project. Originally, Nicolls Island had been planned as a separate project. The plan was to prepare the customers on Nicolls Island for a voltage conversion to 27.6kV as well. This would require pole replacements, new insulators, dual overhead transformers, new frames and conductors. There are 16 single-phase customers on the island, and it is unlikely that the electrical demand will increase. Growth on this small island is not supported by Parks Canada, the City of Ottawa or the Rideau Valley Conservation Authority due to septic and potable water challenges, unstable land, and ease of access problems for emergency vehicles. The greatest challenge is that the only access to the site is an old bridge with limited weight capacity. It would therefore be difficult to transport our vehicles and equipment to site. In terms of the cost savings, approximately $300K is saved by not doing a voltage conversion of Nicolls Island.

3.2.3.2 *Project/Program Timing & Expenditure*

The total cost of this project is $1,474,559. HOL is minimizing the cost of this project by coordinating construction schedules with the Rideau Valley Voltage Conversion (92008686) project. HOL's own crew will work on both projects together, beginning with Rideau Valley. Doing these projects at the same time is convenient due to their close proximity, and this is expected to save $1M in time and labour costs. Additionally, the decision to install a step-down transformer to service Nicolls Island as opposed to preparing it for a voltage conversion saves a considerable amount of money which can be allocated towards other sustainment projects. The cost to do a voltage conversion of Nicolls Island would have been in the range of $400K, while installing a single-phase step-down transformer is estimated at $93K. This represents a cost saving of over $300K.

Historical ($M)					Future ($M)				
2011	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
-	-	-	-	1.47	-	-	-	-	-

Table 93 - Project Expenditures

3.2.3.3 *Benefits*

Benefits	Description
System Operation Efficiency and Cost-effectiveness	This project is a necessary contribution to the overall goal of upgrading supply capacity in the south of Ottawa. System operation efficiency will be improved with the double circuit loop that will be created in 2016, once the asset replacement project is complete on Prince of Wales Drive and Greenbank Road. Once the new 27.6kV substation is built, this project will contribute to creating a more interconnected system which will lead to faster restoration times, thus reducing SAIDI. It is expected that SAIFI will also be reduced by replacing aging assets proactively. It is known that the equipment on Prince of Wales Drive is in poor condition. Within the scope of this project, the most cost-effective alternatives were chosen. For instance, servicing Nicolls Island with a single-phase step-down transformer rather than doing a voltage conversion saves HOL hundreds of thousands of dollars. Coordinating this project with the Rideau Valley Voltage Conversion (92008686) project will also save a large amount of construction and labour costs.
Customer	This project will achieve two objectives: to supply future demand and to improve reliability in the south of the city. While this particular project is being driven by the need for increased capacity, HOL is taking this opportunity to better the system. The planned feeder connections will contribute to reducing outage durations and eliminating radial segments that exist in the current distribution system. By replacing assets in preparation for a voltage upgrade, this not only brings equipment up to current standard but also improves the asset condition.

Safety	Rebuilding and upgrading this pole line will address the predicted thermal overload of existing feeders that will occur in the near future. Overloading the system can lead to equipment damage and safety hazards. This project will mitigate that risk. Replacing aging assets will also contribute to eliminating potential safety hazards, by installing stronger poles and removing old transformers.
Cyber-Security, Privacy	Not Applicable
Co-ordination, Interoperability	Not Applicable
Economic Development	This project is not expected to contribute directly to economic growth or job creation, but extending circuits within HOL's service territory will inevitably lead to additional operation and maintenance. HOL's own crews will handle the construction of the project, with a contractor handling the pole holes and anchors.
Environment	Not Applicable

Table 94 - Project Benefits

3.2.4 Prioritization

3.2.4.1 *Consequences of Deferral*

The completion of this project is important in providing adequate capacity to the anticipated development in the next few years. Preparing for a future voltage conversion and extending a second circuit along Prince of Wales Drive is crucial in order to supply the upcoming demand in the area. This project will enable a looped supply for the expected development near Greenbank Road and Barnsdale Road. Since this project addresses a capacity issue, the consequence of deferring the project would be the inability to service the required load. Allowing the system to experience thermal overload for an extended period of time would lead to equipment damage and customer outages. Customers working or living in the proposed developments would simply not have the electricity they required. The eventual failure of the system to keep up with demand validates the necessity of this project.

This project involves the replacement of aging assets such as poles, conductors and transformers which will improve system reliability. Poles along Prince of Wales Drive are currently in poor condition, and replacing them will minimize their likelihood of failure.

3.2.4.2 *Priority*

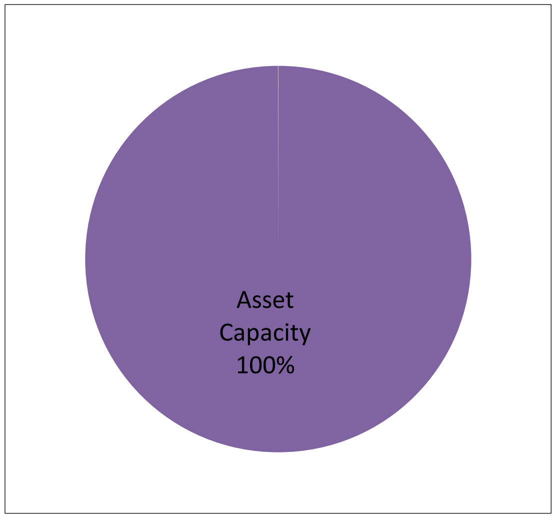


Table 95 - Project Avoided Risk

Project Score = 0.24

3.2.5 Execution Path

3.2.5.1 *Implementation Plan*

This project is scheduled to begin construction in March 2015. The implementation plan involves installing new poles, conductors and transformers for the new double circuit pole line. Both circuits will be rated for 27.6kV, although only one circuit will carry 27.6kV while the other remains at 8.32kV for now. Then the existing pole line will be removed along with old transformers and other associated hardware.

This project will be done in conjunction with the Rideau Valley Voltage Conversion (92008686) project. The Rideau Valley Voltage Conversion (92008686) project will begin construction first in February 2015, followed by the Prince of Wales Voltage Conversion (92008543) project in March 2015. This order is simply a reflection of the 92008686 project design and drawings being completed first. HOL's own 11-person construction crew will work on these two projects, with a contractor to take care of pole holes and anchors. Pole replacements and framing will be completed first, starting with Rideau Valley. Following the pole replacements, conductor will be strung for both projects simultaneously. Although not dependent on each other, doing these projects together is expected to save considerable time and labour, thus reducing the overall project cost.

3.2.5.2 *Risks to Completion and Risk Mitigation Strategies*

Project drawings have been submitted to the City of Ottawa for municipal consent. Once approved, HOL will request a road cut permit. Receiving municipal consent is not expected to be an issue; however, the process is known to take time. HOL is aware of the typical approval time and submitted the drawings in anticipation of the planned construction date. Crews are prepared to proceed with surveying and staking once municipal consent is approved. Approval has already been granted by the City of Ottawa for tree trimming.

Limebank MS recently received an upgrade, with the addition of a station transformer to provide more capacity to the Riverside South and Barrhaven areas. This upgrade affects the long term capability of Limebank substation to provide adequate supply to the South Nepean area. This project is proceeding as planned, with an anticipated commissioning and energization date in December 2014. All construction for this project is complete.

3.2.5.3 *Timing Factors*

As with all projects involving asset replacement, timing can be affected due to unforeseen events, such as encountering rock beneath the surface of the soil or facing extreme weather conditions. Any events that arise and were not planned for will likely affect the timing of the project, either causing a delay or moving it ahead of schedule. HOL does not foresee any problems in completing this project in 2015.

The procurement of equipment and materials may affect the project timing, but this is not expected. HOL has already ordered material in 2014 which will be delivered at the end of December 2014 and beginning of January 2015.

Planned City development is the driver for this project, and it is unlikely that the priority of this project will change. It is necessary to increase the electrical supply in the area of load growth. If City development is delayed for any reason, it is possible that this project could be shifted slightly but this is unlikely, as this project contributes to expanding supply in the South Nepean area and extends needed circuits from Limebank substation. For the priority of this project to change, City development would have to be delayed and HOL would have to have a sudden change in priorities due to an unexpected requirement.

3.2.5.4 *Cost Factors*

It is possible that construction crews will encounter more rock beneath the surface than anticipated when installing new poles, but this is unlikely as there is an existing pole line along Prince of Wales Drive.

3.2.5.5 *Other Factors*

One public communication package will be created for both the Prince of Wales project and the Rideau Valley project. Letters of notification was done in 2014, as customers will experience planned outages and potential construction on or around their properties. Customer input is not expected to cause any problems as there is already an existing pole line along Prince of Wales Drive.

3.2.6 Renewable Energy Generation (if applicable)

N/A

3.2.7 Leave-To-Construct (if applicable)

N/A

3.2.8 Project Details and Justification

Project Name:	Prince of Wales Voltage Conversion
Capital Cost:	$1,474,559
O&M:	N/A
Start Date:	March 2015
In-Service Date:	Fall 2015
Investment Category:	System Service
Main Driver:	Capacity
Secondary Driver(s):	Reliability
Customer/Load Attachment	Approximately 70 customers
Project Scope	
Replace 72 poles, frame for double circuit, string new 27.6kV conductors Install new dual overhead transformers Replace customer owned insulators on existing customer owned poles Transfer secondary services and remove existing pole line and associated hardware Tree trimming	
Work Plan	
Install poles and framing for Rideau Valley Voltage Conversion project first Install poles and framing for Prince of Wales Voltage Conversion project next String new conductor for both projects together	
Customer Impact	
Available distribution capacity to supply new loads for upcoming development Reliability improvement associated with replacement of aging assets and equipment upgrades Reduced outage durations by allowing for future double circuit loop	

3.3 Rideau Valley Voltage Conversion

3.3.1 Project/Program Summary

The project is a line upgrade along Rideau Valley Drive in the preparation of a future voltage conversion from 8.32kV to 27.6kV. This project will contribute to upgrading the electrical capacity in the South Nepean area while improving system reliability. 37 customers will be affected on the 8.32kV FAL03 circuit from Fallowfield DS along Rideau Valley Drive, south of Prince of Wales Drive and extending as far as the current circuit to 4174 Rideau Valley Drive, including customers along Lockview Road. The project will upgrade the existing 8.32kV single-phase overhead line with new poles, conductors and transformers which will be 3-phase and rated for 27.6kV. No voltage conversion will take place yet. Although independent from the Prince of Wales Voltage Conversion (92008543), this project is being done for the same purpose, to prepare the area for the increased capacity that will accompany the New South 27.6kV Substation (92008537).

3.3.2 Project/Program Description

3.3.2.1 *Current Issues*

The south region of Ottawa is expected to develop and expand rapidly over the next few years. It is estimated that HOL's current distribution system will not be fully capable of supporting the load growth. Expansion based on city plans in the South Nepean area is shown below.

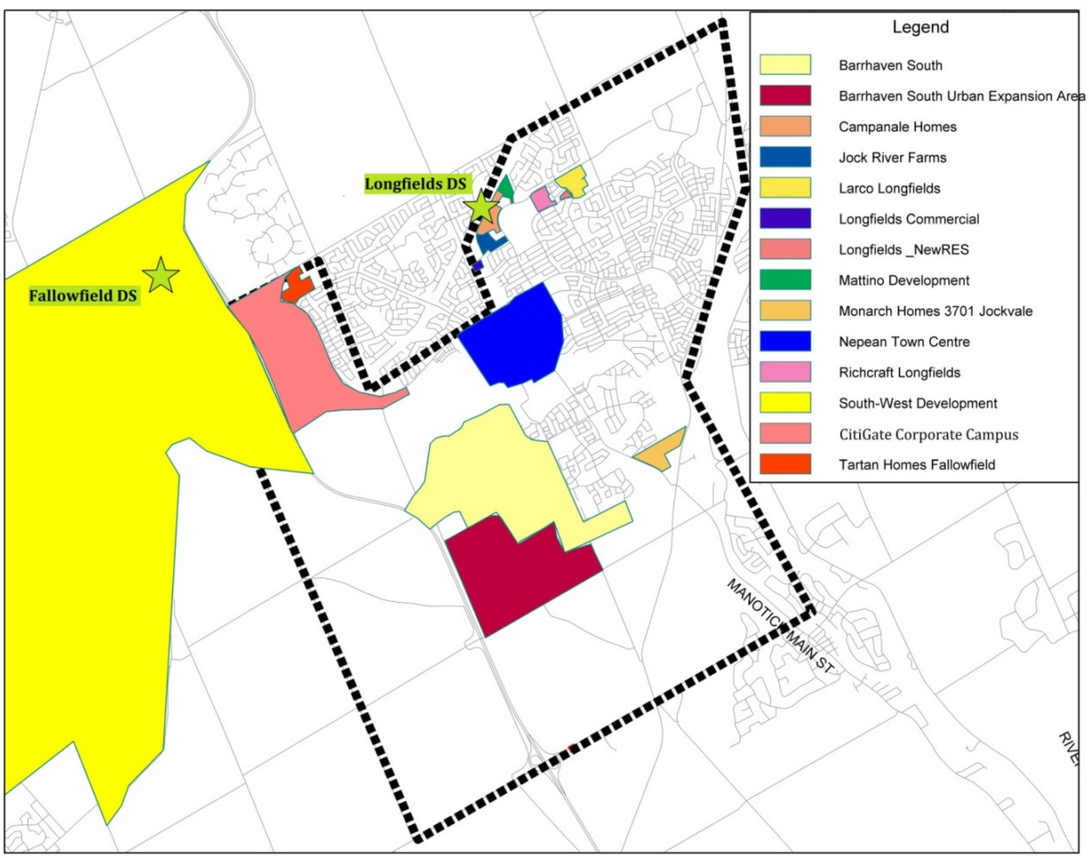


Figure 88 - Proposed Developments

In order to meet demand, the distribution system must be upgraded to a higher voltage. Although some portions of the south are supplied by a 27.6kV system, many areas still only have an 8.32kV supply. The overall goal is to convert the entire south area to a 27.6kV voltage supply, to support upcoming development while maintaining a reliable system.

In order to achieve the overall goal, a new 27.6kV distribution station with 6-8 feeders will be constructed to provide additional capacity to the area, as described in the business case for the New South 27.6kV Substation (92008537) project. The new station feeders will create ties with existing feeders, which will be upgraded in terms of their voltage rating. Converting the majority of the supply in the area to 27.6kV will enable backup connections between stations and feeders. Hence, reliability will be improved while anticipated capacity issues are resolved. Other major projects that have contributed or will contribute to the overall goal for the area include: Richmond South DS voltage conversion to 27.6kV, Limebank MS transformer upgrade, Fallowfield DS capacity upgrade and the transformer protection and base replacement at Longfields DS.

It can be seen in the above figures that there is proposed development on the east side of Highway 416, which is currently supplied by 8.32kV feeders. There are multiple projects taking place in the short term to prepare this section for a voltage upgrade. This includes both the Prince of Wales Voltage Conversion and the Rideau Valley Voltage Conversion projects.

The purpose of the Rideau Valley Voltage Conversion project is to prepare Rideau Valley Drive for a 27.6kV voltage conversion of the existing line. Although the current 8.32kV line is being upgraded to 27.6kV-rated equipment, no voltage conversion will take place within the scope of this project. This project will begin construction in February 2015, coordinating with the Prince of Wales Voltage Conversion project, and is expected to be completed before the end of 2015.

3.3.2.2 *Program/Project Scope*

This project involves the replacement of the existing single-phase pole line, including 56 poles and 9 overhead transformers. New poles will be framed for one 3-phase 27.6kV circuit and new insulators and conductors will be installed. The new overhead transformers will be 16/4.8kV dual rated. Customer-owned insulators will be replaced on existing customer-owned poles. Secondary services will be transferred and the existing pole line and associated hardware will be removed. The plan is illustrated on the following map.

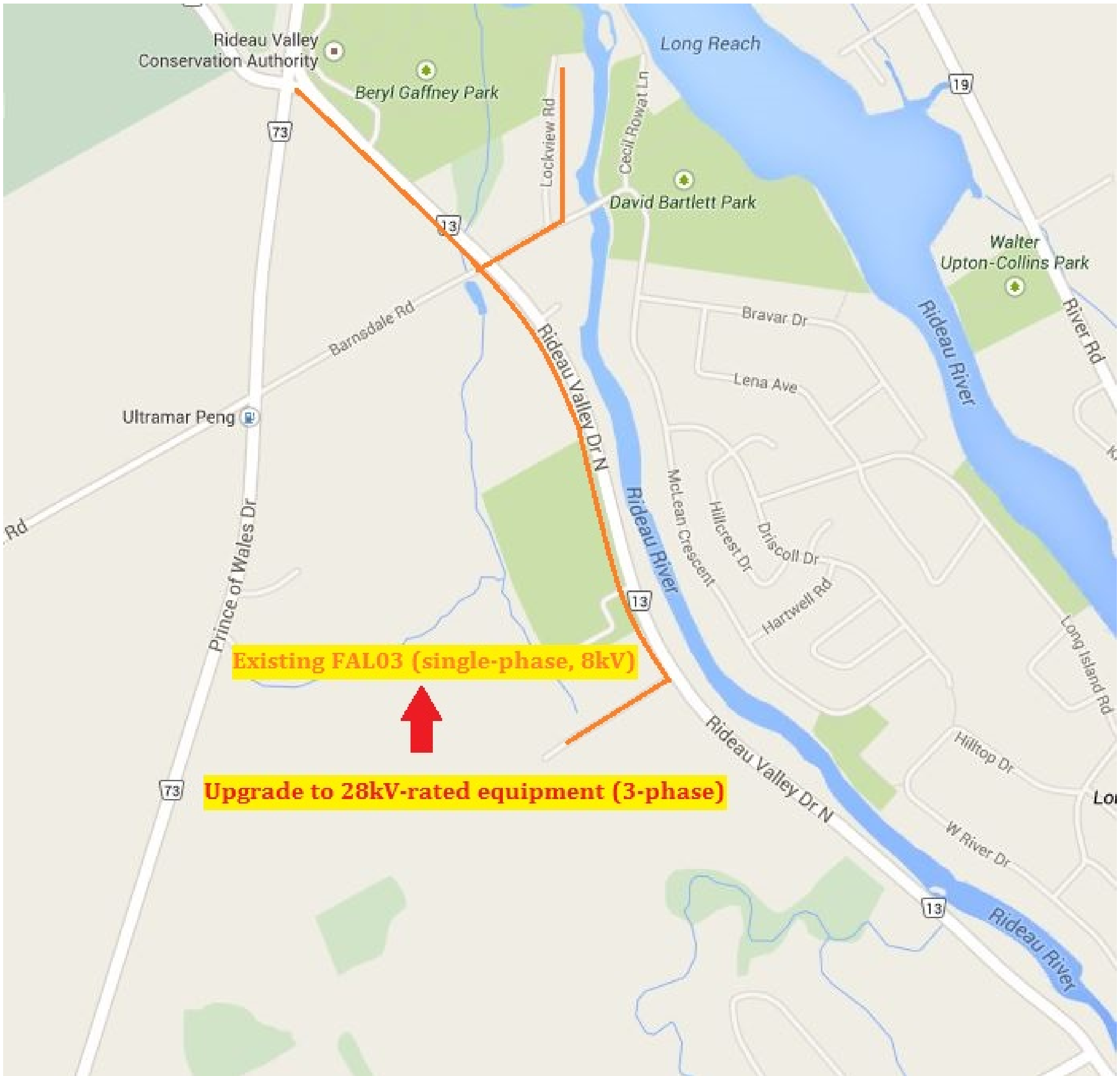


Figure 89 - Proposed Conversion

Not included in the scope of this project is the installation of new civil structures, the digging of pole holes, the installation of anchors, tree trimming or the transfer of communication lines. It is also important to note that this project does not include the voltage conversion itself, only the preparation for it because of capacity restrictions at the stations. The upgraded existing line will have capacity for 27.6kV but will remain at 8.32kV for now, until more capacity becomes available.

3.3.2.3 *Main and Secondary Drivers*

The main driver of this project is the upcoming load growth in the area. It is expected that the area's capacity limitations will be reached within the next five years. The 8.32kV circuits in the south of Barrhaven are being prepared for a conversion to 27.6kV, which will be needed to satisfy the demand. As a secondary driver for this project, reliability will be improved with the replacement of aging assets.

The poles along Rideau Valley Drive are in bad condition and the installation of new poles and related equipment will decrease the likelihood of failure.

Additionally, when the New South 27.6kV Substation is complete, the circuit along Rideau Valley Drive will be prepared to accept ties with the new substation feeders, thus improving reliability by creating backup loops to decrease the restoration time in the event of an outage. It will also be prepared to accept the eventual tie with the 7F4 circuit that currently services Manotick Island and crosses the Rideau River to the southern portion of Rideau Valley Drive.

An important consideration which acted as a driver for the timing of this project is the magnitude of the cost savings as a result of coordinating this project with the Prince of Wales project. Construction and labour costs are expected to be $1M lower than if these two projects were to be carried out separately.

3.3.2.4 *Performance Targets and Objectives*

The primary objective of this project is to prepare Rideau Valley Drive for an upcoming voltage conversion. This involves the replacement of all utility poles, overhead transformers, primary conductor and related assets, as well as an upgrade from the current single-phase line to a 3-phase circuit. The replacement of aging assets will contribute to improving reliability in this area. The upgrade will allow a voltage conversion within the next few years as needed and will create the possibility for eventual backup ties with the New South 27.6kV Substation feeders and existing lines. The project will be deemed a success if all of the core objectives are met in a timely manner while minimizing the impact to HOL's customers.

3.3.3 Project/Program Justification

3.3.3.1 *Alternatives Evaluation*

3.3.3.1.1 Alternatives Considered

The value of completing this project is found in its contribution to the overall goal of upgrading the supply voltage in the south, combined with reliability improvements. The section of overhead line to be upgraded is currently radial, and will be extended to create a tie with the 7F4 feeder from Limebank MS. This would provide backup to both circuits and utilize the upgraded transformer capacity at Limebank substation. Another alternative to this project would be to leave the existing single-phase supply as is, and install a step-down transformer at the intersection of Prince of Wales Drive and Rideau Valley Drive. This would be a temporary solution to allow the Prince of Wales Voltage Conversion to proceed, however it is desired for planning purposes to upgrade this line by the time the new station feeders are ready for construction.

3.3.3.1.2 Evaluation Criteria

The evaluation criteria for project alternatives are based primarily on feasibility, reliability considerations and cost. A utility must anticipate and provide the needed services in an efficient manner. HOL strives to minimize project costs and customer interruptions. This involves planning ahead for future work that is expected to occur in the same area as the project in question.

3.3.3.1.3 Preferred Alternative

The FAL03 circuit being upgraded in this project is currently radial. The 7F4 feeder is also radial along Rideau Valley Drive, and is found a few spans away from the project boundary. It is desired to connect the two segments and create a backup tie for both circuits.

Unfortunately, it was found that a large portion of the 7F4 feeder supplying Manotick Island is currently supplied through undersized conductor. Therefore, the circuit is currently unable to provide the required capacity and the Island will require an upgrade before a connection between the two circuits can be made. This upgrade was too large and costly to be considered feasible within the scope of this project.

There is also a significant advantage to the timing of this project, in coordinating it with the Prince of Wales Voltage Conversion (92008543) project. Rideau Valley Drive could have maintained adequate supply in the short term by installing a step-down transformer at the tap to Prince of Wales Drive. However, the upgrade of this line is important in contributing to the overall goal for the system, as it will provide a tie point for new feeders. It was decided that it would be cost-efficient to do this project simultaneously with the Prince of Wales project. Due to the close proximity, approximately $1M is saved in construction and labour costs by doing these projects together. As an added consideration, the poles along Rideau Valley drive are in poor condition so HOL is taking advantage of the situation by addressing two issues at once.

3.3.3.2 *Project/Program Timing & Expenditure*

The total cost of this project is $1,035,465. HOL is minimizing the cost of this project by coordinating construction schedules with the Prince of Wales Voltage Conversion (92008543) project. HOL's own crew will work on both projects together, beginning with Rideau Valley. Doing these projects at the same time is convenient due to their close proximity, and this is expected to save $1M in time and labour costs.

Historical ($M)				Future ($M)					
2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
-	-	-	-	1.04	-	-	-	-	-

Table 96 - Project Expenditures

3.3.3.3 *Benefits*

Benefits	Description
System Operation Efficiency and Cost-effectiveness	This project is an important contribution to the overall goal of upgrading supply capacity in the south of Ottawa. System operation efficiency will be improved by providing an alternate supply route around Barnsdale Road, along with the ability to accommodate a future backup connection. Once the New South 27.6kV Substation is built, this project will contribute to creating a more interconnected system which will lead to faster restoration times, thus reducing SAIDI. It is expected that SAIFI will also be reduced by replacing aging assets proactively. It is known that the equipment on Rideau Valley Drive is in poor condition. Coordinating this project with the Prince of Wales Voltage Conversion (92008543) project is a cost-effective decision that saves a large amount of construction and

	labour costs.
Customer	This project will achieve two objectives: to supply future demand and to improve reliability in the south of the city. While this particular project is being driven by the need for increased capacity, HOL is taking this opportunity to better the system. The planned feeder connections will contribute to reducing outage durations and eliminating radial segments that exist in the current distribution system. By replacing assets in preparation for a voltage upgrade, this not only brings equipment up to current standard but also improves the asset condition.
Safety	Replacing aging assets will also contribute to eliminating potential safety hazards, by installing stronger poles and removing old transformers.
Cyber-Security, Privacy	(Not applicable)
Co-ordination, Interoperability	(Not applicable)
Economic Development	This project is not expected to contribute directly to economic growth or job creation, but extending circuits within HOL's service territory will inevitably lead to additional operation and maintenance. HOL's own crews will handle the construction of the project, with a contractor handling the pole holes and anchors.
Environment	(Not applicable)

Table 97 - Project Benefits

3.3.4 Prioritization

3.3.4.1 *Consequences of Deferral*

The completion of this project is important to providing adequate capacity for the anticipated development in the next few years. Preparing for a future voltage conversion is crucial in order to supply the upcoming demand in the area. This project will enable an alternate circuit route to customers on Rideau Valley Drive while providing the capability for future backup from the southern portion of the road. Although this project contributes towards the overall goal of upgrading the supply voltage in the south to address capacity limitations, it is not an essential component in the immediate future. However, HOL has decided to proceed with this project due to its importance in the short term, and the significant cost savings in preparing this segment of the system at the same time as the Prince of Wales project, which is required in 2015. For this reason, the consequence of deferring this project would be a much larger future cost.

This project involves the replacement of aging assets such as poles, conductors and transformers which will improve system reliability. Poles along Rideau Valley Drive are currently in poor condition, and replacing them will decrease their likelihood of failure.

3.3.4.2 *Priority*

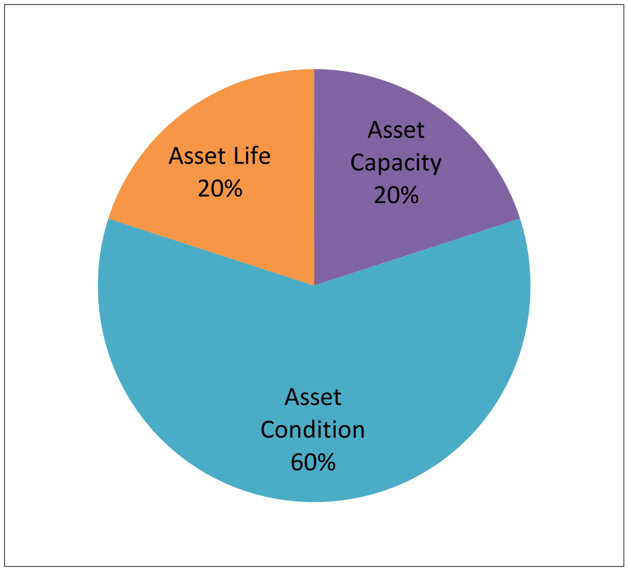


Figure 90 - Project Avoided Risk

Project Score = 0.42

3.3.5 Execution Path

3.3.5.1 *Implementation Plan*

This project is scheduled to begin construction in the middle of February 2015. The implementation plan involves installing new primary and secondary poles, replacing customer owned insulators on existing customer owned poles, framing the new 27.6kV poles, and stringing new conductors. New primary conductors will be tensioned and tied along with the neutral. Then new overhead transformers will be installed as well as a 266MCM field spun bus. Secondary services will be transferred and the existing pole line and associated hardware will be removed.

This project will be done in conjunction with the Prince of Wales Voltage Conversion (92008543) project. The Rideau Valley Voltage Conversion (92008686) project will begin construction first, followed by the Prince of Wales Voltage Conversion (92008543) project. This order is simply a reflection of the 92008686 project design and drawings being completed first. HOL's own 11-person construction crew will work on these two projects, with a contractor to take care of pole holes and anchors. Pole replacements and framing will be done first for either project, starting with Rideau Valley, then conductor will be strung for both projects simultaneously. Although not dependent on each other, doing these projects together is expected to save considerable time and labour, thus reducing the overall project cost.

3.3.5.2 *Risks to Completion and Risk Mitigation Strategies*

Project drawings have been submitted to the City of Ottawa for municipal consent. Once approved, HOL will request a road cut permit. Receiving municipal consent is not expected to be an issue, however the process is known to take time. HOL is aware of the typical approval time and submitted the drawings in anticipation of the planned construction date. Crews are prepared to proceed with surveying and staking once municipal consent is approved.

3.3.5.3 *Timing Factors*

As with all projects involving asset replacement, timing can be altered due to unforeseen events, such as encountering rock beneath the surface of the soil or facing extreme weather conditions. Any events that arise and were not planned for will likely affect the timing of the project, either causing a delay or moving it ahead of schedule. HOL does not foresee any problems in completing this project in 2015.

The procurement of equipment and materials may affect the project timing, but this is not expected. HOL has already ordered material in 2014 which will be delivered in the middle of December 2014. Transformers and conductors still have yet to be ordered.

Planned City development is the driver for this project, and it is unlikely that the priority of this project will change. It is necessary to increase the electrical supply in the area of load growth. If City development is delayed for any reason, it is possible that this project could be shifted slightly but this is unlikely, as this project contributes to expanding supply in the South Nepean area. For the priority of this project to change, City development would have to be delayed and HOL would have to have a sudden change in priorities due to an unexpected requirement.

3.3.5.4 *Cost Factors*

It is possible that construction crews will encounter more rock beneath the surface than anticipated when installing new poles, but this is unlikely as there is an existing pole line along Rideau Valley Drive.

3.3.5.5 *Other Factors*

One public communication package will be created for both the Prince of Wales project and the Rideau Valley project. These letters of notification will be done in 2014, as customers will experience planned outages and potential construction on or around their properties. Customer input is not expected to cause any problems as there is an existing pole line along Rideau Valley Drive already.

3.3.6 Renewable Energy Generation (if applicable)

N/A

3.3.7 Leave-To-Construct (if applicable)

N/A

3.3.8 Project Details and Justification

Project Name:	Rideau Valley Voltage Conversion
Capital Cost:	$1,035,465
O&M:	N/A
Start Date:	February 2015
In-Service Date:	Fall 2015
Investment Category:	System Service
Main Driver:	Capacity
Secondary Driver(s):	Reliability
Customer/Load Attachment	37 customers/782 kVA
Project Scope	
Replace 56 poles, frame for double circuit, string new 27.6kV conductors Install new dual overhead transformers Replace customer owned insulators on existing customer owned poles Transfer secondary services and remove existing pole line and associated hardware	
Work Plan	
Install poles and framing for Rideau Valley Voltage Conversion project first Install poles and framing for Prince of Wales Voltage Conversion project next String new conductor for both projects together	
Customer Impact	
Available distribution capacity to supply new loads Reliability improvement associated with replacement of aging assets and equipment upgrades Reduced outage durations by allowing for future backup circuit	

3.4 Richmond Voltage Conversion

3.4.1 Project/Program Summary

In the West 8.32kV Regional Planning Study, the projected developments were assessed for construction, timing and associated load. Anticipated developments in the Richmond village area include commercial, light industrial and residential developments. In 2012, Richmond was identified to increase in size by 600% over a 20 year horizon. The Richmond Voltage Conversion project is intended to upgrade infrastructure that has reached end of life to be capable of sustaining the expected load growth. The decision for a 27.6kV voltage conversion was driven by the limitation of 8.32kV circuits in terms of capacity, their inability to extend long distances and maintain adequate voltage levels and to allow for increased operability to transfer load to neighboring 27.6kV stations. Conversion from 8.32kV to 27.6kV is the long-term goal of all areas within the Stittsville, Kanata and Barrhaven communities in order improve reliability and eliminate on-going power quality issues with the 8.32kV system.

3.4.2 Project/Program Description

3.4.2.1 *Current Issues*

Current issues in the village of Richmond include deteriorating reliability due to failure of aging infrastructure and power quality issues which can be attributed to the length of the feeders and the limitation of 8.32kV to supply the distances without significant voltage drop. The projected load growth in the village of Richmond will become an issue for the 8.32kV system within a five-year timeframe.

3.4.2.2 *Program/Project Scope*

The scope of this project is to extend two (2) 27.6kV feeders along the major streets in the village of Richmond. The upgrade of Richmond South DS will continue to supply 8.32kV for the existing customers as well as 27.6kV for the voltage conversion to be completed in a phased approach. The two (2) feeders being constructed along the major streets will have one feeder energized at 8.32kV to continue supply to existing customers and one feeder at 27.6kV to begin the voltage conversion. All services supplied from the major roads undergoing re-construction will be converted during the project. The Richmond Voltage Conversion includes eleven (11) sub-projects divided in order to phase the construction in Richmond, but still have infrastructure in place for the energization of the upgraded Richmond South DS.

Phase 1, which will include all work and expenses to occur within 2016, includes two projects, 92010186 Richmond South Voltage Conversion – McBean and 92010188 Richmond South Voltage Conversion – Shea. The scopes of these two projects include the replacement of sixty-two (62) poles, eighteen (18) overhead transformers, 95m of direct buried cable with concrete encased cable and installation of two (2) new gang-operated automated switches.

Phase 2, which will include all work and expenses to occur within 2017, includes four projects: 92010920 Richmond South Egress – Garvin East, 92010922 Richmond South Voltage Conversion – Perth East, 92010924 Richmond South Voltage Conversion – Perth West, and 92010926 Richmond South Voltage Conversion – Huntley. The scopes of these four projects include the replacement of 104 poles, thirty (30) overhead transformers, four (4) padmounted transformers, 365m of direct buried cable with concrete encased cable and installation of three (3) new gang-operated automated switches.

Phase 3, which will include all work and expenses to occur within 2018, includes five projects, 92010954 Richmond South Voltage Conversion – King, 92010956 Richmond South Voltage Conversion – Fortune, 92010958 Richmond South Voltage Conversion – Ottawa, 92010960 Richmond South Voltage Conversion – Burke, and 92010962 Richmond South Voltage Conversion – Eagleson. The scopes of these five projects include the replacement of 127 poles, thirty-five (35) overhead transformers, seven (7) padmounted transformers, 545m of direct buried cable with concrete encased cable and installation of two (2) new gang-operated automated switches.

3.4.2.3 *Main and Secondary Drivers*

The main driver of this project is to supply the future expected load in the village of Richmond. The forecasted load for the next 20 years in the Richmond area indicates that the area's capacity limitations will be reached within the next five years. The 8.32kV system currently supplying the village of Richmond is not capable of supplying the increased capacity without exceeding thermal limitations of the infrastructure and would worsen the power quality issues that have been experienced by customers in this area.

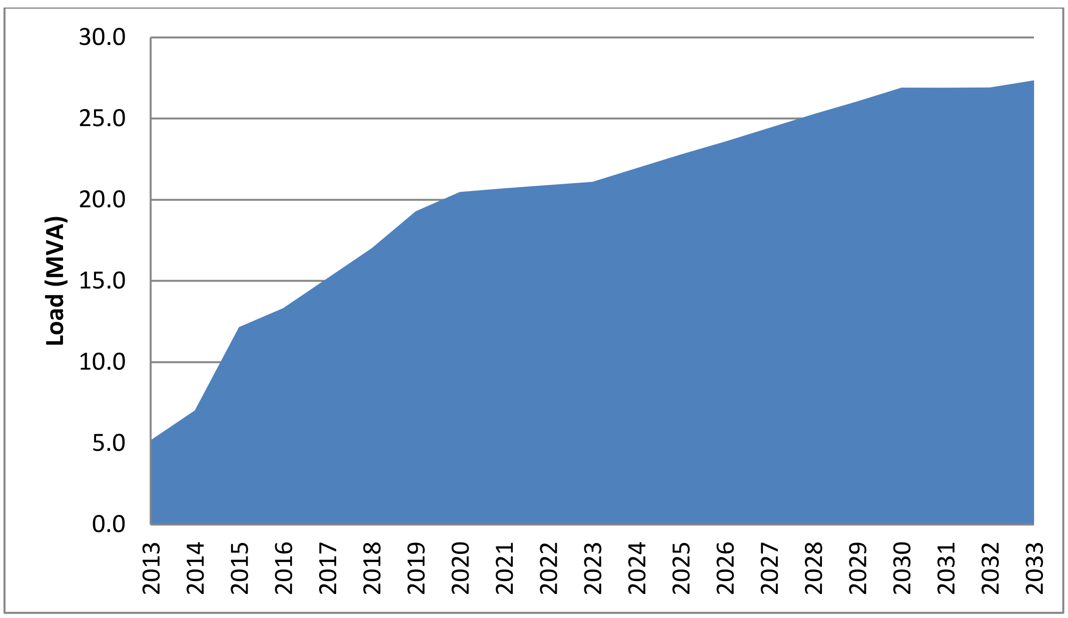


Figure 91 - Richmond Village Load Profile

There are many City of Ottawa development plans that have been reviewed to estimate the load demand over the next twenty years. The following outlines the development projects in the Richmond area.

Richmond Community Design Plan

The Village of Richmond CDP was initiated in 2008 and covers a planning period from 2010 to 2030. Based on this plan the residential capacity is planned to increase from approximately 1,550 dwelling units to between 4,400 and 5,500 units (including existing), for an increase of 2,850 – 3,950 which accounts for a load increase of 7.3 MVA – 10.1 MVA (using an estimate of 2.56 kVA/unit).

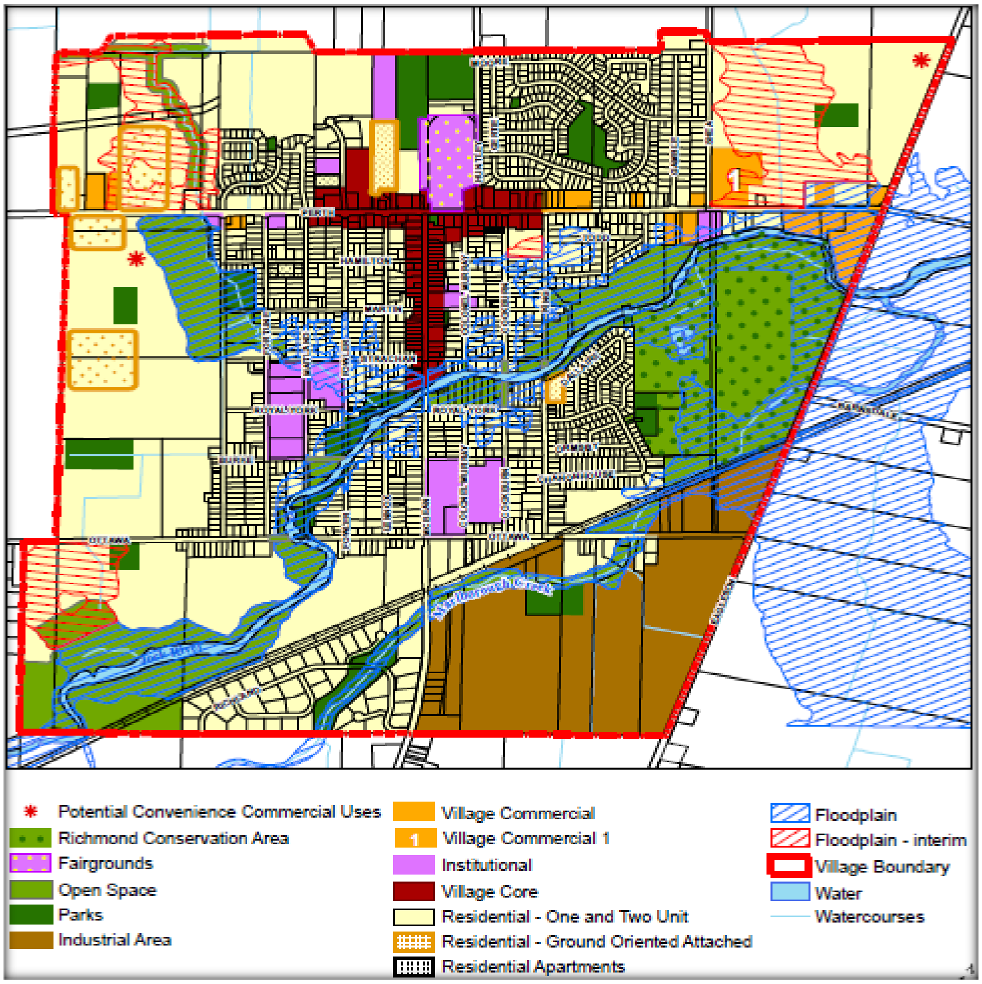


Figure 92 - Richmond CDP Land Use

Industrial Lands

The Richmond CDP describes the Industrial Lands as providing “an opportunity for industrial and employment-generating uses that require large parcels of land and that are not always compatible with residential uses”. The maximum building height in this area is restricted to the equivalent of three or four storeys with the following permitted uses: light industrial, office, printing plant, service and repair shop, small batch brewery, warehouse and heavy equipment and vehicle sales, rental and servicing, research, technology, nurseries, greenhouses, catering, places of assembly, broadcasting and training. Existing areas with a similar profile have a load estimate within the range of 10 – 20 MVA/km^2 depending on particular uses. The proposed industrial lands cover approximately 0.9 km^2 which would predict a load profile within the range of 9 – 18 MVA. For planning purposes the low end, 9 MVA, will be used, assuming that no large industrial plants will develop on these lands.

Figure 93 - Industrial Lands Demonstration Plan

Western Development Lands

Development in the Western Development Lands will primarily consist of detached dwellings, townhouses, parks, open space, a school and a pathway system. The density and unit mix provisions for this area are contained in the chart below.

Dwelling Type	Max Density Units/Net Ha	Unit Mix (% of Total)
One & Two Units Large Lots	17	2-7% Minimum
One & Two Units Small Lots	30	58-78% Maximum
Townhouses	45	20-35% Minimum
Townhouses with Rear Lanes	80	
Back-to-Back Townhouses	99	

Table 98 - Proposed Density

Figure 94 - Western Development Lands Demonstration Plan

The Western Development Lands demonstration plan was developed through a workshop hosted by Mattamy Homes in December 2008. Since that time Mattamy has developed a plan for a section of the western area, which is described below.

Mattamy Homes Residential

The Mattamy development covers the southern portion of the Western Development Lands and will account for approximately 1000 units, or 2.5 MVA of load. They have submitting the Draft Plan of Subdivision to the City of Ottawa in 2013 with closings to begin around 2017 since it is currently outside of their five year plan.

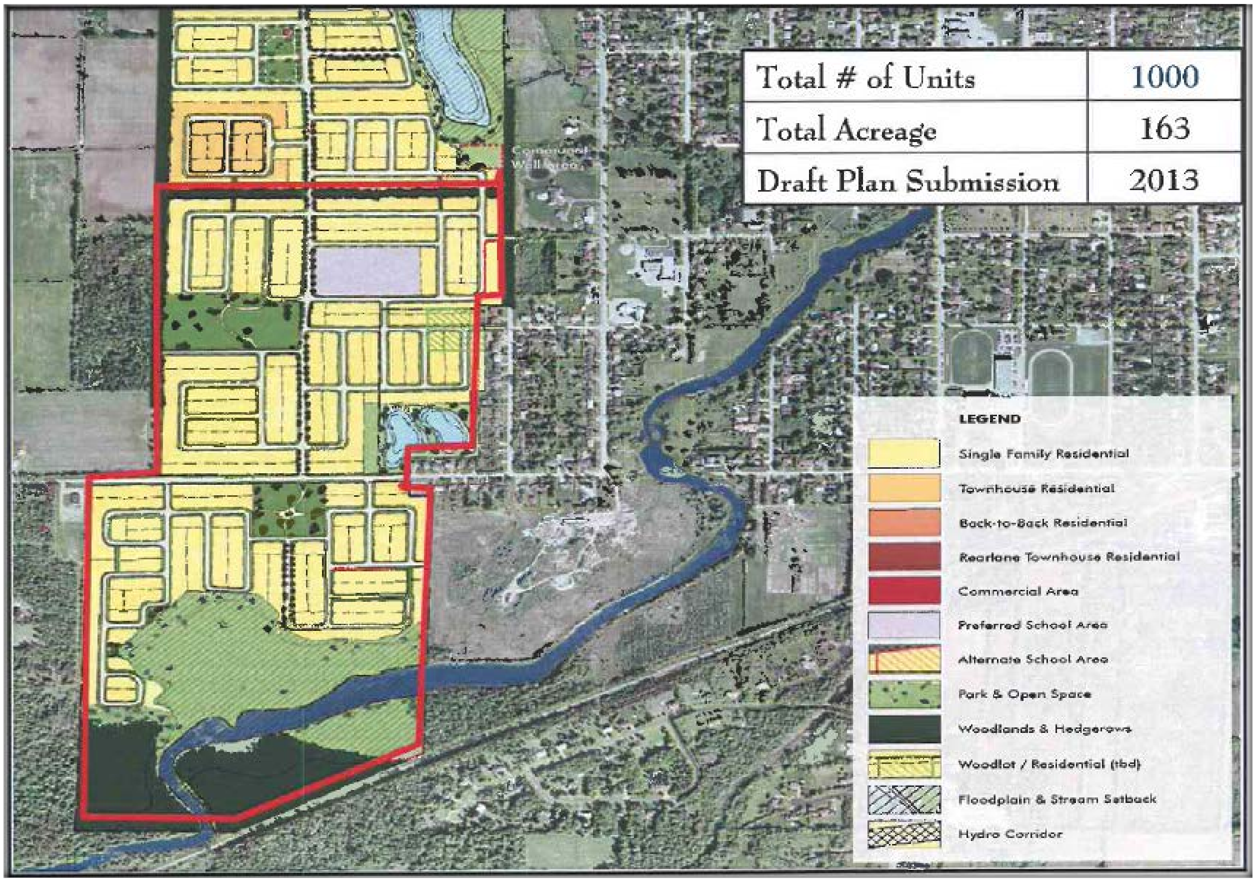


Figure 95 - Mattamy's Richmond West Development

Northeast Development Lands

The plans for this area follow the same general outline as that for the Western Development Lands.

Figure 96 - Northeast Development Lands Demonstration Plan

Richmond Village Square

The development known as Richmond Village Square is a commercial plaza that will consist of six single storey buildings for a total of 7,039 m^2. Using an estimate of 75.38 W/m^2 gives a load estimate of 590 kVA. The servicing for this site will consist of 3 x 1000 kVA transformers, and using an estimate of 60% of connected capacity provides a load estimate of 1.8 MVA. A load estimate of 1.0 MVA will be used for planning purposes.

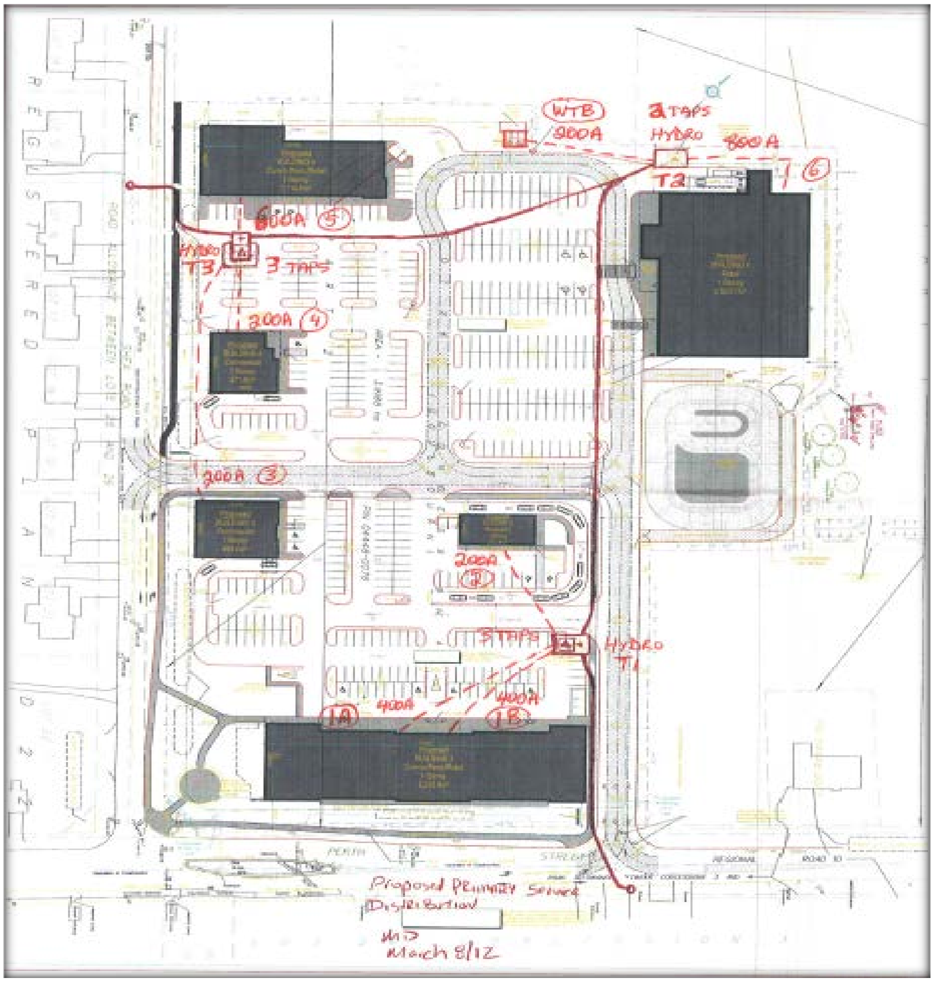


Figure 97 - Richmond Village Square Layout

As a secondary driver for this project, power quality will be improved as well as reliability by eventually creating ties to other 27.6kV stations, specifically Janet King DS, Bridlewood DS, Terry Fox MTS, Fallowfield DS and the New South 27.6kV Substation.

3.4.2.4 *Performance Targets and Objectives*

The main objective of this project is to be capable of supplying the new growth, while maintaining and improving power quality and reliability for customers in the village of Richmond. Conversion will directly allow developments in the village of Richmond to proceed on schedule and with adequate supply. The Richmond Voltage Conversion projects are expected to be completed in time for energization of Richmond South DS and the new 27.6kV supply.

A secondary objective is to improve reliability and power quality in the village of Richmond. New infrastructure will directly improve SAIFI and the feeder ties will directly reduce the impact on SAIDI.

Conversion will also directly reduce the impact on the System Average RMS Variation Frequency Index (SARFI) used to measure power quality issues in the system.

3.4.3 Project/Program Justification

3.4.3.1 *Alternatives Evaluation*

3.4.3.1.1 Alternatives Considered

The infrastructure in the Richmond 8.32kV system has reached end of life and requires upgrading to meet load growth requirements, reliability and power quality targets. The following eleven (11) projects have been identified to facilitate the required upgrades in order to meet these objectives:

- 92010186 Richmond South Voltage Conversion – McBean
- 92010188 Richmond South Voltage Conversion – Shea
- 92010920 Richmond South Egress – Garvin East
- 92010922 Richmond South Voltage Conversion – Perth East
- 92010924 Richmond South Voltage Conversion – Perth West
- 92010926 Richmond South Voltage Conversion – Huntley
- 92010954 Richmond South Voltage Conversion – King
- 92010956 Richmond South Voltage Conversion – Fortune
- 92010958 Richmond South Voltage Conversion – Ottawa
- 92010960 Richmond South Voltage Conversion – Burke
- 92010962 Richmond South Voltage Conversion – Eagleson

Alternative #1: includes the completion of all eleven (11) projects with infrastructure to support 27.6kV.

Alternative #2: includes the completion of all eleven (11) projects with infrastructure to support 8.32kV; direct replacements of all assets like for like.

3.4.3.1.2 Evaluation Criteria

Costs:

Alternative #1: $8.32M

Alternative #2: $8.32M

Labour costs account for the majority of project costs and as a result material cost increments between 8.32kV and 27.6kV are considered negligible.

Ability to supply load:

Alternative #1: The 8.32kV system in the village of Richmond has reached end of life and cannot support additional load growth without compromising the power quality issues further. The renewal of infrastructure with 27.6kV in this area will permit further load growth.

Alternative #2: The 8.32kV system in the village of Richmond has reached end of life and cannot support additional load growth without compromising the power quality issues further.

Reliability Benefits:
Both alternatives would benefit reliability in the community by renewing infrastructure and ties created between feeders would ultimately reduce SAIDI.

3.4.3.1.3 Preferred Alternative
Alternative #1 is the preferred alternative due to its ability to supply the anticipated future load growth, and reliability benefits associated with this alternative.

3.4.3.2 *Project/Program Timing & Expenditure*
The total project cost is $8,320.427 and is anticipated to be completed in 2018. HOL aims to minimize the costs and meet the deadlines associated with all projects by completing pre-planning of the construction schedule and ensuring vehicles, staff and material are all available for start of construction.

Historical ($M)						Future ($M)			
2010	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
$0	$0	$0	$0	$0	$0	$1.64	$3.02	$3.66	$0

Table 99 - Project Expenditures

3.4.3.3 *Benefits*
Key benefits that will be achieved by implementing the Richmond Voltage Conversion project are summarized below.

Benefits	Description
System Operation Efficiency and Cost-effectiveness	This project is required to satisfy the upcoming load growth in the village of Richmond. It is an essential system service project to supply the needed capacity. System operation efficiency will be improved by the new station feeders' ability to connect with other 27.6kV feeders in the area. The backup ties will ensure faster restoration times in the event of an outage, as well as the capability to maintain adequate supply in a station contingency scenario. This should inevitably contribute to reducing SAIDI, which is important in an area where the overhead distribution system is subject to weather-related outages. Voltage conversion is the most cost-effective solution to provide the required demand and renew aging infrastructure.
Customer	This project will achieve two objectives: to supply future demand and to improve reliability in the south-west end of the city. Not only will development projects be given adequate electrical supply, but the feeder ties present several opportunities to improve the system. This project will contribute to a larger system plan to convert the entire south-west to a 27.6kV system, in order to keep up with city development. This larger system plan will provide enhanced capacity and improved reliability to customers in several communities: Richmond, Munster, Kanata, Stittsville and Barrhaven. The various upcoming ties between stations servicing this region will reduce outage durations and eliminate several radial segments that exist in the current distribution system. These projects involve asset replacement, which further improves system reliability.
Safety	The infrastructure in place today has begun approaching end of life and poses a small risk of failure and safety concern. By replacing the infrastructure, the

	safety risk is significantly reduced.
Cyber-Security, Privacy	Not Applicable.
Co-ordination, Interoperability	The Richmond Voltage Conversion projects will coincide with ongoing developments in the village of Richmond and will reduce the last minute expansion requirements from developers to service the new developments.
Economic Development	This project is not expected to contribute directly to economic growth or job creation, but due to the number of assets being replaced in this project, will inevitably require operation and maintenance. Contractor labour will be used extensively to complete the project.
Environment	The infrastructure in place today has begun approaching end of life and poses a small risk of failure and environmental concern. By replacing the infrastructure, the environmental risk is significantly reduced.

Table 100 - Project Benefits

3.4.4 Prioritization

3.4.4.1 *Consequences of Deferral*

Since the purpose of this project is to address an upcoming capacity issue, the most important consequence of deferral would be the inability to service the required load in 2019. Allowing the system to experience thermal overload for an extended period of time would lead to equipment damage and customer outages. Customers working or living in the proposed developments would simply not have the electricity they require. The eventual failure of the system to keep up with demand validates the necessity of this project.

The new 27.6kV feeders will create ties with other stations and backup other feeders. This presents an additional consequence of deferral, which is that the current radial segments of other feeders in the area will remain radial for a longer period of time. If an outage occurs on these segments, the affected customers will likely experience long outage times.

This project also promotes a series of equipment upgrade projects, to prepare the area for the larger 27.6kV voltage conversion. This involves replacing aging assets such as poles, conductors and transformers which inherently improves system reliability.

3.4.4.2 *Priority*

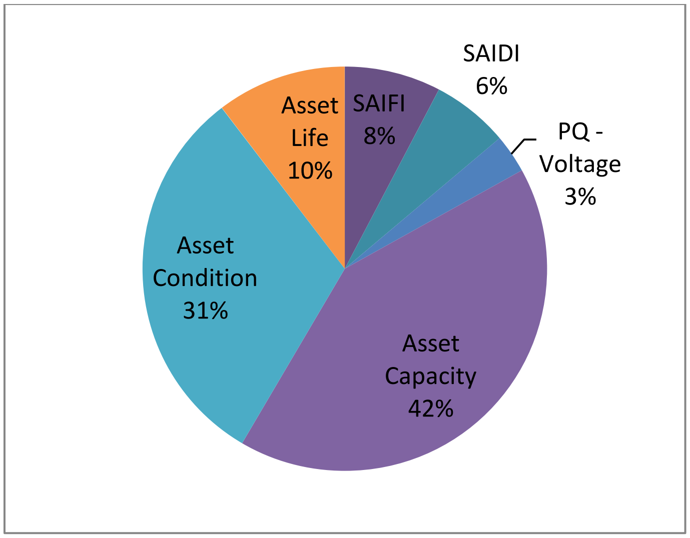


Figure 98 - Project Avoided Risk

Project Score: 0.867

3.4.5 Execution Path

3.4.5.1 *Implementation Plan*

Phase 1, which will include all work and expenses to occur within 2016, includes two projects, 92010186 Richmond South Voltage Conversion – McBean and 92010188 Richmond South Voltage Conversion – Shea. The scopes of these two projects include replacement of sixty-two (62) poles, eighteen (18) overhead transformers, 95m of direct buried cable with concrete encased cable and installation of two (2) new gang-operated automated switches.

Phase 2, which will include all work and expenses to occur within 2017, includes four projects: 92010920 Richmond South Egress – Garvin East, 92010922 Richmond South Voltage Conversion – Perth East, 92010924 Richmond South Voltage Conversion – Perth West, and 92010926 Richmond South Voltage Conversion – Huntley. The scopes of these four projects include replacement of 104 poles, thirty (30) overhead transformers, four (4) padmounted transformers, 365m of direct buried cable with concrete encased cable and installation of three (3) new gang-operated automated switches.

Phase 3, which will include all work and expenses to occur within 2018, includes five projects, 92010954 Richmond South Voltage Conversion – King, 92010956 Richmond South Voltage Conversion – Fortune, 92010958 Richmond South Voltage Conversion – Ottawa, 92010960 Richmond South Voltage Conversion – Burke, and 92010962 Richmond South Voltage Conversion – Eagleson. The scopes of these five projects include replacement of 127 poles, thirty-five (35) overhead transformers, seven (7) padmounted transformers, 545m of direct buried cable with concrete encased cable and installation of two (2) new gang-operated automated switches.

3.4.5.2 *Risks to Completion and Risk Mitigation Strategies*

Risks that may affect this project are easement acquisition, existing location of trees, and bedrock. HOL takes many steps in the design phase of the project to minimize these risks by investigating them early on.

3.4.5.3 *Timing Factors*

Factors affecting the timing of this project include easement acquisition, City of Ottawa Municipal Consent, customer outage limitations and weather conditions. Any delays in energization of the upgraded Richmond South DS will result in delays for energizing the 27.6kV feeders.

3.4.5.4 *Cost Factors*

Factors that may affect costs of the project include costs associated with digging through rock and delays due to weather conditions.

3.4.5.5 *Other Factors*

Not applicable.

3.4.6 Renewable Energy Generation (if applicable)

Not applicable.

3.4.7 Leave-To-Construct (if applicable)

Not applicable.

3.4.8 Project Details and Justification

Project Name:	Richmond Voltage Conversion - Shea
Capital Cost:	$665,000
O&M:	$0
Start Date:	2016
In-Service Date:	2016
Investment Category:	System Service
Main Driver:	Capacity
Secondary Driver(s):	Reliability
Customer/Load Attachment	1,097 Customers/4,049kVA
Project Scope	
The scope of this project is to extend two (2) 27.6kV feeders along Shea Road, from Garvin Road to Perth Street. The upgrade of Richmond South DS will continue to supply 8.32kV for the existing customers as well as 27.6kV for the voltage conversion to be completed in a phased approach. The two (2) feeders being constructed along McBean Street will have one feeder energized at 8.32kV to continue supply to existing customers and one feeder at 27.6kV to begin the voltage conversion. All services supplied from the pole line along McBean Street will be converted during the project. The intent is to have this infrastructure in place for the energization of the upgraded Richmond South DS.	
Work Plan	
Work break down for this projects includes replacement of twenty-four (24) poles and seven (7) overhead transformers, all to be completed in 2016.	
Customer Impact	
By integrating new Richmond South DS feeders into the distribution system in Richmond, it will improve the flexibility of the system. The average number of customer hours per interruption should diminish significantly. This project will also increase the available capacity in the village of Richmond for the upcoming developments.	

Project Name:	Richmond Voltage Conversion - McBean
Capital Cost:	$971,000
O&M:	$0
Start Date:	2016
In-Service Date:	2016
Investment Category:	System Service
Main Driver:	Capacity
Secondary Driver(s):	Reliability
Customer/Load Attachment	1,189 Customers/4,222kVA

Project Scope

The scope of this project is to extend two (2) 27.6kV feeders along McBean Street, from Perth Street to Ottawa Street. The upgrade of Richmond South DS will continue to supply 8.32kV for the existing customers as well as 27.6kV for the voltage conversion to be completed in a phased approach. The two (2) feeders being constructed along McBean Street will have one feeder energized at 8.32kV to continue supply to existing customers and one feeder at 27.6kV to begin the voltage conversion. All services supplied from the pole line along McBean Street will be converted during the project. The intent is to have this infrastructure in place for the energization of the upgraded Richmond South DS.

Work Plan

Work break down for this projects includes replacement of twenty-seven (27) poles, eleven (11) overhead transformers and 175m of direct buried cable to be encased with concrete encased cable, all to be completed in 2016.

Customer Impact

By integrating new Richmond South DS feeders into the distribution system in Richmond, it will improve the flexibility of the system. The average number of customer hours per interruption should diminish significantly. This project will also increase the available capacity in the village of Richmond for the upcoming developments.

Project Name:	Richmond South Egress – Garvin East
Capital Cost:	$438,279
O&M:	$0
Start Date:	2017
In-Service Date:	2017
Investment Category:	System Service
Main Driver:	Capacity
Secondary Driver(s):	Reliability
Customer/Load Attachment	1,097 Customers/4,049kVA

Project Scope

The scope of this project is to egress three (3) 27.6kV feeders along Garvin Road, from Richmond South DS to Shea Road. The upgrade of Richmond South DS will continue to supply 8.32kV for the existing customers as well as 27.6kV for the voltage conversion to be completed in a phased approach. The three (3) feeders being constructed along Garvin Road will have one feeder energized at 8.32kV to continue supply to existing customers and two feeders at 27.6kV to begin the voltage conversion. All services supplied from the pole line along Huntley Road will be converted during the project. The intent is to have this infrastructure in place for the energization of the upgraded Richmond South DS.

Work Plan

Work break down for this projects includes replacement of ten (10) poles, 200m of direct buried cable to be encased with concrete encased cable and installation of one (1) gang-operated automated switch, all to be completed in 2017.

Customer Impact

By integrating new Richmond South DS feeders into the distribution system in Richmond, it will improve the flexibility of the system. The average number of customer hours per interruption should diminish significantly. This project will also increase the available capacity in the village of Richmond for the upcoming developments.

Project Name:	Richmond Voltage Conversion - Huntley
Capital Cost:	$1,094,105
O&M:	$0
Start Date:	2017
In-Service Date:	2017
Investment Category:	System Service
Main Driver:	Capacity
Secondary Driver(s):	Reliability
Customer/Load Attachment	1,972 Customers/6,254kVA

Project Scope

The scope of this project is to extend two (2) 27.6kV feeders along Huntley Road, from Garvin Road to Perth Street. The upgrade of Richmond South DS will continue to supply 8.32kV for the existing customers as well as 27.6kV for the voltage conversion to be completed in a phased approach. The two (2) feeders being constructed along Huntley Road will have one feeder energized at 8.32kV to continue supply to existing customers and one feeder at 27.6kV to begin the voltage conversion. All services supplied from the pole line along Huntley Road will be converted during the project. The intent is to have this infrastructure in place for the energization of the upgraded Richmond South DS.

Work Plan

Work break down for this projects includes replacement of thirty-seven (37) poles, twelve (12) overhead transformers, three (3) padmounted transformers, 90m of direct buried cable to be encased with concrete encased cable and installation of one (1) gang-operated automated switch, all to be completed in 2017.

Customer Impact

By integrating new Richmond South DS feeders into the distribution system in Richmond, it will improve the flexibility of the system. The average number of customer hours per interruption should diminish significantly. This project will also increase the available capacity in the village of Richmond for the upcoming developments.

Project Name:	Richmond Voltage Conversion – Perth East
Capital Cost:	$965,169
O&M:	$0
Start Date:	2017
In-Service Date:	2017
Investment Category:	System Service
Main Driver:	Capacity
Secondary Driver(s):	Reliability
Customer/Load Attachment	1,097 Customers/4,049kVA

Project Scope

The scope of this project is to extend two (2) 27.6kV feeders along Perth Street, from Huntley Road to Eagleson Road. The upgrade of Richmond South DS will continue to supply 8.32kV for the existing customers as well as 27.6kV for the voltage conversion to be completed in a phased approach. The two (2) feeders being constructed along Perth Street will have one feeder energized at 8.32kV to continue supply to existing customers and one feeder at 27.6kV to begin the voltage conversion. All services supplied from the pole line along Perth Street will be converted during the project. The intent is to have this infrastructure in place for the energization of the upgraded Richmond South DS.

Work Plan

Work break down for this projects includes replacement of thirty-seven (37) poles, fourteen (14) overhead transformers and installation of one (1) gang-operated automated switch, all to be completed in 2017.

Customer Impact

By integrating new Richmond South DS feeders into the distribution system in Richmond, it will improve the flexibility of the system. The average number of customer hours per interruption should diminish significantly. This project will also increase the available capacity in the village of Richmond for the upcoming developments.

Project Name:	Richmond Voltage Conversion – Perth West
Capital Cost:	$525,298
O&M:	$0
Start Date:	2017
In-Service Date:	2017
Investment Category:	System Service
Main Driver:	Capacity
Secondary Driver(s):	Reliability
Customer/Load Attachment	976 Customers/2,983kVA

Project Scope

The scope of this project is to extend two (2) 27.6kV feeders along Perth Street, from Huntley Road to Fortune Street. The upgrade of Richmond South DS will continue to supply 8.32kV for the existing customers as well as 27.6kV for the voltage conversion to be completed in a phased approach. The two (2) feeders being constructed along Perth Street will have one feeder energized at 8.32kV to continue supply to existing customers and one feeder at 27.6kV to begin the voltage conversion. All services supplied from the pole line along Perth Street will be converted during the project. The intent is to have this infrastructure in place for the energization of the upgraded Richmond South DS.

Work Plan

Work break down for this projects includes replacement of twenty (20) poles, four (4) overhead transformers, one (1) padmounted transformers and 75m of direct buried cable to be encased with concrete encased cable, all to be completed in 2017.

Customer Impact

By integrating new Richmond South DS feeders into the distribution system in Richmond, it will improve the flexibility of the system. The average number of customer hours per interruption should diminish significantly. This project will also increase the available capacity in the village of Richmond for the upcoming developments.

Project Name:	Richmond Voltage Conversion – King
Capital Cost:	$967,556
O&M:	$0
Start Date:	2018
In-Service Date:	2018
Investment Category:	System Service
Main Driver:	Capacity
Secondary Driver(s):	Reliability
Customer/Load Attachment	1,097 Customers/4,049kVA

Project Scope

The scope of this project is to extend two (2) 27.6kV feeders along King Street, from Perth Street to Ottawa Street. The upgrade of Richmond South DS will continue to supply 8.32kV for the existing customers as well as 27.6kV for the voltage conversion to be completed in a phased approach. The two (2) feeders being constructed along King Street will have one feeder energized at 8.32kV to continue supply to existing customers and one feeder at 27.6kV to begin the voltage conversion. All services supplied from the pole line along King Street will be converted during the project. The intent is to have this infrastructure in place for the energization of the upgraded Richmond South DS.

Work Plan

Work break down for this projects includes replacement of thirty-two (32) poles, nine (9) overhead transformers, two (2) padmounted transformers, 170m of direct buried cable to be encased with concrete encased cable and installation of one (1) gang-operated automated switch, all to be completed in 2018.

Customer Impact

By integrating new Richmond South DS feeders into the distribution system in Richmond, it will improve the flexibility of the system. The average number of customer hours per interruption should diminish significantly. This project will also increase the available capacity in the village of Richmond for the upcoming developments.

Project Name:	Richmond Voltage Conversion – Fortune
Capital Cost:	$774,500
O&M:	$0
Start Date:	2018
In-Service Date:	2018
Investment Category:	System Service
Main Driver:	Capacity
Secondary Driver(s):	Reliability
Customer/Load Attachment	976 Customers/2,983kVA

Project Scope

The scope of this project is to extend two (2) 27.6kV feeders along Fortune Street, from Perth Street to Ottawa Street. The upgrade of Richmond South DS will continue to supply 8.32kV for the existing customers as well as 27.6kV for the voltage conversion to be completed in a phased approach. The two (2) feeders being constructed along Fortune Street will have one feeder energized at 8.32kV to continue supply to existing customers and one feeder at 27.6kV to begin the voltage conversion. All services supplied from the pole line along Fortune Street will be converted during the project. The intent is to have this infrastructure in place for the energization of the upgraded Richmond South DS.

Work Plan

Work break down for this projects includes replacement of twenty-two (22) poles, six (6) overhead transformers, three (3) padmounted transformers and 250m of direct buried cable to be encased with concrete encased cable, all to be completed in 2018.

Customer Impact

By integrating new Richmond South DS feeders into the distribution system in Richmond, it will improve the flexibility of the system. The average number of customer hours per interruption should diminish significantly. This project will also increase the available capacity in the village of Richmond for the upcoming developments.

Project Name:	Richmond Voltage Conversion – Ottawa
Capital Cost:	$821,750
O&M:	$0
Start Date:	2018
In-Service Date:	2018
Investment Category:	System Service
Main Driver:	Capacity
Secondary Driver(s):	Reliability
Customer/Load Attachment	1,097 Customers/4,049kVA

Project Scope

The scope of this project is to extend two (2) 27.6kV feeders along Ottawa Street, from Eagleson Road to McBean Street. The upgrade of Richmond South DS will continue to supply 8.32kV for the existing customers as well as 27.6kV for the voltage conversion to be completed in a phased approach. The two (2) feeders being constructed along Ottawa Street will have one feeder energized at 8.32kV to continue supply to existing customers and one feeder at 27.6kV to begin the voltage conversion. All services supplied from the pole line along Ottawa Street will be converted during the project. The intent is to have this infrastructure in place for the energization of the upgraded Richmond South DS.

Work Plan

Work break down for this projects includes replacement of thirty-two (32) poles, nine (9) overhead transformers, two (2) padmounted transformers and 125m of direct buried cable to be encased with concrete encased cable, all to be completed in 2018.

Customer Impact

By integrating new Richmond South DS feeders into the distribution system in Richmond, it will improve the flexibility of the system. The average number of customer hours per interruption should diminish significantly. This project will also increase the available capacity in the village of Richmond for the upcoming developments.

Project Name:	Richmond Voltage Conversion – Burke
Capital Cost:	$475,320
O&M:	$0
Start Date:	2018
In-Service Date:	2018
Investment Category:	System Service
Main Driver:	Capacity
Secondary Driver(s):	Reliability
Customer/Load Attachment	1,860 Customers/5,793kVA

Project Scope

The scope of this project is to extend two (2) 27.6kV feeders along Burke Street, from McBean Street to Fortune Street. The upgrade of Richmond South DS will continue to supply 8.32kV for the existing customers as well as 27.6kV for the voltage conversion to be completed in a phased approach. The two (2) feeders being constructed along Burke Street will have one feeder energized at 8.32kV to continue supply to existing customers and one feeder at 27.6kV to begin the voltage conversion. All services supplied from the pole line along Burke Street will be converted during the project. The intent is to have this infrastructure in place for the energization of the upgraded Richmond South DS.

Work Plan

Work break down for this projects includes replacement of thirteen (13) poles and four (4) overhead transformers, all to be completed in 2018.

Customer Impact

By integrating new Richmond South DS feeders into the distribution system in Richmond, it will improve the flexibility of the system. The average number of customer hours per interruption should diminish significantly. This project will also increase the available capacity in the village of Richmond for the upcoming developments.

Project Name:	Richmond Voltage Conversion – Eagleson
Capital Cost:	$622,450
O&M:	$0
Start Date:	2018
In-Service Date:	2018
Investment Category:	System Service
Main Driver:	Capacity
Secondary Driver(s):	Reliability
Customer/Load Attachment	1,097 Customers/4,049kVA

Project Scope

The scope of this project is to extend two (2) 27.6kV feeders along Eagleson Road, from Perth Street to Ottawa Street. The upgrade of Richmond South DS will continue to supply 8.32kV for the existing customers as well as 27.6kV for the voltage conversion to be completed in a phased approach. The two (2) feeders being constructed along Eagleson Road will have one feeder energized at 8.32kV to continue supply to existing customers and one feeder at 27.6kV to begin the voltage conversion. All services supplied from the pole line along Eagleson Road will be converted during the project. The intent is to have this infrastructure in place for the energization of the upgraded Richmond South DS.

Work Plan

Work break down for this projects includes replacement of twenty-eight (28) poles, seven (7) overhead transformers and nineteen (19) poles that require change of insulators, all to be completed in 2018.

Customer Impact

By integrating new Richmond South DS feeders into the distribution system in Richmond, it will improve the flexibility of the system. The average number of customer hours per interruption should diminish significantly. This project will also increase the available capacity in the village of Richmond for the upcoming developments.

3.5 Goulbourn Street Voltage Conversion

3.5.1 Project/Program Summary

The Goulbourn Street Voltage conversion is intended to fix power quality issues experienced by customers in and around Goulbourn Street in Stittsville. This community has seen significant change since the time of its first development. Properties have experienced multiple severances of land in order to build multiple homes and have resulted in unbalanced load and over loading of the one phase supplying this area, which has ultimately led to low voltage experienced by these customers. By converting these customers and looing them in with the 27.6kV JKGF4 feeder, renewed infrastructure and balancing load amongst the phases will eliminate their low voltage issues. Limited expansion is required in order to have 27.6kV available to the area. Conversion from 8.32kV to 27.6kV is the end goal of all areas within the Stittsville community in order improve reliability and eliminate power quality issues on-going with the 8.32kV system.

3.5.2 Project/Program Description

3.5.2.1 *Current Issues*

Current issues in the Goulbourn Street community include deteriorating power quality due to land splitting for residential development that has resulted in unexpected customers being added to a single 8.32kV phase at the end of the 44F1 feeder. Aging infrastructure has also contributed to the degradation of power the customers are experiencing.

3.5.2.2 *Program/Project Scope*

The scope of this project is illustrated below, which is to extend one (1) 27.6kV phase from JKGF4 along Goulbourn Street to convert the 8.32kV to 27.6kV and incorporate changes to the distribution layout to enhance operability. This includes a 90m extension along Cypress Gardens through the use of a direct buried duct system to encase the single phase cable, that will then rise up to the existing 8.32kV overhead system on Goulbourn Street. Incorporated in this project will be the replacement of forty-seven (47) poles, nine (9) overhead transformers, five (5) padmounted transformers and a total of 220m of direct buried duct encased trunk. Also included will be the change of phase on five (5) transformers that will allow each phase of the feeder to most efficiently extend through the neighbourhood and remain relatively balanced. The 27.6kV phases will then meet at a primary pedestal located on Elm Crescent which will be used to complete the residential developments. Completion of the developments in the community will create a tie between JKGF4 and TFXF5 that will improve reliability to this community.

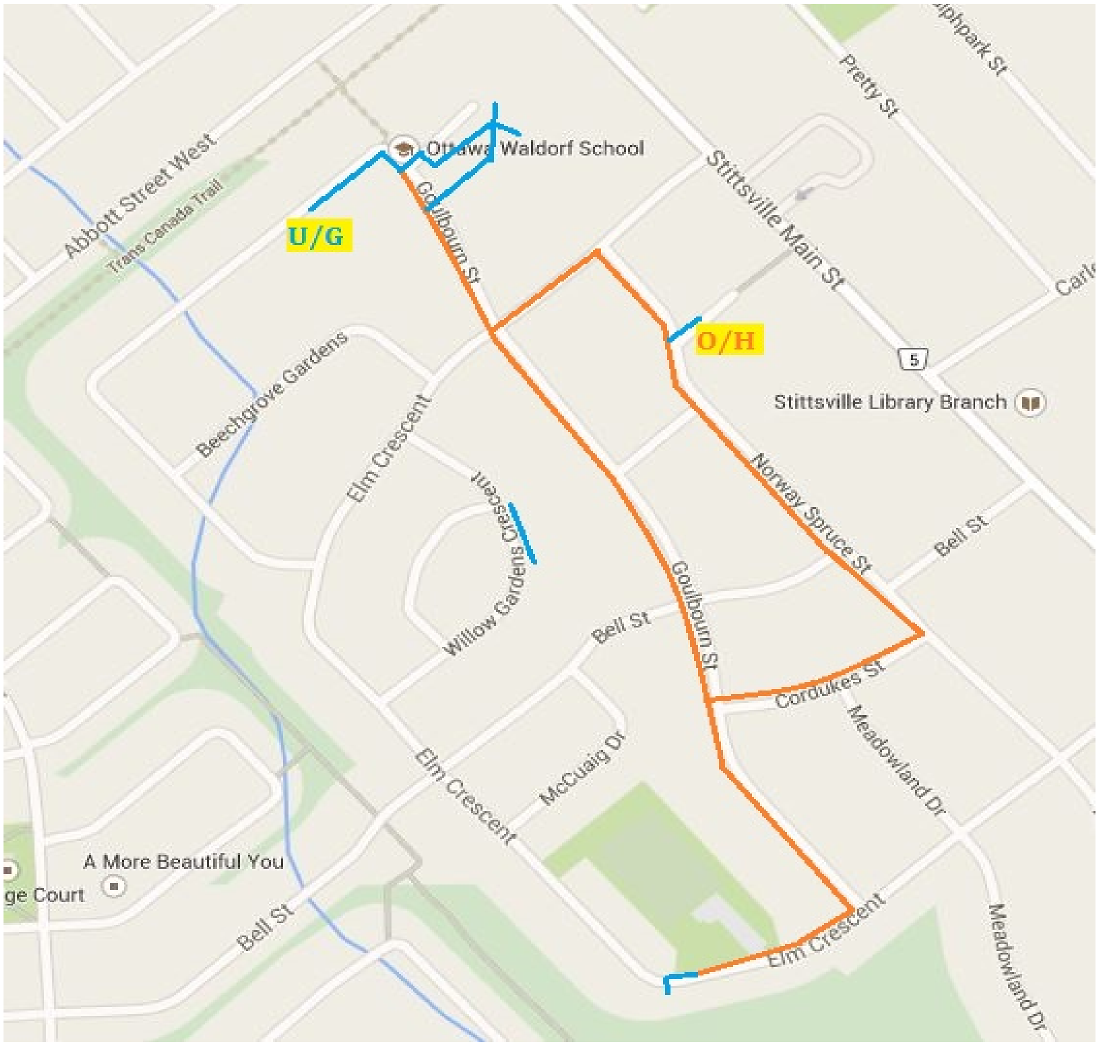


Figure 99 - Goulbourn Street Voltage Conversion Scope

3.5.2.3 *Main and Secondary Drivers*

The main driver of this project is to improve power quality on the 8.32kV system around Goulbourn Street. The area is supplied from 8.32kV by a single phase from 44F1 and due to the load and the location of the neighbourhood at the end of the feeder; customers have experienced voltage drops below acceptable limits during summer peak periods. The 27.6kV system is within 90m of the 8.32kV and requires minimal adjustment in order to extend a phase to convert the 27.6kV. Converting the customers on Goulbourn Street will improve the power quality that these customers experience, but will also benefit the customers remaining on the 8.32kV system.

The secondary driver of this project is to improve reliability as the 8.32kV system in this neighbourhood is radially supplied with no source of alternate supply. Through the completion of the development in this neighbourhood, a tie will be created between TFXF5 and JKGF4 which will be beneficial to more customers as a result of the conversion. Renewed infrastructure will directly improve SAIFI and the feeder ties will directly reduce the impact on SAIDI.

3.5.2.4 *Performance Targets and Objectives*

The main objective of this project is to improve power quality experienced by customers in the community surrounding Goulbourn Street. Conversion will directly benefit the customers being converted and those remaining on the 8.32kV system. This project will directly reduce the impact on the System Average RMS Variation Frequency Index (SARFI) used to measure power quality issues in the system.

A secondary objective is to improve reliability in the Goulbourn Street community. New infrastructure will directly improve SAIFI and the feeder ties will directly reduce the impact on SAIDI.

3.5.3 Project/Program Justification

3.5.3.1 *Alternatives Evaluation*

3.5.3.1.1 Alternatives Considered

Power quality in the Goulbourn Street community has been greatly impacted by the increasing number of customers on a radial 8.32kV supply at the end of the feeder, due to land splitting that has occurred.

Alternative #1: Routing considered is along Goulbourn Street. This route would extend the JKGF4 from Cypress Gardens to Elm Crescent. This option is the most direct route to extend 27.6kV to be capable of converting the 8.32kV infrastructure. Conversion will directly benefit the customers being converted and those remaining on the 8.32kV system. This project will directly reduce the impact on the System Average RMS Variation Frequency Index (SARFI) used to measure power quality issues in the system. New infrastructure will directly improve SAIFI and the feeder ties will directly reduce the impact on SAIDI.

Alternative #2: Routing considered is along Elm Crescent and Goulbourn Street. This route would replace the existing forty-one (41) poles and single phase 8.32kV infrastructure with three phases of the 44F1 8.32kV feeder. Having all three phases would permit the balancing of load across each phase. Also required would be a three phase voltage regulator to be installed on Stittsville Main Street that would provide the ability to better regulate voltage at the end of the 44F1 feeder and in the Goulbourn Street community.

3.5.3.1.2 Evaluation Criteria

Costs:

Alternative #1: $0.802M

Alternative #2: $0.940M

Ability to supply load:

Alternative #1: The 8.32kV system in the Goulbourn Street community cannot support additional load growth without compromising the power quality issues further. Extension of 27.6kV into this area will permit further load growth, which this area has experienced due to large lot sizes being split to accommodate more residential homes.

Alternative #2: This option will permit load growth in the Goulbourn Street community, but may not completely eliminate the power quality issues due to its location at the end of the 44F1 8.32kV feeder.

Reliability Benefits:
Both alternatives would benefit reliability in the community by renewing infrastructure; however Alternative #1 would create a tie between two feeders that would ultimately reduce SAIDI.

3.5.3.1.3 Preferred Alternative
Alternative #1 is the preferred alternative due to power quality improvements, project costs and reliability benefits associated with this alternative.

3.5.3.2 *Project/Program Timing & Expenditure*
The total project cost is $802,000 and the project is anticipated to be completed in 2016. HOL aims to minimize the costs and meet the deadlines associated with all projects, by completing pre-planning of the construction schedule and ensuring vehicles, staff and material are all available for start of construction.

Historical ($M)						Future ($M)			
2010	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
$0	$0	$0	$0	$0	$0	$0.802	$0	$0	$0

Table 101 - Project Expenditures

3.5.3.3 *Benefits*
Key benefits that will be achieved by implementing the Goulbourn Street Voltage Conversion project are summarized below.

Benefits	Description
System Operation Efficiency and Cost-effectiveness	This project is required to improve reliability in the Goulbourn Street community. It is an essential system service project needed in order to improve power quality issues and system operation efficiency by interconnecting the new Terry Fox TS to the distribution system in Stittsville and provide an alternative source when restoring outages. This should inevitably contribute to reducing SARFI and SAIDI. Re-constructing the infrastructure on Goulbourn Street is the most cost-effective solution and has the greatest benefit of improving the power quality and reliability in the Goulbourn Street community.
Customer	This project will achieve power quality and reliability improvement for customers in the Goulbourn Street community. The conversion of 8.32kV to 27.6kV should eliminate the power quality issues experienced by these customer and renewed infrastructure that will ultimately improve SAIFI.
Safety	The infrastructure in place today has begun approaching end of life and poses a small risk of failure and safety concern. By replacing the infrastructure, the safety risk is significantly reduced.
Cyber-Security, Privacy	Not Applicable.
Co-ordination, Interoperability	Not Applicable.
Economic	This project is not expected to contribute directly to economic growth or job

Development	creation, but due to the number of assets being replaced in this project, will inevitably require operation and maintenance. Contractor labour will be used extensively to complete the project.
Environment	Not Applicable.

Table 102 - Project Benefits

3.5.4 Prioritization

3.5.4.1 *Consequences of Deferral*

The consequence of deferring this project will result in further power quality issues experienced by customers of the Goulbourn Street community. Infrastructure that currently supplies this community will continue to deteriorate and both power quality and reliability can be expected to continue to worsen, which contributes highly to the total system SARFI and reliability statistics due to the number of customers in the community.

3.5.4.2 *Priority*

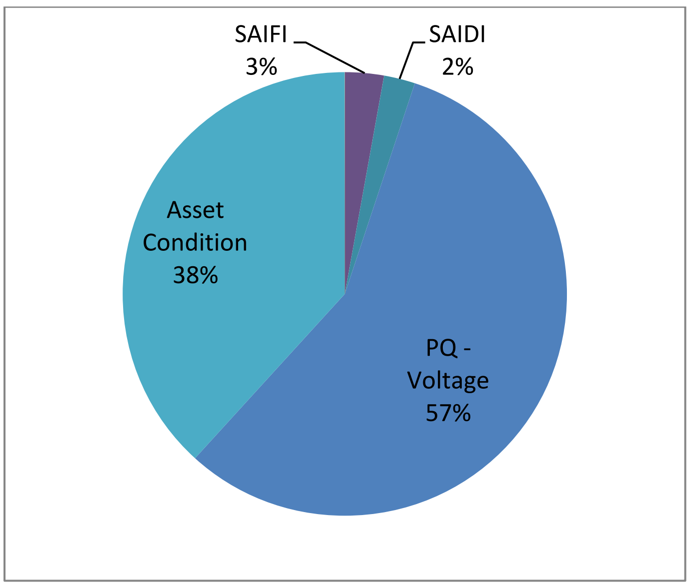


Table 103 - Project Avoided Risk

Project Score: 0.235

3.5.5 Execution Path

3.5.5.1 *Implementation Plan*

This project is to be entirely completed in 2016 and includes extension of JKGF4 90m along Cypress Gardens through use of direct buried duct system to encase the single phase cable, that will then rise up to the existing 8.32kV overhead system on Goulbourn Street. Incorporated in this project will be the replacement of forty-seven (47) poles, nine (9) overhead transformers, five (5) padmounted transformers and a total of 220m of direct buried duct encased trunk. Also included will be the change of phase on five (5) transformers that will allow each phase of the feeder to most efficiently extend through the neighbourhood and remain relatively balanced.

3.5.5.2 *Risks to Completion and Risk Mitigation Strategies*

Risks that may affect this project are easement acquisition, existing location of trees, and bedrock. HOL takes many steps in the design phase of the project to minimize these risks by investigating them early on.

3.5.5.3 *Timing Factors*

Factors affecting the timing of this project include easement acquisition, City of Ottawa Municipal Consent, customer outage limitations and weather conditions.

3.5.5.4 *Cost Factors*

Factors that may affect costs of the project include costs associated with digging through rock and delays due to weather conditions.

3.5.5.5 *Other Factors*

Not applicable.

3.5.6 Renewable Energy Generation (if applicable)

Not applicable.

3.5.7 Leave-To-Construct (if applicable)

Not applicable.

3.5.8 Project Details and Justification

Project Name:	92010184 – Goulbourn Street Voltage Conversion
Capital Cost:	$0.802M
O&M:	$0
Start Date:	2016 – Q1
In-Service Date:	2016 – Q4
Investment Category:	System Service
Main Driver:	Power Quality
Secondary Driver(s):	Reliability
Customer/Load Attachment	200 Customers/500kVA
Project Scope	
The Goulbourn Street Voltage conversion is intended to fix power quality issues experienced by customers in and around Goulbourn Street in Stittsville. This community has seen significant change since the time of its first development. Properties have experienced multiple severances of land in order to build multiple homes and have resulted in unbalanced load and over loading of the one phase supplying this area, which has ultimately led to low voltage experienced by these customers. By converting these customers and looing them in with the 27.6kV JKGF4 feeder, renewed infrastructure and balancing load amongst the phases will eliminate their low voltage issues. Limited expansion is required in order to have 27.6kV available to the area. Conversion from 8.32kV to 27.6kV is the end goal of all areas within the Stittsville community in order improve reliability and eliminate power quality issues on-going with the 8.32kV system.	
Work Plan	
The scope of this project, to be completed in 2016, is to extend one (1) 27.6kV phase from JKGF4 to convert the 8.32kV to 27.6kV. This includes 220m direct buried duct system to encase the single phase cable extension, replacement of forty-seven (47) poles, nine (9) overhead transformers, and five (5) padmounted transformer. Also included will be the change of phase on five (5) transformers that will allow each phase of the feeder to most efficiently extend through the neighbourhood and remain relatively balanced.	
Customer Impact	
By integrating 27.6kV into the distribution system in the Gouldbourn Street community, it will improve system power quality and reliability. The number of customers experiencing power quality issues should diminish significantly. This project will also increase reliability through development completion and integrating with Terry Fox feeders on Fernbank Road.	

4 Distribution Automation

4.1 Telecommunications Master Plan

4.1.1 Project/Program Summary

The Telecommunications Master Plan is a project to focus all of the HOL communications spending into one core network architecture. With a single converged network, HOL will make efficient use of its telecommunication budget while at the same time establishing the capacity that will accommodate all future traffic needs. This network plan involves a mix of radio systems which comprise the Field Area Network (FAN) connected to a core Wide Area Network (WAN) made up primarily of high capacity fibre optic links. Therefore, this project will involve the architecting, design, procurement, and construction of a complete communications network solution.

4.1.2 Project/Program Description

4.1.2.1 *Current Issues*

Currently, HOL makes use of a variety of communications technologies and services across various business units including:

- SCADA Communications:
  - o A leased fibre optic network connecting 41 locations (substations, SCADA head offices) across the service territory with low bandwidth serial communications channels. This system was installed by a predecessor utility (Ottawa Hydro) in the early to mid-1990's and was divested at the time of deregulation. Therefore as the assets are approaching the end of their useful life, and given the size of the network, replacement should begin in the very near future.
  - o Leased public owned telephone service (POTS) lines connect several substations with the SCADA head-end using legacy serial modem technology. These links are particularly expensive considering their low capacity. Furthermore, due to the age of the modems used for these lines a replacement in the near term is preferable.
  - o Leased 3G/4G services providing higher-capacity links to substations that are equipped with distribution automation equipment and sensors. This hardware is fairly new however the services are costly for data intensive locations.
  - o Two serial radio systems (both licensed and un-licensed 900MHz spectrum) connect various automation devices to substations and the SCADA head offices. These low cost technologies will be carried forward into the proposed network as a connection from the substations to the surrounding distributed sensors and devices. The hardware involved in these networks has been installed for several years and can be reused in the proposed network.
  - o A pilot WiMAX network which is being trialed as a new point-to-multipoint communications system to reach distant substations and devices that are outside of the feasible reach of a private fibre network (e.g. rural substations).
- Corporate communications:

- Leased high-capacity data services are used to connect the various offices to each other for network connectivity between sites. This asset is not owned by HOL.
- Microwave point-to-point radio links. These links are designed to provide a backup communication path in the event of a failure in the leased data link. The radio equipment is owned by HOL while the spectrum is licensed from Industry Canada.
- Office telephone lines are leased however in-building infrastructure is at a significantly advanced age and is requiring repair.

The fibre optical cable assets proposed in this project have a typical lifespan of 25 years which will make this an excellent long term investment. This network will be designed in a highly reliable configuration to accommodate all SCADA and Office communications traffic with sufficient capacity to handle future growth.

While the age of the assets discussed above is not the primary driver of this project, many parts of the network that HOL uses are nearing their end of life. Given the time required to deploy a large communications network, it is important that the planning begin at once.

The bulk of the communications assets are not owned by HOL but are approaching the end of their expected life span (particularly the leased SCADA fibre network). Due to its size, complexity, and cost, it is important that the planning phase for a replacement begin immediately. As a result, this project aims to systematically consolidate all of the disparate communications systems into one coherent wide area network to accommodate all of HOL's network communications needs.

Without a comprehensive network built and operated by HOL, we will be forced into unfavorable contracts with service providers that will charge based on the amount of data capacity required. This will result in a financially untenable situation as the demand for data increases exponentially as the amount of smart grid devices and sensors are deployed on the distribution system.

4.1.2.2 *Program/Project Scope*

This project encompasses the communications needs of HOL across its entire service territory. Therefore, the scope of this project is exceptionally wide as there will be multiple stakeholders across the organization and the project will span a significant geographical area.

At the conclusion of this project, HOL will own and operate the following assets:

- A high capacity fibre optic network which will provide connectivity between all offices and the bulk of the centrally located substations.
- A point to multi-point microwave or WiMAX radio network which will provide connectivity to rurally located substations and to field equipment requiring broadband network connections (e.g. distribution automation groups, AMI gatekeepers etc.)
- A point to multi-point unlicensed radio network which will provide connectivity to end-point equipment in the local proximity to a higher bandwidth node. (e.g. individual distribution automation equipment, sensors, smart meters etc.)

Therefore, all communications equipment owned or leased by HOL and communications services purchased by HOL will fall within the scope of this project. The overall objective of this project is to eliminate both legacy communications equipment, and the use of expensive communications services. These will be replaced with a private, high bandwidth network capable of securely handling all of HOL's communications needs.

4.1.2.3 *Main and Secondary Drivers*

The primary driver for this telecommunications master plan project is to ensure the long term financial viability of the HOL field (SCADA) and office networks. This is due in part to the fact that customers of the 21st century are more demanding than ever before. They expect service providers to be pro-active, responsive and cost-effective. HOL customers are no different. They expect us to be fully aware of the distribution system performance at all times: outages, brown outs, voltage disturbances, and power quality issues. In the age of electronics, all of these issues are critical to our customers. These new expectations are reshaping how utilities will deliver service now and in the future. HOL believes the Smart Grid is the future.

In 2012, HOL commissioned a study called Grid Transformation Action Plan (GTAP) which articulated what the Smart Grid means in the context of both the Ontario electricity market and HOL's distribution system. Amongst the conclusions of this study was the idea that the Smart Grid has three key qualities: it is instrumented, intelligent, and interconnected. Although power systems have remained virtually unchanged over the years, how they are monitored and restored has changed greatly in the last 25 years. New automated switches, sensors and smart meters all connected to a high speed network help make the system more reliable and efficient. This is the Smart Grid. By merging the distribution system with high-performance communications, HOL will achieve its goal of providing reliable service and value to its customers and shareholder.

Therefore, the primary drivers for this project are:

- The long term financial viability of HOL's communications needs.
- To accommodate the ever increasing communications needs of intelligent devices and distribution automation (i.e. to accommodate the 'Smart Grid').

The secondary drivers for this project are:

- To create a private network that can be fully controlled by HOL in the interest of improving the cyber-security of the SCADA system thereby protecting the critical infrastructure of the nation's capital city.
- To expand connectivity and allow each and every substation to become a data aggregation point capable of communicating with thousands of devices.

4.1.2.4 *Performance Targets and Objectives*

With a unified communications infrastructure connecting the bulk of the HOL substations, the ability to collect and utilize data from the field will be dramatically improved both in terms of bandwidth and reliability. As mentioned in the introduction, HOL has invested wisely in intelligent devices and sensors within the substation environment. By having these devices connected to each other and the office through reliable high speed links, a vast array of smart-grid applications will become available for implementation. These include:

- Bringing device and operational data into the asset management system, enabling more intelligent maintenance and investment
- Real-time collection of fault data for calculating the fault location, thereby reducing outage time and person-hours lost to discovering the root cause
- Device coordination between substations and field devices, allowing for automatic fault isolation which could significantly reduce outage statistics

One of the most important benefits of the core network strategy is enhanced financial strength. As discussed in the introduction above, HOL currently has several different systems with independent communications links. The consolidation of these communications links onto a core network will help monetize HOL's communications dollars. While there will still be the need to reach each individual device with a link, a core wide area network (WAN) will allow each and every substation to become a data aggregation point for many types of devices. Moving these aggregation points from the main office further into the field will reduce the distance to each individual sensor and allow for the use of lower cost wireless links (such as unlicensed 900MHz or WiMAX). Furthermore, by having a high capacity core network the future growth of data intensive field connections (as driven by Smart Grid applications) will be easily accommodated, thereby containing future costs per connection.

In addition to data coming in from the field, the core WAN network will allow corporate data traffic to be accessible from the substations. This connectivity will serve to increase the productivity of the outdoor staff by allowing access to documents and drawings without the need for expensive cellular connectivity or the delays of returning to the corporate office. Further productivity gains may be realized with the IT operations staff as well. This is due to the fact that a single core WAN infrastructure will serve to reduce overall complexity (with use of similar hardware) of the HOL communications networks. The reduced complexity will aid in monitoring and maintenance of a single network.

The most important aspect of this telecommunications master plan is that it aligns well with our corporate strategy - the customer. With a fully interconnected grid, this utility will be able to make use of advanced Smart Grid technologies which could drastically improve the customer experience. From the reduction of both the frequency and duration of outages, to making more information available in a timely manner; the customer experience will be enhanced. While there will still be a need to proactively analyze and act on the state of the intelligent devices, the communications infrastructure provides the invaluable ability to collect the data from the field.

4.1.3 Project/Program Justification

4.1.3.1 *Alternatives Evaluation*

4.1.3.1.1 Alternatives Considered

HOL evaluated four main alternatives for the communications master plan. Alternative one would be to maintain the status quo; with each application continuing to use and maintain its own separate infrastructure on a case by case basis (e.g. Meter data collection and SCADA uses separate backhaul infrastructure). The second and third alternatives involve the design and construction of a complete wireless or fibre system to cover the entire HOL service territory (e.g. Entirely wireless system or entirely Fibre based system). Finally, the fourth alternative would create a hybrid network which would see a core wide area network made primarily from fibre links with wireless systems providing connectivity where most appropriate (e.g. the Field Area Network and to remote substations).

4.1.3.1.2 Evaluation Criteria

Each of these alternatives was evaluated against the following criteria:

1) Cost-effectiveness
    a) Is the current infrastructure cost-effective or sustainable?
    b) Is the considered alternative more cost efficient in the long term?
    c) Is it sustainable as a HOL owned asset?
2) Functionality
    a) Can the considered alternative accommodate the current data requirements?
    b) Can the considered alternative accommodate the future growth in data traffic?
    c) Can the considered alternative accommodate different traffic priorities?
3) Future expandability
    a) Is the considered alternative expandable to accommodate future needs?
4) Security (both cyber-security and in terms of reliability
    a) Is the considered alternative more or less secure against cyber-attack?
    b) Is the considered alternative more or less reliable than the current network?

4.1.3.1.3 Preferred Alternative

The preferred alternative is to create a hybrid-network with a core comprised of a fibre optical network between the main office locations and the majority of substations augmented with wireless systems to connect field devices and remote substations. This hybrid network offers the most functionality and the best overall connectivity. In addition, the core fibre network offers the highest cyber-security and reliability while the peripheral wireless networks will aid in balancing the overall cost of the network. The hybrid-network approach is the most cost efficient over the long term, particularly as more and more data intensive sensors and devices are deployed across HOL's service territory. As each device is deployed, a pre-planned network will easily accommodate the new connections with limited ongoing cost as opposed to the cost growth from purchasing new data services from an outside vendor as is typically done today.

Beyond the preferred alternative were the two monolithic network solutions of an all fibre network and an all wireless network. While both of these solutions can provide the connectivity required, they do not have the cost advantages of the hybrid topology. Finally, the least preferred alternative is to do nothing and continue to deploy connections on individual disparate communications networks. This 'do nothing' alternative will become unsustainably expensive as smart devices and sensors become necessary across the distribution grid.

4.1.3.2 *Project/Program Timing & Expenditure*

As described in the above sections, the communications system proposed in this Telecommunications Master Plan is a significantly large undertaking. In order to fully deploy the hybrid network it will involve over 10 years of capital investment as well as ongoing OM&A expenses. While this may seem to be an overly ambitious expenditure, the project is broken down into three phases of investment in order to ease the transition to a new communications infrastructure.

Phase 1 of the project is the initial design and construction of the core high-speed optical network, including pilot projects and their associated studies. Included here is the equipment required to transition the current leased fibre from a low-speed serial link to a high-speed network connection. This phase also sees the installation of new fibre optical cable in order to bring the network up to the required level of redundancy for passing all of HOL's network traffic.

Phase 2 of the project is focused on expansion of the fibre network to connect additional substations to the core wide area network. More importantly is the installation of the wireless equipment needed to connect field area devices to base station radios located within selected substations.

Finally, phase 3 is designed to incrementally replace the leased fibre optic cable with HOL owed infrastructure. This will prevent the need from entering into another unfavorable lease and to replace infrastructure that would be at the end of its useful life.

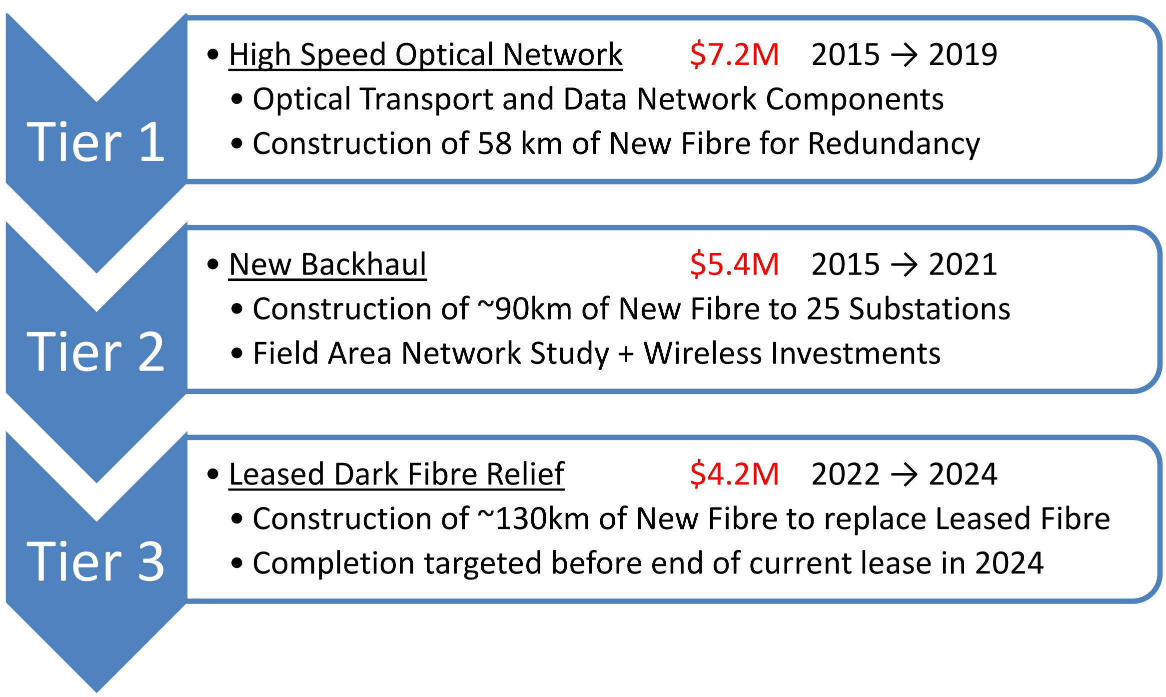
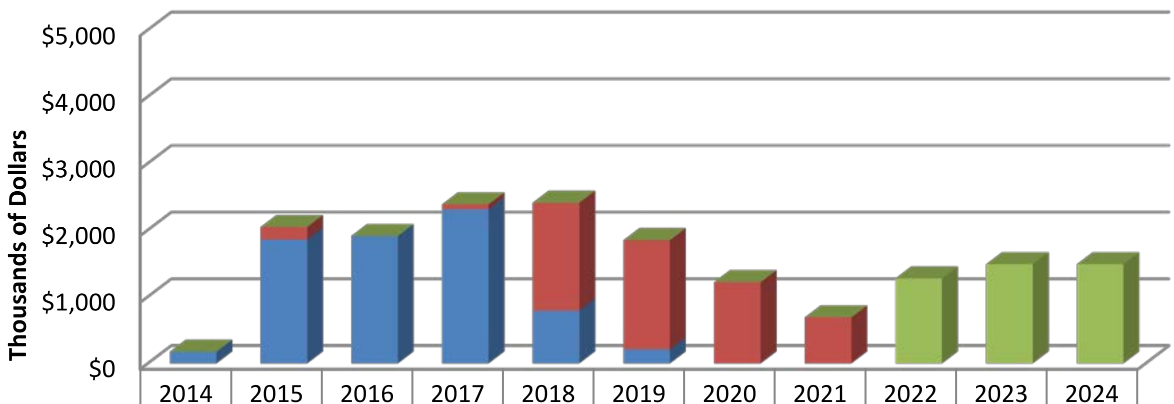


Figure 100 - Project Timing

The following chart illustrates the breakdown in the capital expenditure for each year and shows the category in which the investments are made. While this initial plan shows a steady stream of investment over the next 10 years, the modular nature of the proposed infrastructure means that individual investments can be shifted around into more favorable years.



	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Total	$175	$2,044	$1,910	$2,383	$2,408	$1,846	$1,218	$689	$1,274	$1,487	$1,487
Tier 3	$0	$0	$0	$0	$0	$0	$0	$0	$1,274	$1,487	$1,487
Tier 2	$0	$189	$0	$77	$1,616	$1,638	$1,218	$689	$0	$0	$0
Tier 1	$175	$1,855	$1,910	$2,306	$792	$208	$0	$0	$0	$0	$0

Figure 101 - ROM Capital Investment by Year and Tier

Due to the transformational nature of this telecommunications plan, the analysis of the impacts on the OM&A budget is significantly more complicated. Therefore, the following section will address the assumptions that were made in three parts; IT costs, communications cost reductions, and avoided future costs. Following the description of the assumptions, the total impacts on the operations budget will be combined in a high level analysis summary.

One key area of HOL that will be impacted by this network infrastructure change is the IT department. While a larger and more advanced network will increase the demands on IT resources, the fact that it will be designed for manageability as a single network will serve to streamline operations. To address this increased demand there will be a need for additional resources. Furthermore, there will be associated costs for a network operations centre, network management systems, and associated software licenses.

As described earlier one of the drivers for creating a new core wide area network is to control the current communications costs. With the construction of the new high-speed network, HOL will be able to eliminate both the fibre lease and the leased public telephone lines. These leased network costs together with the cellular and licensed radios represent a significant burden on the overall OM&A budget. Unfortunately, given the size and the complexity of the leased infrastructure, it will take several years before these lease costs transition to the maintenance and operational costs associated with a private infrastructure. Therefore, until the communications master plan is complete, the majority of this expenditure will remain in the annual budget.

Most importantly, this telecommunications master plan is about controlling the future costs of communications as the HOL distribution system is transformed into a smarter grid. With the increased interconnectedness as demanded by smart grid applications, this core WAN strategy will provide all of the required connectivity at a drastically lower cost than the current solutions. In order to realize these savings it is assumed that HOL will be incrementally transitioning to a fully connected and automated distribution system over 25 years. In order to achieve this end state, HOL will need to install sensors and automated systems out onto the distribution grid each and every year which has indeed been the case.

Therefore with the future investments in distribution sensors and automated devices, HOL requires lower cost, high bandwidth connections across its service territory.

4.1.3.3 *Benefits*

Benefits	Description
System Operation Efficiency and Cost-effectiveness	With an advanced communications network connecting office locations and substations across its service territory, HOL will be able to add new connections for a very limited additional cost. Therefore, as more and more devices are connected, the communications network will become more and more cost efficient. These additional sensors and devices are an unavoidable reality for a modern distribution utility.
Customer	With a comprehensive communications network across the service territory, HOL will be able to deploy advanced sensors and distribution automation equipment. These devices will have a direct and measurable effect on the duration of outages experienced by customers (SAIDI). Furthermore, by collecting more and more data from substation and field devices, there will be a significant improvement in the prioritization of maintenance activities. This evidence based maintenance will lead to significant reductions in the frequency of asset failures over the longer term. Therefore, customers will see an associated reduction in asset failure based outages thereby reducing the outage frequency (SAIFI)
Safety	In designing a complete, reliable communications network with redundant paths built in, HOL will eliminate its dependence on third part networks which can fail at inopportune moments. Therefore, a more reliable network will allow for higher reliability in the SCADA connections thereby improving the overall safety of system operations.
Cyber-Security, Privacy	With a private network HOL will no longer be dependent on third party carriers for the bulk of its network traffic. This will serve to reduce the overall exposure of the HOL SCADA system to cyber-attacks.
Co-ordination, Interoperability	The proposed network will make extensive use of standards based technology in order to ensure the long term availability of replacement parts. Furthermore, by creating a common network for all HOL traffic there will be a significant improvement in the internal co-ordination of communications systems deployment and usage.

Economic Development	Given the size and scope of this investment, it is likely that the construction phase will require the support of third party firms in the Ottawa area. These design and construction contracts will provide direct economic benefits to both the high tech community as well as the construction firms within the capital region.
Environment	The communications network proposed in this project is an enabling technology. By connecting the sensors and devices across the distribution system, HOL will be in a better position to operate the grid in a more efficient and environmentally friendly way.

Table 104 - Project Benefits

4.1.4 Prioritization

4.1.4.1 *Consequences of Deferral*

While this communications network is not critical to providing electricity to HOL's customers, it will aid in the transformation of HOL's business. This transformation will result in a significant improvement in the capabilities of this utility to collect, analyze, and act on data collected from the field. These actions will have a direct and significant benefit to both HOL's customers and its shareholder. The former will see improved outage statistics while the latter will see improved financial performance garnered from a reduction in the cost growth associated with communications expenses. Therefore, any delay in this project will delay the realization of the associated benefits to HOL's stakeholders.

4.1.4.2 *Priority*

The overall priority of this project is medium. Due to the fact that the communications systems are not central to the distribution of electricity to HOL customers, this investment cannot be rated as a high priority. However, due to the benefits that will be garnered from the connectivity and the associated cost growth of 3rd party connections, this project cannot be listed as a low priority.

4.1.5 Execution Path

4.1.5.1 *Implementation Plan*

As discussed in section 3.2 above, this project will be executed in three distinct phases. The first phase will be the initial design and the conversion of the current fibre network to a high-speed network. The second phase will involve enhancement to the capacity of the network in terms of geographical coverage. This expansion will be in the form of new fibre optical cabling as well as the deployment of radio systems into the field. Finally, the third phase will see construction of fibre optic connections to replace the connections that are currently leased from a third party network provider.

4.1.5.2 *Risks to Completion and Risk Mitigation Strategies*

The largest risk to completion of this project is the overall cost of implementing the network. While it appears to be a significant expenditure, the overall cost of owning this network will be far lower than the associated service costs from third parties.

4.1.5.3 *Timing Factors*

Due to the fact that this is a long term investment, there is little risk that schedule pressure will be an issue. HOL requires a replacement to the leased fibre optic network before the end of the year 2024. While it is advisable that the full network be implemented as soon as possible, there is a significant amount of time remaining for execution.

4.1.5.4 *Cost Factors*

Given any project of this magnitude, the overall cost of implementation is a factor. Due to the fact that the network proposed in this project will cost in excess of $17 million dollars to fully implement, it has been broken down into much smaller investments. While it would be ideal to implement this network as fast as possible, it is recognized that this would prove infeasible. Therefore to mitigate the risk of cancellation, the project will be delivered in smaller investments over the next 10 years thereby positioning HOL to be independent of a costly lease at the end of its current contract.

4.1.5.5 *Other Factors*

N/A

4.1.6 Renewable Energy Generation (if applicable)

N/A

4.1.7 Leave-To-Construct (if applicable)

N/A

4.1.8 Project Details and Justification

Project Name:	Telecommunications Master Plan
Capital Cost:	Approximately $17M
O&M:	TBD
Start Date:	January 1 2014
In-Service Date:	December 31 2024
Investment Category:	System Service
Main Driver:	Long-Term Economic Viability of Communications Infrastructure
Secondary Driver(s):	Accommodate Ever Increasing Demands for Device Connectivity
Customer/Load Attachment	305,000

Project Scope

This project encompasses the entire network communications infrastructure of HOL. This includes corporate data and voice traffic between offices as well as SCADA traffic between facilities, substations, and field devices.

Work Plan

This project will be executed over a 10 year time frame starting from 2014 and ending in the year 2024. The work will be broken out into three distinct phases of work, phase one will see the transition of the existing system to a high-speed network. Phase two will feature expansion of the communications infrastructure to include more field devices and substations. Finally the third phase will feature replacement of the leased fibre infrastructure.

Customer Impact

A comprehensive and advanced communications infrastructure will allow HOL to improve both its ability to react to customer outages as well as its ability pro-actively maintain its assets, thereby preventing outages from occurring. This improvement will come from HOLs ability to collect more data from assets in the field, and its ability to interactively communicate with intelligent devices on the distribution system.

5 SCADA Upgrades

5.1 SCADA Upgrade Project

5.1.1 Project/Program Summary

The Supervisory Control and Data Acquisition (SCADA) System replacement project is necessary to bring both the hardware and software components up to date. Installed in the fall of 2006, the current system uses an out of date operating system, end of life hardware, and is no longer regularly maintained by the vendor. It is therefore necessary to install new hardware and software that utilizes a modern architecture and is designed for both maximum security and reliability.

5.1.2 Project/Program Description

5.1.2.1 *Current Issues*

The current SCADA system was installed in the fall of 2006 and has been operational for over 8 years. This operational period is well beyond the typical 5-year lifespan of information technology hardware. Over the past year, there have been several hardware failures within the server equipment which clearly indicate that the assets are approaching the end of their useful life and should be replaced immediately.

In addition, the software used in the HOL SCADA system is running on an operating system that is no longer being supported by the vendor and (according to our SCADA vendor) cannot be migrated to a new operating system. It is the intention of this project to bring the HOL SCADA system back onto a solution where regular maintenance of the software, operating systems, and hardware is once again possible.

The SCADA system at HOL provides real-time situational awareness of the state of the distribution system and assets to the control room. Equally important is the fact that the SCADA system provides the control room with the ability to operate devices remotely without the need to dispatch field staff. This remote operation is extremely important in cases of public or employee safety where a device needs to be opened with little or no advanced warning.

As a result of the above mentioned dependencies, the HOL SCADA system cannot be allowed to fail. Without the ability to supervise and control the distribution system, there would be a significant impact on the ability to detect and mitigate outages and, as a result, the customers would be severely impacted (particularly the SAIDI measure of outage duration).

While the current system does have redundancy across multiple servers in two locations by design, the similar age and software dependencies of all systems serves to erode any reliability gained.

5.1.2.2 *Program/Project Scope*

This project will involve the purchase and installation of an entirely new SCADA system for the HOL control room. Due to the fact that the current system is no longer on an upgrade path with the vendor (i.e. there are no patches or service packs available) a new installation will be required. This replacement project presents an opportunity to architect a new system that takes into account matters of functionality, reliability and cyber-security.

Therefore, this project will be focused on acquiring new hardware including: database servers (9), engineering servers (3), interface servers (13), workstations (25), networking equipment, firewalls (8), and communications equipment. More importantly this project will have a significant software purchase including: the Supervisory Control and Data Acquisition system, advanced distribution management systems, intrusion detection systems, and firewall software.

These systems will be located across several HOL locations including the Merivale Road and Albion Road offices as well as either the Bank Street or Maple Grove Road facilities. The project will not include any of the remote terminal units in the field or substations unless absolutely necessary.

5.1.2.3 *Main and Secondary Drivers*

The primary driver for this project is to ensure the continued operation and reliability of the HOL SCADA system. This will be achieved by replacing the computer and networking equipment with newer hardware and acquiring the software from a trusted and proven vendor.

The secondary objectives of this project are to enhance the functionality and reliability of the SCADA system moving forward. Under this functionality and reliability goals are the following:

- Improving Cyber Security: The current system does not have any specific intrusion detection measures or third party tools for monitoring traffic within the SCADA network.
- Enhancing Functionality: The current SCADA system does not have any advanced distribution management system functionality. These new functions serve to provide operators with analysis and in some cases can help to automatically restore customers.
- Improving reliability: While the current system has redundant hardware in two physical locations, it would be beneficial to expand this hardware to cover a third location. This third site would be used as both a disaster recovery location as well as a quality assurance (development) environment for testing any changes or new technologies. With this third location available the overall reliability of the system will be improved as new patches and other improvements can be tested without affecting the production environment.

5.1.2.4 *Performance Targets and Objectives*

The following represents the targets and objectives for the SCADA replacement project.

1) The primary objective of the SCADA replacement project is to have a new SCADA system deployed at HOL by the end of 2017. This new system must be:
   a) Capable of aggregating data from all of the current sensors and devices
   b) Capable of controlling all of the current remotely operated devices
   c) Capable of distributing information to engineering systems and related control systems
2) The second objective is to improve upon the reliability of the current system with:
   a) New enterprise class server hardware capable of running 24x7 for several years
   b) New networking equipment capable of routing SCADA traffic with high reliability
   c) Deployed systems configured for high reliability (dual power sources etc.)
   d) Regular maintenance and patching from the system vendor
3) The first upgrade objective is to improve the cyber-security posture of the HOL SCADA system

   a) Advanced Firewalls and network security equipment capable of securing SCADA traffic
   b) Enhanced user roles and management to prevent unauthorized access
   c) Detailed auditing capability for capturing all SCADA connected assets and users
4) The second upgrade objective is to include a third physical location in the network topology
   a) This will provide a disaster recovery location that could save the system database
   b) This will also allow for an environment for the purposes of testing and training
   c) It will aid in the transition to new facilities sometime over the next 5 years
5) The third upgrade objective is to enhance the features available to the control room staff
   a) Adding Distribution Management System (DMS) features can improve outage response
   b) Adding system drawing and pin-board features can reduce the number of additional tools needed within the control room

5.1.3 Project/Program Justification

5.1.3.1 *Alternatives Evaluation*

5.1.3.1.1 Alternatives Considered

Unfortunately, due to the age of the current SCADA system and the consequences of failure, the ‘do nothing’ alternative is not a valid option. Like any modern utility, HOL is dependent on the information collected from, and the control provided by the SCADA system. Operating without a reliable SCADA system over the long term would represent an untenable situation.

Alternative 1 is to perform a full replacement of both the hardware and software of the SCADA system. Given the age of the software and the operating systems used in the HOL SCADA system, it makes the most sense to perform a full replacement while the hardware is also being upgraded. This project should include expansion of the system and enhancement to the features in order to have the most impact on reliability, security and performance.

Therefore, there is essentially only one other alternative to the proposed replacement project which involves replacing only the hardware of the currently installed system. To do this, HOL would still require the purchase of new servers and networking equipment as the current equipment is near end of life. In order to keep the current SCADA software running, a set of virtual machines would need to be created from the existing systems and ported over to the new hardware. While the underlying operating system running on the servers would be new, both the operating system and the SCADA software running on the virtual machines would not be new. Although the primary objective of ensuring the continued operation of the SCADA system would be met, the secondary objectives of increasing functionality, reliability, and cyber security would either not be met or only partially met.

5.1.3.1.2 Evaluation Criteria

The following criteria will be used to evaluate the alternatives for the SCADA replacement project:

1) Mitigate Risk of System Failure: The proposed solution should address the current risk of hardware failure.

2) Improved System Reliability: The chosen solution should serve to improve the ability to recover from a major disaster.
3) Improved Cyber Security: The chosen solution should contain features that improve the defense in depth as well as the ability to audit the system hardware, network traffic, and users.
4) Cost: The selected alternative should serve to minimize the future replacement costs of the SCADA system.

5.1.3.1.3 Preferred Alternative

The preferred project alternative is to perform a full replacement of the SCADA hardware and software, with the enhancements described in alternative 1 above. This option is preferred over all others as it accomplishes all of the primary and secondary goals, but more importantly it is the option with the least amount of future risk. By upgrading the system with additional features for cyber security as well as a third redundant location, the risk posture of the HOL SCADA system would be dramatically reduced. This reduced risk posture more than compensates for the delta cost for adding these features to the new system. Additionally, installing new hardware during the acquisition of new software will allow for an easier transition to the new system while reducing disruption to the existing system.

Among the benefits of deploying a new system is the ability to engage ongoing support from the system vendor. Due to the fact that the current system is no longer on the vendor's development path it is not getting regular maintenance patches. With a properly selected replacement system (i.e. one with a clear development future) the future upgrades can come in the form of regular maintenance as opposed to infrequent major upgrade projects such as this one. This type of process is currently being used to maintain the HOL Outage Management System (OMS) which has resulted in both regular system improvements and predictable maintenance costs.

5.1.3.2 *Project/Program Timing & Expenditure*

This upgrade is coming at the very end of the typical life cycle of a SCADA system; therefore there is no comparable project for which costs can be directly compared over the recent past. However, by building a modern and fully featured system, HOL will be mitigating the costs and potential impacts of either a cyber-event or a disaster event.

The currently installed SCADA system at HOL has the following hardware: database servers (6), engineering servers (1), interface servers (3), workstations (17), networking equipment, firewalls (3), and communications equipment. The proposed system has 2 additional database servers (8), one additional engineering server (2), 10 additional interface servers (13), 8 additional workstations (25), additional networking equipment, 5 additional firewalls (8), and additional communications equipment.

The following chart illustrates the expected capital expenditure over the course of the SCADA replacement project. It is expected that the bulk of the spending is on vendor equipment and services from 2016 to 2018 while costs in 2015 are primarily for consulting and design services.

Historical ($M)					Future ($M)				
2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
N/A	N/A	N/A	N/A	N/A	0.3	1.0	1.0	0.5	0

Table 105 - Project Expenditures

5.1.3.3 *Benefits*

Benefits	Description
System Operation Efficiency and Cost-effectiveness	A new SCADA system will provide direct benefits on system operation efficiency as it is used to collect data and provide a real time picture of the distribution system. Therefore any improvements will result in greater situational awareness and enhanced capabilities for the control room staff. Furthermore, by increasing the capabilities and intelligence available in the control room, decisions will be made faster and result in more effective use of field resources.
Customer	As mentioned above, the enhanced situational awareness and advanced functionality provided to the control room staff from a new SCADA system will result in improved response times which will serve to reduce outage durations (SAIDI). Furthermore, added functionality of a new SCADA system can provide information to support day-to-day system operations and help to offload at risk assets and reduce the number of preventable outages (thereby improving SAIFI). While it is infeasible to quantify these impacts, features such as a Distribution Management System (DMS) and Power Flow analysis are designed to aid the system operators in the performance of their duties.
Safety	As described in an earlier section, the SCADA system is an integral part of protecting employees during planned and emergency work. Therefore this replacement project serves to improve the overall safety of staff by fully mitigating the risk of failure of the current system.
Cyber-Security, Privacy	As stated in the upgrade objectives above, one of the key elements specified in the new system will be tools and hardware dedicated to the defense of the SCADA system. These security features will be procured in accordance with industry best practices. With the improved security posture, HOL will be in a better position to protect the critical electrical infrastructure within the Ottawa area.
Co-ordination, Interoperability	The new SCADA system will employ industry standard technologies and best practices. A solution will be selected that allows for continued coordination and communications (over Inter-Control Centre Communications Protocol or ICCP) with both Hydro One and with the Independent Electricity System Operator. The new SCADA system will also be selected based partially on the ability to collect data from a variety of new sensors and technology that has been deployed throughout the HOL distribution system since the last SCADA solution was installed.
Economic Development	Due to the distinct nature of SCADA systems and the particular skills required to install them, it would be unwise to restrict purchasing to one geographic area at this time. While there are SCADA vendors and service providers within the province of Ontario, they should be evaluated for their ability to address the project objectives first, before addressing the economic development objectives.
Environment	A modern and fully featured SCADA system will help HOL's operations utilize

	assets in the field more effectively (with features such as volt-var control) which will help reduce losses. Furthermore, a reliable SCADA system will allow HOL to readily detect issues with failing assets and to easily remove them from service (with features such as power flow analysis) and prevent catastrophic failures which can lead to environmental spills (e.g. transformer oil leakage).

Table 106 - Project Benefits

5.1.4 Prioritization

5.1.4.1 *Consequences of Deferral*

As discussed above, the SCADA system that is currently installed at HOL is at the end of its useful life and is no longer receiving regular updates from the vendor. Therefore a replacement system is required in the short term. Should this replacement project be deferred, the risk of hardware failure will become unacceptably high. Furthermore, due to the fact that the Operating Systems and SCADA software are no longer receiving regular updates, the risk of new vulnerabilities will not be fully mitigated as they would be with a new system. As a result, deferral of this project would be an inappropriate risk to the safe and reliable operation of the HOL distribution system.

5.1.4.2 *Priority*

As a result of the consequences of deferral discussed above, this project is considered a very high priority when compared to most other projects (in this and other categories). Without an updated SCADA system in place, HOL operations could be significantly affected by a failure in the current system. To recover from such an unplanned failure would result in significant additional expenses for emergency work over and above those planned in this project.

5.1.5 Execution Path

5.1.5.1 *Implementation Plan*

This project will be completed in several phases over the next 4 years starting in 2015.

- Phase 1: Beginning in early 2015, HOL will engage the services of a consulting firm with experience in helping distribution companies select and install new SCADA systems. At the completion of this phase, it is expected that a detailed set of specifications would be used to select a SCADA vendor for the replacement system.
- Phase 2: During the course of 2016-17, the successful vendor will install the hardware and software for the new SCADA system and will complete the transition of the existing database to the new system. This will include the bulk of the server and workstation hardware for the control room. This end of phase will have the HOL control room fully trained and transitioned to the new system.
- Phase 3: The final phase occurring in 2017-18 will involve transitioning the SCADA system to the new facilities and to create and install the disaster recovery location.

5.1.5.2 *Risks to Completion and Risk Mitigation Strategies*

There are risks to any project of this size and complexity including documentation issues, project mismanagement, poor resourcing etc. Recognizing that HOL is unable to commit the number of resources with the required skills to mitigate those risks, an outside firm will be contracted to manage the replacement project. This project management service will serve to reduce the level of risk that HOL is exposed to by leveraging experienced professionals for the duration of the project.

Of course, this additional relationship between HOL and the consulting firm, comes with some level of risk. Therefore, a risk to the successful completion of this project is a failure on the part of the project management firm selected. To mitigate this risk, only a small group of firms with previous experience in SCADA deployments are being invited to bid on the contract. Furthermore, part of the criteria in selecting the successful bidder will be a thorough review of the staff and involvement in previous projects.

5.1.5.3 *Timing Factors*

There are several factors which could affect the timing of this project including:

- Early failure of existing SCADA system: It is possible that the existing system fails in such a way that requires immediate replacement. This would necessitate a significant advancement of the schedule.
- Vendor and support availability: This risk has been mitigated by starting the project a full three years before the target completion date.
- Additional time required to integrate with existing HOL systems: This risk has been mitigated by engaging a consultant to help define the requirements of the new system early on in the project.

5.1.5.4 *Cost Factors*

With any project involving IT hardware and software, there are risks that additional features, licenses, or modules will be required that could serve to inflate the cost of the overall project. Furthermore, while every effort has been made to ensure that adequate funding has been earmarked for this project, it is possible that there will be additional funds required to ensure the smooth transition from the old system and that all of the data is preserved in the new system. This risk has been partially mitigated by bringing in an outside firm to aid in the selection of the new system vendor.

5.1.5.5 *Other Factors*

N/A

5.1.6 Renewable Energy Generation (if applicable)

N/A

5.1.7 Leave-To-Construct (if applicable)

N/A

5.1.8 Project Details and Justification

Project Name:	SCADA Replacement Project
Capital Cost:	$2.8 M Est.
O&M:	$50k/yr Est
Start Date:	January 2015
In-Service Date:	January 2018
Investment Category:	System Service
Main Driver:	Current Assets at End of Life
Secondary Driver(s):	Improving Cyber-Security Improving Overall Reliability Improving the Tool Set
Customer/Load Attachment	305,000

Project Scope

This project will encompass the selection, design, installation, and commissioning of an entirely new SCADA system at HOL. The project will begin with a requirements definition phase beginning in 2015 and end with user training and the transition to the new system in 2017/18.

Work Plan

This project will occur in the basic phases:

- Phase 1: With outside support, requirements will be defined and a new system selected
- Phase 2: System installation, training n and commissioning
- Phase 3: Reliability Enhancement and transition to new facilities.

Customer Impact

With the new SCADA system customers will see enhanced system reliability and improved outage performance. The system reliability will be improved through hardening of the SCADA system itself from failure or cyber-attacks. The improved outage performance will come from the advanced features which will help the HOL system office respond faster and more effectively to outage events.

General Plant

1 Facilities Implementation Plan

1.1 Project/Program Summary

Hydro Ottawa's Facilities Implementation Plan is the result of a determination by executive management team and Board of Directors to procure new facilities intended to:

a) consolidate operations and administrative staff;
b) to move its operational centers out of high traffic residential districts to land parcels or sites with easy access to major highways within the Ottawa area;
c) to replace the aging buildings; and
d) to upgrade the operational centers in order to provide better response to customers.

This is a once in a 50 year generation investment that has already been deferred by Hydro Ottawa for 15 years.

1.2 Project/Program Description

During the 2016-2020 Custom IR period Hydro Ottawa will construct facilities on two parcels of land, namely an Eastern Operations & Administrative Campus and a Southern Operations & Warehouse. The facilities will be built on two parcels of land already purchased by Hydro Ottawa in the eastern and southern regions of the City of Ottawa. The Eastern Operations & Administration Campus land parcel was purchased in April 2013 and is located at the corner of Hunt Club and Hawthorne beside the 417 highway. The Southern Operations land parcel was purchased December, 2012 and is located at the corner of Moodie & Fallowfield drives near the 416 highway. Construction is expected to begin in 2016 with the eastern and southern facilities build being treated as two separate and distinct projects.

1.3 Project/Program Justification

The need for new facilities was identified 15 years ago when Hydro Ottawa amalgamated from five former municipal utilities, namely Ottawa Hydro, Gloucester Hydro, Nepean Hydro, Kanata Hydro and Goulbourn Hydro. Due to the short timeframe given for amalgamation and the magnitude of capital required Hydro Ottawa opted to temporarily keep its existing facilities. Since then, the need for new facilities has been revisited internally an in consultation with real estate experts a number of times. The current facilities are beyond their useful lives.

1.4 Main and Secondary Drivers

Driver		Explanation
Primary	**Asset End of Life**	Like other LDCs in Ontario, Hydro Ottawa's investment in new facilities is a once in a generation investment. This generational investment was identified 15 years ago to consolidate administrative functions, to better locate the operation centres, to modernize the work environment and to provide for future growth. Buildings such as the Albion Road facility of Hydro Ottawa are 60 years old and were designed and built in an era to meet a very different need from what is currently and prospectively serves. Hydro Ottawa's facilities are at capacity,

		are poorly located and in need of repair.
Secondary	**Public Safety**	Due to commercial and residential growth in the areas surrounding Hydro Ottawa facilities, truck and employee traffic now pose safety risks to the general public. At the Albion Road facility for example, school children board and debark from school buses just outside the Hydro Ottawa facility. Wide turning trucks must navigate heavily populated residential streets posing significant risk to public safety.
Secondary	**Operational Efficiency**	Hydro Ottawa's move to new facilities is further motivated by the need to align its administrative and operational staff in a manner allowing better cultural and organizational synergies. Consolidating administrative, technical and operational staff will permit greater operating efficiencies by increasing opportunities for collaboration and cross-functional teamwork. In addition to providing a greater foundation for productive collaboration, the new facilities are being located close to major traffic arteries in the City of Ottawa are expected to significantly reduce travel time to work locations by all work crews resulting in better customer service and response times.
Secondary	**Health & Safety (employees)**	Hydro Ottawa existing facilities are being extended beyond their useful lives but are unable to meet future capacity requirements without major renovations or requiring new construction/leasing off-site facilities. The current facilities have several deficiencies many of which present health and safety concerns for Hydro Ottawa's staff, crews and customers and/or require substantial investment to replace or repair. Examples of major investments that would be required include bringing the buildings up to code to meet the Accessibility for Ontarians with Disabilities Act (hereinafter "AODA Act"), or investments necessary to upgrade the building envelope (roof, windows, flooring, HVAC system) to facilitate a more favourable work environment. Examples of safety concerns include numerous and increasing incidents of theft and crime in the areas surrounding the Albion head office including a recent incident of an intruder found in the garage. Other examples include uneven pavement and flooring causing risks for slips or trips.

Table 107 - Facilities Implementation Plan Drivers

1.5 Alternatives Considered

1.5.1 Alternatives Evaluation

In Exhibit B1, Tab 2, Schedule 4 filed by Hydro Ottawa in 2012 in support of its cost of service rate case (EB-2011-0054), it described in detail beginning in section 4.3 the numerous options considered by Hydro Ottawa in consultation with its expert consultants for deriving the optimal facilities arrangement. Some of the options considered include:

a) retaining and retrofitting Hydro Ottawa's existing facilities;

b) consolidating all administrative staff at the Albion Road location;
c) consolidating all Administration staff at the Merivale location; and
d) constructing new facilities.

In Section 4.4 of Exhibit B1, Tab 2, Schedule 4 provided its analysis of the alternatives as well as its conclusion that Option 4, namely to construct new facilities, was the superior economic option resulting in long term value to ratepayers.

The evidence filed by Hydro Ottawa in Exhibit B1, Tab 2, and Schedule 4 was thoroughly explored in interrogatories exchanged with the stakeholders including Board Staff, VECC, SEC and Energy Probe. The capital expenditures proposed in Hydro Ottawa's 2012 Cost of Service Application were addressed in the context of the settlement agreement. Hydro Ottawa's proposal to construct new facilities and its proposal to set aside an initial $4.0 million to purchase land was reviewed and in its settlement agreement. Consequently, Hydro Ottawa does not propose to review the alternatives of staying in its existing facilities versus building new facilities as this issue was addressed in the context of Hydro Ottawa's 2012 Cost of Service application as reviewed pursuant to the proceeding initiated under EB-2011-0054.

1.6 Project/Program Timing

Below is a table that sets out the activities associated with the realization of Hydro Ottawa's Facilities Implementation Plan and the approximate timelines within which each of these activities is currently scheduled to take place.

Activity	Estimated Timeline
Dibblee Land Purchase	Closed December 2012
Hunt Club Land Purchase	Closed April, 2013
Issue Request for Qualification	May 2013
Engage Fairness Commissioner	May - October 2013
Review request for Qualification responses and Shortlisting of Design Build Proponents	December 2013 - May 2014
Issue & Review Design Build RFP	Q2 2015
RFP Evaluation and Award	Q32015
East Operations and Administrative Campus	
Design	Q3-Q4 2015
Site Plan Approval and Permitting	Q4 2015 – Q2 2016
Construction	Q3 2016- 2018
Move In	2018
South Operations, Warehouse	
Design	Q3-Q4 2015
Site Plan Approval and Permitting	Q4 2015 –Q2 2016
Construction	Q3 2016 - 2017
Move In	2017

Table 108 - Facilities Implementation Plan Timelines

1.7 Project/Program Expenditure

As discussed in section 3.4.3 of B-5(A) HOL's Distribution System Plan, the historical spend (2011-2015) is attributed to monies spent to procure the land upon which Hydro Ottawa will construct its new facilities. Forecasted spend (2016-2020) represents monies that Hydro Ottawa estimates it will need to facilitate the construction of the new facilities. The table below sets out the historical and forecasted spend on the land and building for each of the two projects.

Facility		2011 Act	2012 Act	2013 Act	2014 Q2	2015 Bud	2016 Bud	2017 Bud	2018 Bud	Total
		$'000								
East Ops / Admin Campus	Land	-	250	12,445	21	-	-	-	-	12,716
	Building	234	492	287	432	3,835	19,642	25,818	6,073	56,813
South Ops	Land	-	6,704	94	-	-	-	-	-	6,798
	Building	68	140	83	-	1,098	5,620	9011	-	16,020
Total		302	7,586	12,909	453	4,933	25,262	34,829	6,073	92,347

Table 109 - Facilities Implementation Plan Expenditures

1.8 Prioritization

1.8.1 Consequences of Deferral

Hydro Ottawa has deferred the current projects by 15 years. The consequences of further deferral are escalating repair and replacement costs as well as health and safety costs. Further deferring Hydro Ottawa's facilities implementation plan would have cascading impacts on inflationary values of construction materials and costs necessary to construct the facilities. In addition to inflationary costs, Hydro Ottawa would also incur costs associated with replacing key elements of the building envelop such as the roofs, windows and HVAC systems. This does not include the costs to upgrade each of Hydro Ottawa's facilities to comply with the AODA. Like many other investments project deferral introduces significant risks and associated costs of risk.

1.9 Execution Path

1.9.1 Implementation Plan

1.9.1.1 *Land Purchase (historical implementation)*

The land parcels upon which the two projects will be built were purchased in 2012 and 2013. The purchase of these land parcels followed a lengthy search and evaluation of approximately forty candidate listings. The search was complicated by restrictions on land use imposed by National Capital Commission and the unavailability of vacant lands due to protected status. Bidding for the two properties was done on a "no-name" anonymous basis to avoid attracting a price premium.

In total Hydro Ottawa purchased approximately 41 acres at an average price of $460K per acre totalling $19 million. Ultimately market availability and alignment with Hydro Ottawa's stated criteria[1] dictated the parcels purchased.

1.9.1.2 *Building Construction (historical and prospective implementation)*

Following the appointment of PPI Consulting Limited (hereinafter PPI) as Fairness Commissioner in the fall of 2013, Cresa Partners[2], Hydro Ottawa and PPI prepared a Request for Qualification ("RFQ") to prequalify design-build contractors for the design and construction of Hydro Ottawa's new Administrative Building and Operations Centers. The RFQ was divided into two projects, the first covering the Administrative Building and the second covering the East and South Operations Centers. Respondents to the RFQ were given the option to respond to and prequalify for one or both projects. For each project as many as five respondents could pre-qualify for the design-build RFP.

The RFQ was posted on MERX December 24, 2013 and closed on February 28, 2014. Upon closing eight Statements of Qualification ("SOQ") were received for the Administrative Building and ten for the Operations Centers.

Hydro Ottawa expects to issue an RFP in Q2 2015 to the five design-build proponents who pre-qualified for the Head Office and Training Center and the five design-build proponents that pre-qualified to build the two Operations Centers.

Hydro Ottawa again hired the services of PPI to oversee the RFP process and documentation to ensure its fairness and transparency.

1.9.1.3 *Estimated Square Footage/Employee and Workstation Estimates*

In designing the space requirements for the new building and operations centers, Hydro Ottawa estimates that the Administrative Campus will provide for 166,000 square feet of space which works out to be approximately 332 gross square feet per employee. Hydro Ottawa notes that this is well below the International Facility Management Association ("IFMA"[3])'s average of 396 gross square feet per occupant as well as the IFMA average of 425 gross square feet per occupant for utilities. Hydro Ottawa further notes that its estimated gross square foot per employee is also well below Enersource's move in, five year and ten year forecast gross square footage per employee allotment and below Powerstream's. See Table 110.

[1] Hydro Ottawa's criteria were a) to be near a major artery for ease of access to highways; b) be central and accessible for employees and visitors; c) to be located beside public transit or proposed light rail transit system and d) have suitable zoning within an industrial area.

[2] Cressa Partners Corporate Real Estate Advisors

[3] (see website: http://www.ifma.org/publications/books-reports/research---benchmarks-iv).

	Hydro Ottawa (proposed)	Enersource	Powerstream
Total Space (Admin building only)	155,000[4]	79,000	92,000
# of Employees (@ move in)	511	150	270
Gross Square foot per employee	303	526	341

Table 110 - Gross Square Footage per Employee

In assessing comparable space allocations for employees, Hydro Ottawa commissioned a study of comparable office and workstation standards. Table 111 sets out the results of its findings. It was determined that Hydro Ottawa's current office and workstation space allocations are consistent with or lower than the space allocations of other utilities within Ontario. As such, Hydro Ottawa determined that it would retain the existing office and workstation space allocations for current and future staff.

Comparable Office and Workstation Standards (SF)								
	CEO	**EMT**	**DIR**	**MGR**	**WS1**	**WS2**	**WS3**	**WS4**
Comp 1	300	200-225		150	80	64	48	15
Comp 2	n/a	200		125	72	61	42-55	12
HOL Current	n/a	225	150	150	80	64	48	n/a
HOL Proposed	300	225	150	150	80	64	48	15

Table 111 - Space Allocations per Employee

1.9.1.4 *Sale of Existing Facilities*

Part of the implementation of Hydro Ottawa's facilities plan entails the sale of Hydro Ottawa's vacated facilities. To gauge the relative value of Hydro Ottawa's existing facilities, Hydro Ottawa engaged the services of Altus Group Limited to estimate the approximate market value of the Albion, Merivale and Bank Street facilities. In estimating the market value for each of the three facilities that Hydro Ottawa intends to sell, Altus advises that the valuations will be positively or negatively impacted by current zoning designations and the ability to change said designations. Decisions on zoning will not be known until Hydro Ottawa is closer to the sale date.

Other factors that could impact the market value are the need that a purchaser may have to demolish the buildings or any need to undertake any supplemental remediation in order to repurpose the sites.

[4] Space Design allows for 30% growth in number of employees to accommodate at the facility.

1.10 Project Details and Justification

Project Name:	Facilities Implementation Plan
Capital Cost:	$66.3M
O&M:	$0
Start Date:	January 2015
In-Service Date:	Date to be confirmed
Investment Category:	General Plant
Main Driver:	Current Assets at End of Life
Secondary Driver(s):	Public Safety Operational Efficiency Health & Safety
Customer/Load Attachment	N/A
Project Scope	
During the 2016-2020 Custom IR period Hydro Ottawa will construct three new facilities on two sites, namely an Eastern Operations & Administrative Campus and a Southern Operations & Warehouse. The facilities will be built on two parcels of land already purchased by Hydro Ottawa in the eastern and southern regions of the City of Ottawa.	
Work Plan	
This project will occur in the basic phases: • Phase 1: Land parcels purchase • Phase 2: Construction of three facilities • Phase 3: Move from existing facilities to new facilities • Phase 4: Sale of existing facilities	
Customer Impact	
N/A	

2 CC&B Enhancements

2.1 Project/Project Summary

Operational Efficiency: Ensure efficient and effective operations of the Customer Care & Billing (CC&B) application which is used to produce all customer bills by ensuring that the application remains fully supported by IBM and Oracle.

2.2 Project/Program Description

2.2.1 Current Issues

Hydro Ottawa's customer information system environment was implemented in March 2014 with a Customer Care and Billing (CC&B) v2.3.1 component and the premier support for this component ends in June of 2016. To ensure this critical application remains fully supported by Oracle and IBM, an upgrade to either version 2.4 or 2.5 (considered a minor lift) would be performed in 2016 with a preliminary estimate of $2.5M. In 2019, we plan on performing a significant lift to what we believe will be the next major version of CC&B (version 3.0) with a preliminary estimate of $6M.

2.2.2 Program/Project Scope

- To perform an upgrade of a key component, CC&B, including enhancement & interfaces, of Hydro Ottawa's customer information system environment which consists of CC&B, OIM/OVD, interfaces including ODI & Globalscape, In-tool-lect Dashboard, BI Publisher and Hypertension SQR, from v2.3.1 to v2.x (minor lift) and from version 2.x to version 3.0 (significant lift).
- To confirm all components of the Hydro Ottawa customer information system environment work with these upgraded components (i.e. CC&B, enhancements and interfaces)

2.2.3 Main and Secondary Drivers

- Provide a solid supported system as the foundational platform that will position Hydro Ottawa to better leverage our other technologies and provide enhanced services to our customers
- To remain in Premier Support for the CC&B application which is industry standard and to be compliant with the maintenance contract for the CC&B system with IBM covering 2014 to 2022 inclusive ($21M) which specifies that HOL must keep current with upgrades throughout the duration of the contract.
- Additional functionality in CC&B v2.x & v3.0 which would imply that less future enhancements would be required as they would be included as part of base CC&B.
- To strengthen HOL's position with Oracle and with our regulators by being on the same version as other large distribution companies in Ontario (i.e., Toronto Hydro-currently on v2.2, Enersource -currently on v2.2 and Powerstream- will be going live with v2.4).

2.2.4 Performance Targets and Objectives

Performing upgrades to Hydro Ottawa's core customer information system would meet the following objectives:

- Ensure that the Oracle CC&B product, which is a key component of our meter to cash system remains in premier or extended support which is required by our managed service provider IBM to deliver on our contracted service level agreements.

2.3 Project/Program Justification

2.3.1 Alternatives Evaluation

2.3.1.1 *Alternatives Considered*

Alternative 1: Upgrade to version 2.x in 2016 and v3.0 in 2019

This alternative is to perform an upgrade to CC&B v2.x in 2016 (considered a minor lift) and v3.0 (considered a significant lift) in 2019 to allow HOL to remain on a fully supported platform.

Alternative 2: No upgrade in 2016 and upgrade to version 3.0 in 2019

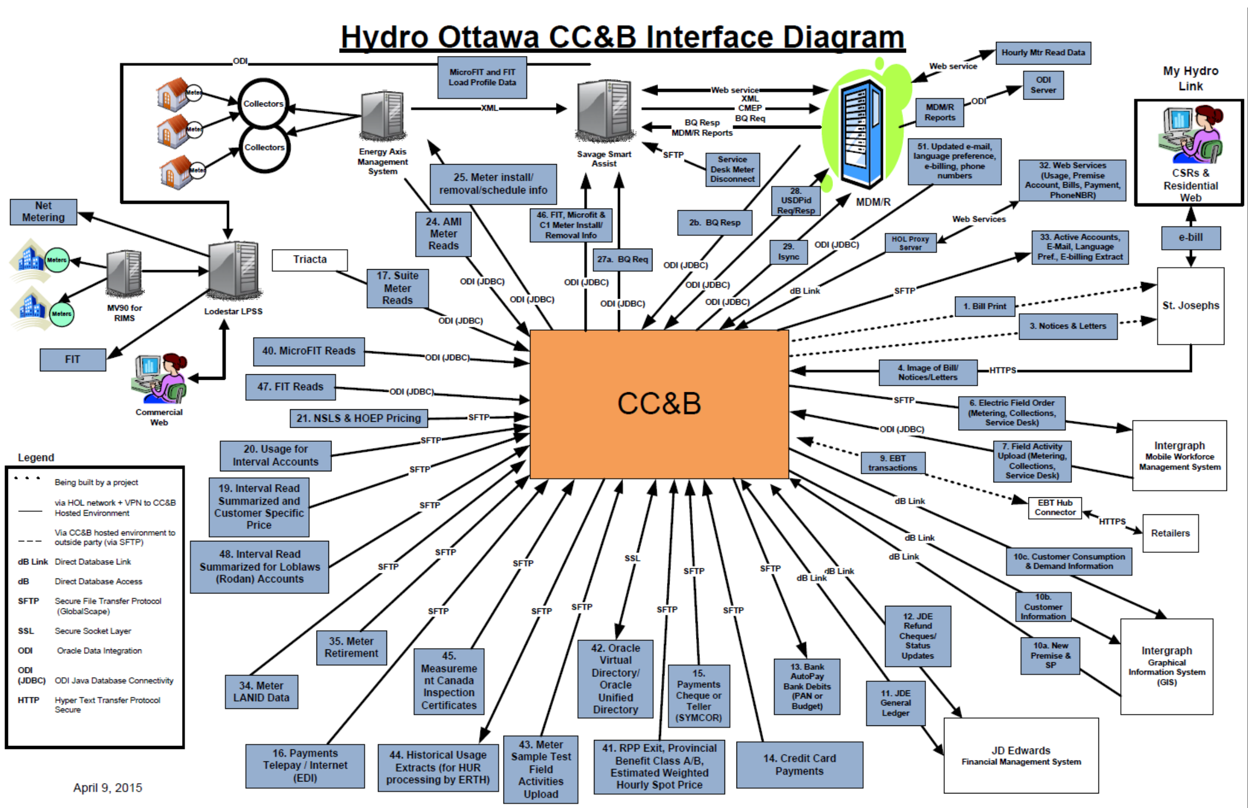
This alternative is to remain on CC&B v2.3.1 and only perform an upgrade to CC&B v3.0 in 2019. By having no upgrade in 2016 consuming resources, this would allow the tuning of CC&B v2.3.1 in the years of 2016, 2017 & 2018.

Alternative 3: Do not perform any upgrades

This alternative would be to remain on CC&B v2.3.1 and not perform any upgrades (between the years of 2015- 2020).

Figure 102 demonstrates the number of interfaces to/from CC&B that would need to be considered as part of the analysis for each upgrade.

Figure 102 - CC&B Interfaces



2.3.1.2 *Evaluation Criteria*

Evaluation criteria: Below are the criteria's used to evaluate the alternatives for the CC&B path as well as the points used to rank these criteria's.

1. **Capital costs:** outweighing upgrading to a later version of CC&B versus capital costs avoided to build new functionality to make up for features not available should the upgrades not occur
   a. Ranking: 10 points = lowest, 20 points = medium, 30 points = highest
2. **Impact on OM&A costs:** due to additional licensing costs tied to Oracle support (premier vs extended vs sustaining) for CC&B and increased managed services cost with IBM.
   a. Ranking: 10 points = highest, 20 points = medium, 30 points = lowest
3. **Risk profile:** due to not being on a fully supported platform. This will impact the managed services with IBM as they will not have access to all security patches, fixes to the database, operating system and or servers. Therefore, should a critical issue occur, or a new regulatory change is imposed on HOL, we would be left exposed if we did not have access to premier or extended support.
   a. Ranking: 10 points = lowest, 20 points = medium, 30 points = highest

<u>Detailed assessment</u>:

Alternative 1: Upgrade to version 2.x in 2016 and v3.0 in 2019

The alternative is to perform an upgrade to CC&B v2.x in 2016 and v3.0 in 2019:

- Capital Costs (Ranking: 10 points):
  - Capital investments will continue to be required to maintain regulatory compliance in years 2017, 2018 & 2020
- No increased OM&A (Ranking: 30 points)
  - Hydro Ottawa would remain in premier support, included in 22% of Oracle support fees
  - No additional fees for IBM managed services and Oracle licensing costs
- Risk profile is low as we will have access to all patching and will be fully supported (Ranking: 30 points)

Costs	2016	2017	2018	2019	2020	Total
Capital	$2.5M	$500K	$500K	$6M	$500	$11.7M
Increased OM&A	$0	$0	$0	$0	$0	$0

Table 112 - CC&B Alternative 1 Costs

Alternative 2: No upgrade in 2016 and upgrade to version 3.0 in 2019

The alternative is to remain on CC&B v2.3.1 and perform an upgrade to CC&B v3.0 in 2019:

- Capital Costs (Ranking: 20 points):
  - An additional $25K per year (2016, 2017 & 2018) for capital costs will be required to enhance CC&B due to not acquiring the new features with a later version of CC&B (version 2.x)
- Increased OM&A (Ranking: 20 points):
  - Increase in Oracle support from 22% per year to 37% per year (~$100K/year) due to being on extended support.

- o Potential increases to the monthly fees paid to IBM for managed services on an increasing scale based on being on extended (i.e., hosting and application support- a rough estimate of what this additional cost could be $240K/year which is approximately 10% increase to monthly fees). Then on sustaining support a rough estimate of what this additional cost could be $480K/year which is approximately 20% increase to monthly fees.
- Risk profile is medium based on the fact that for a year and half (Ranking: 20 points):
  - o We will be on sustaining support from July 2018 to Dec 2019 as extended support for version 2.3.1 runs out in June 2018 which leaves HOL exposed to not be able to meet new regulations.
  - o IBM will not be able to apply all security patches and fixes to the database, operating system and or servers as they will be limited by the interoperability of CC&B v2.3.1 with these components of the solution stack.
  - o It should be noted that Oracle still needs to confirm the feasibility of upgrading from CC&B v2.3.1 directly to CC&B version 3.0

Costs	2016	2017	2018	2019	2020	Total
Capital	$525K	$525K	$525K	$6M	$500K	$8.075M
Increased OM&A	$170K	$340K	$410K	$480K	$0	$1.4M

Table 113 - CC&B Alternative 2 Costs

Alternative 3: Do not perform any upgrades

This alternative would be to remain on CC&B v2.3.1 and not perform any upgrades (between the years of 2015- 2020):

- Capital Costs(Ranking: 30 points):
  - o An additional $25K per year (up to June 2018) for capital costs will be required to enhance CC&B due to not acquiring the new features with a later version of CC&B (version 2.x). From June 2018 to 2020, an additional $50K per year to cover capital costs for features not acquired in major version of CC&B 3.0.
- Increased OM&A (Ranking: 10 points):
  - o Increase in Oracle support from 22% per year to 37% per year (~$100K/year) due to being on extended support.
  - o Potential increases to the monthly fees paid to IBM for managed services on an increasing scale based on being on extended (i.e., hosting and application support- a rough estimate of what this additional cost could be $240K/year which is approximately 10% increase to monthly fees). Then on sustaining support a rough estimate of what this additional cost could be $480K/year which is approximately 20% increase to monthly fees.
- Risk profile is high based on the fact that for 2 and a half years (Ranking: 10 points):
  - o We will be on sustaining support from July 2018 to 2020 as extended support for version 2.3.1 runs out in June 2018, which leaves HOL exposed to not be able to meet new regulations.
  - o IBM will not be able to apply all security patches and fixes to the database, operating system and or servers as they will be limited by the interoperability of CC&B v2.3.1 with these components of the solution stack.

Costs	2016	2017	2018	2019	2020	Total
Capital	$525K	$525K	$538K	$550K	$550K	$2.688M
Increased OM&A	$170K	$340K	$410K	$480K	$480	$1.880M

Table 114 - CC&B Alternative 3 Costs

2.3.1.3 *Preferred Alternative*

Based on the above analysis, Hydro Ottawa recommends alternative 1: Upgrade to version 2.x in 2016 and v3.0 in 2019. Although the capital investments are the highest of all alternatives ($11.7M), we would be avoiding the increased OM&A costs of $1.4M (Alternative 2) and $1.88M (Alternative 3). Of all of the alternatives, alternative 1 is the least risky as it would allow HOL to remain on a fully supported platform with access to all security patching, fixes to the database, operating system and or servers without any increase to OM&A costs.

A points system was used to rank the alternatives against the evaluation criteria outlines above. The chart below demonstrates the outcome of how each alternative ranked:

Criteria	Alternative 1	Alternative 2	Alternative 3
Capital Costs	10	20	30
OM&A Costs	30	20	10
Risk Profile	30	20	10
Total	**70**	**60**	**50**

Table 115 - CC&B Alternative Evaluation

2.3.2 Project/Program Timing & Expenditure

Historical ($M)					Future ($M)					
2010	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
					1.70	2.50	0.50	0.50	6.06	0.50

Table 116 - Project Expenditures

2.3.3 Benefits

Benefits	Description
System Operation Efficiency and Cost-effectiveness	• Ensuring efficient and effective operations of the CC&B application which is used to produce all customer bills by ensuring that the application remains fully supported by IBM and Oracle. • Keeping CC&B fully upgraded to the latest versions would save the organization in increased OM&A ($1.4M with alternative 2) and ($1.880M with alternative 3). • An upgraded CC&B system will be capable of meeting more of our future regulatory and business requirements through configuration changes, instead of developing code.
Customer	• Will allow HOL to fully automate customer moves without the manual involvement of our resources. • Is the foundational platform that will position Hydro Ottawa to better leverage our other technologies and services such as our award-winning Outage Communications system and MyHydroLink (our account management web portal). • Will enable us to strengthen our relationships with landlord customers

	through automated landlord agreements.
Safety	N/A
Cyber-Security, Privacy	Performing these upgrades to CC&B would allow for IBM to continue to have access to all security patches as HOL would continue to be supported via premier or extended support.
Co-ordination, Interoperability	Increased cooperation/sharing of best practices among Ontario LDCs who are also on CC&B (Toronto Hydro, Enersource & Powerstream) on business critical systems leading to cost savings and improvements in customer service.
Economic Development	N/A
Environment	N/A

Table 117 - Project Benefits

2.4 Prioritization

2.4.1 Consequence of Deferral

If the decision was to defer the CC&B upgrades, the consequences / risks of deferring these projects would be the following:

- Increased in OM&A costs for both licensing and managed services costs for IBM OM&A ($1.4M with alternative 2) and ($1.880M with alternative 3).
- IBM would not have access to the latest security patches, fixes to the database, operating system and or servers as they will be limited by the interoperability of CC&B v2.3.1 with these components of the solution stack.
- HOL would not be able to leverage additional functionality easily to further automate processes that would benefit our customers.
- HOL would be on sustaining support for several years, which leaves HOL exposed to not be able to meet new regulations.
- Collaborating with other local distributors in the Ontario market (Toronto Hydro, Powerstream & Enersource) would be less feasible if we are all operating under different CC&B versions.

2.4.2 Priority

High

- With these upgrades it is expected that some future enhancements will not be required as they are now base functionality in the newer versions of the application

2.5 Execution Path

2.5.1 Implementation Plan

2.5.2 Risks to Completion and Risk Mitigation Strategies

Risk	Mitigation Strategy
Resource constraint potentially required for other projects	• Prioritize projects • Combine CC&B enhancements within the upgrade to free up resources
CC&B version 3.0 would be considered “bleeding	• Detailed analysis of functionality offered in

edge"	version 3.0 to make an informed decision of whether to proceed with CC&B version 3.0 or to a different version

Table 118 - Risks & Mitigation Strategy

2.5.3 Timing Factors

- Premier Support of CC&B v2.3.1 ending in June 2016 and Extended Support in June 2018
- Premier Support of CC&B v2.4 ending November 2017 and Extended Support in November 2020
- Release date of CC&B v2.5 June/July 2015 – support timelines not currently available
- Release date of CC&B v3.0 and maintenance support is tied to it is not currently available

2.5.4 Cost Factors

- Preliminary estimates were provided by our managed services contractor IBM for these upgrades, these estimates could change once the detailed analysis of these projects have been performed
- Duration of the upgrade projects extending longer than original estimates
- Potential for increased scope

2.6 Project Details and Justification

<table>
<tr><td>Project Name:</td><td>CC&B Upgrade from v2.3.1 to v2.x</td></tr>
<tr><td>Capital Cost:</td><td>$2.5M</td></tr>
<tr><td>O&M:</td><td>N/A</td></tr>
<tr><td>Start Date:</td><td>January 2016</td></tr>
<tr><td>In-Service Date:</td><td>September 2016</td></tr>
<tr><td>Investment Category:</td><td>General Plant</td></tr>
<tr><td>Main Driver:</td><td>Provide a solid supported system as the foundational platform that will position Hydro Ottawa to better leverage our other technologies and provide enhanced services to our customers
To remain in premier support for the CC&B application which is industry standard and to honour the maintenance contract for the CC&B system with IBM covering 2014 to 2022 inclusive ($21M) which outlines that HOL must keep current with upgrades throughout the duration of the contract.
Additional functionality in CC&B v2.x & v3.0 which would mean that we do not need some future enhancements – as they would be included as part of base CC&B.</td></tr>
<tr><td>Secondary Driver(s):</td><td>To strengthen HOL’s position with Oracle and with our regulators by being on the same version as other large distribution companies in Ontario (i.e., Toronto Hydro-currently on v2.2, Enersource -currently on v2.2 and Powerstream- will be going live with v2.4).</td></tr>
<tr><td>Customer/Load Attachment</td><td>N/A</td></tr>
<tr><td colspan="2" align="center">Project Scope</td></tr>
<tr><td colspan="2">Analysis, design and build of this technical upgrade of CC&B customizations, interfaces and reports (35 interfaces (see diagram below), 50 customizations, 100 reports)
Functional testing, integration testing
User acceptance testing
Organizational Change Management
Training
CC&B Functional configuration
Coordinate and manage participation of third parties</td></tr>
<tr><td colspan="2" align="center">Work Plan</td></tr>
<tr><td colspan="2">Assign a dedication project team (HOL and contractors)
Assess upgrade requirements
Design Upgrade changes
Build/Develop Upgrade changes
System Functional Testing
System Integration Testing
Training
User Acceptance & Regression Testing
Deploy into production
Stabilization period</td></tr>
<tr><td colspan="2" align="center">Customer Impact</td></tr>
</table>

The impact to Hydro Ottawa's customers would be that we could achieve further efficiencies in the future that would benefit our customer, for example: • It will allow us to fully automate customer moves without the manual involvement of our resources. • Will be the foundational platform that will position Hydro Ottawa to better leverage our other technologies and services such as our award-winning Outage Communications system and MyHydroLink (our account management web portal). • Will enable us to strengthen our relationships with landlord customers through automated landlord agreements.

Project Name:	CC&B Upgrade from version 2.x to v3.0
Capital Cost:	$6M
O&M:	N/A
Start Date:	January 2019
In-Service Date:	December 2019
Investment Category:	General Plant
Main Driver:	Same as above
Secondary Driver(s):	Same as above
Customer/Load Attachment	N/A
Project Scope	
Same as above. However seeing as this upgrade is a significant lift to the application (moving from version 2.x to 3.0), this usually entails architectural changes which then equates to more work: • Review all existing enhancement interfaces created to work with v2.x to ensure that they are still required with CC&B v3.0. Some may require re-work due to the changes between versions. • Regression testing phase would be extended due to the potential for more architectural changes to the application.	
Work Plan	
Same as above	
Customer Impact	
Same as above	

3 Outage Communications System

3.1 Project/Project Summary

Hydro Ottawa's current Outage Communications System (OCS) needs to be replaced with a state-of-the art and scalable mobile solution, designed to be a specifically compatible foundation for all current and future Customer Experience Management initiatives. While the existing solution was delivered to resolve a broken outage communications process, Hydro Ottawa is now embarking on a proactive mission to deliver outage communications at the next level. Hydro Ottawa's vision of "2-way, proactive, personalized, and premise-based Outage Communications" is totally consistent with industry thought leaders.

3.2 Project/Program Description

3.2.1 Current Issues

Customers are demanding proactive two-way communications with relevant, timely and accurate outage information being provided not only via the call centre and Interactive Voice Recognition (IVR) but also through social media, utility websites and modern communication devices (e.g. tablets, smartphones) and apps.

The existing APEX point based outage system is made up of a number of subsystems that all play specific roles in arriving at the point of creating information, or notifying customers, with respect to outages. Factoring in APEX application history and current vulnerabilities, Outage Communications risk profile, and reliability, supportability, and scalability needs, we have reached the conclusion that the current APEX OCS application is not a suitable foundation upon which to build the future vision.

3.2.2 Program/Project Scope

In keeping with our strong commitment to improving customer service, we intend to provide a rich customer experience with 2-way, proactive, personalized, premise-based outage communications. In doing so, the following objectives must be met:

Reporting Personalization: Allowing the customer to report an outage utilizing the channel that they prefer. Typically this will include the traditional outage line, augmented by mobile, web, and text.

Notification Personalization: Allowing the customer to specify preferences that determine how and when they receive outage alerts, updates, and restoration information.

Message Personalization: Provides the intelligence for the overall solution. It determines the messaging to go out for a particular outage, the customers it should be delivered to, and via which channel, as dictated by the customer's stated preferences.

Customer Administration: A robust customer administration capability is a core requirement in allowing Hydro Ottawa to scale from administering a few hundred key customers to our base of over 318,952 customers.

3.2.3 Main and Secondary Drivers
The main driver for this project is the ability to meet evolving customer needs as identified above.

3.2.4 Performance Targets and Objectives
A new OCS solution must be architected and designed in the context of Hydro Ottawa's reality. IVR, Web, OMS, CC&B, MHL, and Mobile are all key contributors to the business and full compatibility with those systems is a pre-requisite for any replacement.

Customer Value: Hydro Ottawa has a customer-centric view to the future. As of December 31, 2014, there were 122,300 MyHydroLink accounts. Hydro Ottawa will establish a multi-channel communication strategy that reached customers across a variety of communication channels.

Organizational Effectiveness: The custom solution will be developed using current application development standards. Hydro Ottawa will not be locked in to a proprietary toolset. Skilled resources should be common and permit risk avoidance/mitigation in the need of hiring or future partner development.

Corporate Citizenship: The development of a replacement Outage Communications System will enable Hydro Ottawa to communication with our customers using the methods that they want to be communicated with. Hydro Ottawa will continue to offer a customer-centric view, raising the bar on customer satisfaction even further, and reaching the broadest number of customers possible.

Financial Strength: Proactive communication has resulted in the reduction in the cost per customer contact as well as decreased the number of calls to our Outage Reporting call centre during outages. As a specific example, redirecting customers to using the Outage Web Maps reduced telephone call volumes to the Call Centre by 67,926 over 2013/14 at a savings of almost $900k.

3.3 Project/Program Justification

3.3.1 Alternatives Evaluation

3.3.1.1 *Alternatives Considered*
Commercial-Off-The-Shelf (COTS), Hybrid, and Custom solutions were all deemed to be approaches that could meet the needs of Hydro Ottawa.

In the initial high level pricing estimate, COTS was most expensive, followed by Hybrid, then Custom as the least expensive. In the latest estimates, Outage Maps have been excluded, making the Hybrid approach redundant. In terms of magnitude, the custom solution costs 40% of the cost for the COTS solution.

3.3.1.2 *Evaluation Criteria*
Business decisions will drive the solution evaluation, with the following mandatory requirements:

- Reduce operational burdens while extending customer interaction capabilities. This is critical, as any new Outage Communication process should create less work for Operations, not more.

- Manage customer preferences efficiently while allowing a high level of personalization. The customers' wishes must be integral to any Customer Experience Management initiative.
- The Messaging Engine must be able to support all known channels. Although business decisions must drive which channels will be supported and when, the engine must be designed in such a way as to be capable of supporting all channels. No development work should be required should the company choose to add channels at a later date.

3.3.1.3 *Preferred Alternative*

The recommendation to proceed with a custom solution significantly reduces the total cost of ownership over the 5 Year Total Cost of Ownership assessment, realizing a cost savings of approximately $1,234,000 over the five year period.

3.3.2 Project/Program Timing & Expenditure

Historical ($k)							Future ($k)			
2010	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
-	-	-	-	-	-	-	910	-	-	-

Table 119 - Project Expenditures

3.3.3 Benefits

Benefits	Description
System Operation Efficiency and Cost-effectiveness	Proactive communication has resulted in the reduction in the cost per customer contact as well as decreased the number of calls to our Outage Reporting call centre during outages. As a specific example, redirecting customers to using the Outage Web Maps reduced telephone call volumes to the Call Centre by 67,926 over 2013/14 at a savings of almost $900K.
Customer	Hydro Ottawa has a customer-centric view to the future. As of December 31, 2014, there were 122,300 MyHydroLink accounts. Hydro Ottawa will establish a multi-channel communication strategy that reaches customers across a variety of communication channels. The development of a replacement Outage Communications System will enable Hydro Ottawa's to communicate with our customers using the methods that they want to be communicated with. Hydro Ottawa will continue to offer a customer-centric view, raising the bar on customer satisfaction even further, and reaching the broadest number of customers possible.
Safety	N/A
Cyber-Security, Privacy	HOL will ensure all applicable laws and standards are met throughout.
Co-ordination, Interoperability	N/A
Economic Development	N/A
Environment	N/A

Table 120 - Project Benefits

3.4 Prioritization

3.4.1 Consequence of Deferral

To maintain customer satisfaction and reach the broadest number of customers possible, and to respond to widespread internet use and mobile phone ownership, utilities need to establish a multi-channel communication strategy that reaches customers across a variety of communication channels. As the internet becomes the new communication standard, utilities will need to adapt to continue meeting customers' expectations for responsiveness, accuracy, and personalization. Customers will be frustrated by websites that are not formatted for mobile phone access or communication that doesn't include text messages.

With the increase in the frequency and duration of outages caused by extreme weather events across North America, customers are expecting utilities to keep them continually updated on the status of outages; especially the estimated restoration time. In fact, customers are requiring utilities to keep them informed via two-way communications using the IVR, call centre, social media, utility websites and modern communications devices (e.g. tablets, smartphones) and applications (apps).

Hydro Ottawa has a customer-centric view to the future. Outage communications, planned or unplanned, are key customer interactions. An increasing number of utility companies are now launching proactive communication channels – that is, channels (usually voice messaging, text or email) through which they can "push" alerts to customers. These allow the utility to contact the customer many times with updates during an event, informing them when their estimated restoration time changes or when crews have determined the cause of their outage.

Failure to provide the power outage information accurately and in a timely manner will result in customer complaints, create unwanted media attention, and negatively impact customer satisfaction.

3.4.2 Priority

High – the project will allow HOL to meet customer expectations.

3.5 Execution Path

3.5.1 Implementation Plan

This project will be initiated and completed in 2017.

3.5.2 Risks to Completion and Risk Mitigation Strategies

As with any planned project, the limited availability of skilled resources with competing priorities may impact the timely implementation of an Outage Communications System. With executive support, stakeholder engagement, and careful planning and attention to schedules, this risk can be managed effectively.

3.6 Project Details and Justification

Project Name:	Outage Communications Systems
Capital Cost:	$910
O&M:	$412 (2016-2020)
Start Date:	2017
In-Service Date:	2017
Investment Category:	General Plant
Main Driver:	Customer Service
Secondary Driver(s):	Communication efficiency
Customer/Load Attachment	N/A
Project Scope	
Reporting Personalization: Allowing the customer to report an outage utilizing the channel that they prefer. Typically this will include the traditional outage line, augmented by mobile, web, and text. **Notification Personalization:** Allowing the customer to specify preferences that determine how and when they receive outage alerts, updates, and restoration information. **Message Personalization:** Provides the intelligence for the overall solution. It determines the messaging to go out for a particular outage, the customers it should be delivered to, and via which channel, as dictated by the customer's stated preferences. **Customer Administration:** A robust customer administration capability is a core requirement in allowing Hydro Ottawa to scale from administering a few hundred key customers to our base of over 318,952 customers.	
Work Plan	
Implementation 2017	
Customer Impact	
The development of a replacement Outage Communications System will enable Hydro Ottawa's to communicate with our customers using the methods that they want to be communicated with. Hydro Ottawa will continue to offer a customer-centric view, raising the bar on customer satisfaction even further, and reaching the broadest number of customers possible.	

4 JDE Application Upgrade

4.1 Project/Project Summary

An effective Enterprise Resource Planning (ERP) solution is a critical component to Hydro Ottawa's ongoing business operations. In 2003, J.D. Edwards (JDE) EnterpriseOne Xe was implemented. Since that time, investments were made to provide enhancements and stay relatively current on related technology components to enable ongoing business requirements and mitigate risk. The current ERP solution is JDE EnterpriseOne v9.0. After a decade of using the JDE solution as Hydro Ottawa's ERP, there was cause to pause and consider multiple factors impacting future ERP decisions. Assessment by Hydro Ottawa's Executive Management, IM&IT support and input from key impacted Stakeholder groups of a variety of consideration criteria, concluded that a full upgrade within the JDE product line should be pursued with adherence to Out of the Box (OOTB) product wherever possible to leverage best practices. Since Hydro Ottawa is currently operating on JDE version 9 (v9.0) for which only Sustaining Support will be available from the vendor after Sept. 2016, time is of the essence to proceed with the project.

Figure 103 - JDE EntrepriseOne Releases

Oracle's JD Edwards EnterpriseOne Releases

Release	GA Date	Premier Support Ends	Extended Support Ends	Sustaining Support Ends
Xe	Sep 2000	Dec 2013	Not Available	Indefinite
8	Jun 2002	Dec 2013	Not Available	Indefinite
8.9	Sep 2003	Sep 2008	Not Available	Indefinite
8.10	Jun 2004	Jun 2009	Not Available	Indefinite
8.11	Dec 2004	Dec 2009	Dec 2012	Indefinite
8.11 CRM Mobile Sales(both i-Series and non i-Series)	Dec 2004	Dec 2009	Dec 2010	Indefinite
8.12	Apr 2006	Apr 2011	Apr 2014	Indefinite
8.12 CRM Mobile Sales(both i-Series and non i-Series)	Apr 2006	Apr 2011	Dec 2010	Indefinite
9.0	Sep 2008	Sep 2013	Sep 2016	Indefinite
9.0.2	Nov 2010	Nov 2015	Nov 2018	Indefinite
9.1	Mar 2012	Mar 2017	Mar 2020	Indefinite

Source: http://www.oracle.com/us/support/library/lifetime-support-applications-069216.pdf (Note: Our current status context has been highlighted for ease of reference)

4.2 Project/Program Description

4.2.1 Current Issues

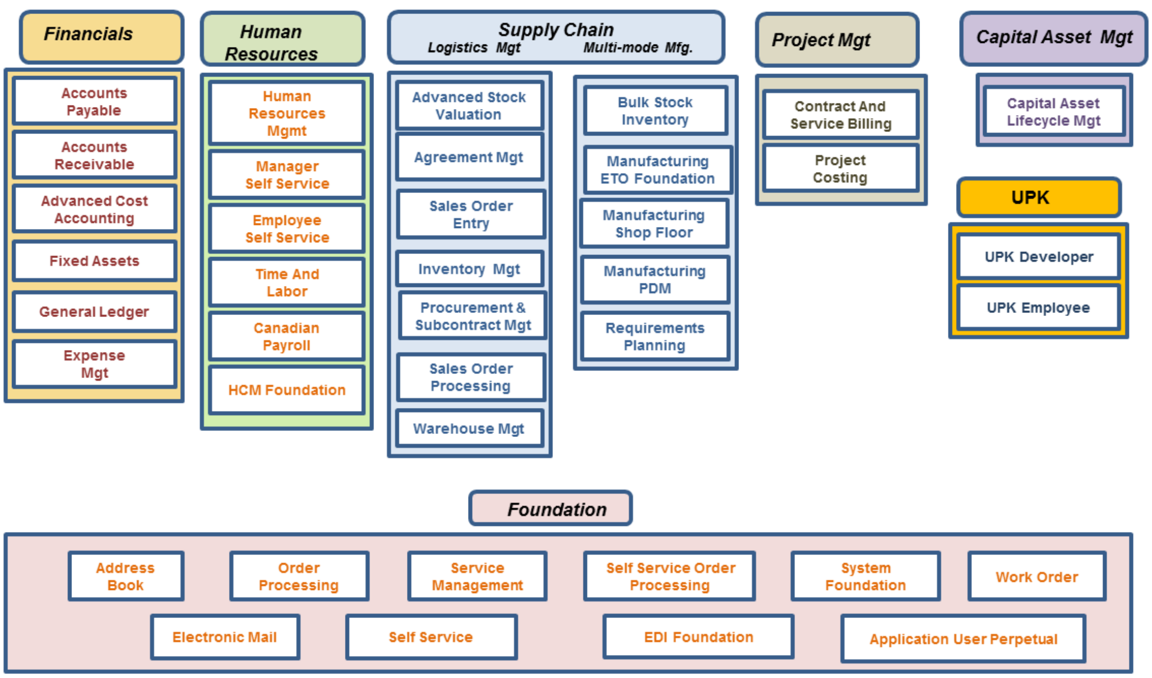
Since its implementation, JDE has proven to be a consistently dependable solution for core operational outcomes like financial accounting, accounts payable and receivable, budget management, procurement administration, inventory management, and payroll. However, the ERP solution did have some adaptability shortcomings to address specific, evolving business needs and/or business processes. These resulted in the extraction of business outcomes like Fleet Management from the ERP footprint and customizations to the JDE solution which can cause ongoing support complexities and/or challenges.

Ensuring full vendor support for ERP as a critical business solution is aligned with prudent stewardship. Since JDE v9.0 will lapse into Sustaining Support soon, a project is necessary to mitigate the risk.

4.2.2 Program/Project Scope

As shown in Figure 104, the JDE solution encompasses multiple modules to provide a comprehensive solution enabling vital business capabilities such as financial accounting, Accounts Payable and Receivable, budget management, procurement administration, inventory management, human resource management, payroll etc.

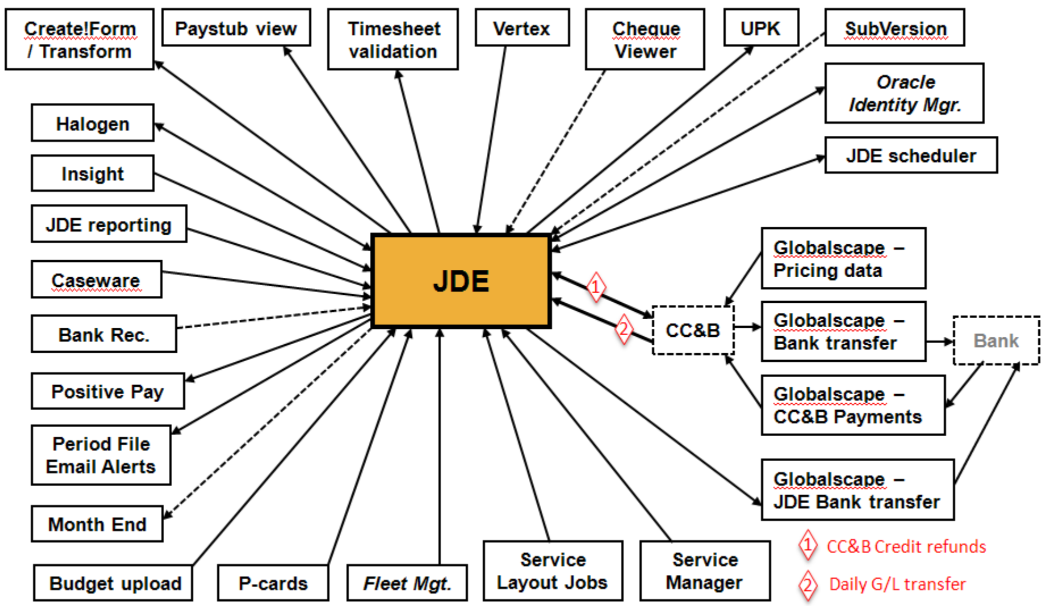
Figure 104 - JDE Solution Modules



Ongoing operational support is achieved by a small Enterprise Solutions team in the Systems Management group within IM & IT in collaboration with functional Stakeholder Subject Matter Experts (SME's) as part of a matrix support model. In addition, vendor engagements are leveraged when necessary to augment skills, complete development and/or provide additional capacity for support. Adherence to the future OOTB product vision will enhance the opportunities for external assistance. Infrastructure, hardware and database support services are currently provided by resources within Hydro Ottawa's CIO Division.

JDE is a highly integrated solution as evidenced by interfaces with both internal systems as well as external systems, as shown in Figure 105.

Figure 105 - JDE Interfaces



Various functional areas at Hydro Ottawa rely on JDE to achieve their operational mandates in an expedient, cost-effective manner. Stakeholder desires to maximize business efficiency and/or effectiveness, or address emerging legal or business requirements can lead to requests for further integration and/or JDE changes.

4.2.3 Main and Secondary Drivers

The main driver for this project is to ensure efficient, effective ERP business outcomes are sustained for HOL's ongoing business operations in a manner that mitigates immediate and longer term risk. In addition, the identified project is directly aligned with key guiding principles in HOL's approved IM&IT Strategy (excerpt below).

- HO's business strategies and corporate priorities will be the primary driver of the IM&IT initiatives.
- Where feasible, HO will leverage existing systems and services prior to investing in new solutions and will leverage its IT Investments in Oracle, Intergraph, and Microsoft by adhering to a "Best of Brand" strategy.
- Commercial-off-the-Shelf (COTS) solutions will be implemented with limited customization, in preference to custom-developed business applications, to reduce risks and costs, and to facilitate software supportability and upgrade paths.
- Standard architectural framework will be established to improve integration, facilitate access to key data, re-engineer business processes to improve outcomes, productivity and efficiency.

4.3 Project/Program Justification

4.3.1 Alternatives Evaluation

Alternatives considered for the future ERP strategy include:

1. Remain operating on current ERP solution (JDE v9.0 with customizations) and accept the inherent risks of not retaining the maximum support from the vendor
2. Upgrade/re-implement a newer OOTB version of JDE with a strategy to divest of customizations and fully leverage the products' best practices, support
3. Upgrade to a newer version of JDE with a mandate to port forward current customizations
4. Evaluate available Tier 1 ERP solutions for the best alignment to HOL's identified fit/form/function requirements
5. Evaluate potential Tier 2 ERP solutions for the best alignment to HOL's identified fit/form/function requirements against a heightened risk profile for ERP outcomes.

4.3.1.1 *Alternatives Considered*

4.3.1.2 *Evaluation Criteria*

After a decade of using the JDE solution as HOL's ERP, there was cause to pause and consider multiple factors impacting future ERP decisions from immediate, short and long term perspectives. Evaluation criteria considerations included:

- Anticipated business requirements to define essential scope;
- Functionality features and adaptability capabilities in the out-of-the-box (OOTB) product version;
- Degree and complexity of integration needs;
- Industry trends for ERP solutions;
- Vendor commitment towards future investments in the product line;
- Business operational risks of change;
- Alignment with technology strategy and ongoing stewardship; and
- Cost effectiveness of options

4.3.1.3 *Preferred Alternative*

Assessments by HOL's Executive Management, IM&IT support and input from key impacted stakeholder groups to date, have concluded that the preferred alternative would be a full application upgrade within JDE product line should be pursued with adherence to a strategy to divest of current customizations in favour of the OOTB product wherever possible. The outlined budget and project path details are reflective of this intention, but are subject to change based on evolving information.

4.3.2 Project/Program Timing & Expenditure

The projected overall costs are $6.5M and will take 1 year to complete. Recommended project timeline will target a Q3 2016 transition.

Historical ($M)						Future ($M)				
2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
-	-	-	-	-	1.5	5.0	-	-	-	-

Table 121 - Project Expenditures

4.3.3 Benefits

Operating on a current OOTB ERP solution within the JDE product line will align with desire to mitigate critical business outcome risks caused by the transition, leverage in-house knowledge of the JDE solution and related investments such as Insight reporting, improve overall system operational efficiency and provide new opportunities for cost-effective support and/or development assistance from vendors when needed.

4.4 Prioritization

4.4.1 Consequence of Deferral

Deferral of this project will negatively impact the risk for critical ERP business outcomes once the maximum level of product support from the vendor will lapse in 2016.

4.4.2 Priority

This project is considered to be a High priority based on risk to critical ERP business outcomes.

4.5 Execution Path

4.5.1 Implementation Plan

The JDE upgrade/re-implementation plan will follow best practices for change and project management. The plan's approach will also align with Oracle's Unified Method (OUM) for JD Edwards implementations which prescribes five distinct phases (Inception, Elaboration, Construction, Transition and Production). Based on the mandate of achieving OOTB installation, a preliminary phase will be needed to assess current customizations against standard offerings to identify business processes and/or outcome impacts. Outcomes of this preliminary phase will help to define specifics of project scope.

4.5.2 Risks to Completion and Risk Mitigation Strategies

Risks to completion include resource availability of key subject matter experts, strains to desired business outcomes caused by adherence to OOTB approach, potential extended timeline and/or scope creep. These risks will be mitigated through involvement of HOL's Executive Management Team in the Steering Committee to reinforce expectations, independent project management oversight, strict scope containment through change management process that restricts approvals to essential items only, and internal resource reassignments for full-time dedicated participation in the project along with empowerment to make decisions.

4.5.3 Timing Factors

To avoid the risk of not having maximum vendor product support for our critical ERP solution, the recommended project timeline will target a Q3 2016 transition.

4.5.4 Cost Factors

Final cost of the project will be affected by negotiated contracts with vendors.

4.6 Project Details and Justification

Project Name:	JDE Application Upgrade
Capital Cost:	$6.5M
O&M:	No change from existing program
Start Date:	2015
In-Service Date:	Q3 2016
Investment Category:	General Plant
Main Driver:	Business operations efficiency
Secondary Driver(s):	N/A
Customer/Load Attachment	N/A
Project Scope	
Upgrade/re-implement a newer OOTB version of JDE with a strategy to divest of customizations and fully leverage the products' best practices, support	
Work Plan	
The plan's approach will also align with Oracle's Unified Method (OUM) for JD Edwards implementations which prescribes five distinct phases (Inception, Elaboration, Construction, Transition and Production). Based on the mandate of achieving OOTB installation, a preliminary phase will be needed to assess current customizations against standard offerings to identify business processes and/or outcome impacts. Outcomes of this preliminary phase will help to define specifics of project scope.	
Customer Impact	
Provide HOL with a more effective framework to address evolving business needs and customer expectations in a more timely and efficient manner by utilizing an OOTB approach and not having to build custom applications.	

5 Fleet Replacement

5.1 Project/Program Summary

Hydro Ottawa Limited ("Hydro Ottawa") requires a fleet of specialized vehicles to complete many daily activities. Hydro Ottawa maintains approximately 270 vehicles and other related equipment. Vehicles are an essential component in providing efficient and reliable service to customers through the quick restoration of power, the efficient construction and maintenance of the distribution system and the safety of employees.

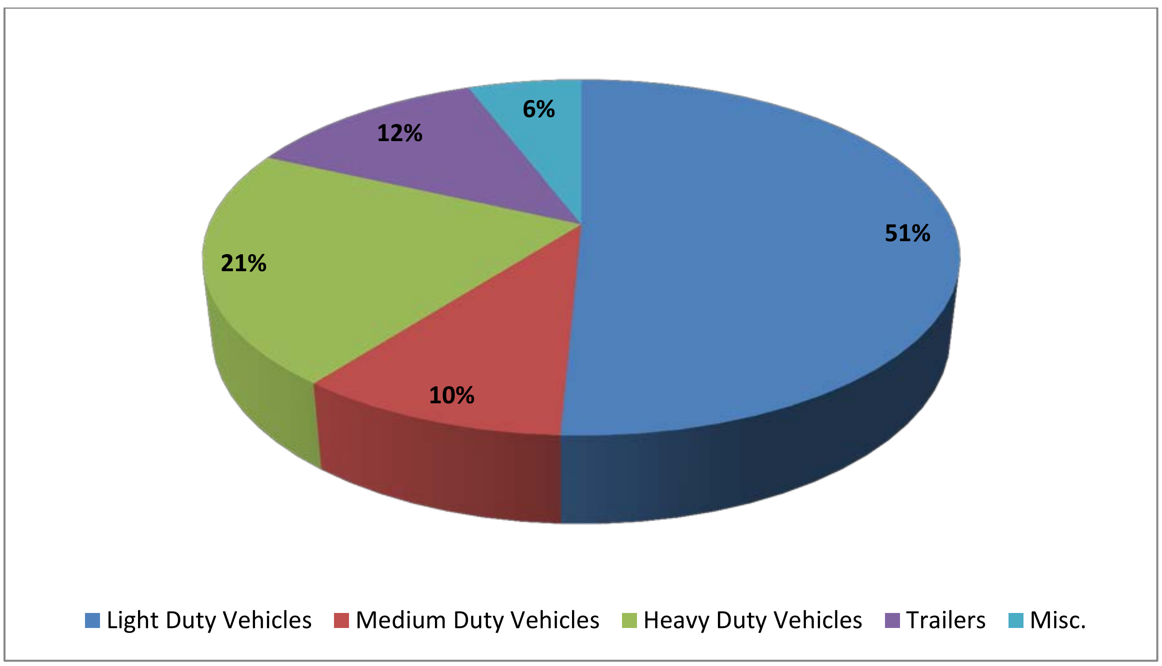
Hydro Ottawa maintains a multiple year capital plan to effectively manage its fleet assets. This plan is an essential tool for both long and short term planning and budgeting. This document outlines the 2016-2020 Fleet capital replacement plans.

5.2 Project/Program Description

5.2.1 Current Composition of Fleet

Figure 106 below shows the current composition of Hydro Ottawa fleet grouped by major category of asset.

Figure 106 - Composition of Fleet



5.2.2 Program/Project Scope

Hydro Ottawa's Fleet replacement plan lists all current vehicles and proposes future replacement dates and costs, based on past experience and accepted industry standard vehicle lifecycles. Factors taken into consideration in establishing the replacement date of individual vehicles include:

- Vehicle age

- Mileage
- Engine hours
- Power take off hours
- Operating and maintenance costs
- Overall general condition of the vehicle

As the result of these evaluations, vehicles may be retained longer due to being in better than average condition and while others may be replaced earlier due to being in poorer condition.

Preventative scheduled maintenance on the entire Fleet is conducted regularly. Schedules are implemented per the manufacturers' recommendations, unless Fleet determines the condition of equipment is extreme or the equipment is lightly operated.

Hydro Ottawa operates a repair centre to maintain a large majority of our fleet internally. We strive to minimize potential risks involved by subcontracting our aerial units to unqualified vendors. Hydro Ottawa provides extensive training to our technicians in order to achieve the qualifications necessary to sign off on inspection documents. These documents are signed by our technicians stating that the aerial units are safe to operate in proximity of high voltage power lines.

Hydro Ottawa regularly inspects the aerial equipment on a 4-month basis, as well as monitors mileage and engine hours, which may trigger an earlier inspection. On light duty equipment, Hydro Ottawa performs regular scheduled maintenance every six months or 6,000 km.

5.3 Main and Secondary Drivers

The main driver of this program is System Capital Investment Support: providing safe, reliable and efficient vehicles and equipment that meet operational requirements.

5.4 Performance Targets and Objectives

The objectives of Hydro Ottawa's Fleet replacement plan are:

- Provision of safe, reliable and efficient vehicles and equipment to meet the operational requirements;
- Compliance with legislation and regulations, as well as accepted industry norms and practices,
- Cost effectiveness;
- Optimization of size of fleet;
- Standardization of equipment specifications; and
- Environmental considerations such as fuel economy and exhaust emissions.

5.5 Project/Program Justification

Hydro Ottawa applies the following metrics in determining fleet asset life cycle replacement projections (see Table 121).

Unit Type	Years	Kilometres	Engine Hours	Power Take Off (PTO) Hours
Automobile	10	150,000	4,000	
Vans – Compact	7	150,000	5,000	
Vans - Cargo	8	150,000	6,000	
Vans – Step / Cube	10	150,000	8,000	
Trucks – Pickup (Compact)	7	100,000	5,000	
Trucks – Pickup (Conventional)	8	150,000	6,000	
Trucks – Dump	10	125,000	6,000	
Trucks – Stake	10	150,000	8,000	
Trucks – Knuckle Boom	15	200,000	10,000	5,000
Trucks – Buckets	12	200,000	10,000	5,000
Trucks – Line / RBD	12	200,000	10,000	5,000
Forklifts	15		10,000	
Trailers	12			
In addition to the above quantitative metrics, the overall general condition of the vehicle is also assessed leading to some vehicles replaced in advance of reaching these metrics while others are retained for a longer period.				

Table 122 - Fleet Replacement Metrics

Note that the plan does not provide for any growth to the current size of the fleet but rather just the replacement of aging vehicles.

Hydro Ottawa uses a passive GPS tracking system to collect data any time while a vehicle is running. The data is stored onboard the GPS until such time the vehicle returns to a home base and shuts off. At this time, the data is downloaded to Hydro Ottawa's internal system and the data is calculated. This data includes routes, idling time, kilometer traveled, excessive accelerating/braking, speeding, and unacceptable operation.

5.5.1 Project/Program Timing & Expenditure

In the first few years following amalgamation in 2000 (2000 – 2004) insufficient capital was spent on fleet replacement however between 2005 and 2009 an accelerated replacement plan was implemented. Replacement spending is now required annually to maintain the fleet. Table 122 shows the vehicle purchase history from 2012 to 2013 and the budgeted vehicle purchases from 2014 to 2020. In 2013, a large group of vehicles were due to be replaced, causing the capital expenditures to be higher than normal in that year. Again in 2020, a higher than normal amount of vehicles are due for replacement as shown in the table below.

In order to increase fleet efficiencies, Hydro Ottawa purchased a fleet management software system, FleetWave, in 2014. With this fleet software, Hydro Ottawa was able to streamline processes. FleetWave is a web-based enterprise fleet management software solution. It utilises the very latest technologies to provide comprehensive fleet management for Hydro Ottawa fleet operation:

- Asset Tracking and Management including Capital Replacement Planning
- Preventative Maintenance Scheduling
- Workshop Management (Workflow Planning, Scheduling, Job Assignment);
- Work Order Management;
- Warranty, Recalls & Campaigns;
- Operating Cost Management (Fuel, Licences, Permits, etc.);
- Inventory Management (parts supply system);
- Motor Pool Management;
- Risk Management (MVA, Safety, MOT Compliance, Records, etc.); and
- Technician Records and Training Plan.

Historical ($M)					Future ($M)			
2011	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
2.02	2.54	3.06	1.44	1.54	1.45	1.21	1.45	1.48

Table 123 - Project Expenditures

5.5.2 Benefits

Benefits	Description
System Operation Efficiency and Cost-effectiveness	Fleet replacement is required to support the day to day business activities and sustain operations by minimizing down-time and minimizing the total vehicle life cycle costs.
Customer	Newer vehicles are required to maintain and sustain operations and ensure appropriate response times to customers, older vehicles require more repairs resulting in increased downtime.
Safety	Newer vehicles are needed to maintain safe work practices, new safety features in newer models also improve workplace safety
Cyber-Security, Privacy	N/A
Co-ordination, Interoperability	N/A
Economic Development	N/A
Environment	New vehicles are more fuel efficient than older units, improvements in emission standards and engine design also result in a reduction of green house gas emissions.

Table 124 - Project Benefits

5.6 Prioritization

5.6.1 Consequence of Deferral

If this program is deferred the crews will not have the vehicles and equipment that they require in order to complete daily activities to meet customer expectations in a safe, reliable and efficient manner.

5.7 Execution Path

5.7.1 Implementation Plan

HOL uses the criteria identified in sections 5.2.2 and 5.5 to prioritize and stage the work.

5.8 Project Details and Justification

Project Name:	Fleet Replacement
Capital Cost:	$7.47M (2016-2020)
O&M:	N/A
Start Date:	Ongoing
In-Service Date:	N/A
Investment Category:	General Plant
Main Driver:	System Capital Investment Support
Secondary Driver(s):	N/A
Customer/Load Attachment	N/A

Project Scope

Hydro Ottawa's Fleet replacement plan lists all current vehicles and proposes future replacement dates and costs, based on past experience and accepted industry standard vehicle lifecycles. Factors taken into consideration in establishing the replacement date of individual vehicles include:

- Vehicle age
- Mileage
- Engine hours
- Power take off hours
- Operating and maintenance costs
- Overall general condition of the vehicle

As the result of these evaluations, vehicles may be retained longer due to being in better than average condition and while others may be replaced earlier due to being in poorer condition.

Work Plan

Preventative scheduled maintenance on the entire Fleet is conducted regularly. Schedules are implemented per the manufacturers' recommendations, unless Fleet determines the condition of equipment is extreme or the equipment is lightly operated.

Hydro Ottawa operates a repair centre to maintain a large majority of our fleet internally. We strive to minimize potential risks involved by subcontracting our aerial units to unqualified vendors. Hydro Ottawa provides extensive training to our technicians in order to achieve the qualifications necessary to sign off on inspection documents. These documents are signed by our technicians stating that the aerial units are safe to operate in proximity of high voltage power lines.

Hydro Ottawa regularly inspects the aerial equipment on a 4-month basis, as well as monitors mileage and engine hours, which may trigger an earlier inspection. On light duty equipment, Hydro Ottawa performs regular scheduled maintenance every six months or 6,000 km.

Customer Impact

Newer vehicles are required to maintain and sustain operations and ensure appropriate response times to customers, older vehicles require more repairs resulting in increased downtime.

6 Enterprise Architecture Program

6.1 Project/Project Summary

The HOL vision is that information is accessible, when and where it is needed to support customer interaction, decision making, ongoing business operations, regulatory compliance and business sustainability. As and where ever possible cost effectiveness will be sought to ensure all information technology and information management measures are managed appropriately. A guiding principle, to achieve the vision, is that a standard architectural framework is to be established to improve integration, facilitate access to key data, re-engineer business processes to improve outcomes, productivity and efficiency, and implement master data management.

The ***Enterprise Architecture Program – Enterprise Service Bus*** project was launched in 2014 to establish a Service Oriented Architecture (SOA) methodology for managing, measuring, executing, and optimizing processes within HOL to help better achieve business outcomes and enable realization of the above visions. A key component of the SOA methodology is the deployment of an Enterprise Service Bus (ESB) to establish and prioritize a standard architectural framework for all system and solution work across HOL that leverages industry best practices and enables real-time integration of business applications.

HOL's strategy is to put the customer at the centre of everything HOL does, to that end this project will be a major enabler/contributor to that strategy and the associated critical areas of performance as addressed in Table 124 below.

HOL Corporate Objectives	Details
Customer Value	ESB/SOA Enables: • Leveraging of existing IT investments (e.g., Contact Centre 6) to provide consistent inbound and outbound communications for customers across media (phone, website, text, etc.) • Providing customers with real-time access to data as well as providing them with self-service that flows automatically to the various business applications (e.g., today the move-in/move-out web form that customers fill out on the website is actually processed manually through HOL • Automating processes/workflows to provide more timely response to customer requests (e.g., Orlando Utility can achieve a service re-connect request in 3 min. from time request is entered on website to when electricity is reconnected, used to be days)
Organizational Effectiveness	ESB/SOA Enables: • Access to real-time data for more timely decision making • Automating processes/workflows to increase productivity, reduce staff labour, and complete tasks more quickly, thereby reducing OM&A • Wrapping of legacy/existing applications with Web Services in order to provide better service to internal users, provide new services more quickly than waiting for an application refresh • Applications developed using Service Oriented Architecture (SOA) principles to perform faster, thus increasing productivity and timeliness (Studies have SOA applications to perform up to 30% faster)
Financial Strength	ESB/SOA Enables:

	• Delivery of new services/functionality at lower costs and more quickly • Access to real-time data for faster financial decision making • Providing internal users with new services/functionality by leveraging investments in existing applications and wrapping with Web Services which can defer/or reduce application refresh/rip & replace, thereby reducing costs and risks
Corporate Citizenship	n/a

Table 125 - ESB/SOA as an Enabler to HOL's Strategy

Industry has realized significant business benefits from aligning on the Service Oriented Architecture (SOA) methodology and deploying an Enterprise Service Bus (ESB) platform for application integration. Some of the business benefits of SOA/ESB, from recent studies, are shown in Table 125. It is expected that HOL can realize many of these benefits from this project.

Data Point	Source
• 30% improvement in application performance using SOA/ESB • 100% system uptime. • Replaced >30 point-to-point integration links with a flexible, standardized business platform	HydroOne – Case Study (Oracle) http://www.oracle.com/jp/hydro-one-business-benefit-brief-335567-ja.pdf
• 36% faster implementation and integration of new applications using SOA/ESB • 50% reduction in time spent on supporting and maintaining the system using SOA/ESB	Tucson Electric Power Company – Case Study (Oracle) http://www.oracle.com/us/corporate/press/015318_EN.doc
• 35% of IT activity in a typical enterprise is dedicated to application integration – includes development, maintenance and operational cost.	Gartner http://www.serenecorp.com/v3/pdf/Serene_DS_EAI.pdf
• 60% of the implementation cost of an ERP package is spent on integration.	METAgROUP http://www.serenecorp.com/v3/pdf/Serene_DS_EAI.pdf
• 13% to 35% lower cost can be achieved with SOA software development as compared to non-SOA development	Return on Investment for Composite Applications and Service Oriented Architectures Enterprise Applications Consulting http://www.eaconsult.com/articles/SOA_ROI_EACReport.pdf
• Integration development cycle time cut by 50% compared to proprietary integration broker • Integration development in less than 4 weeks compared to estimated 3 to 4 months using PLSQL-based point-to-point integration • Non-expert internal IT resource up to speed in 8 days, ready to maintain 22 core BPEL processes	Heald College "From EAI to SOA by Accident – Case Study (Oracle) http://smartintegration.com.au/Resources/reading/SOA%20Value%20Patterns.pdf
• Core process automation in six months compared to a typical two-year-long IT project • Avoided a "rip and replace" project estimated at $100M over four years with less than $1M in SOA development	ING Lease/ING Group "From Two Years to Six Months – Case Study (Oracle) http://smartintegration.com.au/Resources/reading/SOA%20Value%20Patterns.pdf

Table 126 - Realized Benefits of SOA/ESB by Industry

6.2 Project/Program Description

6.2.1 Current Issues

With a significant portion of the company's business tied to information systems and technology, tighter alignment and a more integrated environment is needed to achieve standardization of technology, broader use of functionality across business lines with better grouping of specific purpose services, improved user-interfaces and significantly reduced development of point-to-point integrations and associated on-going support.

Current projections are that, during the period 2015 to 2020, potentially 20 or more new applications will be deployed which will result in a significant increase in application-to-application integration. Based on current methods used in Hydro Ottawa today, this growth will drive up operating and support costs further and increase data flow complexity. This is an unsustainable trend that has led other industries, including those within the utility sector, to deploy enterprise-wide Enterprise Service Bus architecture, as a best practice.

Preparation of the Smart Grid data environment in terms of greater integration between systems is needed to more fully realize the benefits of the Smart Grid.

There is a significant amount of replicated data stored across HOL in application specific databases (staging tables and staging folders) and user specific databases which indicates a master data management strategy is needed for better protection of data, and reduction of database and storage costs. Real-time access to data, will enable stricter management of master data, establishment of authoritative sources of data, ensure access to most current data and reduce data storage costs.

No uniform and standard structured approach is used to transfer data between HOL and external businesses (service providers, partners, banks, IESO, etc.) for Business-to-Business communications.

Processes are typically isolated at the application level (application-centric) and there is little use of automated business processes/workflows and real-time monitoring of process data flows. Inconsistencies are experienced in the transfer of data between Operational Technologies systems and the HOL business systems.

The time to market for offering new services (customer or internally facing) is slow due to the reliance on the application vendor's feature release roadmap or the need to customize the application (which leads to on-going support challenges and higher costs). The investments in some existing applications are not fully leveraged for offering new services.

HOL IT environment was not well positioned to leveraging public cloud services or for integrating them in to existing processes.

6.2.2 Program/Project Scope

The project involves adopting a "service-centric" model for providing new internal and external services based on Service Oriented Architecture (SOA) methodology, use of web services for creating new services and the deployment of an Enterprise Service Bus (ESB).

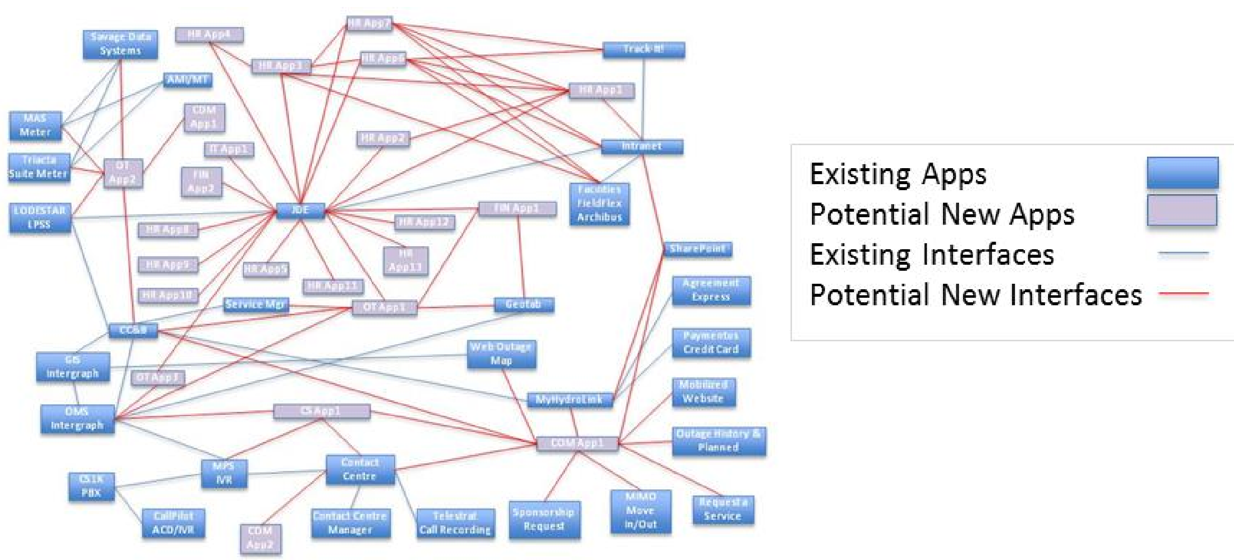
There are three major phases to the project which began in 2014:

- Architecture Planning and Design: ESB Solution Design; Governance; Application Integration Roadmap; and Operational Pre-Planning – *completed in 2014*
- ESB Platform Deployment: Deployment of the ESB platform in the following environments: Development Workstation; Test/Quality Assurance; and Production with high availability (HA) – *targeted for completion in 2015*
- Application Integration and Service Orchestration: Integration of initial foundational applications and subsequent new applications, with a view to automating key processes through service orchestration – *targeted to begin in 2015*

This project is using the industry leading Oracle Enterprise Service Bus technology that has been implemented by many Utilities and other enterprises in North America, as well as globally. HOL is benefitting from the maturity of this technology, over the past ten years and wide deployment.

6.2.3 Main and Secondary Drivers

Figure 107 - Illustration of the Projected Growth in Applications & Interworking



The main drivers for the project:

- Stability and standardization of data interworking across HOL applications / systems
- Fully realize the benefits of Smart Grid with greater integration of applications in Operations Technologies and with business applications
- Stronger and more consistent controls on application interworking
- Scalable and cost-effective approach to application integration (to address growth illustrated in Figure 107 and the potential 350% increase in point to point integrations)
- Centralized security controls for applications on the ESB and data traversing the ESB
- Real-time flow of data across Hydro Ottawa for improved decision making and improved employee productivity
- Automating processes through service orchestration to reduce costs, increase reliability, and increased employee productivity

- Centralized application and management of security to all data traversing the ESB

Secondary drivers for the project:

- Master data management with significant reduction and avoidance of data replication
- Leverage and extend current investments and de-risk rollout of new services
- Faster and lower cost approach to delivering new services for customers and improving internal operations
- Avoid the need to "rip & replace" some legacy applications, by wrapping legacy applications with web services to enhance user access to information
- Easy integration of public cloud services to on premise applications, as well as integrate public cloud services in to existing processes

Reduction in number of secondary databases as well as reduction in the myriad of personal databases.

6.2.4 Performance Targets and Objectives

The performance targets and objectives are:

- Automate key processes, through service orchestration, to reduce cost of processes, increase reliability, and reduce completion time of processes
- Reduce the number of new point to point integrations and the associated costs of maintaining integrations
- Reduce the amount of replicated data, through real-time access to data, that will be realized by reduction in databases and storage
- Enable faster integration for new applications
- Potentially reduce further the number of existing point to point integrations

6.3 Project/Program Justification

6.3.1 Alternatives Considered

The only alternative is to continue to experience the "current issues" and projected increase in the point to point integrations growing exponentially to the point of being unsustainable in size, variety and purpose and on-going maintenance and support, as illustrated in Figure 107.

6.3.1.1 *Preferred Alternative*

This project is a shift in the way applications will be integrated, and data shared between applications.

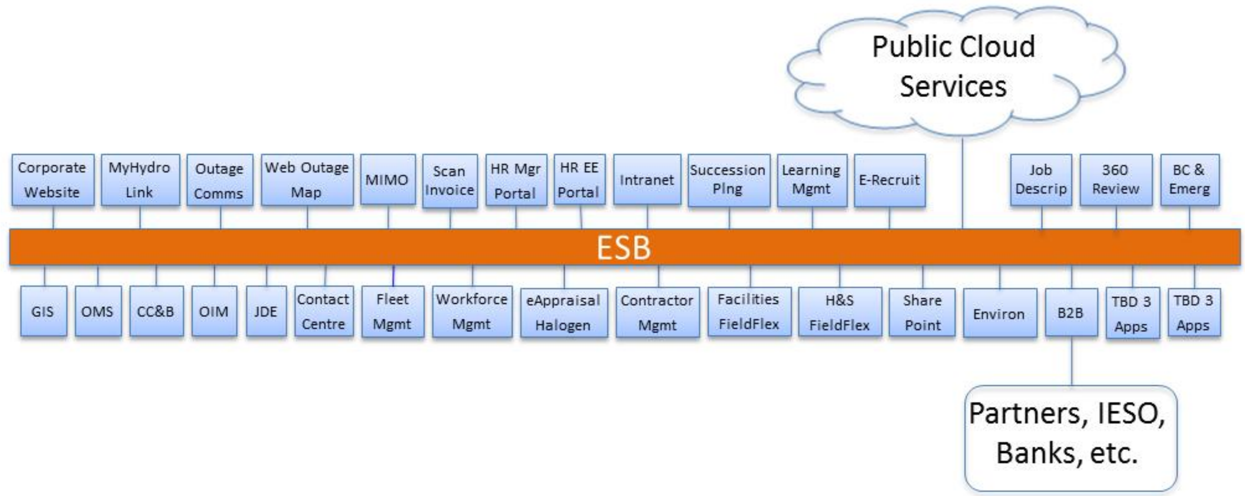
6.3.2 Project/Program Timing & Expenditure

This business case for 2016 to 2020 is focused on Phase 3 "Application Integrations"

- Architecture Planning and Design (2014)
- ESB Platform Deployment (2015)
- Application Integration and Service Orchestration (2015 to 2020)

A view of the 2020 "To Be State", consisting of projected application integrations to the ESB is shown in Figure 108.

Figure 108 - Illustration of the Projected Integration of Applications to ESB



2014

The upfront Architecture Planning and Design work done in 2014, in terms of: Business Case; Analysis; Research; ESB Solution Design; Governance; Application Integration Roadmap; and Operational Pre-Planning, has set the foundation for the work outlined in this project and will be used to issue the associated RFPs for the consulting work. The HOL investment in the detailed Architecture Planning and Design work has contributed significantly to minimizing risk and unexpected expenses.

2015

In 2015, there will be the deployment of the ESB platform in the following environments: Development Workstation; Test/Quality Assurance; and Production with high availability (HA). As well starting in 2015 and continuing in 2016 will be the integration of initial foundational applications.

2016 to 2020

The work done in 2014 to 2016 will lay the foundation for all application integration work, as well as process automation, through to 2020 and beyond. It will comprise and embrace all existing integrations (where eligible) and all net new acquisitions, services (including Public Cloud), and solutions.

HOL minimized and will control costs in this project by:

- Securing high discounts on the software licensing and thus reducing the annual software maintenance expenses
- Deploying integrated system/server platform (Oracle Database Appliance) for hosting the ESB software, as well as other future applications and databases, that improves: reliability through built-in redundancy; reduces on-going support efforts and costs through simplified patching procedures and centralized monitoring and management; and flexible software license management

Historical ($k)				Future ($k)						
2010	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
				783	797	787	364	290	295	300

Table 127 - Project Expenditures

6.3.3 Benefits

Near-Term Benefits

The expected near-term benefits of SOA/ESB to HOL are:

- Reduce number of links needed to integrate new applications.
- Reduce current data flow issues, especially for OMS to CC&B and Corporate website, by improving integration of disparate applications.
- Build new applications, such as Outage Communications and Employee Self-Service Portal by leveraging existing enterprise assets and making them accessible for reuse outside their original purpose.
- Expose web services of Contact Centre to build communications functionality in new applications.
- Using existing services /reusable software to build new application reduces the risk of delayed IT projects and thus increasing the likelihood of timely new product and service introductions.
- Enable OT to harness full capability of Intergraph OMS, will apply to other purchased apps.

Longer Term Benefits

The expected longer term benefits of SOA/ESB to HOL are:

- Enable Hydro Ottawa to adapt quickly in response to changes in the industry, regulatory, marketplace, by quickly deploying new services.
- Use of the Security Services of ESB/SOA, enables quick application of any security changes once, in one location and used throughout the enterprise, to comply with CIP, NSERC, etc.
- Extending life of current investments and exposing functionality as services (re-useable) for other applications
- Any component can be connected, ejected, or modified without impacting the performance of others.
- Increase efficiency in working with partners for saving costs, off-loading non-core functions.

Benefits	Description
System Operation Efficiency and Cost Effectiveness	• Stability and standardization of data interworking across HOL applications / systems • Fully realize the benefits of Smart Grid with greater integration of applications in Operations Technologies and with business applications • Stronger and more consistent controls on application interworking • Scalable and cost-effective approach to application integration • Centralized security controls for applications on the ESB and data traversing the ESB • Real-time flow of data across Hydro Ottawa for improved decision making and improved employee productivity • Automating processes through service orchestration to reduce costs, increase reliability, and increased employee productivity • Master data management with significant reduction and avoidance of data

	replication • Centralized application and management of security to all data traversing the ESB
Customer	• Faster response to customer enquiries will be realized through real-time access to data and automated services • Potential automation of Outage Communications and enabling solutions such as mobile workforce management, and will provide more reliable service and enhance the level of service • Increased reliability of external and internal services through well managed and monitored data flows and automated processes
Safety	• Health and safety processes could be automated to provide real-time access to information and to ensure consistent processes
Cyber-Security, Privacy	• Centralized security controls will be applied at the ESB level thus providing consistent and enhanced security for all data traversing the ESB • Changes to security controls can be quickly applied centrally via the ESB
Co-ordination, Interoperability	• Utilities and enterprises across North America are standardizing on Service Oriented Architecture (SOA) methodologies for interoperability • ESB enables the leveraging of publicly available web services to create new services • The SOA technologies purchased from Oracle and used for the Enterprise Service Bus include B2B (Business to Business) application for standardized data transfer with 3rd parties, including IESO, Banks, etc. • The deployment of an ESB will enable HOL to easily integrate to services provided through Public Cloud providers.
Economic Development	n/a
Environment	Reduction in point to point environment (footprint), code, and change management at individual interface layer.

Table 128 - Project Benefits

6.4 Prioritization

6.4.1 Consequence of Deferral

Deferral of this project would result in HOL continuing to incur the costs and operational issues identified under "current issues", and with a projection of approximately 30 new applications being deployed in the next 5 years, the impact of the current issues and exponential growth of point to point integrations will continue to increase.

This is a multi-year project and deferral of the project at this time would strand the current investments with no operational benefit, while at the same time having to pay the annual maintenance on the software licenses (over $110K per year).

6.4.2 Priority

This project is rated as a High priority project relative to the other IT projects. The execution of this project with Service Oriented Architecture (SOA), web services, and Enterprise Service Bus (ESB) will fundamentally change how applications are integrated, new services/functionality is implemented, processes are automated, and public cloud services are leveraged. This project will enable HOL to achieve its goals of reducing costs, increasing productivity, delivering new services, and providing access to information anywhere, anytime (as stated in IMIT Strategy).

6.5 Execution Path

6.5.1 Implementation Plan

The implementation plan is as follows:

- Phase 1 – Architecture planning and design
- Phase 2 – Build and deploy ESB platform, and establish the operational model
- Phase 3
    - Integrate foundational applications via ESB
    - Automate major processes through service orchestration
    - Integrate new applications

6.5.2 Risks to Completion and Risk Mitigation Strategies

Delay in rolling out potential to allow current practices to build more point to point integrations.

6.5.3 Timing Factors

Phase 1 has been completed, Phase 2 is underway in 2015 and work has begun for Phase 3 in 2015.

A factor that may affect the timing of the project completion is the availability of skilled resources to operate and manage the ESB. Vendor expertise has been identified to address and de-risk any potential deficiency/need.

6.5.4 Cost Factors

The total staffing effort to operate and manage the ESB once in operation and the need for external expertise to resolve operational issues have been estimated and may end up being lower or higher than the estimates.

6.6 Project Details and Justification

Project Name:	Enterprise Architecture Program – Enterprise Service Bus
Capital Cost:	2,036,416
O&M:	n/a
Start Date:	2014-09-26
In-Service Date:	2020-12-31
Investment Category:	General Plant
Main Driver:	System Operation Efficiency and Cost Effectiveness
Secondary Driver(s):	Enabling master data management and reducing database and storage costs
Customer/Load Attachment	n/a

Project Scope

The scope of the project from 2016 to 2020 will be focused on integrating applications via the Enterprise Service Bus and automating major processes using SOA service orchestration. The integration will mainly involve integrating new applications to existing applications.

Work Plan

The work plan for 2016 to 2020 is to continue the integration and service orchestration work begun in 2015. In particular, this will involve supporting the Field Service Management project planned to begin in 2015 and that will be leveraging SOA and service orchestration.

Customer Impact

- Faster response to customer enquiries will be realized through real-time access to data and automated services
- Potential future automation of Outage Communications will provide more reliable service and will enhance the level of service
- Increased reliability of external and internal services through well managed and monitored data flows and automated processes

7 Mobile Workforce Management

7.1 Project/Project Summary

Hydro Ottawa has a large mobile workforce that is responsible for a wide range of work from simple disconnect, reconnects or meter changes to the more complex and longer duration pole changes and cable replacements. To date we have been using a combination of Excel spreadsheets, in-house developed databases, and our Intergraph In-Service system for scheduling and dispatching work. This is accomplished in a decentralized model with several different groups dispatching mainly to their own resources. Although this has been relatively effective, the organization needs to invest in a Mobile Workforce Management (MWM) tool to drive productivity to the next level.

7.2 Project/Program Description

7.2.1 Current Issues

Effective mobile workforce management is critical to our ongoing corporate success, especially as it relates to Customer Service, Productivity, Operating Costs, and System Reliability. A comprehensive review of the systems currently in use for managing field service workloads confirmed that there are significant opportunities to drive improvements across many facets of our field operations.

We currently use a combination of tools to schedule and dispatch work. Medium and long term work is managed using spreadsheets which are useful, but very manual and labour intensive to manage and maintain. We also have a home grown solution called Service Manager that assists with managing the checklists and information for service connections and other work managed by the Service Desk. We are able to send service layout requests out to field staff and it includes some calendar functionality for booking Service Truck appointments. From a mobile perspective we are using the Outage Management System (OMS) as a basic dispatch system. Flat files of work orders are received from systems like Service Manager and Customer Care & Billing (CC&B). Staff from various groups then needs to access OMS to dispatch this work to internal and contract resources. There is no schedule or optimizer available in OMS to ensure that the right jobs are allocated to the right resource based on all the other work and variables to take into account for that day.

Furthermore, we do not have ready access to data and information to track, monitor, report and manage the day to day performance of field staff. Many of the tools we have reviewed have strong performance management capabilities to provide Supervisors and Managers access to timely, relevant and accurate data. Supervisors will have access to reports that will summarize activity from the prior day while allowing them to drill down into specific areas of concern quickly and easily.

Hydro Ottawa operations teams have done well with their current disparate systems, however new tools are required to drive improvements being demanded around service delivery and cost reduction/containment. The current system is resulting in tangible expenditures that could and should be avoided. The current process has some limitations that impact Hydro Ottawa's continued ability to effectively dispatch work, and generate more "on the job" time.

These limitations include:

- All jobs available to dispatch are not held in one system, complicating the job of optimizing the dispatch of work;
- Forecasting and profiling are separate from dispatching systems;
- Significant amounts of manual dispatching is required;
- Sub-optimal routing of crews against jobs;
- Significant limitations in real time control of planned work, and new work, emergent or otherwise; and
- A lack of performance management capabilities to understand current and future work dynamics.

In summary:

- HOL must focus on increasing the productivity across the organization;
- The Field Service teams are doing well managing with their current tool set;
- The current systems and processes result in less than optimal dispatching of work leading directly to latent capacity in field service teams;
- Sub-optimal routing for jobs is contributing to excess fuel costs, truck rolls, and kilometers being driven;
- Lack of a unified dispatching system and processes has resulted in a steady backlog of work potentially impacting reliability, bad debt expense, etc.;
- There is a need for improved real time analysis to support intraday decision making; and
- Performance management capabilities along with compliance on capturing key job metrics is an absolute must to allow for better decision making.

7.2.2 Program/Project Scope

To purchase and implement an industry leading Mobile Workforce Management tool to enhance scheduling and dispatch at Hydro Ottawa.

7.2.3 Main and Secondary Drivers

The main driver for this project is business operations efficiency. Workforce Management systems enable an organization to centralize all of the scheduling and dispatch functions for all field resources, improve overall visibility of workload and resource availability and ensure consistent application of scheduling policies to all types of work. With features such as schedule optimization and route planning, it improves field resource productivity, reduces mileage and overtime costs, and increases the ability to meet customer commitments. It also reduces the time spent on scheduling allowing the dispatcher to focus on handling exceptions or emergencies like trouble calls or outages.

The result is a consolidated view of both immediate and long term jobs and a vehicle to consistently make smart decisions about prioritization, crew scheduling, and fast response to emergencies and outages. Through more effective planning, scheduling and dispatch the company will ensure that the right resource, with the right skills is at the right location, with the right tools, parts and equipment to complete the work at the lowest cost while meeting customer needs.

7.2.4 Performance Targets and Objectives

The objective of the project is to purchase and implement an industry leading MWM tool to enhance scheduling and dispatch at Hydro Ottawa. These tools provide the ability to optimize work load versus resources in real time while balancing priorities that will enable the following:

Improve Productivity – Less than optimal dispatching and routing of work using Hydro Ottawa's current systems and tools is leading to latent capacity in the field service teams, and presents a real opportunity to increase daily job completion rates. Another area of opportunity is that of administration tasks, more specifically, time capture. Timesheets are completed by all field service personnel daily, and timesheets are a significant time drain when viewed over the course of a full year. Our review of the capabilities of newer systems indicated the ability to automate time capture for field service staff.

A portion of this improved productivity could be used to complete tasks currently being contracted out to third party resources including things like infrared scans and asset inspections. There will be an increase in the need for quality asset condition information to populate the new Asset Investment Planning tool that was recently implemented. We have several skilled resources that can complete these inspections with little to no training.

Cut Operating costs – Implementing unified dispatching in concert with route optimization capabilities typically has been shown to reduce kilometers driven and fuel consumption anywhere from 15%, to as much as 40%. In reducing kilometers driven and the related travel time, additional work can be completed within a typical daily operating window. This when combined with the afore mentioned productivity gains will have the additional benefit of having less work needed off core shifts, and is expected to result in a 10% reduction in overtime costs.

Exploit Unfulfilled Opportunity Costs – Most every field services discipline is maintaining a backlog of work that they are expected to deal with, on top of the ongoing daily workload. Often these backlog items are important from the perspective of avoiding future outages and certainly can have a detrimental impact on SAIFI and SAIDI if gone unattended. In the case of collections, these back logged work orders could have a negative impact on bad debt expense. Utilizing a unified dispatch technology with intelligent dispatching will ensure that these back logged work orders are scheduled and dispatched to appropriate resources based on priority, severity and resource availability. The new system will make it easier to take advantage of available time at the beginning of a shift and in between customer appointments for completing backlog items, testing, inspection, or maintenance activities to ensure they are completed in a more timely fashion.

Increase performance against service levels and enhance customer satisfaction – MWM tools have the capability to tailor dispatching rules to prioritize work based on a variety of factors including those represented by proximity to missing a customer appointment or service level agreement target. Meeting customer commitments and service level agreements will lead to enhanced customer satisfaction.

Execute better decisions with Performance Management – Even as we exploit what MWM tools have to offer there is a continuing need to analyze business trends, costs per job, and a variety of other key metrics to stay in control of the complex business of field service delivery. Several of the MWM tools provide sophisticated performance management capabilities needed to assist decision makers, while reducing the need for time spent aggregating date. These modules will also assist with the tracking and monitoring of the metrics and key performance indicators contained in the OEB's performance based Renewed Regulatory Framework.

7.3 Project/Program Justification

7.3.1 Alternatives Evaluation

7.3.1.1 *Alternatives Considered*

An analysis was done to understand our current system and the requirements of any possible replacement. A significant amount of research was done to both identify and complete a high level evaluation of the wide array of solutions and systems that are available on the market. We focussed our initial efforts on a review of the capabilities of solutions offered by the following vendors: IFS360, ClickSoft, Viryanet, and Oracle. This initial assessment included product demos and discussions with other utilities across the industry to better understand the capabilities and benefits associated with implementing these types of tools.

The status quo was considered as an option. Although we do have some electronic dispatching of work orders, we do not have an "intelligent" schedule with supporting algorithms to optimize dispatching, trip routing, etc. Because the tasks and work orders reside in several different systems, it can be difficult for supervisors and dispatchers to make the "best" decisions on resource utilization, or to provide additional work to crews on short notice should unexpected capacity be made available. Furthermore, we currently do not provide Supervisors or Managers with timely, accurate data that they can use to measure, monitor and manage the performance of their staff.

Based on the evaluation of the options and review of the quantitative and qualitative benefits, the decision was made to move ahead with the initiative.

7.3.1.2 *Evaluation Criteria*

After our initial assessment, Hydro Ottawa reduced the list of potential solutions to two vendors, ClickSoft and Oracle, based on their consistent ranking in the top, right quadrant of Gartner's system assessments. Hydro Ottawa then developed a set of business and technical requirements to assist in the evaluation and selection of the options. The business requirements looked specifically at the actual functionality and options of the systems to ensure that it would meet the majority of our documented needs. The technical requirements were focussed on the nuts and bolts of the systems including how they would fit into our current architecture and hardware arrays. Overall cost of the solution was also a key consideration in the decision making process.

7.3.1.3 *Preferred Alternative*

Based on the evaluation, both of the systems met the vast majority of the business requirements. The Oracle solution scored better in the technical requirements section largely due to the fact that we have many Oracle products and databases already installed which should make integration into our current systems more straight forward. The overall cost for the Oracle solution also benefited from our existing architecture.

Based on the results of the evaluation the decision was made to select the Oracle Mobile Workforce Management system.

7.3.2 Project/Program Timing & Expenditure

The capital cost for implementation of this project is $1,950k. There will be incremental operating costs that include an additional resource in IT to support the new application as well as an annual maintenance agreement for the vendor that covers system patches, updates and ongoing technical support. The costs of an IT resource is approximately $120k and the annual maintenance cost is approximately $150k.

Historical ($M)						Future ($M)				
2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
-	-	-	-	-	1.95	-	-	-	-	-

Table 129 - Project Expenditures

7.3.3 Benefits

A summary of the financial benefits is included below:

- As a result of increased productivity we anticipate reducing headcount through attrition by two resources over the next two years, a savings of approximately $180k annually.
- We also anticipate a 15% increase in productivity from resources on the service trucks by better utilizing their idle time. This amounts to a benefit of approximately $140k annually.
- We also anticipate a 10% savings in OT due to increased productivity. This translates into approximately $55k annually
- We will reduce our reliance on external parties to assist with collections activities and anticipate annual savings of approximately $50k
- We will reduce our reliance on external parties to assist with certain asset inspections as well by better leveraging the capacity of our skilled resources on a daily basis. By using internal staff to complete infrared scans, manhole inspections and other asset testing we anticipate avoided costs of approximately $300k annually.
- We anticipate a 15% savings in fuel costs as a result of optimized routing or $42k annually

The combination of increased productivity, reduced operating costs, and exploiting opportunity costs offset by increased operating costs for maintenance agreements and IT resources results in approximately $2,920k in savings over 6 years with a payback period of 48 months.

The project will also drive many qualitative or unquantified benefits:

- Enhanced performance in meeting customer appointments and service level agreements
- Greater access for Call Centre resources to book customer appointments at the time the accept the customer call
- Real time information regarding field work status available to Call Centre resources for responding to customer inquiries
- Potential positive impact on bad debt expense with improvements in collection field activities
- Increased capacity to complete additional asset inspections required to populate the new Asset Investment Tool being implemented

7.4 Prioritization

7.4.1 Consequence of Deferral

A decision to defer the project would lead to a delay in achieving the quantitative and qualitative benefits defined in the business case.

7.4.2 Priority

This project has a high priority due to the quantitative and qualitative benefits. The solution will have a positive impact on business operations efficiency, customer satisfaction and system reliability.

7.5 Execution Path

7.5.1 Implementation Plan

The project will be implemented in phases as follows:

Phase 1

- Initial installation and configuration
- Integration with CC&B
- Groups: Residential Connections, Damage Prevention and Collections
- Users/Work Orders: 13 staff; 80,000 work orders in 2014

Phase 2

- Integration with Service Manager
- Groups: Metering, Service Layout, Plant Inspections, Forestry
- Users/Work Orders: 34 staff; 18,976 work orders in 2014

Phase 3

- Integration with OMS
- Groups: 24x7, Reliability, Service Truck, Construction
- Users/Work Orders: 125 staff; 10,762 work orders in 2014

7.5.2 Risks to Completion and Risk Mitigation Strategies

The major risks that will be closely monitored during the project are:

Risk Description	Impact Statement (Budget, Schedule, Scope, Quality)	Mitigation Strategy
There is a risk that there will be resistance to the adoption of a “drip feed” method of dispatch	If significant resistance is encountered there could be a delay realizing the benefits expected from the new system.	Consult Field Technicians throughout the design and development of the application to ensure solution meets basic user needs. Proactively communicate to Field Technicians via Managers and Supervisors. Provide Supervisors sufficient reporting

		capabilities to speak to staff concerns.
Internal HOL staff may not have the correct skill set to configure and test the new tool without support from the supplier.	An over reliance on internal staff may result in delays to the completion of the project.	Ensure the professional services contract includes sufficient assistance from the supplier to ensure a successful implementation. Add contingency to the project budget to cover an extension of Oracle Professional Service time.
CC&B resource constraint	The CC&B team who will be participating in the workshops and configuring the system will not have any resources available until the beginning of April	Delay configuration workshops until this resource can join.

Table 130 - Risks and Mitigation Strategy

7.5.3 Timing Factors

We do not anticipate many constraints from a timing perspective. We are sensitive to limiting the amount of configuration and testing completed during the busy construction season due to availability of resources.

7.5.4 Cost Factors

No material variances are expected in the execution of the project.

7.6 Project Details and Justification

Project Name:	Mobile Workforce Management Software
Capital Cost:	1,950,000
O&M:	$150,000 (annual maintenance agreement)
Start Date:	February 2015
In-Service Date:	November 2015
Investment Category:	General Plant
Main Driver:	Business Operations Efficiency
Secondary Driver(s):	Customer Satisfaction System Reliability
Customer/Load Attachment	N/A

Project Scope

The scope of this project is to select and implement a mobile workforce management system for short and long cycle work.

Work Plan

Project Start	February 2015
Project Planning Complete	April 2015
Project Execution	May – November 2015
Project Implementation	November 2015

Customer Impact

- Enhanced customer satisfaction by meeting service levels and appointments
- Enhanced reliability by eliminating backlog of work orders and ensuring priority work is completed in a timely fashion
- Real time view into field work status by call centre staff should lead to increased first call resolution for related customer inquiries