Distribution System Plan Appendices

Engineering Report SP14-03,

Multi-Year Electricity Distribution System Asset Management Plan: 2016 – 2020

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1 Introduction

1.1 Background

Halton Hills Hydro (HHH) is a community-based electricity distribution company responsible for the distribution of electrical power received mainly from the provincial transmission grid to homes, businesses and institutions throughout its service territory in a reliable, safe and cost-effective manner.

Halton Hills Hydro's electricity distribution network services approximately 22,000 households and businesses with 1,527 kilometers of medium- and low-voltage distribution circuits that transport electricity from the provincial transmission grid. The distribution system transferred 533,816,195 kilowatt-hours of energy in 2014 and serviced a summer peak demand of 98,677 kW.

In the development and update of Halton Hills Hydro's multi-year investment plan, many inputs are considered, namely:

- System expansion plans that define feeder circuit reinforcements and voltage conversion projects necessary to deliver additional supply capacity within the service territory;
- Reliability reports that identify underperforming feeder circuits and remedial action plans;
- Relocations, usually due to municipal road widening projects or similar infrastructure renewal projects.
- Relocations, line extensions, etc. associated with new developments
- Asset Life-cycle Management Plans that identify those electricity distribution systems components that are approaching end-of-life and need to be replaced, refurbished, or considered as a candidate for life extension technology.
- Other drivers.

Figure 1-1 Inputs to Five-Year Investment Plan

These inputs are not mutually exclusive. For example, the Life-Cycle Management Plan that deals with modernization or life-extension of older components of the distribution system also addresses reliability issues (i.e. contributors to the "worst performing feeder" in reliability reports) and quality of supply issues (i.e. identified as a candidate neighborhood for voltage conversion in a planning report). A municipal road widening project may be the catalyst not only for relocating Halton Hills Hydro's infrastructure but also an opportunity for modernizing a portion of the distribution system improving reliability and quality of supply. This multi-year investment plan is the overarching document that brings the various input drivers together to provide maximum benefit per investment dollar.

Inputs for this Electricity Distribution System Asset Management Plan are gathered from a variety of sources that include our GIS register, asset maintenance programs, and historical archives available to Halton Hills Hydro staff. The information within this document is primarily based on data compiled between 2007 and the end of 2014.

This plan and its related input documents is a dynamic document that shall be periodically updated to reflect changing and evolving asset conditions and requirements.

1.2 Purpose

The purpose of this Electricity Distribution System Asset Management Plan is to:

- Inform stakeholders about how Halton Hills Hydro intends to manage its electricity distribution network;
- Demonstrate alignment between electricity network asset management and Halton Hills Hydro's vision and goals;
- Provide effective asset management at Halton Hills Hydro;
- Provide a basis for capital expenditures related to refurbishing or replacing aging assets.
- Demonstrate the value proposition that capital expenditures based on asset management principles provides to the customers of Halton Hills Hydro.

1.3 Qualification

This comprehensive Asset Management Plan will assist Halton Hills Hydro in increasing operational effectiveness, financial performance and system reliability while ensuring prudent and effective spending.

Halton Hills Hydro follows an annual budget process and the implementation of the works programs may be modified to reflect any changing operational and economic conditions as they exist or are foreseen at the time of finalizing the budget, or to accommodate changes in regulatory or customer requirements that may occur from time to time. Any expenditure must be approved through normal internal governance procedures. This Electricity Distribution System Asset Management Plan does therefore not commit Halton Hills Hydro to any of the individual projects or initiatives or the defined timelines described in the plan.

1.4 Scope

This Electricity Distribution System Asset Management Plan covers major fixed assets owned and operated by Halton Hills Hydro. This report provides a comprehensive assessment of the assets, asset health, quantity of assets owned, and maintenance programs specific to the assets. The purposes of this Electricity Distribution System Asset Management Plan is to identify the assets owned and operated by Halton Hills Hydro, provide insight as to the useful life of each component, identify potential risk factors, and determine where and when asset renewal will be required.

Asset useful life is determined based Halton Hills Hydro's financial revenue reporting system which utilized Kinectrics Inc. report K-418022-RA-0001-R003 as the starting point for asset useful life.

For each asset identified, a description of the asset is provided, the quantity in service and age profile (where possible), and any preventative maintenance relates to the asset. This Electricity Distribution System Asset Management Plan is the result of staff utilizing a variety of sources on information such as our Geographic Information System (GIS), as-built plans, project files, and asset tables and databases.

The Asset Management Plan addresses the following asset classes:

- Overhead Plant
    - Conductor
    - Poles
    - Insulators
    - Transformers
    - Sectionalizers
- Underground Plant
    - Vaults
    - Chambers
    - Transformers – submersible, padmount
    - Switchgear/sectionalizers
    - Cable
    - Duct bank – DB, CE
- Substation Plant
    - Breakers
    - Switchgear
    - Protection
    - Buildings
    - UPS Systems
- General Plant
    - SCADA Systems
    - GIS Systems
    - Vehicles
    - Buildings

1.5 Terminology

The definitions given below are not intended to embrace all legitimate meanings of the terms. They are applicable to the subject matter treated in this report.

Ampacity is an electrical term used interchangeably with the term current-carrying capacity. These words refer to the maximum load or current a cable can carry. Ampacity can vary greatly from one cable to the next. The variance can be based on the cable construction, as well as external factors such as the thermal environment, or both.

Geographic information system (GIS) is a computer system designed to capture, store, manipulate, analyze, manage, and present all types of spatial or geographical data. In a general sense, the term describes any information system that integrates, stores, edits, analyzes, shares, and displays geographic information. GIS applications are tools that allow users to create interactive queries (user-created searches), analyze spatial information, edit data in maps, and present the results of all these operations. Geographic information science is the science underlying geographic concepts, applications, and systems.

Sulfur hexafluoride (SF6) is an inorganic, colorless, odorless, non-flammable, extremely potent greenhouse gas which is an excellent electrical insulator.

1.6 Acronyms, Abbreviations and Symbols

1.6.1 Acronyms

Acronyms used within this report are presented following in alphabetic order:

DGA	=	Dissolved Gas Analysis
GIS	=	Geographical Information System
IED	=	Intelligent Electronic Device
RTU	=	Remote Terminal Unit
SCADA	=	Supervisory Control & Data Acquisition
VRLA	=	Valve Regulated Lead Acid

1.6.2 Abbreviations

Abbreviations used in this report are presented following in alphabetic order:

A	=	amperes
kV	=	kilovolt
kVA	=	kilovolt-ampere
MVA	=	megavolt-ampere

These abbreviations are consistent with CSA Standard Z85-1983, Abbreviations for Scientific and Engineering Terms.

2 Asset Management Planning

Halton Hills Hydro's approach to asset management covers the full implementation of the asset from specification and installation standards, frequency of preventative maintenance during the assets service life, to determination of when the asset should be removed from service. Strategic management of distribution assets is essential to ensuring the longevity of the distribution system. By collecting and organizing data specific to each asset Halton Hills Hydro aims to ensure investments in assets are made at the right time, address the core necessities of the investment, and provide maximum value to the utility and its customers. Optimal performance improves, system reliability, customer satisfaction, and improves safety factors. The overarching goal of this asset management plan is to provide a framework for asset management planning from which sustainable levels of capital investments can be made responsibly and optimally and which address the needs of the asset.

Figure 2-1 Contributing Elements for Asset Management Investments

As assets age, HHH makes decisions about the assets to achieve optimal performance, lowest operating cost, and ensure safety. Such decisions often include preventative maintenance timing, the potential for rehabilitation rather than replacement, and where necessary asset replacement. The majority of asset renewal investments is triggered by declining performance, increased operational cost, safety, and anticipated load growth requiring upgrades to increase capacity and/ or reduce system constraints.

This prudent approach to asset management ensures that Halton Hills Hydro's assets are maintained in good condition and that only the necessary investments are made.

2.1 Asset Management Planning Objectives

Halton Hills Hydro's overall philosophy on maintaining its electrical distribution system assets is based on the following key factors:

- Safety - Ensuring the safety of consumers, the public and its field staff;

The safety goal has been set to ensure that the safety of workers and the public remains the number one priority over the planning period.

Measure	Target
Lost/non-lost time injuries	Strive for zero lost time injuries
ESA Non- Compliance	Zero Needs Improvements

- Reliability - Ensuring reliable and sustainable distribution system operation, in a cost-efficient manner;

The reliability goal is designed to ensure appropriate management of HHH assets to provide a sustainable and reliable service to our customers. The goal is set based on a 5-year average of reliability statistics for the utility.

Measure	Target
SAIDI	1.72 hours
SAIFI	1.98 incidents
CAIDI	0.88 hours

- Financial Integrity - Achieving the optimal trade-off between maintenance and replacement costs. That is, replacing assets only when it becomes more expensive to keep them in service. Halton Hills Hydro has adopted, where practical, condition-based assessments rather than age-based replacement programs.

Measure	Target
Pole testing and replacements	175-200 Poles per Year
Ontario Energy Board PEG Report Benchmarking	Maintaining a stretch factor assignment within the top two groupings

- Conservation

Measure	Target
Net Cumulative Energy Savings	30.9 GWh by end of 2020

- Community Focused

Measure	Target
Customer Satisfaction	Maintain or exceed 90% of customer satisfaction survey respondents very or fairly satisfied.

2.2 Asset Management Planning Policy

Halton Hills Hydro uses its distribution system assets to deliver services to its customers in the Halton Hills Hydro service area. In order to provide high quality, reliable services at a reasonable price, Halton Hills Hydro has developed an Asset Management Policy to ensure a continual and continuous focus on delivering services in a way that balances risk and long term costs. This policy establishes the core asset management principles that drive Halton Hills Hydro's planning framework.

It is Halton Hills Hydro policy that distribution networks be designed, constructed, operated, maintained and renewed in an efficient manner which:

- Ensures the safety of the community and employees
- Supports Halton Hills Hydro strategic goals and Asset Management Objectives;
- Supports OEB RRFE outcomes;
- Implements Halton Hills Hydro business plan;
- Complies with regulatory and statutory requirements;
- Effectively controls and balances investment levels and service levels with asset lifecycle costs and risks

It is the responsibility of the Halton Hills Hydro Board to establish roles, responsibilities, authorities and controls to achieve the asset management policy, strategy, objectives and plans. Responsibility for asset management is held from the Board to the President and CEO of Halton Hills Hydro. The President and CEO has overall responsibility for developing Halton Hills Hydro's Asset Management System and reporting on the status and effectiveness of the system to the board.

2.3 Asset Inventory

Information on the quantity, age and capability of existing assets is essential to understand and effectively manage the asset base.

The asset register, Halton Hills Hydro's ESRI geographical information system (GIS) and associated databases, store information and technical characteristics for all assets including their location, history and performance. Halton Hills Hydro utilizes Asset Alteration Reports and Mapping Information Update forms to gather changes to our field assets from which we can update our asset information records. These forms are displayed in Appendix D.

3 Overhead Distribution Systems

This section identifies the major components of an overhead electricity distribution system, the typical useful life for each component, and the life-cycle management plan for each component.

3.1 Major Components of Overhead Electricity Distribution Systems

The major components of an overhead electricity distribution system are:

- Distribution poles, primarily of wood;
- Distribution transformers;
- Group-operated load-interrupter switches;
- Voltage regulators and automatic circuit reclosers; and
- Conductors, both bare conductors for primary circuits and insulated conductors for overhead secondary buses and service connections.

The life-cycle management plans discussed in this section are organized by these groupings of major equipment.

3.2 Typical Useful Life of Overhead Distribution System Components

As part of Halton Hills Hydro asset management program, we along with other GTA utilities commissioned Kinectrics to prepare a study of the useful life of assets used for distributing electricity and supporting the distribution system. This document is identified as Kinectrics report K-418022-RA-0001-R003, Useful Life of Assets; Issued December 10, 2009. The useful lives identified in that report were then analyzed with consideration for the utility's specific operating environment. Final determination of useful lives was established and approved in our 2012 Cost of Service rate application (EB-2011-0271). The revised useful lives was required for the transition to International Financial Reporting Standards (IFRS) in which components of a like structure were grouped and given a useful life representative of the major component of the entire structure.

The information specific to overhead distribution system components is referenced and summarized below.

Asset Category	Typical Useful Life (years)
(Col 1)	(Col 2)
Wood distribution pole	50
Transformers	40
Reclosers	40
Switches	40
Voltage regulators	40
Conductors	50

Table 3-1 Useful Life Values for Overhead Distribution Components

3.3 Life-Cycle Management Plan for Wood Distribution Poles

Distribution poles are normally framed with line post insulators, stand-off brackets, messenger suspension clamp, and sometimes guying accessories. These accessories are all inorganic in nature, have an expected life-time greater than a wood distribution pole, and would be replaced in conjunction with the replacement of a wood distribution pole due either to technical obsolescence or cost efficiency.

3.3.1 Age Profile of In-Service Assets

The age profile for Halton Hills Hydro's population of wood distribution poles as of December 2014 is illustrated in Figure 3-1 below.

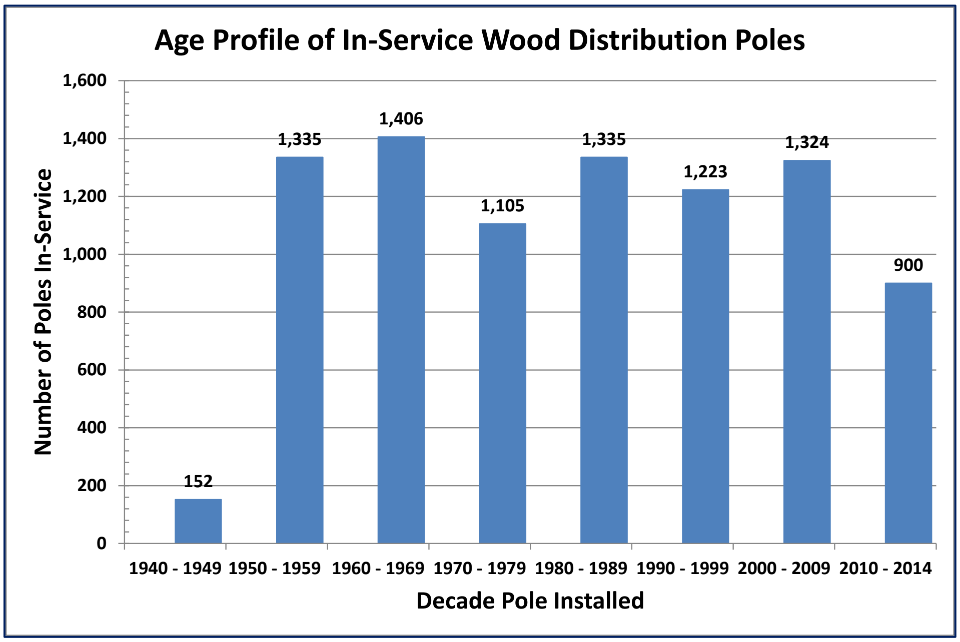


Figure 3-1 Age Distribution of In-Service Wood Distribution Poles

There are 1,487 distribution poles that were installed prior to 1960. The expected in-service life of a wood distribution pole is a function of its species (i.e. western red cedar, red pine, etc.), pole treatment (i.e. the type of wood preservative applied), the extent to which treatment is applied (i.e. untreated, butt treated, or fully treated), and the soil environment in the vicinity of the pole butt.

3.3.2 Condition Testing Methodology

There are several in-situ non-destructive evaluation methods available for ascertaining a wood distribution pole's loss of mechanical strength primarily due to ground-line decay where moisture conditions are ideal for propagating and supporting fungal attack.

Figure 3-2 Examples of Carpenter Ant Damage (left) and Severe Ground-Line Decay (right)

The following evaluation methods are used:

There are several in-situ non-destructive evaluation methods available for ascertaining a wood distribution pole’s loss of mechanical strength primarily due to ground-line decay (where moisture conditions are ideal for propagating and supporting fungal attack).

The following evaluation methods are used by Halton Hills Hydro (to complement visual observations of advanced decay and extensive insect damage):

- Visual inspection of wood cross-arms and pole tops for signs of rot, feathering, insect and woodpecker damage and other signs of damage.
- Sounding the pole at various heights to check for weak points and visual checks for rot, decay, and holes above and below ground line.
- Sonic stress wave evaluation - a sonic test signal is applied to each pole and is compared to a test database that includes pole strength. By comparing the test signal to that stored in the database for the same pole species, a measure of pole strength can be determined.
- Resistograph testing - Resistograph is a trademark characterizing electronic high-resolution needle drill resistance measurement devices used for inspecting timber in order to find internal defects and to determine wood density. With this testing method, a thin and long needle is driven into wood. The electric power consumption of the drilling device is measured, recorded and printed. Resistograph devices are different from other resistance drills because they provide a high linear correlation between the measured values and the density of the penetrated wood.

Since 2004, Halton Hills Hydro has arranged for recognized pole testing contractors to provide annual in-situ evaluations of a nominal 1,200 wood distribution poles, to mark poles that have deteriorated to a marginal or unacceptable state, and to provide a comprehensive electronic report of all test data. Halton Hills Hydro assesses the annual report to determine the quantity of poles to be changed imports that data into our own pole management database and manages our asset reports from within.

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

Appendix E contains Halton Hills Hydro’s non-destructive pole testing schedule for 2016 to 2020. The current rate of testing ensures that each utility pole in the distribution system is tested using the aforementioned non-destructive techniques on an eight (8) year cycle.

3.3.3 Prioritization of Expenditures

As identified in Figure 3-1, Halton Hills Hydro has a significant number of wood distribution poles that are past the upper value in the useful life range.

To address this backlog in a prudent manner, Halton Hills Hydro has developed a prioritization (ranking) method for planned pole replacements that considers:

- The age and condition of the pole.
- The proximity of the pole to public gathering spaces, i.e. a vintage pole located adjacent to a school or recreational facility has a higher priority than a pole located in a rural area.
- The highest voltage available on the pole, i.e. a vintage pole carrying a 44 kV sub-transmission feeder has a higher priority than a pole that supports only a low-voltage overhead bus.
- The impact on system reliability, i.e. a vintage pole carrying backbone distribution circuits has a higher priority than a pole that supports fused lateral circuits.
- Other factors and opportunities, i.e. if there is an opportunity to carry out a voltage conversion project or other modernization effort in conjunction with the pole replacements, these poles will be assigned a higher priority than otherwise would have been the case.

In cases where the condition testing reveals an advanced state of decay, these wood distribution poles are scheduled for replacement.

Appendix C contains Halton Hills Hydro’s Pole Testing Procedure.

3.3.4 Active Pole Replacement Program

Recognizing that there was a backlog of wood distribution poles well beyond their expected service lifetime, in the summer of 2012, Halton Hills Hydro initiated an accelerated program of wood pole replacements mainly using contracted resources. Moving forward from 2012, Halton Hills Hydro combines its workforce with that of contracted resources to effect the replacement of aged and deteriorated wood distribution poles.

To ensure we address the backlog of aging poles in a timely manner, Halton Hills Hydro is investing $2,000,000 per year in pole replacements as part of this Asset Management Plan.

The advantage of cluster pole replacements (i.e. replacing all the poles on a street) is that it offers the opportunity to completely modernize the segment of circuitry (e.g. modernize the framing, secondary bus arrangement, etc.). Spot replacements, by contrast, are simply like-for-like replacements with little or no other concurrent modernization. With very old poles, it is often preferable to modernize the infrastructure at the same time as the poles are replaced rather than opting for spot replacements. Where a pole is replaced and other utilities or telecommunication companies are also attached to the same pole, Halton Hills Hydro coordinates replacement and efforts with the affected parties in respect of Ontario Regulation 22/04 "Electrical Distribution Safety".

Halton Hills Hydro plans to continue with an accelerated pole replacement program targeting a nominal 275 to 280 distribution poles per year in each of the next five years. This plan recognizes that this pole replacement strategy is ongoing as existing poles continue to age.

3.4 Life-Cycle Management Plan for Pole-Mounted Distribution Transformers

3.4.1 Age Profile of In-Service Pole-Mounted Transformer Assets

Halton Hills Hydro operates three (3) distinct distribution voltages within its service territory, namely 2.4/4.16Y kV, 4.8/8.32Y kV and 16/27.6Y kV.

Figure 3-3 Typical Pole-Mounted Distribution Transformer

The three-wire 44 kV system is classified as a sub-transmission level and only supplies customer-owned power transformers and municipal substation power transformers. There are no connected distribution transformers.

Pole-mounted distribution transformers can be attached to a pole as:

- a single unit to provide a single-phase 120/240 V supply to one or more customers; or
- three (3) single-phase transformers arranged in a bank to provide a three-phase 120/208Y or 347/600Y V supply to one or more customers.

The capacity profile for Halton Hills Hydro's population of single-phase pole-mounted distribution transformers is tabulated in Table 3-2 below by supply voltage level. This table gives the apparent power ratings of individual transformers, not the composite rating of three-phase transformer banks.

Supply Voltage	Transformer Apparent Power Rating, kVA							
	≤ 10	15	25	37½	50	75	100	167
16 or 16/27.6Y kV	22	65	101	5	61	1	30	--
4.8 or 4.8/8.32Y kV	261	340	608	87	262	31	37	6
2.4 or 2.4/4.16Y kV	6	34	183	102	397	52	68	--

Table 3-2 Capacity Profile of 1-Phase Pole-Mounted Distribution Transformers

The age profile for Halton Hills Hydro's population of single-phase pole-mounted distribution transformers is shown below by supply voltage level.

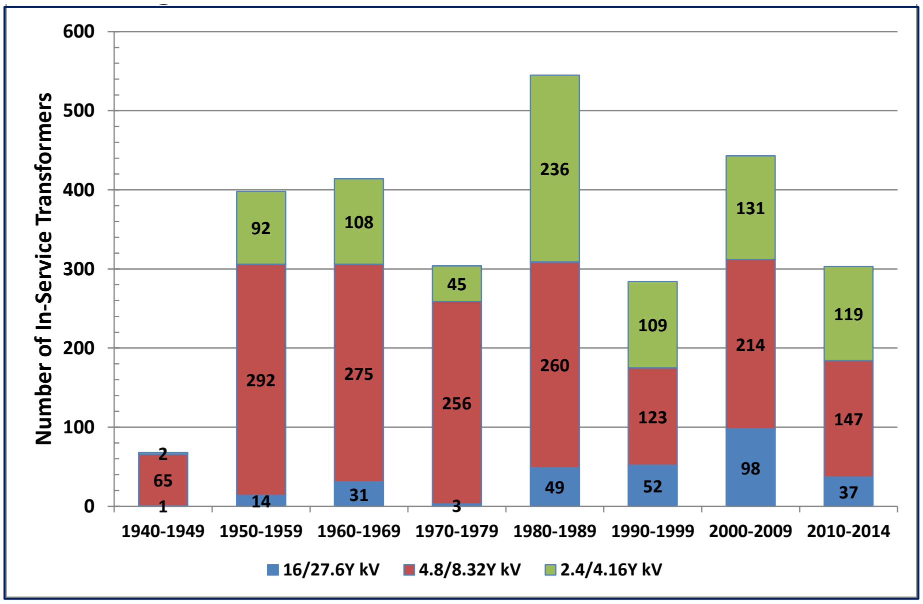


Figure 3-4 Age Profile of 1-Phase Pole-Mounted Distribution Transformers

Where the nameplate data for in-service transformers is incomplete, reasonable assumptions have been made using work order dates, in-service dates on a connected customer revenue meter, etc.

The typical useful life of distribution transformers is 40 years. Halton Hills hydro has:

- 880 single-phase pole-mounted distribution transformers, representing 32% of the overall population, were installed prior to 1970 (i.e. they have been in-service for 45 years or more); and
- 68 single-phase pole-mounted distribution transformers, representing 2½% of the population, were installed prior to 1950 (i.e. they have been in-service for 65 years or more).

3.4.2 Inspection Methodology

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

Halton Hills Hydro conducts an infrared thermography scan of its entire electrical distribution system every two years. Typical imagery from an infrared thermography instrument is depicted in Figure 3-5.

Pole-mounted distribution transformers are normally run-to-failure.

3.4.3 Active Transformer Replacement Program

Pole-mounted distribution transformers are normally run to

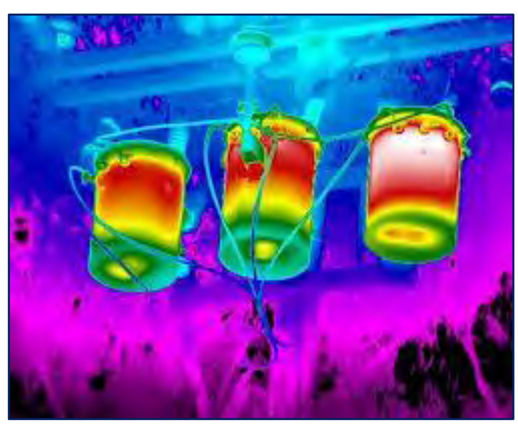


Figure 3-5 Thermo-graphic Image of Distribution Equipment

failure and, with two (2) notable exceptions there is no program for the planned replacement of vintage distribution transformers. Vintage transformers are normally replaced in conjunction with voltage conversion or pole replacement projects.

The first specific exception is the modernization of certain vintage distribution transformers connected to Halton Hills Hydro's 2.4/4.16Y kV distribution system that provide a three-wire 600 V supply (also sometimes referred to as a "600V delta supply") to certain business customers. This initiative encompasses modernization of transformers, overhead secondary bus conductors, and revenue metering systems.

The second specific exception is where transformers are overloaded. Often in established overhead distribution communities a multitude of residential customers had been connected to a single transformer to a point where the transformer has become overloaded, seen in Figure 3-6. Overloading of a transformer can be problematic in that continued excessive loading generates sustained heat from which the thermal impacts can damage the cellulose insulation and reduce the overall life expectancy of the transformer. Halton Hills Hydro makes a concerted effort when these situations are identified to remedy the problem by replacing the transformer with a larger one or by installing a second transformer and dividing the customers.

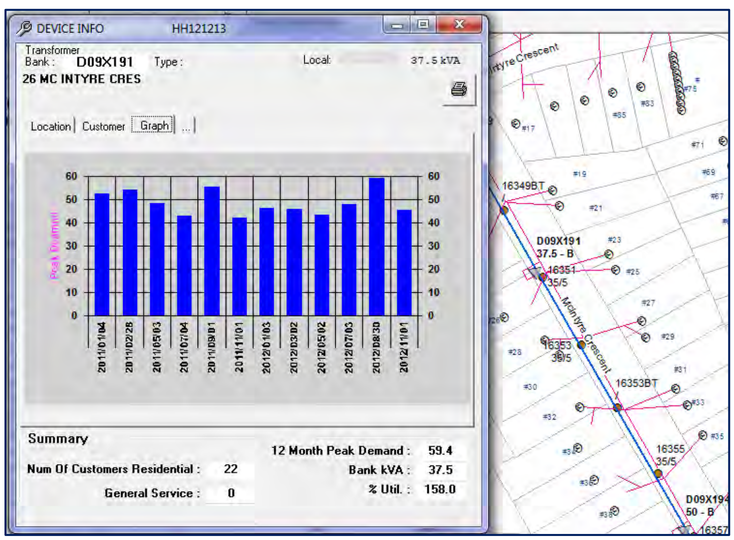


Figure 3-6 Example of Overloaded Transformer shown in GIS

In the mid-1980's the utility sector throughout North America embraced consideration of the recurring cost of transformer losses as an ownership cost and introduced loss evaluation formulas in the procurement phase. As such, transformers manufactured prior to the mid-1980's are considered inefficient and are usually replaced with efficient transformers in conjunction with other opportunities, e.g. pole replacement projects.

3.5 Life-Cycle Management Plan for Sectionalizing Switches

Pole-mounted, three-pole, group-operated load interrupter switches, as illustrated in Figure 3-7 below are required on the three-wire 44 kV sub-transmission system for live switching operations to reconfigure feeder circuits and to sectionalize a feeder circuit to isolate a faulted or failed component and restore supply to other customers. Similar switches are also deployed on the three-phase four-wire 16/27.6Y kV distribution system at designated tie points between different transformer stations and at designated tie points between feeder circuits emanating from different buses from the same transformer station. Over time, some of these switches may be candidates for replacement with automated switches operable via the SCADA system.

Figure 3-7 Typical Gang-Operated Load-Interrupter Switch

3.5.1 Age Profile of In-Service Assets

There are thirty-four (34) three-pole group-operated load-interrupter switches installed on Halton Hills Hydro's 44 kV sub-transmission system and 16/27.6Y kV distribution system as tabulated in Table 3-3 below. For the purposes of this report, pole-mounted three-pole group-operated load-interrupter switches have been classified as *distribution automation* if they are already outfitted with a motor operator, radio transceiver, and current sensing instruments (and marked with the ❶ symbol in the first column) or designed to be outfitted with such accessories in future (and marked with the ❷ symbol in first column).

Operating Designation of Switch	Feeder Voltage	Feeder Designation	Normal Operating State	Year of Installation
27-010	16/27.6Y kV	41M21	OPEN	
S250	16/27.6Y kV	41M21	CLOSED	
27-001	16/27.6Y kV	41M21	CLOSED	
27-002	16/27.6Y kV	41M30	CLOSED	
27-052 ❷	16/27.6Y kV	41M30	CLOSED	2012
27-023	16/27.6Y kV	41M21	CLOSED	
27-020	16/27.6Y kV	42M28	CLOSED	
4275-1	44 kV	42M25	CLOSED	
4280-3	44 kV	42M25	CLOSED	
2504 ❶	44 kV	42M25	CLOSED	2012
4264-1	44 kV	42M23	OPEN	
2305	44 kV	73M04	CLOSED	
7309	44 kV	42M23	OPEN	
4281-1	44 kV	42M23	CLOSED	
4281-2	44 kV	42M23	CLOSED	

2313 ❶	44 kV	42M23	CLOSED	2012
2316 ❶	44 kV	73M04	CLOSED	2012
7303-1	44 kV	73M04	OPEN	
7312 ❶	44 kV	42M23	CLOSED	2012
2314 ❶	44 kV	42M23	OPEN	2012
4273-2	44 kV	42M28	CLOSED	
4287-2	44 kV	42M28	OPEN	
2804 ❶	44 kV	42M23	CLOSED	2012
19T1-L	44 kV	41M21	CLOSED	
4271-1	44 kV	41M21	CLOSED	
4280-1	44 kV	42M25	CLOSED	
4280-2	44 kV	42M25	CLOSED	
4268-1	44 kV	42M25	OPEN	
4267-1	44 kV	42M25	OPEN	
27-054 ❷	16/27.6Y kV	41M21	OPEN	2013
27-058 ❷	16/27.6Y kV	41M21	CLOSED	2014
27-050 ❷	16/27.6Y kV	41M21	OPEN	2012
27-046 ❷	16/27.6Y kV	41M21	OPEN	2011
27-048 ❷	16/27.6Y kV	41M21	OPEN	2011

Table 3-3 Inventory of Distribution Automation Switches (as of December 31, 2014)

There are twenty-two (22) manually-operated pole-mounted gang-operated load interrupter switches connected to the 44 kV sub-transmission system or 16/27.6Y kV distribution system that will remain as manually-operated switches for the foreseeable future.

3.5.2 Inspection Methodology

The most commonly encountered operating issue associated with three-pole gang-operated load interrupter switches is seizing of the articulated mechanical linkages due to the application of an incorrect lubricant or the ingress of airborne contaminants into the lubricant. Halton Hills Hydro is mandated by the provisions of the Distribution System Code to carry out regular inspections of its distribution system assets.

Halton Hills Hydro is developing a program to be in place by the end of 2016 which will have all airbreak and loadbreak switches within the service territory operated on a rotating schedule for routine maintenance.

3.5.3 Active Replacement Program

Halton Hills Hydro does not have an active replacement program for vintage pole-mounted, gang-operated, load interrupter switches. HHH has made strategic investments in distribution automation switches for its 44 k sub-transmission system to improve the overall reliability performance of its system.

A number of group-operated automated 46 kV and 25 kV class distribution switches have been purchased and installed. The next phase of the project will be to activate radio channels for these devices for connection to the SCADA systems.

3.6 Life-Cycle Management Plan for Regulators and Reclosers

Step voltage regulators and automatic circuit reclosers are typically applied on long rural feeder circuits to maintain voltage supply within acceptable limits and keep feeder reliability performance within acceptable limits.

Figure 3-8 Typical Platform-Mounted Single-Phase Step Voltage Regulator

Figure 3-9 Typical Single-Phase Pole-Mounted Automatic Circuit Recloser

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

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

Halton Hill Hydro has:

- nine (9) single-phase voltage regulators in active service (on the 4.8/8.32Y kV distribution system) at three locations as defined in Table 3-4 below; and
- nine (9) automatic circuit recloser banks in active service (on the 4.8/8.32Y kV distribution system) at nine locations as defined in Table 3-5 below.

3.6.1 Age Profile of In-Service Step Voltage Regulators

As illustrated in Table 3-4, the oldest step voltage regulators were manufactured in 1981 and are well within the 40 year typical useful life.

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

Table 3-4 Inventory of Single-Phase Step Voltage Regulator Installations

3.6.2 Age Profile of Single-Phase Automatic Circuit Reclosers

The year of manufacture information for some single-phase automatic circuit reclosers is not recorded on the equipment nameplates. It is estimated that oil circuit reclosers are within their useful lives and have been overhauled over the years to keep them in good working order. A listing of existing recloser locations is indicated in Table 3-5 below.

Feeder Designation	Location Description	Regulator Manufacturer & Type	Controls	Year of Manufacture
5F1	4th Line/Coles Crt	G&W Viper ST	Electronic	2012
5F2	4th Line/CNR	Cooper L	Hydraulic	
5F2	4th Line & 22 Sdrd	G&W Viper ST	Electronic	2012
5F2	Hwy 25 & 22 Sdrd	Cooper 4H	Hydraulic	Unknown
5F2	22 Sdrd & Hwy 25	Cooper 4H	Hydraulic	Unknown
11F3	8th Line/Fallbrook Trail	Cooper L	Hydraulic	Unknown
11F3	8th Line/Bishop Crt	Cooper L	Hydraulic	Unknown
23F1	15 Sdrd/Hwy 25	Cooper L	Hydraulic	Unknown
23F2	17 Sdrd/Trafalgar	Cooper L	Hydraulic	Unknown

Table 3-5 Inventory of Single-Phase Automatic Circuit Recloser Installations

3.6.3 Inspection Methodology

The inspection and test methodology of step voltage regulators is given in Section 7.12.1.1 of NETA Standard MTS-2001, Maintenance Testing Specification for Electrical Power Distribution Equipment and Systems [Ref 2].

HHH presently inspects all line voltage regulators every six months and performs routine visual inspections and operational checks to ensure that they remain functional. Depending on the manufacturers recommended maintenance schedules and operational experience; the regulators are periodically removed from service and are overhauled. A typical overhaul involves changing the insulating oil and inspecting the tap changer contacts for wear. Over time, as older solid state controls become less reliable they are updated to newer electronic types.

Reclosers are inspected as part of regular line patrols and inspections and are routinely rotated out of the system for overhauls. Often reclosers require periodic overhauls due to their nature of interrupting fault level currents. Manufacturer recommended duty and operational experience determines when units are removed from service and overhauled.

3.6.4 Active Replacement Program

Voltage regulators and automatic circuit reclosers are considered tools to address distribution system performance issues. Voltage regulators address power quality by keeping voltage levels within acceptable limits whereas reclosers address reliability by protecting distribution lines from temporary faults and allowing the faults to clear avoiding lengthy customer outages.

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

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

3.7 Life-Cycle Management Plan for Primary & Secondary Conductors

3.7.1 Age Profile of In-Service Assets

Halton Hills Hydro owns and operates primary conductor and secondary cable throughout its service territory. The GIS system and operating maps track the size and type of primary and secondary conductors. Asset tracking distinguishes between vintage open secondary bus secondary distribution circuits in residential subdivisions (as illustrated in Figure 3 9 below) and modern spun bus secondary distribution circuit as illustrated in Figure 3 10 below.   Primary conductors are also tracked.

Figure 3-10 Illustration of Vintage Open Secondary Bus System

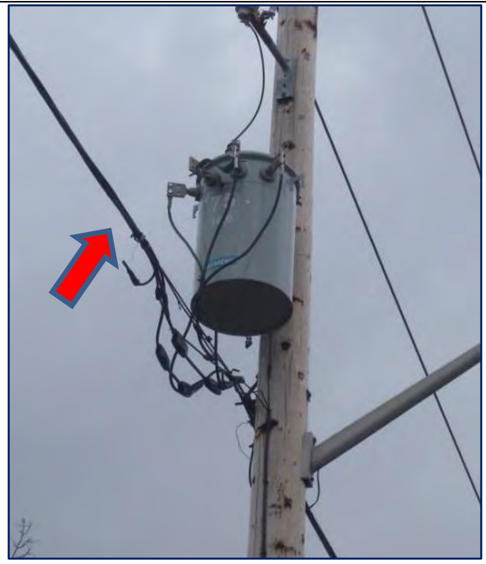


Figure 3-11 Example of Modern Spun Secondary Bus System

3.7.2 Inspection Methodology

Along with visual inspections, HHH employs infrared thermography every two years to detect localized over-heating typically of electrical connections.

3.7.3 Active Replacement Program

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

3.8 Life Cycle Management of Porcelain Line Post Insulators and Switches

3.8.1 Description of Assets and Operational Challenges

Halton Hills Hydro employs line post insulators and switches on its distribution system to support and conduct the deliverance of electricity. Since the 1990's Halton Hills Hydro has been predominantly installing polymer type insulators and switches, however, before that time it was a common utility practice to install porcelain insulators and switches.

Line post insulators are devices used to hold a conductor in place along a distribution pole line. Insulators have specific voltage class ratings and the selection of insulators is based on the line-to-neutral operating voltage, consideration for future voltage conversion, and the location of the installation. For example, on a 16.0/ 27.6kV distribution system, Halton Hills Hydro would normally use a 35kV line post insulator to support the conductor and insulate the voltage from the pole. However, where areas of higher contamination are present, such as major traffic corridors and industrial parks, the utility may choose to install 46kV insulators to have a higher level of insulation as well as a greater dry arc distance across the insulator to safeguard the public.

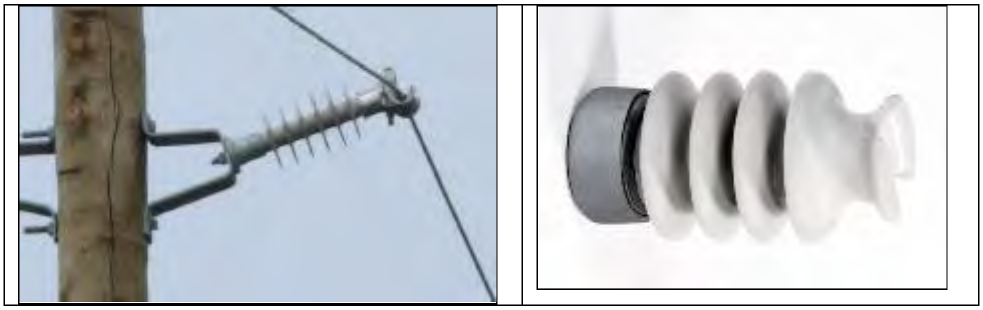


Figure 3-12 Polymer and Porcelain Line Post Insulators

Switches include in-line and cutout switches and are used to convey electricity to customers. They provide the utility with means to change the direction of flow in the distribution system for operational needs, establish isolation, and protect upstream circuits/ devices through use of fused switches.

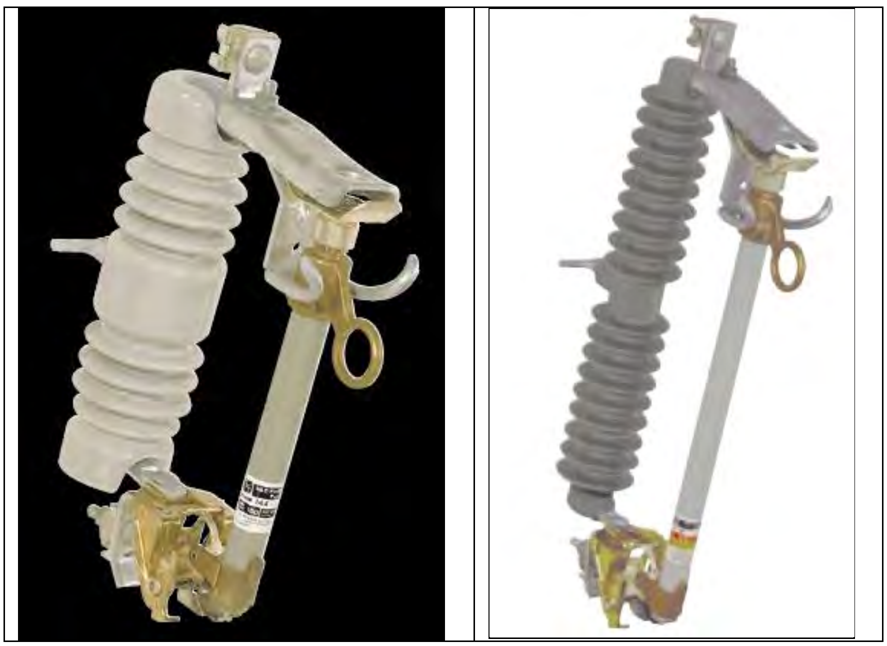


Figure 3-13 Porcelain and Polymer Cutout Switches

Both porcelain and polymer insulation offer the same level of protection. The major challenge experienced by Halton Hills Hydro is that porcelain insulators and switches are more susceptible to damage and failure than the equivalent polymer type. Porcelain insulators can develop small cracks in the external housing of the insulator. These cracks contribute to the overall failure and resulting safety concerns surrounding porcelain housed insulation. When a crack occurs, water can ingress into the crack. During the colder months that water will freeze and expand, causing the crack to expand. Overtime the crack can become large and in instances results in equipment failure. Such failure can occur on its own or when the device in operated.

3.8.2 Major Insulator Failure

On February 21, 2012 at 3:01pm Halton Hills Hydro experienced a significant porcelain insulator failure. Forty-Four (44) Customers along Hwy 7, Dublin Line and Turtle Lake Drive experienced a voltage surge when an insulator on our 44kV circuit (73M04) sheared off and dropped onto our 4.8kV single phase

(5F1 – red phase) under-build. The momentary contact between these two conductors allowed a higher than normal voltage “spike” to travel along our 4.8kV system adversely affecting all customers connected to it. This equipment failure is expected to have happened due to the age of the equipment and visible, hairline cracks that can be seen along the edge of the broken porcelain. No other outside forces acted on this equipment such as weather or impact on the pole or equipment. Affected customers described sparks coming from the electrical receptacles in their homes, a burnt electrical smell as well as popping and cracking noises coming from connected appliances and equipment. All customers that contacted Halton Hills Hydro describing issues related to the voltage surge were given the recommendation to contact an electrician to determine if there were any issues within their homes that needed to be addressed and to contact Halton Hills Hydro to determine the next steps to replace or repair equipment damaged during this event. Halton Hills Hydro filed an insurance claim in the amount of $57,000 with The Mearie Group.

Figure 3-14 Porcelain Insulator Failure

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

3.8.3 Active Replacement Program

Distribution insulators and switches are not normally replaced based on their performance. They are typically replaced when the pole or equipment they are associated with is replaced as part of a larger infrastructure project. Halton Hills Hydro employs this method for many passive devices.

Halton Hills Hydro has implemented a regular replacement program for porcelain insulators and switches. The current program and investments are both reactive and proactive to ensure that the distribution system is reliable and safe to operate. Reactive investments are made in conjunction with other projects, while proactive replacement removes aged assets that are more susceptible to failure. The utility has directed its workforce to replace any porcelain switch with a polymer type switch when they are working on them in the field. They are also identifying areas where suspect porcelain insulators are located for inspection and replacement purposes.

Figure 3-15 Cracked Porcelain Insulator (left), Broken Porcelain Switch (right)

3.9 Life Cycle Management Plan for Solar Panels on Poles

Halton Hills Hydro has 200 Pole Mounted Solar Panels installed throughout its service territory. These panels were installed as a pilot project to evaluate the smart grid and renewable energy capabilities of this technology. This project, which was partially funded through the LDC Tomorrow Fund, included a third party review to quantify and evaluate the distribution system benefits of the technology. These solar panels generate electricity and also provide voltage and frequency monitoring of the secondary distribution system.

Figure 3-16 Typical solar panel being installed on pole.

3.9.1 Maintenance and Upkeep of Solar Panels

The anticipated lifespan in the field is 20 years. These panels are maintained as part of the utility's overhead distribution system. Halton Hills Hydro continues to monitor the performance of these panels but has no current plans to expand this project.

3.9.2 Active Replacement Program

Halton Hills Hydro has not expanded it solar panels on poles program at the present time, however existing devices continue to be monitored. The current devices are run to failure. If individual panels fail the panel will be removed from service and not replaced. If a pole having a solar panel on it is replaced/ relocated the solar panel may be relocated to the new pole and put into service provided there is a connection point

4 Underground Distribution Systems

This section identifies the major components of an underground electricity distribution system, the typical useful life for each component, and the life-cycle management plan for each component.

4.1 Major Components of Underground Electricity Distribution Systems

The major components of an underground electricity distribution system are:

- Padmounted distribution transformers - single-phase and three-phase;
- Single-conductor, medium-voltage power cables;
- Padmounted sectionalizing switchgear and junctions; and
- Low-voltage triplexed underground service cables.

4.2 Typical Useful Life of Underground Distribution System Components

Halton Hills Hydro owns and operates 636 km of underground primary cables energized at 2.4/ 4.16Y kV, 4.8/ 8.32Y kV, 16/ 27.6Y kV, and 44kV. As part of Halton Hills Hydro's asset management program, HHH along with other GTA utilities commissioned Kinectrics to prepare a study of the useful life of assets used for distributing electricity and supporting the distribution system. This document is identified as Kinectrics report K-418022-RA-0001-R003, Useful Life of Assets; Issued December 10, 2009. The useful lives identified in that report were then analyzed with consideration for the utility's specific operating environment. Final determination of useful lives was established and approved in our 2012 Cost of Service rate application (EB-2011-0271). The revised useful lives was required for the transition to International Financial Reporting Standards (IFRS) in which components of a like structure were grouped and given a useful life representative of the major component of the entire structure.

The information specific to underground distribution system components is referenced and summarized below.

Asset Category	Typical Useful Life
(Col 1)	(Col 2)
TR-XLPE power cable (Duct)	40
Secondary cables(PVC Jacket)	40
Padmounted transformers	40
Padmounted switchgear	20

Table 4-1 Useful Life Values for Underground Distribution Components

4.3 Life-Cycle Management Plan for Pad-Mounted Distribution Transformers

4.3.1 Age Profile of In-Service Pad-Mounted Transformer Assets

Halton Hills Hydro operates three (3) distinct distribution voltages within its service territory, namely 2.4/4.16Y kV, 4.8/8.32Y kV and 16/27.6Y kV.

4.3.1.1 Single-Phase Padmounted Distribution Transformers

There are 1,270 single-phase padmounted distribution transformers installed within Halton Hills Hydro's service territory. A typical single-phase distribution transformer is generally used within underground residential subdivisions to provide a single-phase 120/240 V_{ac} supply to residential dwellings.

The capacity profile for this population of single-phase padmounted distribution transformers is tabulated below by supply voltage level.

Supply Voltage	Transformer Apparent Power Rating					
	≤ 25 kVA	37½ kVA	50 kVA	75 kVA	100 kVA	167 kVA
16,000 V	7	--	599	6	2	--
4,800 V	19	--	267	36	26	1
2,400 V	8	--	232	16	49	2

Table 4-2 Capacity Profile of 1-Phase Padmounted Distribution Transformers

Halton Hills Hydro has a number of single-phase distribution transformers with a high-voltage winding that is designed for two voltages. For example the transformer high-voltage winding may be rated 4160GrdY/2400 x 8320GrdY/4800 meaning there is an internal switch allowing the utility to energize the transformer at 2400 V or 4800 V. Table 4-2 is based on the transformer's current energization voltage.

The age profile for Halton Hills Hydro's population of single-phase pad-mounted distribution transformers is shown in Figure 4-1 below again by supply voltage level.

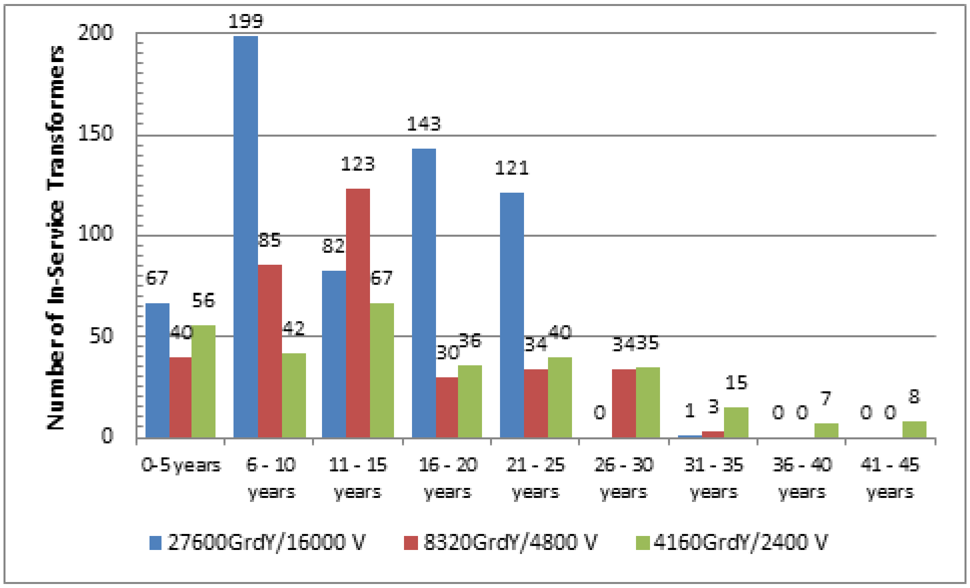


Figure 4-1 Age Profile of 1-Phase Padmounted Distribution Transformers

In cases where the transformer's year of manufacture was not recorded, reasonable assumptions have been made using work order dates, in-service dates on a connected customer revenue meter, etc.

Halton Hills Hydro has:

- Eight (8) single-phase padmounted distribution transformers, supplied from the 2.4/4.16Y kV distribution system, that have been in active service for more than the 40-year typical useful life; and
- Seven (7) single-phase padmounted distribution transformers, again supplied from the 2.4/4.16Y kV distribution system, that are approaching the end of their expected useful life.

Padmounted distribution transformers are not proactively replaced based solely on their age. Other factors such as degree of corrosion, evidence of leaking gaskets, and technical obsolescence are also considered. With aging transformers, typically, the underground primary cables that supply these transformers are also at or past their expected useful life. As such, the residential subdivisions where these transformers and primary cables are installed can be candidates for a combination infrastructure renewal project.

4.3.1.2 Three-Phase Padmounted Distribution Transformers

There are 152 three-phase padmounted distribution transformers installed within Halton Hills Hydro's service territory. A typical three-phase distribution transformer is generally used to provide a three-phase 120/208Y V or 347/600Y V supply to one or more commercial customers.

The capacity profile for this population of three-phase padmounted distribution transformers is tabulated below by supply voltage level.

Supply Voltage	Transformer Apparent Power Rating, kVA											
	< 75	75	112½	150	225	300	500	750	1000	1250	1500	> 1500
16/27.6Y kV		1	--	6	--	16	22	11	3	--	1	--
4.8/8.32Y kV	1	2	--	5	--	5	6	--	--	--	--	
2.4/4.16Y kV	1	6	7	10	1	39	9	--				

Table 4-3 Capacity Profile of 3-Phase Padmounted Distribution Transformers

The shaded cells in Table 4-3 reflect apparent power ratings not recognized within industry standards such as CSA Standard C227.4, Three-Phase, Pad-Mounted Distribution Transformers with Separable Insulated High-Voltage Connectors.

Halton Hills Hydro has a number of single-phase distribution transformers with a high-voltage winding that is designed for two voltages. For example a transformer high-voltage winding may be rated 27600GrdY/16000 x 8320GrdY/4800 meaning there is an internal switch allowing the utility to energize the transformer at 16/27.6Y kV or 4.8/8.32Y kV. Table 4 3 is based on the transformer's current energization voltage.

The age profile for Halton Hills Hydro's population of three-phase pad-mounted distribution transformers is shown below by supply voltage level.

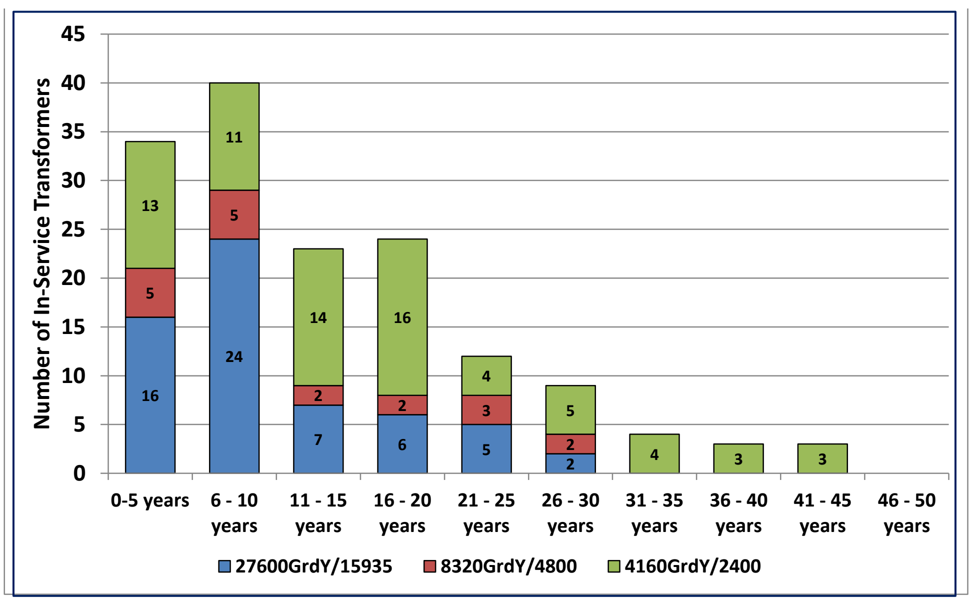


Figure 4-2 Age Profile of 3-Phase Padmounted Distribution Transformers

Halton Hills Hydro has:

- Three (3) three-phase padmounted distribution transformers, supplied from the 2.4/4.16Y kV distribution system, that have been in active service for more than the 40-year typical useful life; and

- Three (3) three-phase padmounted distribution transformers again supplied from the 2.4/4.16Y kV distribution system that are approaching the end of their expected useful life.

Padmounted distribution transformers are not proactively replaced based solely on their age. Other factors such as degree of corrosion, evidence of leaking gaskets, and technical obsolescence (i.e. internal fusing, padlocking provisions, etc.) are also considered. With aging transformers, typically, the underground primary cables that supply these transformers are also at or past their expected useful life. As such, the businesses where these transformers and primary cables are installed can be candidates for a combination infrastructure renewal project.

4.3.2 Inspection Methodology

Single-phase and three-phase pad-mounted dead-front distribution transformers are subject to visual inspection every three years for signs of excessive corrosion, insulating oil on external tank surfaces, signs of attempted forced entry and other indications of vandalism. Insulating oil on external tank surfaces can be indicative of overloading or a leaking gasket on the secondary terminals or off-circuit tap changer. Unless indicated by visual inspection, pad-mounted distribution transformers are normally run-to-failure.

Figure 4-3 Typical Single-Phase Padmounted Transformer


Figure 4-4 Typical Three-Phase Padmounted Transformer

4.3.3 Active Transformer Replacement Program

Pad-mounted distribution transformers are normally “run to failure” with three exceptions.

The first specific exception is the phase-out of indoor transformer vaults and PoleTrans units.

The second specific exception is pre-mature aging of the exterior shell due to weather factors, salt contamination causing pre-mature rusting.

The third exception is with respect to live front padmounted transformers.

4.3.3.1 Live Front Padmounted Transformers

This type of transformer depicted in figure 4-5 below contains exposed primary and secondary connections. Halton Hills Hydro has seven (7) live front transformers in service. These transformers were manufactured in the late 1960's and early 1970's and have been in service for approximately 40 or more years. Live front transformers are no longer installed by Halton Hills Hydro as CSA standard C227.4 permits only dead-front padmounted transformers.

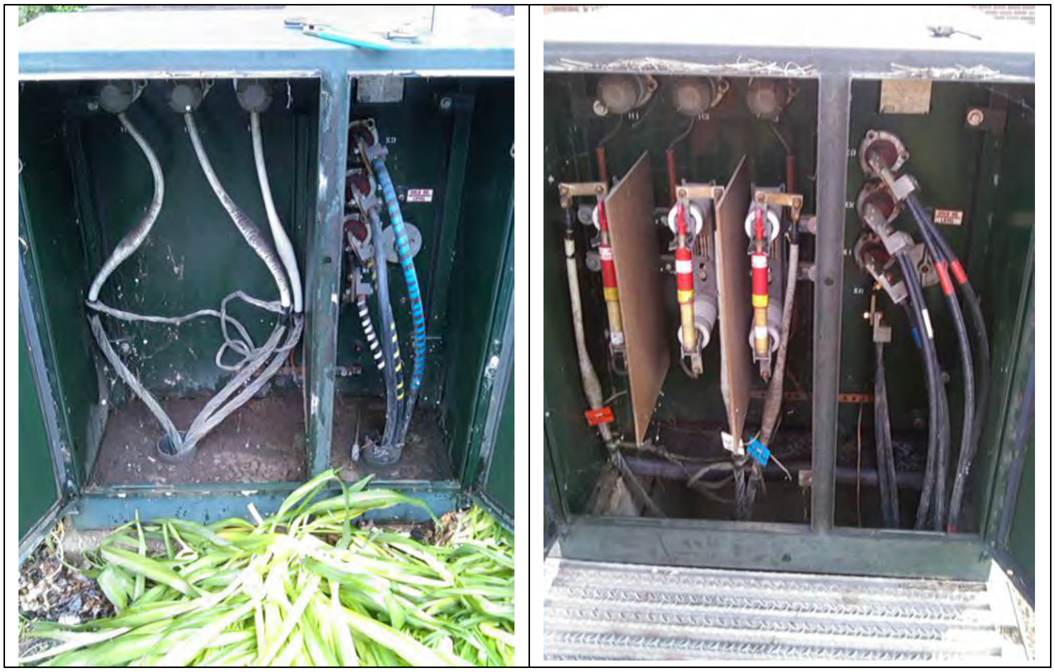


Figure 4-5 Inside Typical Live-Front Transformers

Halton Hills Hydro's asset management strategy with respect to these transformers is developed based on factors including useful life, safety of operation, and difficulty of repair or replacement. The strategy for these transformers also includes the related assets such as the concrete base the transformer sits on, terminations, and primary cable supplying the transformer. In the event of a transformer failure, a live front unit will be replaced with a dead front transformer.

The replacement strategy includes addressing a number of site specific factors:

- Replacement of the poured concrete foundation with a precast foundation.
  - Often live front padmounted transformer installation will have included a poured concrete foundation rather than pre-cast foundation. Newer transformers generally have a larger dimension then live front units and may overhang the edges of the poured concrete foundation.
- Replacement of the primary cables.
  - Primary cables are often found to be 5kV rated rather than 15kV or 28kV and such cable may not be compatible with normally stocked material.
  - It may be difficult to re-terminate primary cables. Standard practice per CSA C227.4 and IEEE 385 requires the use of separable connectors (elbow) to make the high voltage connection between the primary cable and the transformer. Live front primary terminations, often hand tapped, must be cut off. A reduced length of cable may make

it difficult to attach a re-terminated cable to the dead front transformer as there is often little or no extra cable to work with.
    - The primary cables may need to be replaced if damaged. As they are direct buried and enter the transformer high-voltage compartment often through a single conduit, replacement can require installing an entirely new service trench.
- Physical location of the new dead front padmounted transformer.
    - Vegetation around the transformer, public utilities in the right-of-way and demand loading of the existing service.
- Assessment of secondary cables and if necessary coordination with a licensed electrician/ electrical contractor to replace or extend the secondary cables.
- Condition of upstream switches.

Replacement of live front transformers are assessed on a location by location basis and associated costs determined in a similar manner. In some instances however where a larger portion of the distribution system is being renewed/ rebuilt, efficiencies may present themselves to include replacement of a live front padmounted transformer as part of a larger project.

4.4 Life-Cycle Management Plan for Indoor Transformer Vaults

There are a number of vintage buildings within Halton Hills Hydro's service territory wherein the supply arrangement is oil-filled distribution transformers installed in an electrical vault within the building.

There are seven (7) instances of buildings wherein Halton Hills Hydro has oil-filled distribution transformers installed in electrical vaults and supplied from the 2.4/4.16Y kV distribution system. These vaults are identified in Table 4-4 below. Transformer vaults owned and operated by Halton Hills Hydro supply three-phase power to our customers whereby each vault is comprised of three (3) individual transformers totaling twenty-one (21) transformers in use.

Operating Designation of Vault	Year of Construction	Installed Transformation Parameters			Supply Feeder Designation
		Apparent Power Rating	Primary Supply Voltage, kV	Secondary Bank Voltage, V	
A02V902	1974	3 x 50 kVA	2.4/4.16Y	347/600Y	3F2
B03V086	1972	3 x 50 kVA	2.4/4.16Y	120/208Y	9F2
B03V084	1972	3 x 50 kVA	2.4/4.16Y	120/208Y	9F2
D09V326	1975	3 x 100 kVA	2.4/4.16Y	347/600Y	17F3
D09V210	1986	3 x 75 kVA	2.4/4.16Y	120/208Y	17F1
C10V109	1990	3 x 75 kVA	2.4/4.16Y	347/600Y	15F2
C08V148	1998	3 x 100 kVA	2.4/4.16Y	120/208Y	13F2

Table 4-4 Listing of Indoor Transformer Vaults

The access door and ventilation grill for a typical indoor transformer vault is depicted in Figure 4-6 below, and the arrangement of transformers within the vault is depicted in Figure 4-7 below.

Figure 4-6 Typical Vault Access Door and Ventilation Vent

Figure 4-7 Typical Transformer Arrangement within Vault

4.4.1 Age Profile of Indoor Transformer Vaults

The capacity profile for Halton Hills Hydro's population of single-phase distribution transformers installed in indoor transformer rooms is tabulated in Table 4-5 below by supply voltage level.

Supply Voltage	Transformer Apparent Power Rating, kVA							
	≤ 10	15	25	37½	50	75	100	167
16 or 16/27.6Y kV	--	--	--	--	--	--	--	--
4.8 or 4.8/8.32Y kV	--	--	--	--	--	--	--	--
2.4 or 2.4/4.16Y kV	--	--	--	--	9	6	6	--

Table 4-5 Capacity Profile of 1-Phase Vault Transformers

The age profile for Halton Hills Hydro's population of single-phase vault-style distribution transformers is shown in Figure 4-8 below. As can be seen here, most of this equipment is considered at the end of its typical useful life.

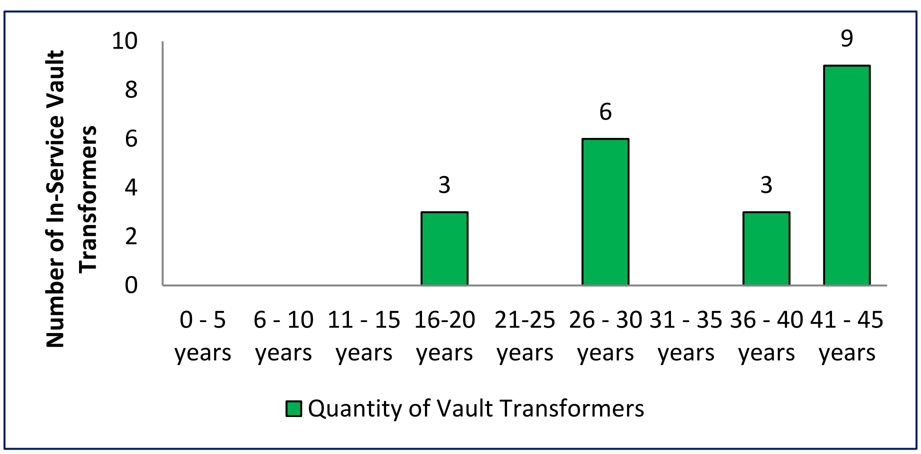


Figure 4-8 Age Profile of In-Service Vault Transformers

4.4.2 Inspection Methodology

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

As discussed in Appendix A herein, transformer vault rooms in which utility transformers are located are not up to modern standards and in instances do not effectively exchange air within the vault rooms. There is also evidence that vault rooms are not regularly cleaned as evidenced by cobwebs restricting air flow on vents, insulating oil leaking from secondary bushings, etc.

4.4.3 Modernization of Indoor Transformer Vaults

Modernizing the existing indoor transformer vaults within Halton Hills Hydro's service territory will be a multi-year endeavor that will require significant coordination effort. There are two main options for modernizing the existing indoor transformer vaults:

- Decommission the transformer vault and re-supply the building via a three-phase padmounted transformer complete with new primary and secondary supply cables. Transformation external to buildings is preferable as it can be more readily accessed, imposes less safety concerns for the building owner, and is consistent with Halton Hills Hydro's current practices for dead-front supply to customers; or
- Retrofit the existing indoor transformer vault with modern equipment including: vault-style transformers with radiators and filled with less-flammable dielectric such as R-Temp, metal-enclosed current-limiting fuses, and elbow-style surge. Address the ventilation system design deficiencies, and make other changes as necessary to bring the vault into compliance with present-day codes and safe working practices.

Investment in indoor transform vault modernization is scheduled to begin in 2017 and continuing in 2019 and 2020 forecasting two vaults per year in the latter two years. Further detail on indoor transformer vaults is found in Appendix A.

4.5 Life Cycle Management Plan for Pole-Trans Units

In a number of residential areas in Halton Hills with underground distribution systems, past practice was to install a "PoleTrans" transformer unit – a metallic street-lighting pole with a liquid-filled distribution transformer integrated into the base of the pole. These devices are now obsolete and have not been manufactured for many years. One such unit is depicted in Figure 4-9.

The subdivisions within Halton Hills Hydro's service territory where such Pole-Trans combination streetlight pole / distribution transformers exist are identified in Appendix B herein.

Figure 4-10 below shows the lower segment of a typical Pole-Trans unit where there are two (2) pad-lockable access panels; one for the incoming medium-voltage power cables, and the other for the outgoing low-voltage cables.

Figure 4-11 shows the high-voltage compartment without the two (2) McGraw-Edison arc-strangler switches (that would occupy the two outer positions) and current-limiting fuse (that would occupy the center position). The arc-strangler switches provide loop-sectionalizing functionality for the incoming and outgoing medium-voltage power cable, whereas the fuse provides over-current protection for the liquid-filled distribution transformer.

Figure 4-12 shows the low-voltage compartment with several outgoing underground secondary cables connected to the internal bus bars.

Figure 4-9 Access Panels in Base Section of Pole-Trans

Figure 4-10 High-Voltage Compartment of Pole-Trans

Figure 4-11 Secondary Compartment of Pole-Trans

The clearances within the high-voltage compartment (as shown in Figure 4-11) were adequate for 2.4/4.16Y kV distribution systems but inadequate for higher voltage distribution systems. Also, the design is inconsistent with modern worker safety needs, e.g. the utility industry is transitioning to adopting insulated elbow-style connectors. Furthermore, with this design, one cannot install temporary protective ground sets on the incoming or outgoing medium-voltage power cables and then close and lock the access panel.

4.5.1 Age Profile of In-Service Pole-Trans Assets

There are seventy-seven (77) PoleTrans units remaining in-service in both Acton and Georgetown, primarily in subdivisions and townhouse developments.

The capacity profile for the population of PoleTrans units supplied from the 2.4/4.16Y kV distribution system is tabulated in Table 4-6 below.

Supply Voltage	Transformer Apparent Power Rating, kVA							
	≤ 10	15	25	37½	50	75	100	167
16 or 16/27.6Y kV	--	--	--	--	--	--	--	--
4.8 or 4.8/8.32Y kV	--	--	--	--	--	--	--	--
2.4 or 2.4/4.16Y kV	--	43	3	16	15	--	--	--

Table 4-6 Capacity Profile of 1-Phase Pole-Trans Units

The age profile for the population of PoleTrans units supplied from the 2.4/4.16Y kV distribution system is illustrated below.

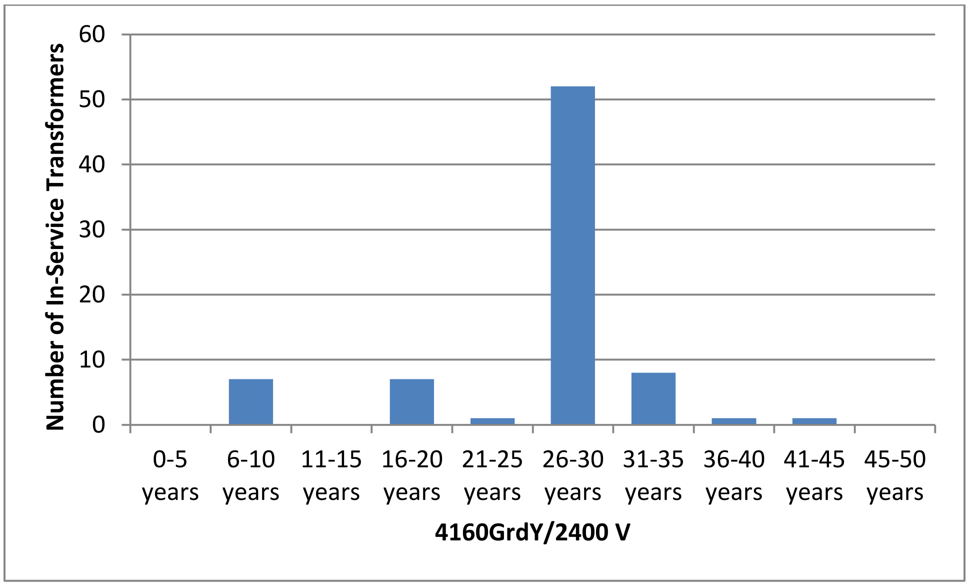


Figure 4-12 Age Profile of 1-Phase Pole-Trans Units

As can be seen in Figure 4-13, There is one (1) Pole-Trans unit that has been in active service for more than the 40-year typical useful life; and one (1) Pole-Trans unit that is approaching the end of its expected useful life.

4.5.2 Phase-Out of Legacy Pole-Trans Units

PoleTrans transformers employed within Halton Hills Hydro's distribution territory have reached or will reach the end of their useful life during the next five (5) to ten (10) years. At the same time much of the underground infrastructure supplying PoleTrans will reach its end of useful life. Rather than replacing PoleTrans with similar units Halton Hills Hydro will be replacing PoleTrans transformers with padmounted transformers and installing new primary distribution cable to supply the padmount transformers. As both types of assets have the same useful life it make sense to replace both assets simultaneously rather than have two related assets with significantly differing useful lives were the assets to be replaced on separate occasions. This approach to replacement will benefit customers due to executing multiple infrastructure replacements simultaneously.

Over the course of the next five (5) years Halton Hills Hydro shall continue to design and replace end of useful life PoleTrans units on an annual basis and eliminate such devices from our system. The annual phase-out of PoleTrans transformers will be completed by 2022. The priority of expenditure shall be ranked by risk factors including:

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

This proactive approach ensures that Halton Hills Hydro's equipment is safe to operate, our distribution system is not put at risk by utilizing aged and obsolete devices, and the assets we operate provide value to the utility.

4.6 Life-Cycle Management Plan for Sectionalizing Switchgear

Padmounted sectionalizing switchgear (typically as depicted in Figure 4-14 below) are used for re-configuring underground distribution circuits and isolating faulted underground cables. The switchgear is necessarily of tamper-resistant construction and has several compartments, some housing load-interrupter switches and others housing power fuses. The internal configuration of a typical padmounted switchgear is shown in Figure 4-16 below.

Figure 4-13 Typical Padmounted Sectionalizing Switchgear

Figure 4-14 Typical Padmounted Junction Enclosure

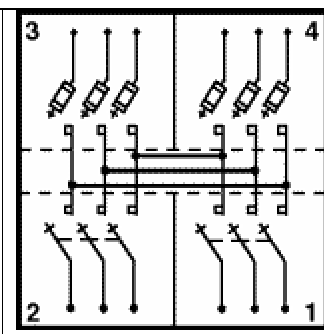


Figure 4-15 Internal Configuration of PMH-9 Padmounted Switchgear

Padmounted junction enclosures (typically as depicted in Figure 4-15 above) are also of tamper-resistant construction and are used for making a tapped connection to an underground cable loop.

The switchgear and junctions are available in both single-phase and three-phase arrangements.

Padmounted distribution switchgear were traditionally air-insulated, but the utility industry is moving toward sulphur hexafluoride (SF6) for both the interrupting and insulating medium.

4.6.1 Age Profile of In-Service Sectionalizing Switchgear Assets

Halton Hills Hydro Inc. owns and operates thirty three (33) padmounted switchgears which are a mixture of live-front and dead-front configurations. Live-front refers to such switchgear as a PMH-9 model whereby the live components inside the switchgear are visible upon opening the external cabinet door. Dead-front refers to set-up whereby the primary cables are terminated using load break elbows and live components are not visible or accessible when the external doors are open.

The profile of switchgears owned and operated by Halton Hills Hydro is shown in Table 4-7 below by supply voltage level.

Supply Voltage	Type of Switchgear	
	Live Front	**Dead-Front**
16/ 27.6Y kV	6	16
4.8/ 8.32Y kV	6	1
2.4/ 4.16Y kV	3	1

Table 4-7 Profile of Padmounted Switchgear

The age profile of the switchgears owned and operated by Halton Hills Hydro is shown in Figure 4-17 below.

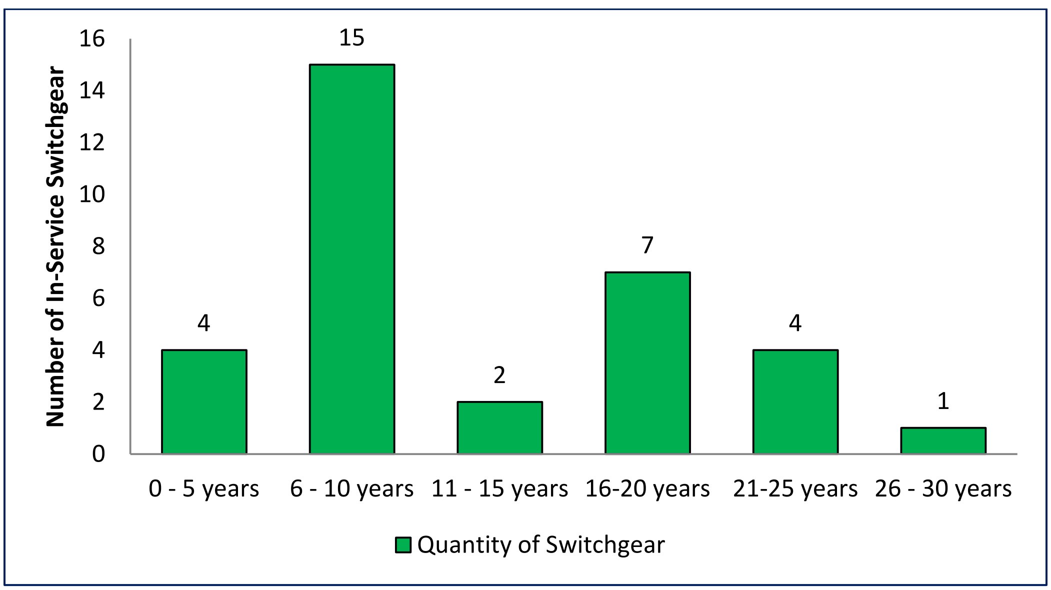


Figure 4-16 Age Profile of In-Service Padmounted Switchgear

In the December 2009 Kinectrics Inc. issued report K-418022-RA-0001-R003 for Halton Hills Hydro in which they determined the typical useful life of air insulated and gas insulated switchgear to be 30 years. This chart illustrates that:

- Five (5) switchgears are between 21 and 30 years old;
- One (1) switchgear is between 26 to 30 years old, approaching its end of useful life.

Padmounted switchgear are not normally part of an active replacement program but rather are assessed individually. Factors such as age, damaged, and degree of corrosion as well as technical obsolescence are also considered.

4.6.2 Inspection Methodology

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

4.6.3 Active Replacement Program

Padmounted sectionalizing switchgear or padmounted junction enclosures are normally run-to-failure devices. Halton Hills Hydro does not have a program to actively replace padmounted sectionalizing switchgear or padmounted junction enclosures based on a typical useful life. Rather we assess the device for damage, corrosion, rusting, and potential safety risks and make a decision for replacement.

4.7 Life-Cycle Management Plan for Power Cables

A typical single-conductor concentric-neutral style underground power cable is illustrated in Figure 4-18 to the right.

Copper or aluminum is used for the core conductor. The conductor gauge size and insulation thickness will be dependent upon the application.

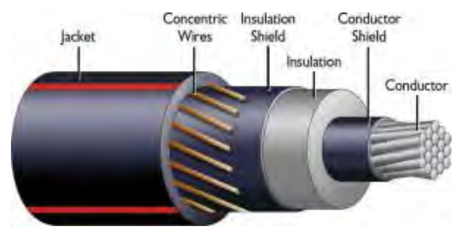


Figure 4-17 Typical Single-Core Medium-Voltage Power Cable

4.7.1 Age Profile of In-Service Power Cable Assets

The profile for Halton Hills Hydro's population of medium-voltage underground power cables is tabulated in Table 4-8 below by supply voltage level and nature of installation (i.e. direct buried, installed in duct, or unknown).

Supply Voltage	Core Conductor Gauge & Material	Number of Circuit-Meters of Underground Power Cable					
		Single-Phase U/G Cable			Three-Phase U/G Cable		
		Direct Burial Installation	Installed in Duct / Conduit	Unknown	Direct Burial Installation	Installed in Duct / Conduit	Unknown
16/27.6Y kV	#1/0 Al	--	--	--	--	--	29
"	#1/0 Cu	--	27,846	37,759	--	1,954	480
"	#2/0 Al	--	1,451	--	--	3,251	
"	500 kcmil Al	--	--	--	--	--	1,299
"	500 kcmil Cu	--	--	880	--	3,800	853
"	1000 kcmil Al	--	--	--	--	2,031	--
"	Unknown	--	5,655	1,162		726	562
4.8/8.32Y kV	#1/0 Al	--	428	--	144	--	--
"	#1/0 Cu	2,169	47,367	4,043	--	--	97

	#2/0 Al	--	5,927	7	--	--	--
	500 kcmil Cu	--	324	--	58	--	17
“	Unknown	1	340	3,172	--	--	1,141
2.4/4.16Y kV	#1/0 Al	--	--	15	--	192	406
“	#1/0 Cu	--	16,908	30,012	--	1,432	1,967
-	#2/0 Al	--	921	--	--	720	--
--	500 kcmil Cu	--	108	70	--	241	311
--	1000 kcmil Al	--	--	--	--	751	--
--	Unknown	--	216	1,738	--	770	2,786
“	**Totals:**	2,170	107,491	78,858	202	15,868	9,948

Table 4-8 Profile of Medium-Voltage Underground Power Cables

Table 4-8 is based on energization voltage rather than the voltage class of the power cable. For example, a concentric neutral power cable may have a 28 kV voltage class rating, but only energized at 2.4 kV. The table does identify a number of unknown entries. As the Geographic Information Systems (GIS) system at Halton Hills Hydro continues to be improved, data collection activities will fill in these gaps.

4.7.2 Inspection Methodology

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

4.7.3 Active Power Cable Replacement / Rejuvenation Program

Power cable age is not the only parameter that is used to ascertain whether to replace the power cable or to extend its life by employing such technologies as silicon injection. Halton Hills Hydro has piloted silicone injection as a method to rejuvenate underground cables. This method is expected to extend the useful life of underground cables by 15-20 years. The utility will continue to pilot this technology as an option to address direct buried underground cable approaching end of life as replacement in this situation can be more costly and intrusive. Future pilots will focus on cables with a history of faults to observe the impact of silicon injection on suspect cable. Based on pilot results, a more comprehensive silicon injection plan may be developed. Where cable is installed in duct, cable replacement may be the best option as these cables approach end of life.

4.8 Life-Cycle Management Plan for Low-Voltage Service Cables

Figure 4-18 Typical Triplex Underground Service Cable

For residential properties, Halton Hills Hydro assumes ownership and operating responsibility for the low-voltage underground triplex service cables that interconnect the single-phase padmounted distribution transformer with the various homes supplied by that transformer. A typical underground triplex cable is illustrated in Figure 4-19 to the right.

There are 12,556 m of underground triplex service cable in service with a breakdown by conductor size and type of installation as indicated in Table 4-9 below. Method of installation for 50% of the udnerground low- voltage service cable and conductor gauge size and material for almost 40% of the triplex is not recorded in Halton Hills Hydro's Geographic Information System (GIS).

Conductor Gauge and Material of Underground Triplex Cable	Number of Meters of Underground Triplex Service Cable			
	Direct-Burial Installation	Installed in Duct / Conduit	Unknown Method of Installation	Total Installed Triplex Cable
#3/0 AWG Al	1	454	85	540
#4/0 AWG Al	20	3,988	2,583	6,591
250 kcmil Al	8	571	5	584
Unknown	73	975	3,793	4,841
	102	5,988	6,466	**12,556**

Table 4-9 Profile of Underground Low-Voltage Triplex Service Cables

4.8.1 Age Profile of In-Service Assets

The ages of in-service underground triplex service cables isn't captured by Halton Hills Hydro's GIS. Rather is needs to be inferred from the age of the single-phase padmounted distribution transformer that supplies the residential dwelling, the date the first revenue meter was installed, or the date the first customer account was established. It is unlikely triplex cable will require replacement. The age of this asset is not actively tracked.

4.8.2 Inspection Methodology

There is no practical method for inspecting the integrity of underground low-voltage service cables.

4.8.3 Active Replacement Program

Underground triplex service cables generally have a 600 V class insulation system which greatly exceeds the minimum insulation requirements for a 120/240 V_{ac} application. As such, it is improbable that the insulation system on even a vintage underground secondary cable will experience a dielectric failure due to age and environmental related conditions such as electrical and water treeing. In fact, the most common cause of cable failure even on the oldest cables is inadvertent dig-in (by a back-hoe, post hole digger, etc.) or failure of an underground secondary cable splice. As such, there is no active replacement program for low-voltage underground triplex service cables.

5 Customer-Owned Substations

Halton Hills Hydro provides supply to fifty-eight (58) customer-owned substations with designations and ratings as tabulated in Table 5-11 below.

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

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

Table 5-1 Customer-Owned Substations Listing

The locations of these customer-owned substations are shown in the latest editions of the following operating maps:

- Halton Hills Hydro drawing entitled: 44 kV Schematic;
- Halton Hills Hydro drawing entitled: 27 kV Schematic.

There are instances whereby a customer facility is serviced via multiple customer-owned substations, each with their own substation designation, but with a common primary revenue metering installation.

The summation of the nameplate ratings of all the transformers is 84,168 kVA.

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

To encourage our customers who own 44kV substations to perform annual maintenance, Halton Hills Hydro offers one (1) free disconnection and reconnection of their 44kV supply per year to enable customers to perform station maintenance.

6 Municipal Substations

This section identifies the major components of a municipal substation, the typical useful life for each component, and the life-cycle management plan for each component.

6.1 Major Components of a Municipal Substation

Municipal substations are used to step-down sub-transmission voltages to lower distribution voltages. A municipal substation usually consists of a step-down power transformer, as depicted in Figure 6-1, with apparent power ratings typically ranging from 5,000 kVA to 10,000 kVA. Power transformers may be equipped with cooling fans which gives two distinct ratings; one based on natural cooling and the other based on forced or fan cooling.

Figure 6-1 Typical Substation Power Transformer

Overcurrent protection for the substation power transformer is normally via a three-pole group-operated load interrupter switch and a cluster of appropriately rated power fuses.

The municipal substation will also have a line-up of 3 or 4 outgoing feeder circuit breakers, as depicted in Figure 6-2. Usually these feeder circuit breakers are installed within a small brick building (deliberately constructed to resemble a bungalow, and hence referred to as a "bungalow-style municipal substation") or a pre-fabricated steel building as depicted in Figure 6-3.

Figure 6-2 Typical Metal-Clad Switchgear

Figure 6-3 Typical Prefabricated Switchgear Building

Also associated with the line-up of switchgear will be:

- Feeder protection relays that detect overcurrent conditions and initiate a trip operation on one of the feeder circuit breakers;
- A DC subsystem, consisting of batteries and a charger system, to provide continuous and reliable supply to the feeder protection relays, the circuit breaker, and other mission-critical elements within the substation; and
- A Remote Terminal Unit (RTU) that provides an interface to a SCADA system for remote monitoring and control.

6.2 Typical Useful Life of Municipal Substation Components

Halton Hills Hydro owns and operates twelve (12) municipal substations that step the voltage down from a 44 kV sub-transmission level to a three-phase four-wire distribution level (either 2.4/4.16Y kV in urban areas or 4.8/8.32Y kV in rural areas).

As part of Halton Hills Hydro's asset management program, we, along with other GTA utilities, commissioned Kinectrics to prepare a study of the useful life of assets used for distributing electricity and supporting the distribution system. This document is identified as Kinectrics report K-418022-RA-0001-R003, Useful Life of Assets; Issued December 10, 2009. The useful lives identified in that report were then considered in Halton Hills Hydro's decisions for what we believe are appropriate useful lives for various equipment with respect to this utilities operating environment. Final determination of useful lives was established and approved in our 2012 Cost of Service rate application (EB-2011-0271). The revised useful lives was required for the transition to International Financial Reporting Standards (IFRS) in which components of a like structure were grouped and given a useful life representative of the major component of the entire structure.

The useful life information specific to municipal substations is referenced and summarized below. SCADA and communications infrastructure is captured in the General Plant section of this document.

Asset Category	Typical Useful Life (years)
(Col 1)	(Col 4)
Power transformers	35
Switchgear	40
DC Station Service	20

Table 6-1 Useful Life Values for Municipal Substation Components

6.3 Life-Cycle Management Plan for Power Transformers

The substation operating designations, supply sub-transmission circuits, and nameplate rating of the substation power transformer are indicated in Table 6-2 below.

Municipal Substation Designation	Municipal Substation Name	Nameplate Rating of Power Transformer	Mfg. Date	Voltage Rating of Power Transformer	Designation of Supply Feeder Circuit
MS 1	Ballinafad	5,000	1972	44000-8320GrdY/4800	42M23
MS 3	Willow	5,000	1969	44000-4160GrdY/2400	73M4
MS 5	Silver Creek	5,000	1973	44000-8320GrdY/4800	42M23
MS 7	Beardmore	5,000	1979	44000-4160GrdY/2400	73M4
MS 9	Queen	5,000	1979	44000-4160GrdY/2400	73M4
MS 11	Glen Williams	10,000/13,300	2007	44000-8320GrdY/4800	42M23
MS 13	Cross	10,000	1999	44000-4160GrdY/2400	42M25
MS 15	River	10,000/13,300	2009	44000-4160GrdY/2400	42M25
MS 17	Mountainview	10,000/13,300	1989	44000-4160GrdY/2400	42M28
MS 19	Armstrong	10,000/13,300	1996	44000-4160GrdY/2400	42M28
MS 21	Norval	5,000	1973	44000-8320GrdY/4800	42M23
MS 23	Ashgrove	5,000	1982	44000-8320GrdY/4800	42M23

Table 6-2 List of Municipal Substations

6.3.1 Age Profile of In-Service Power Transformer Assets

The age profile of the fleet of in-service substation power transformers is depicted in Figure 6-4 below.

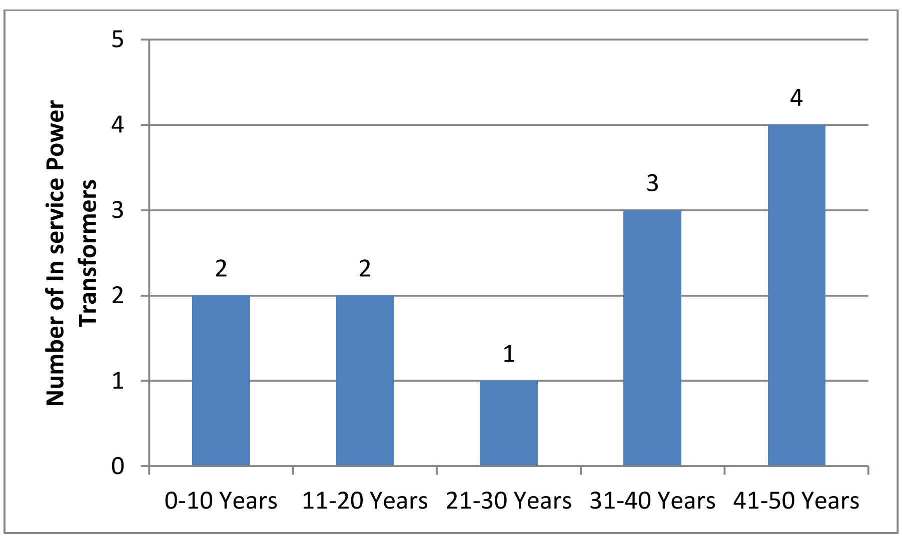


Figure 6-4 Age Profile of In-Service Substation Power Transformers

With reference to the useful life of substation power transformers it can be seen that:

- There are (6) substation power transformers that have been in active service for more than the 35-year typical useful life; and
- Within the 5 year horizon of this Asset Management Plan, an additional substation power transformer will have seen active service greater than the 35-year typical useful life.

Substation power transformers aren't usually proactively replaced based solely on their age. Other factors such as power transformer condition (i.e. degree of corrosion, evidence of leaking gaskets), transformer loading and the impact of an unplanned transformer failure are also considered.

6.3.2 Peak Loading of In-Service Substation Power Transformers

For the preceding four year period (2011-2014) the peak kW demand summary is as follows:

Municipal Substation Designation	Municipal Substation Name	Average Peak Loading (kW)	Summer Peak (kW)	Winter Peak (kW)	kVA Equiv. (0.9 PF)	Nameplate Rating (kVA)	% Utilization
MS 1	Ballinafad	2,326	2,176	3,200	3,520	5,000	70%
MS 3	Willow	3,021	3,237	3,194	3,560	5,000	71%
MS 5	Silver Creek	4,690	5,068	5,208	5,728	5,000	115%
MS 7	Beardmore	1,527	2,048	1,664	2,252	5,000	45%
MS 9	Queen	3,355	3,974	3,265	4,371	5,000	87%
MS 11	Glen Williams	5,400	6,563	6,661	7,392	10,000/13,300	56%
MS 13	Cross	6,382	8,640	6,480	9,504	10,000	95%
MS 15	River	6,674	7,949	6,984	8,743	10,000/13,300	66%
MS 17	Mountainview	6,687	9,200	6,400	10,120	10,000/13,300	76%
MS 19	Armstrong	4,796	6,705	4,276	7,375	10,000/13,300	55%
MS 21	Norval	768	950	950	2,816	5,000	56%
MS 23	Ashgrove	3,373	3,456	4,320	4,752	5,000	95%

Table 6-3 Substation Peak Loading

Power transformers are generally designed to sustain short-term loading beyond their nameplate rating without incurring loss of insulation life. From the foregoing graphics, one can readily see from Table 6-3 that Silver Creek MS 5 is the only municipal substation whereby the peak summer or peak winter loading has exceeded the nameplate rating of the substation power transformer.

6.3.3 Condition Testing Methodology

Insulating oil performs two important functions in substation power transformers. It cools the transformer and provides electrical insulation, as well. Therefore any deterioration in the oil can lead to premature failure of the equipment.

When the mineral oil is subjected to high thermal and electrical stresses, it decomposes and, as a result, gases are generated. Different types of faults will generate different gases, and the chemical analysis of these gases, performed through a procedure called Dissolved Gas Analysis (DGA), will provide information about the condition of the oil, and help to identify the type of fault in the transformer.

A dissolved gas analysis for each power transformer is performed on an annual basis and pursuant to ANSI/IEEE Standard C57.104, Guide for the Detection and Determination of Generated Gases in Oil-Immersed Transformers and Their Relation to the Serviceability of the Equipment, values for each of the key gases are trended over time so that the rate-of-change of the various gas concentrations can be evaluated. Any sharp increase in key gas concentration is indicative of a potential problem within the transformer.

Oil quality tests check for dielectric strength, moisture in oil, interfacial tension and acid number among others. These factors can give leading indicators on the overall condition of the oil. A common practice for conditioning oil is the addition of inhibitor. This preserves the oil and prevents oxidation which can lead to higher acid counts and sludge formation. Once the acid count gets too high, the paper insulation can then lose tensile strength and become more susceptible to through faults leading to premature failure. Furans analysis is used to determine the condition of paper insulation.

Halton Hills Hydro's 2014 test summary is listed below. In the Silver Creek substation, the oil has been previously processed and hence has an excellent paper condition due to the absence of Furans.

6.3.4 Active Refurbishment Program

Municipal Substation Designation	Municipal Substation Name	Oil Quality	Dissolved Gas	Inhibitor Level	Paper Condition (Furans)
MS 1	Ballinafad	Acceptable	Acceptable	Effective	Good
MS 3	Willow	Acceptable	Acceptable	Depleted	Excellent
MS 5	Silver Creek	Acceptable	Acceptable	Effective	Excellent
MS 7	Beardmore	Acceptable	CO/TCG elevated & stable	Depleted	Excellent
MS 9	Queen	Acceptable	Acceptable	Depleted	Excellent
MS 11	Glen Williams	Acceptable	CO/TCG elevated & stable	Effective	Excellent
MS 13	Cross	Acceptable	Acceptable	Depleted	Excellent
MS 15	River	Acceptable	CO elevated & stable	Effective	Excellent
MS 17	Mountainview	Acceptable	Acceptable	Depleted	Very Good
MS 19	Armstrong	Acceptable	CO/TCG elevated & stable	Depleted	Excellent
MS 21	Norval	Acceptable	CO elevated & stable	Depleted	Good
MS 23	Ashgrove	Acceptable	CO elevated & stable	Depleted	Excellent

Table 6-4 Oil Quality and DGA results for substation power transformers

6.3.5 Active Refurbishment Program

Taking into account age, oil condition and loading, where a unit has two or more areas of concern, it may be considered for replacement. Elevated but stable gas in oil may indicate past faults that are not ongoing. In these cases, if the transformer has not reached its useful life, oil processing may be performed to reduce gas levels to acceptable limits. Table 6-5 shows the current refurbishment status of the substation transformers.

Municipal Substation Designation	Municipal Substation Name	Age	Oil Condition	Loading	Recommendation
MS 1	Ballinafad	43	Good	70%	Defer to next 5 year cycle
MS 3	Willow	46	Good	71%	Replace due to age
MS 5	Silver Creek	42	Good	115%	Replace
MS 7	Beardmore	36	Fair	45%	Process oil and defer
MS 9	Queen	36	Good	87%	Defer to next 5 year cycle
MS 11	Glen Williams	8	Fair	56%	Process oil
MS 13	Cross	16	Good	95%	Monitor loading
MS 15	River	6	Fair	66%	Process oil
MS 17	Mountainview	26	Good	76%	Maintain per schedule
MS 19	Armstrong	19	Fair	55%	Process oil
MS 21	Norval	42	Fair	56%	Assess station end of life
MS 23	Ashgrove	33	Fair	95%	Assess station end of life

Table 6-5 Power Transformer Refurbishment Program

6.4 Life-Cycle Management Plan for Switchgear

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

6.4.1 Age Profile of In-Service Switchgear

The age of switchgear and circuit breaker types may be found in table 6-6 below.

Municipal Substation Designation	Municipal Substation Name	Breaker Type	Mfg. Date	Voltage (kV)
MS 1	Ballinafad	Oil Recloser	~1975	8.32
MS 3	Willow	Air Magnetic	1986	4.16
MS 5	Silver Creek	SF6	1988	8.32
MS 7	Beardmore	Vacuum recloser	1979	4.16
MS 9	Queen	Air Magnetic	1979	4.16
MS 11	Glen Williams	Vacuum Recloser	~1950	8.32
MS 13	Cross	Air magnetic	1971	4.16
MS 15	River	Vacuum	2006	4.16
MS 17	Mountainview	SF6	1986	4.16
MS 19	Armstrong	SF6	1996	4.16
MS 21	Norval	Oil Recloser	~1966	8.32

MS 23	Ashgrove	Oil Recloser	~1975	8.32

Table 6-6 Age Profile for Switchgear Useful Life Values for Municipal Substation Components

6.4.2 Condition Testing Methodology

Switchgear contains circuit breakers and their associated protection relays. Circuit breakers are highly mechanical in nature and require periodic maintenance. Halton Hills hydro has overhauled breakers and replaced parts where required. Routine diagnostic tests are performed on the breakers and main bus to ensure electrical insulation integrity is maintained. Contact resistance is measured on the circuit breaker contacts to verify wear and service duty. Breaker trip counts are recorded routinely.

6.4.3 Active Refurbishment Program

As switchgear approach end of useful life, they are evaluated to determine if replacement is warranted or if life extension is more suitable. Factors such as load capacity, breaker type, level of automation, and future expansion capability are each evaluated to determine if replacement is the best option. Safety and reliability also play a factor. For instance, ARC rated switchgear is very cost effective when purchasing new switchgear and provides improvements to operator safety over older technology. Where oil recloser technology exists, cost effective opportunities exist for substation automation initiatives. Table 6-7 summarizes the planned switchgear refurbishments for the planning period.

Municipal Substation Designation	Municipal Substation Name	Age	Breaker Type	Type	Future Requirements	Recommendation
MS 1	Ballinafad	40	Oil Recloser	Open low profile structure	automate	Upgrade to vacuum recloser and automate
MS 3	Willow	29	Air Magnetic	Walk in Metal Clad	None	Maintain
MS 5	Silver Creek	27	SF6	Walk in Metal Clad	None	Maintain
MS 7	Beardmore	36	Vacuum recloser	Metal Clad	None	Maintain
MS 9	Queen	36	Air Magnetic	Walk in Metal Clad	None	Replace in 2020
MS 11	Glen Williams	65	Vacuum Recloser	Open Structure	None	Maintain, assess structure
MS 13	Cross	44	Air magnetic	Walk in metal clad	Upgrade bus, add new feeder	Replace in 2016
MS 15	River	9	Vacuum	EEMAC Type C	Add new feeder	Maintain & expand
MS 17	Mountainview	29	SF6	Indoor Metal Clad	Add new feeder	Maintain & expand
MS 19	Armstrong	19	SF6	EEMAC Type A	Add new feeder	Maintain & expand
MS 21	Norval	49	Oil recloser	Open	None	Assess station end

				Structure		of life
MS 23	Ashgrove	40	Oil recloser	Open low profile structure	None	Assess station end of life

Table 6-7 Substation Switchgear refurbishment Summary

6.5 Life-Cycle Management Plan for DC Station Service

6.5.1 Age Profile of In-Service DC Station Service

Key information about the substation DC subsystems installed in each of the municipal substations is captured in table 6-8 below. Some of the substations do not have a DC subsystem as they use structure-mounted automatic circuit reclosers instead of circuit breakers for the overcurrent protection of outgoing feeder circuits.

Municipal Substation		DC Subsystem Parameters			
Municipal Substation Designation	**Municipal Substation Name**	**Nominal DC Voltage**	**Rated Capacity, A-h**	**Battery Technology**	**Year of Installation**
MS 1	Ballinafad	--	--	--	--
MS 3	Willow	48 VDC	45 A.hr	Voltage Regulated Lead Acid (VRLA)	2004
MS 5	Silver Creek	48 VDC	45 A.hr	VRLA	2006
MS 7	Beardmore	--	--	--	--
MS 9	Queen	48 VDC	45 A.hr	VRLA	2004
MS 11	Glen Williams	48 VDC	45 A.hr	VRLA	2013
MS 13	Cross	48 VDC	45 A.hr	VRLA	2009
MS 15	River	48 VDC	45 A.hr	VRLA	2007
MS 17	Mountainview	48 VDC	45 A.hr	VRLA	2004
MS 19	Armstrong	48 VDC	45 A.hr	VRLA	2012
MS 21	Norval	--	--	--	--
MS 23	Ashgrove	48 VDC	45 A.hr	VRLA	2013

Table 6-8 Inventory of Substation DC Subsystems

6.5.2 Condition Testing Methodology

Halton Hills Hydro has an active station battery maintenance program. Batteries are inspected on a quarterly basis and internal resistance checks are performed. Cells that show an accelerated rate of aging may trigger a load discharge test to be performed. This type of test is used to predict battery end of life and aid in budgeting for replacements.

6.5.3 Active Refurbishment Program

The typical useful life of the substation DC subsystems is 20 years. The VRLA batteries have a 10 year design life. None of the battery systems will be due for replacement during the planning horizon for this asset management plan. The battery chargers are run to failure whereas the batteries themselves are tested periodically to predict end of life and proactively replace before failure. The batteries are tested on a quarterly basis and visual and functional inspections are carried out on the charging system at the same time. A spare portable battery charger system is maintained along with a spare battery in the event of a charger or battery failure. This system also enables in-service batteries to be temporarily removed from service for periodic load testing to determine end of life. The portable system also allows for time to procure spare parts in the event of a main charging system failure.

7 Revenue Metering Systems

7.1 Major Components of Revenue Metering Systems

There are three (3) distinct categories of revenue metering systems:

- Industrial/Commercial, Wholesale Energy Meters - revenue metering systems used to measure Halton Hills Hydro's procurements of electricity from the provincial transmission grid or from transformer stations, retail sale of electricity to large customers and procurement of electricity from embedded retail generators (e.g. solar photovoltaic energy systems);
- PTs and CTs – Instrument Transformers used to convert voltage and current to lower safe levels that the meters will accept. This category includes both primary and secondary voltage levels as well as primary metering units (PMU).
- Smart Meters – comprising residential meters, repeaters and data concentrators

The majority of the revenue metering systems measure electricity consumption at the customer's utilization voltage (i.e. 120/240 Vac, 120/208Y Vac, 347/600Y Vac or 600 Vac), however, some revenue metering systems measure electricity consumption at the sub-transmission level (i.e. 44 kV) or distribution levels (i.e. 16/27.6Y kV, 4.8/8.32Y kV or 2.4/4.16Y kV). These latter systems are referred to as "Primary" revenue metering systems.

Self-contained socket meters typically operate at or below 600 V and 200A. Services greater than this require primary or secondary revenue metering systems that utilize current transformers (CTs) and Voltage (or Potential) Transformers (VTs/PTs) to step higher currents and voltages down to safe levels for the meters to use. Meters that utilize external instrument transformers are referred to as "Transformer Rated".

7.2 Typical Useful Life of Revenue Metering Systems

Halton Hills Hydro's approved useful life information specific to meters is referenced and summarized below.

Asset Category	Typical Useful Life (years)
Industrial/Commercial, Wholesale Meters	20
PTs and CTs	45
Smart Meters	15

Table 7-1 Useful Life Values for Revenue Metering Systems

7.3 Life-Cycle Management Plan for Industrial/Commercial, Wholesale Meters

Industrial and wholesale meters are generally used for larger class customers and typically measure kW demand in addition to kWh consumption. These meters are read remotely via dial up phone lines or cellular modems with consumption data uploaded to the billing system and web portals for customer presentment.

Table 7-2 Typical interval meters for industrial and wholesale installations

7.3.1 Age Profile of Industrial/Commercial, Wholesale Meters

Meters are generally tracked by the date that they were sealed in accordance with Measurement Canada guidelines. Different classes of meters have different seal periods ranging generally from six to ten years. When the seal expires, the meter must be removed from service and sent to a certified meter shop for re-verification testing. As Halton Hills Hydro does not itself have a certified meter shop, this service is contracted out. If the meter still meets the regulated requirements, it is re-sealed and a new expiry date is applied. Typically meters are resealed and used again for as long as they pass re-verification.

7.3.2 Inspection Methodology for Industrial/Commercial, Wholesale Meters

Meters are generally run until their seal expires and them removed from service for re-verification. If re-verification passes, they are resealed with a new expiry date and deployed back into service.

7.3.3 Active Replacement Program for Industrial/Commercial, Wholesale Meters

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

Presently, HHHI communicates with Industrial and Wholesale meters via phone lines and cellular modems. Initiatives are underway to investigate alternative communication methods. Regulatory requirements in the future may require the conversion to new communication methods such as LAN/WAN based TCP/IP or RFID. In this case meters would be phased out and replaced as the seals expire or as dictated by regulation.

7.4 Life-Cycle Management Plan for PTs and CTs

Secondary retail metering systems for larger customer services generally require Current Transformers (CTs) and Potential Transformers (PTs) to convert current and voltage to acceptable levels for the meters to use. These instrument transformers are typically installed within the customer's distribution switchgear on the incoming electrical bus. Also common for smaller services not utilizing switchgear is the practice of running the service cables through a metering cabinet where the instrument transformers may be alternately located. Primary metering units (PMU) exist in cases where customers have more than one substation supplied. Older PMUs contain Instrument transformers within an oil filled tank while modern units use separate solid dielectric Instrument transformers.

Figure 7-1 Typical Ferranti-Packard KMD46 Primary Metering Unit Installation

7.4.1 Age Profile of PTs and CTs

HHHI has seven (7) retail customers that are metered via primary metering units. As can be seen in Table 7-2, the metering units have been in service from 26 to 35 years and are still within their useful life.

Substation Designation	Metering Scheme	Make/Model	Mfg. Date	CT Ratio	R.F.	VT Ratio
BA + WA	2-element	KMD46	1988	40/20-5	1.5	46,000-115
BP + KA + LA	2-element	KM46	~1980	50-5	1.5	46,000-115
FA + RA	2-element	KMD46	1988	40/20-5	1.5	46,000-115
JA	2-element	KM46	~1987	40/20-5	1.5	46,000-115
U	2-element	KMD46	1989	40/20-5	1.5	46,000-115
LA	2-element	CGE	-	600/1200-5	1.0	4,200-120
C05F096	2.5-element	-	~1980	100/200-5	1.5	4,800-120

Table 7-3 In-Service Retail Primary Metering Systems

Wholesale primary metering systems are generally installed on sub-transmission or distribution feeders at the boundaries of Halton Hills Hydro's service territory for settlement with Hydro One Networks (the provincial transmitter) or adjacent LDCs. HHHI has one embedded distributor fed from a primary metering unit on the 4.8/8.32Y kV system.

Feeder Reference	Metering Scheme	Make/Model	Mfg. Date	CT Ratio	RF	VT Ratio
1F1	2.5-element	Ferranti	1980	100/200-5	1.5	4,800-120
41M21	3-element	Ferr/Whse	-	800-5	1.0	16,800-120
41M29	3-element	Sadtem	2006	600/300-5	1.5	16,800-120
41M30	3-element	Sadtem	2006	600/300-5	1.5	16,800-120
72M4	2-element	KM46	-	600/300-5	1.5	4,6000-115
42M23	2-element	KM46	-	600/300-5	1.0	4,6000-115
42M25	2-element	KM46	-	600/300-5	1.0	4,6000-115
42M28	2-element	KM46	-	600/300-5	1.0	4,6000-115

Table 7-4 In-Service Embedded Wholesale and Primary Metering Systems

7.4.2 Inspection Methodology for PTs and CTs

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

7.4.3 Active Replacement Program for PTs and CTs

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

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

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

7.5 Life Cycle Management Plan for Smart Meters

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

7.5.1 Age Profile for Smart Meters

The vast majority of smart meters were installed in 2009 and 2010 as part of the provincially mandated smart metering program. The seal expiry on these meters is 10 years. HHHIs smart meters will come due for re-verification in 2019 & 2020.

7.5.2 Inspection Methodology for Other Meters, CTs and PTs

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

7.5.3 Active Replacement Program for Smart Meters

Residential smart meters are essentially run to failure or until re-verification deems them unsuitable for continued use. A new smart meter group sampling program will be initiated to manage smart meter exchanges and replacements.

8 General Plant

8.1 Life Cycle Management Plan for Fleet

Halton Hills Hydro owns and operations an assortment of fleet vehicles including vans, jeeps, pick-up trucks, bucket and derrick trucks, and a dump truck. Such vehicles are used for everyday utility work for both the Operations Department and the Engineering Department. Vehicles receive regular maintenance by the utility mechanic and are replaced every 10 to 12 years depending on the type of vehicle.

Halton Hills Hydro operates other fleet related equipment (pole trailers, tension stringer, reel trailer, equipment trailer) and non-fleet related vehicles (fork lifts, skid-steer). This equipment is used to transport equipment/ material to site or within Halton Hills Hydro's yard and supports our construction functions.

Halton Hills Hydro maintains a 12 year rolling schedule for vehicle replacement to forecast 12 years of capital expenditures for fleet equipment/ vehicles. A spreadsheet is included in Appendix F and outlines Halton Hills Hydro's forecast of vehicle expenditures from 2015 to 2027. The spreadsheet in appendix F is revised every year and was developed to maintain a relatively even budgeted capital cost on an annual basis.

8.1.1 Age Profile of in-Service Fleet Assets

See the spreadsheet in appendix F for current fleet details including year, make, model, age, life expectancy & scheduled replacement year.

8.1.2 Inspection and Maintenance Methodology

Our fleet is maintained by our company mechanic. Our mechanic performs the following inspections and maintenance routines:

- Vehicle service – small fleet vehicles every 5000km
- Vehicle service – large crew cabs every 5000km and CVOR – annually
- Vehicle service – large fleet vehicles every 300 engine hours and CVOR –annually
- All other maintenance as required

Halton Hills hydro engages a 3rd party to complete annual inspections of large fleet vehicles checking the truck frame, boom and body of each of our large fleet vehicles. We also have a 3rd party complete annual di-electric testing on our large fleet vehicles and every 6 months on the large fleet vehicles used for bare-hand techniques on the 44kV system.

8.1.3 Active Fleet Replacement Program

Small fleet vehicles (vans, jeeps, pick-up trucks) are budgeted for replacement after 10 years of service

Large fleet vehicles (bucket and derrick trucks) are budgeted for replacement after 12 years of service with one exception being our trouble truck which is scheduled for replacement after 5 years due to high mileage; it is then transferred onto a regular crew for the remainder of its 12 year life cycle.

Other equipment such as pole trailers, material trailers, stringing machines, forklifts etc. are scheduled on a 20 year replacement cycle and are evaluated at 20 years and every 5 years after that if they continue to be reliable pieces of equipment.

8.2 Life Cycle Management of SCADA Systems

The utility SCADA system is comprised of three main components: The host system, the communications infrastructure and the Remote Terminal Units (RTUs)/IEDs. The host system is a dual redundant server including routers, network switches, modems and terminal equipment used to connect to remote systems and field devices. The communications infrastructure is comprised of radio and fibre optic networks. The RTUs/IEDs are composed of field devices such as substation relays, communication processors and remotely operated line switches. The host system, being computer system based has a shorter life span in the order of 5 years. The field devices generally have a longer lifespan of 10 – 20 years. As more equipment is becoming electronically controlled and microprocessor based, typical lifespans are decreasing.

8.2.1 Maintenance and Upkeep Methodology

Host systems are proactively replaced on a 5 year basis. While in service, software patches are applied as they become available and regular database backups are performed. A software maintenance agreement is maintained with the SCADA vendor to ensure the system is maintained appropriately. RTUs and IEDs are periodically updated or tested where protection settings change or new firmware features are required. The radio and fibre systems are generally run once commissioned with little maintenance except when equipment failures occur.

8.2.2 Active Maintenance and Upgrade Programs

The existing hosts are presently scheduled for replacement in 2015. Existing RTUs are being proactively phased out in favour of IED based protection relays in the substations. Substation IEDs are run to failure and either repaired or replaced with new units as needed. The existing radio and fibre communication system has performed well since installed. Future requirements and needs for data access to fault records and power quality reporting prompted a review of existing network bandwidth. Presently, Halton Hills Hydro is upgrading its radio communications network to support increased data needs. The backbone network is expected to be completed in 2015 with remote switch connections continuing into 2016/2017.

8.3 Life Cycle Management of Software, GIS Register, and DESS Maps

The GIS register is used to support the asset management program and as such must be kept as up to date as possible. As new system assets are installed or removed, asset alteration data is input into the register. The software is updated periodically as the vendor creates new versions and the host systems are specified to ensure that the hardware platform is appropriate.

8.3.1 Maintenance and Upkeep Methodology

Host systems are proactively replaced on a 5 year basis. While in service, software patches are applied as they become available and regular database backups are performed.

8.3.2 Active Maintenance and Upgrade Programs

Halton Hills Hydro maintains software maintenance agreements for keeping the GIS and system analysis DESS software up to date and to support patch updates and enabling new features as they become available.

Appendices

Appendix A, Indoor Transformer Vault Assessment

B.1 General

Indoor transformer vaults are an electrical servicing option for commercial, industrial and institutional customers that either don't have the physical space to accommodate a three-phase padmounted distribution transformer or they prefer an electrical service arrangement wherein the transformers and associated over-current and over-voltage protective elements are installed in an electrical vault that is constructed as an integral part of the building.

The indoor transformer vaults constructed within Halton Hills Hydro's service territory have been in place for a number of years and are not built to current standards.

Figure B.1-1, Typical Arrangement of Distribution Transformers in Vault

Figure B.1-2, Typical Arrangement of Fuse Cutouts and Surge Arresters

Figure B.1-1 above shows the typical arrangement of the transformer bank (consisting of three single-phase transformers) in an indoor transformer vault. Evidence of insulating oil leaking from the transformer's secondary bushings will be easily seen here.

Figure B.1-2 shows the typical arrangement of fuse cutouts (with a now-obsolete closed mount design) and surge arresters.

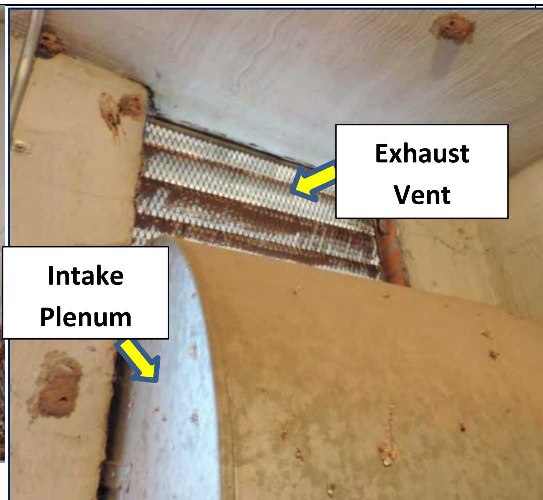
		
Figure B.1-3, Typical Vault Access Door and Ventilation Vent	**Figure B.1-4, Ventilation Opening Viewed from Inside Transformer Vault**	**Figure B.1-5, Ventilation Intake Plenum Viewed from Inside Transformer Vault**

Figure B.1-3 shows the typical access door and ventilation opening grate for indoor transformer vaults. With respect to the grated ventilation opening illustrated in Figure B.1-4 above, it can be seen from that the upper half of the ventilation opening serves as the exhaust vent and from Figure B.1-5 that the lower half of the ventilation opening has a plenum that extends to the floor of the vault to serve as a cool air intake.

B.2 Natural Cooling Design

The natural cooling of transformers installed in an indoor transformer vault is entirely different than occurs in an outdoor environment. In an outdoor environment, the heat generated and dissipated by one or more transformers isn't sufficient to alter the ambient temperature. However, in an indoor transformer vault (or other confined space), the heat generated by one or more transformers can raise the air temperature within the vault.

Within an indoor transformer vault, the heat transfer mechanism is primarily by a thermodynamic phenomenon referred to as thermal pumping. The air within the transformer vault becomes stratified into three (3) layers, a lower zone of denser and cooler air that is generally considered to occupy the lower third of the vault, a middle zone, and an upper zone of less dense and warmer air that is generally considered to occupy the upper third of the vault. With thermal pumping, the cooler air in the lower zone traverses the radiators on the transformers where it absorbs heat and hence its temperature is increased. To complete the thermal circuit, the cool air intake from the outside should be located in the lower third of the vault, and the hot air exhaust vent should be located in the upper third of the vault. Since LDCs commonly load transformers in excess of their nameplate rating (in accordance with IEEE Standard C57.91, Guide for Loading Mineral-Oil-Immersed Transformers and Step-Voltage Regulators), the ventilation openings are usually required to be at least 130% of the opening size stipulated in Rule

26-354, Electrical equipment vault construction, of the Ontario Electrical Safety Code. The thermal pumping phenomenon is illustrated in Figure B.2-1 below.

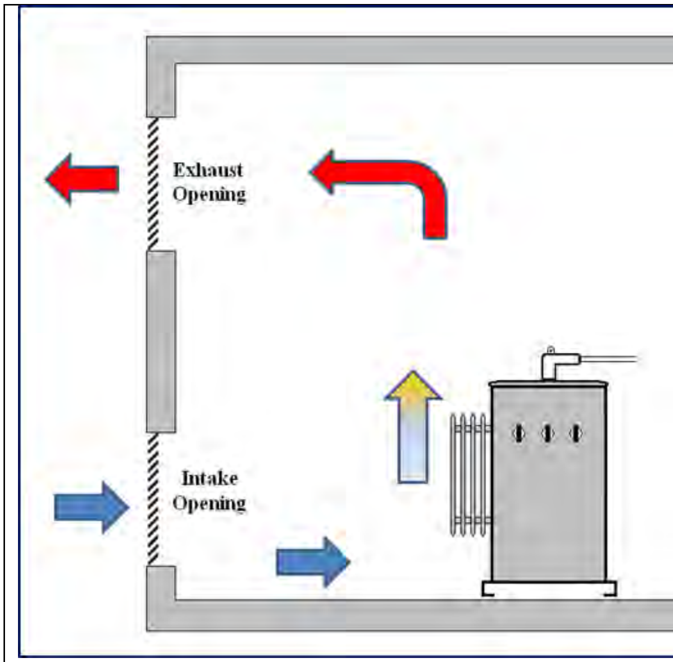


Figure B.2-1, Illustration of Thermal Pumping within Indoor Transformer Vault

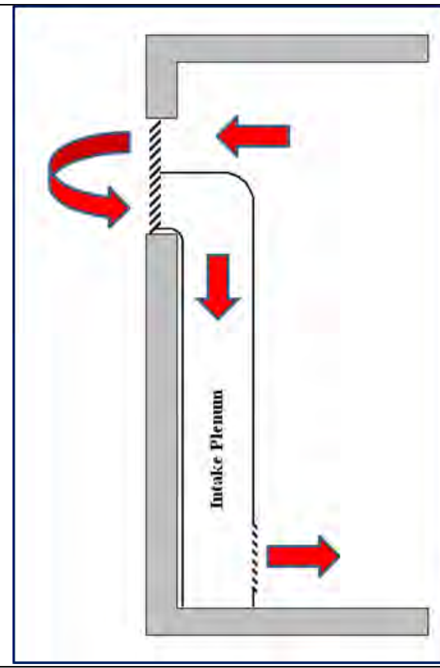


Figure B.2-2, Short-Cycling of Natural Ventilation System

There are two discrete but interrelated deficiencies associated with the design for natural cooling of indoor transformer vaults:

- The distribution transformers installed within indoor transformer vaults are standard single-phase pole-mounted distribution transformers that are devoid of cooling radiators;
- The design of the ventilation opening inherently permits what is referred to as “short cycling”, wherein the intake plenum can easily draw in the warmer exhaust air as illustrated in Figure B.2-2.

A modern vault-style distribution transformer will be equipped with radiators and an elbow-style separable insulated connector as its high-voltage interface.

B.3 Dielectric Fluid

Based on the age of the distribution transformers, they are likely filled with traditional insulating oil as opposed to a less-flammable dielectric fluid such as Cooper Power Systems’ R-Temp® biodegradable fire resistant hydrocarbon fluid. Less-flammable dielectric fluids are used in a modern indoor transformer vault application.

B.4 Vault Remediation and Modernization Options

Modernizing the existing indoor transformer vaults within Halton Hills Hydro's service territory will be a multi-year endeavor that will require significant coordination effort. There are two main options for modernizing the existing indoor transformer vaults:

- Re-supply the building via a three-phase padmounted distribution transformer and remove the existing indoor transformers from the vault; or
- Retrofit the existing indoor transformer vault with modern equipment including: vault-style transformers with radiators and filled with less-flammable dielectric such as R-Temp, metal-enclosed current-limiting fuses, and elbow-style surge. Address the ventilation system design deficiencies, and make other changes as necessary to bring the vault into compliance with present-day codes and safe working practices.

A third option is to decommission the transformer vault and re-supply the building via a three-phase padmounted transformer complete with new primary and secondary supply cables. Transformation external to buildings is preferable as it can be more readily accessed, imposes less safety concerns for the building owner, and is consistent with Halton Hills Hydro's current practices for dead-front supply to customers.

Investment in indoor transform vault modernization is scheduled to begin in 2017 and continuing in 2019 and 2020 forecasting two vaults per year in the latter two years.

Appendix B, Locations of Pole-Trans Units

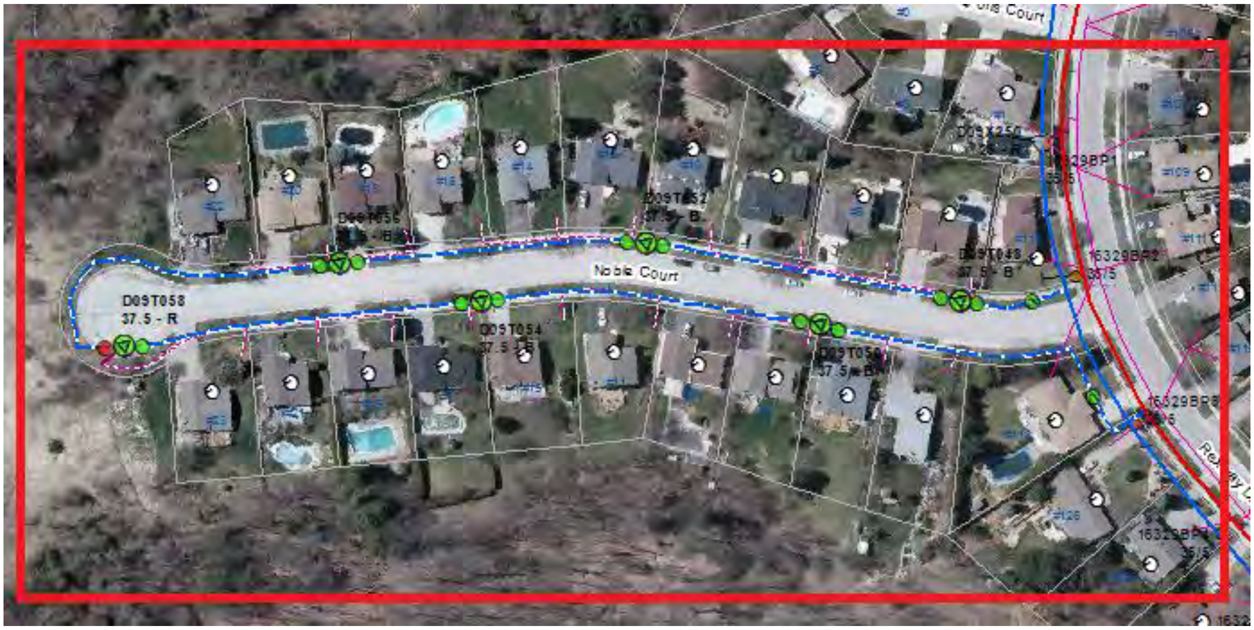
Acton – McDonald Blvd., Norman Avenue, Rosemary Road, Acton Blvd, Division Street, Clare Court

Acton – Prospect Park

Acton – Wright Avenue, Gould Crescent, Holmesway Place

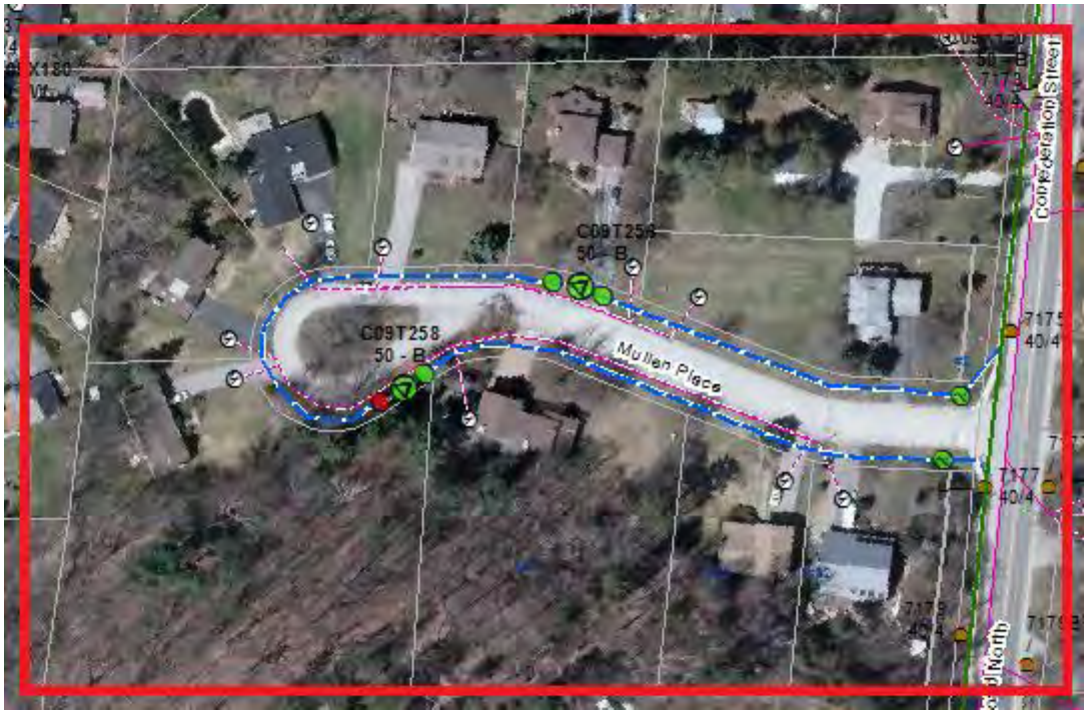
Georgetown – Hillside Drive, Casa Court, Mary Street, Evans Place, Cleaveholm Drive, Harold Street

Georgetown - Noble Court

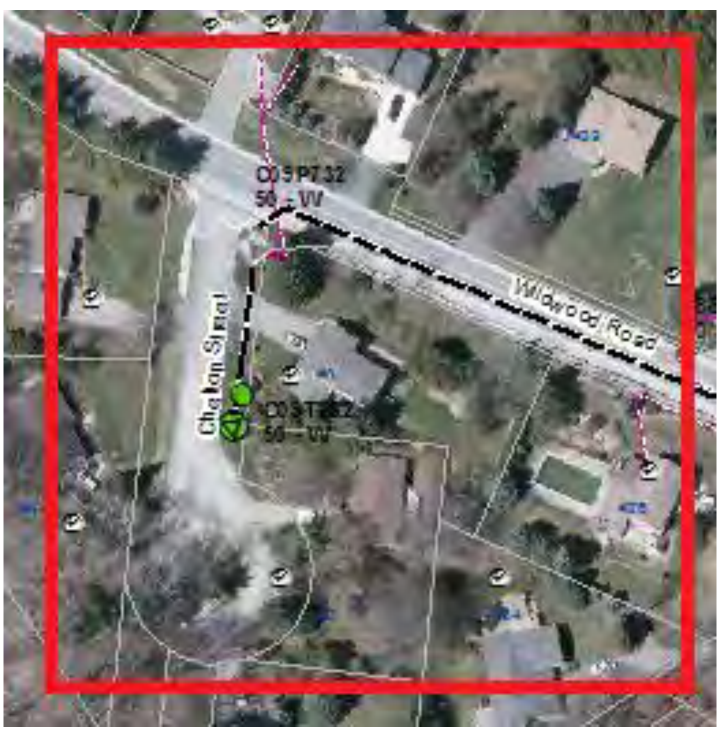


Georgetown – Guelph Street at Hall Road

Georgetown – Mullen Place



Georgetown – Chelton Street



Appendix C, Pole Testing Policy/Procedure

Engineering – Pole Testing and Inspection	**Date: June 2010**
Procedure No HHCEC-ENG-005	**Revision:**
Issued by: Art Skidmore	**Title: President & CEO**

SCOPE OF PROCEDURE

The intent of this procedure is to cover the applicable requirements for pole testing. Halton Hills Hydro shall conduct pole testing as part of a preventative maintenance program to ensure its' utility poles are of sufficient capability to support the utilities distribution. Although this procedure covers pole testing, other preventative maintenance techniques relating to utility poles may be employed.

PROCEDURE DESCRIPTION

Halton Hills Hydro will, as part of its preventative maintenance program, inspect and test a portion of its' utility poles on a yearly basis. This shall entail:

- Each year, a minimum of 1200 poles shall be tested unless otherwise decided.
- An established pole testing company shall be hired to inspect and test the poles using applicable industry standards, from which a report shall be generated indicating the poles requiring replacement and the condition of all poles tested.
- All parties involved shall review the results of the pole testing.
- Each pole marked for replacement shall be inspected by hydro personnel.
- Each pole marked for replacement will be replaced in the same year as the inspection was completed or the following year. If time does not permit replacement within the aforementioned time frame, the pole shall be inspected by hydro to determine if any immediate danger exists by not replacing the pole.
- Pole replacements shall be done on a Like-for-Like replacement basis per O.Reg. 22/04 unless otherwise stated.

PERSONNEL REQUIREMENTS

The Engineering Personnel assigned to oversee the pole testing shall:

- Decide what poles are to be tested in that year based on annual schedule.
- Create a Job in Quadra under which the work will be carried out.
    - Engaged the services of an established pole testing company and arrange an initial meeting at the hydro office with this company to discuss the project.
    - Plot drawings of the areas where poles are to be tested and clearly identify those areas.
    - At the initial meeting, hydro shall provide drawings of the areas to be tested to the pole testing company along with any other pertinent information. Hydro, if they choose, shall ask the pole testing company to number each pole and tag each pole with that number. Hydro shall provide the pole numbering materials to the pole testing company at this meeting. Hydro will also state their expectation for a report from this company that should include a list of poles to be replaced, a list of all poles tested and their present condition with recommendations for retesting, and other pertinent information. Also, hydro shall indicate to that each pole indicated for replacement shall be clearly marked with an “X” to indicate “pole for replacement”.
    - At the initial meeting Hydro shall provide the pole testing company representative with a scope of work, identification badges, and vehicle magnets. Hydro shall also obtain names and contact information for those performing the testing as well as the make, model, and license plate of the vehicle(s) being used by the pole testing company.
    - Hydro personnel may elect to do a site visit to see how the testing is progressing.
    - Following completion of the pole testing, the pole testing company shall complete a report, which shall be provided to hydro for review and action. If another meeting is required, the hydro personnel overseeing the work shall set up a meeting between both parties.
    - Following receipt of the report, hydro personnel shall review the report, make note of each pole marked for replacement, visit each pole in field and make notes as necessary. After field inspection by hydro personnel, the personnel overseeing the pole testing shall put together work order, material lists, drawings, pictures, etc… Another field inspection may be necessary if pole staking or other actions need to be done.
    - A package will be prepared by Engineering personnel that will be given to the Operations Staff and will include:
        1. Job Summary and Instructions.
        2. Material Lists
        3. Drawings indicated what poles are to be replaced
        4. Standard Pole Framings
        5. Pictures of each Pole (if needed)
        6. Table of Poles to be Replaced
        7. Asset Alteration Report sheets
        8. Locates (where obtained before releasing the work order to Operations)
        9. Ministry of Labour Project Notification (projects exceeding $50,000.00) and/ or Registration of Constructors forms (for contract labour)

10. Other information/ documentation as applicable.

- The Engineering Personnel shall arrange a meeting with the Engineering Supervisor to review the information put together. Following that meeting, changes decided upon shall be made prior to a meeting with the Operations Staff.
- The Engineering Personnel shall arrange a meeting with the Manager of Operations and the Operations Foreman to discuss the poles to be replaced. At this meeting all documentation being provided to the Operations Staff shall be reviewed. If any changes are required those changes shall be made and forwarded to the Operations Staff.
- Hydro Operations Staff shall make arrangements to replace the poles marked for replacement within the same year of the testing or the following year provided no immediate danger exists from not replacing the poles immediately. Operations Staff or Engineering Personnel will arrange locates for each pole so as to allow for coordination with their work schedule. In replacing a pole, the Operations Staff shall move the pole number from the recovered pole to the new pole.

- Following replacement of a pole, the Operations Staff shall notify the Engineering Personnel overseeing the project of the replacement by returning the completed work order and Asset Alteration Report.
- Engineering Personnel shall make note in the pole-testing database/ asset management files that the pole was replaced and update the database(s) accordingly.

SUMMARY / CONCLUSION

Pole testing shall be carried out as part of a preventative maintenance program to ensure its utility poles are of sufficient capability to support the utilities distribution network. By following the above procedure, hydro personnel can be confident that aspects of pole testing have been achieved and furthermore, the utility can be confident that their utility poles are of sufficient strength to supports its distribution network.

Christopher Hole, Engineering Supervisor

Appendix D, Asset Alteration Report and mapping Information Update Form

Halton Hills Hydro Asset Alteration Report

Alteration/Installation Date: ______________________ (Day-Month-Year) Name: ____________________

Street: ____ Lot: __________

Civic: ____ Con: __________

Job Description: Work Order:

Pole Installed / Altered: ____________________
Pole Removed: ____________________

Pole Height: 35' 40' 45' 50' 55' 60' Other: _____

Pole Class: 1 2 3 4 5 Other: _____

Pole Owner: HHH Bell Other: ________

Pole Type: Wood Concrete Steel Composite

Pole Species: LPP RPP Cedar Other: _______

Manufacturer: Guelph Bell Pole Co. Other: ______

Year Manufactured: ____________________

Treatment: CCA PEG CCA Creosote Other: ______

Span Guy Pole: YES NO

Joint Use: YES NO

If YES: Cogeco Bell Rogers Other: ________

Streetlight: YES NO Sentinel Light: YES NO

Switch Installed / Altered: ____________________
Switch Removed: ____________________

Pole ID Number: ____________________

Switch Type:

ABS Fused Blade Cut Out Solid Blade LBS Other: ______

Current Rating: _________

Gang Operated: YES NO

Load Break: YES NO

Temp: YES NO

Red Phase – Open Point: YES NO

White Phase – Open Point: YES NO

Blue Phase – Open Point: YES NO

Number of Phases: 1 2 3

Voltage: 16kV 4.8kV 2.4kV 44kV 27.6kV 8.32kV 4.16kV

Additional Information:

Anchor 1: **# of Guys:** ___ **Type:** PISA Expanding Other: ______ **Size:** 10" 12" **Guy Info:** _D/G _Span _Storm _Yoke D/G _Strut
Anchor 2: **# of Guys:** ___ **Type:** PISA Expanding Other: ______ **Size:** 10" 12" **Guy Info:** _D/G _Span _Storm _Yoke D/G _Strut
Anchor 3: **# of Guys:** ___ **Type:** PISA Expanding Other: ______ **Size:** 10" 12" **Guy Info:** _D/G _Span _Storm _Yoke D/G _Strut
Anchor 4: **# of Guys:** ___ **Type:** PISA Expanding Other: ______ **Size:** 10" 12" **Guy Info:** _D/G _Span _Storm _Yoke D/G _Strut
Anchor 5: **# of Guys:** ___ **Type:** PISA Expanding Other: ______ **Size:** 10" 12" **Guy Info:** _D/G _Span _Storm _Yoke D/G _Strut

No. of Circuits: 1 2 3 Other: __________
Voltage: 16kV 4.8kV 2.4kV 44kV 27.6kV 8.32kV 4.16kV **Size:** #556ASC #336ASC 3/0ACSR 1/0ACSR #2ACSR 1/0Cu 2/0Al Other: _____
Voltage: 16kV 4.8kV 2.4kV 44kV 27.6kV 8.32kV 4.16kV **Size:** #556ASC #336ASC 3/0ACSR 1/0ACSR #2ACSR 1/0Cu 2/0Al Other: _____
Voltage: 16kV 4.8kV 2.4kV 44kV 27.6kV 8.32kV 4.16kV **Size:** #556ASC #336ASC 3/0ACSR 1/0ACSR #2ACSR 1/0Cu 2/0Al Other: _____

Neutral Size: #556ASC #336ASC 3/0ACSR 1/0ACSR #2ACSR 1/0Cu 2/0Al Other: ______

Primary Tap: 16kV 4.8kV 2.4kV 44kV 27.6kV 8.32kV 4.16kV **Size:** #556ASC #336ASC 3/0ACSR 1/0ACSR #2ACSR 1/0Cu 2/0Al Other: ___
Neutral Tap Size: #556ASC #336ASC 3/0ACSR 1/0ACSR #2ACSR 1/0Cu 2/0Al Other: ___

Secondary Type: Duplex Triplex Quadruplex None Open Bus Spun Bus U/G Service O/H Service
Secondary Conductor: 266.8kcmil Al 250MCM Al 4/0Al 3/0Al 1/0Al #2Al #4Al Other: ______________

Secondary Type: Duplex Triplex Quadruplex None Open Bus Spun Bus U/G Service O/H Service
Secondary Conductor: 266.8kcmil Al 250MCM Al 4/0Al 3/0Al 1/0Al #2Al #4Al Other: ______________

Secondary Type: Duplex Triplex Quadruplex None Open Bus Spun Bus U/G Service O/H Service
Secondary Conductor: 266.8kcmil Al 250MCM Al 4/0Al 3/0Al 1/0Al #2Al #4Al Other: ______________

Brackets: 3" Qty: ___ 9" Qty: ___ 18" Qty: ___ **Crossarms:** 5'-6" Qty: ____ 9'-6" Qty: _____ **Top Pin:** Qty: ___

Insulator Size: 15kV Qty: ___ 35kV Qty: ___ 46kV Qty: ___ 69kV Qty: ___ **Arrester Size:** 3kV Qty: ___ 6Kv Qty: ___ 21kV Qty: ___ 46kV Qty: ___

Notes/Comments/Concerns:

____
____
____

Halton Hills Hydro Asset Alteration Report

Alteration/Installation Date: ____________________ (Day-Month-Year) Name: ____________________

Street: ____________________ Lot: __________

Civic: ____________________ Con: __________

Job Description: Work Order:

Transformer Installed / Altered: __________

Pole ID Number: ____________________

Transformer Size (kVA): ______ kVA ______ kVA ______ kVA

Tx. Serial No.: ____________________ Phase: R B W

Tx. Serial No.: ____________________ Phase: R B W

Tx. Serial No.: ____________________ Phase: R B W

Manufacturer: Cam Tran Moloney CES Other: __________

Manufacturer: Cam Tran Moloney CES Other: __________

Manufacturer: Cam Tran Moloney CES Other: __________

Manufacture Year: ________ ________ ________

Impedance: ________ Taps: YES NO

Impedance: ________ Taps: YES NO

Impedance: ________ Taps: YES NO

Primary Voltage: 27.6kV 8.32kV 4.16kV 16kV 4.8kV 2.4kV

Secondary Voltage: 120/240V 120/208V 600/347V 600V

Lock Used: Hercules CISA Other: __________

Number of Services: 1 2 3 4 5 6 7 8 9 Other: ___

Transformer Customer Data:

Civic	Street Name	Civic	Street Name

Station Designations: 1 3 5 7 9 11 13 15 17 19 21 23

Feeder: F1 F2 F3

41M21 41M29 41M30 42M23 41M25 42M28 73M04

Padmount Transformer Open Point: YES NO Temp: YES NO

Transformer Removed: __________

Pole ID Number: ____________________

Transformer Size (kVA): ______ kVA ______ kVA ______ kVA

Tx. Serial No.: ____________________ Phase: R B W

Tx. Serial No.: ____________________ Phase: R B W

Tx. Serial No.: ____________________ Phase: R B W

Manufacturer: Cam Tran Moloney CES Other: __________

Manufacturer: Cam Tran Moloney CES Other: __________

Manufacturer: Cam Tran Moloney CES Other: __________

Recloser Installed / Altered: __________
Recloser Removed: __________

Pole ID Number: ____________________

Op Mode: Hydraulic Electronic Vac Breaker Other: ________

Multiphase: YES NO Phase: R W B RWB

Serial Number: __________ Manufacturer Year: ______

Serial Number: __________ Manufacturer Year: ______

Serial Number: __________ Manufacturer Year: ______

Size: ____A Operating Seq.: C13 B13 C22 B22

Type: 4H L D Other: ________ Counter: ___ ___ ___

Regulator Installed / Altered: __________
Regulator Removed: __________

Pole ID Number: ____________________

Voltage Boost: _____ Buck: ____ (-16 to +16) Hand Position: ____

Multiphase: YES NO Phase: R W B RWB Size: ____A

Serial Number: __________ Manufacturer Year: ______

Serial Number: __________ Manufacturer Year: ______

Serial Number: __________ Manufacturer Year: ______

Sectionalizer Installed / Altered: __________
Sectionalizer Removed: __________

Pole ID Number: ____________________

Type: Hydraulic Electronic Other: ________ Size: ____A

Multiphase: YES NO Phase: R W B RWB

Serial Number: __________ Manufacturer Year: ______

Notes/Comments/Concerns:

____

____

____

MAPPING & INFORMATION UPDATES (M.I.U.)

DATE: ___/___/___ (YY MM DD)	**JOB #:** ____________ ☐ Not Applicable	**UPDATE #:** _________

INITIATED BY: ☐ CUSTOMER SERVICE ☐ ENGINEERING ☐ OPERATIONS

NAME: ____

REASON FOR UPDATE:

☐ NEW SERVICE	☐ TRANS LOC ERROR	☐ O/H TO U/G	☐ POLE REPLACEMENT	☐ OTHER:
☐ VOLTAGE CONVERSION	☐ MAP ERROR (S)	☐ PHASE CHANGES	☐ STREET LIGHTS	____________
☐ NEW CIRCUIT (S)	☐ LOAD TRANSFER (S)	☐ FUSING	☐ SERVICE REMOVALS	____________
☐ NEW SUBDIVISIONS	☐ OPEN POINT (S)	☐ SWITCH (S)	☐ RECLOSER (S)	____________

MAP NAME: _________________ **MAP LOCATION:** ____________________________________

VOLTAGES AFFECTED: ☐ 44 ☐ 27.6/16.1 ☐ 8.32/4.8 ☐ 4.16/2.4 ☐ SECONDARY

AS BUILT DRAWING TO FOLLOW: ☐ YES ☐ NO ☐ ATTACHED

COMMENTS ON UPDATE: ____
____
____
____
____
____
____

SKETCH:

FOR OFFICE USE: ☐ ASSETS UPDATED ☐ MAP UPDATED ☐ D.E.S.S UPDATED	**CONTROL ROOM MAP:** UPDATED: ☐ YES ☐ NOT REQUIRED	**BILLING COMPUTER FILES:** UPDATED: ☐ YES ☒ NOT REQUIRED
DATE COMPLETED: ___/___/___	**CHECKED BY:** ______________________________	

U:\Engineering Operations\6 Specs & Documents\Forms\Form Templates\Mapping & Information Updates Form.doc

Appendix E Pole Testing Schedule, 2016-2020

Year	Location(s)
2016	32nd SDRD (5th Line to Trafalgar Road)
	Trafalgar Road (27 SDRD to 32nd SDRD)
	8th Line (22nd SDRD to 27 SDRD)
	Fallbrook Trail & Clayhill Road & Field @ between B09F238 to B10F064
	10th Line north of Clayhill Road to 27 SDRD and part of 27 SDRD stopping at B11F018
	Field Line (8th Line to 9th Line near B08S031 and B09F152)
	9th Line (B09F122 south to Maple Avenue)
	8th Line (22nd SDRD to Wildwood Road)
	Wildwood Road (8th Line to Chelten Place)
	22nd SDRD (Trafalgar Road to 8th Line)
	Glen Cres., Mountain Street, Tweedle Street, Bennett Place (Glen Williams)
	Main Street, Glen Williams (Confederation St. up to WCB @ C11S005)
	8th Line (22nd SDRD to Prince Street)
	Glen Williams (Wildwood Road/ Credit Street/ Erin Street/ Beaver Street/ Karen Drive
	Joyclean Cres./ Moore Park Cres./ Eleanor Cres./ Uplands Crt./ Hyland Ave. - 93 poles.
	Part Ontario St./ Ann St./ Temple St./ Ewing St./ Riverview Cres./ Arletta St./ Cherry St./ Dufferin St./ Hewson Cres./ Elizabeth St. - 101 poles.
	Dayfoot Drive/ Ryan Road/ Morris St./ Chapel St./ Part Mill St.
	Ontario St./ College St./ Victoria St./ Academy Road
	Mountainview Road South (Campbell Gate to Eden Place)
	** Consider testing poles marked for retest in past reports.

Year	Location(s)
2017	Cleaveholm Dr./ Mary St./ Henry St./ Churchill Cres./ Lorne St./ George St./ Draper St./ James St./ Edith St./ Mill St./ Market St./ Church St./ Park St./ Charles St./ William St./ Joseph St. (Georgetown)
	Parking Lot on Mill St. east of Main Street (NE corner) (Georgetown)
	Back St./ Cross St./ Mill St./ Main St. S. of Mill St./ Park Ave.
	Parkview Blvd./ Orchard Blvd. Joseph St.
	Charles St./ Valleywood Rd./ Market St.
	Queen St./ Albert St./ McNabb St./ King St./ Sarah St./ Elgin St./ Union St./ Ostrander Blvd./ Durham St./ Murdoch St.
	John St. (Victoria St. to Mountainview Road)
	River Dr. (W. of Mountainview Rd.)/ Rosetta St./ Caroline St.
	Delrex. Blvd (Maple to Rexway)/ Windsor Rd./ Lorne Crt./ Carole St./ Shelley St./ Byron St./ Prince Charles Dr. (Edward to Rexway)/ Edward St.
	Delrex Blvd. (Rexway to Sargent)/ Hale Dr./ Mackenzie Dr./ Norton Cres./ McGilvray Cres./ Prince Charles Dr./ Bairstow Cres./ Gibbons Pl./ McIntyre Cres./ Dale Gate./ Lyons Crt./ Garnet Dr./ Rexway Dr.
	Delrex Blvd. (Sargent to Mountainview)/ Crombie Pl./ Marilyn Cres./ Faludon Dr./ Torino Gate/ Lucinda Pl./ Stockman Cres./ Sherman Crt./ Dawson Cres./ Irwin Cres./ Airedale Cres./ Eden Pl.
	Sinclair Avenue (Mountainview Rd. to Guelph St.)
	Delrex Blvd. (Mountainview to Guelph)/ Gower Crt./ Gower Rd./ Raylawn Cres./ Duncan Dr./ Langstone Cres./ Moultrey Cres./ Weber Dr./ Gairey Dr./ Jessop Crt./ Stevens Cres./ Regan Cres./ Greystone Cres./ Sims Gate
	** Consider testing poles marked for retest in past reports.

Year	Location(s)
2018	Pennington Cres./ Lewis St./ Bain Crt./ Metcalf Crt./ Danridge Cres./ Hawks Pl.
	Chelvin Dr./ Flamingo Crt./ Fagan Dr.
	Wilson Crt./ Baylor Cres.
	15 Side Road (Trafalgar Road to 8th Line South/ Main Street South)
	Lane Court
	Chipper Court
	Princess Anne Drive/ Hyde Park Drive
	Stewarttown Road/ Mill Pond Drive/ Black Creek Court
	Maple Avenue (Trafalgar Road to Railway Tracks east of Mountainview Road)
	River Drive (Mountainview Road to 10th Line)
	10th Line (Rail Tracks to Clayhill Road) and River Drive (10th Line to Winston Churchill Blvd) and Rail Tracks (10th Line to Winston Churchill Blvd)
	Adamson St./ Draper St./ Pine Crt./ Louisa St./ King St. Green St. (Norval)
	10 Side Road (Trafalgar Road to Winston Churchill Blvd.)
	8th Line South (Maple Ave to 10 SDRD) and Cromar Crt.
	8th Line (5 Side Road to 10 Side Road)
	9th Line (5 Side Road to 10 Side Road)
	10th Line (Steeles Ave. to north of 10 Side Road)
	5th Line (10 Side Road to Steeles Ave.)
	6th Line (Steeles Avenue to 10 Side Road)
	** Consider testing poles marked for retest in past reports.

Year	Location(s)
2019	Coles Court
	Churchill Road (Tx. A03Z036 to Glen Lawson Rd.)/ 3rd Line (Glen Lawson Rd. to 22nd Sdrd)/ Rail Tracks (3rd Line to 4th Line)
	Peel St./ Arthur St./ Wellington St./ Young St./ Mill St. East./ George St./ McDonald Blvd./ Mason Blvd.
	Wallace St./ Perth St./ Commerce Cres.
	Longfield Rd./ Mowbray Pl./ Wynford Pl./ Orville Rd./ Roseford Terrace/ Westcott Rd./ Meadvale Rd.
	Eastern Ave./ Hillcrest St./ Poplar Ave./ Crescent St./ Church St. E./ Wilbur St./ Frederick St./ Elgin St./ John St./ Willow St./ Agnes St./ Bower St./ River St./ St. Alban Dr.
	Vimy St.
	Mill St. West/ Cobblehill Rd./ Cook St./ Church St. West/ Knox St./ Park Ave./ Lake Ave.
	Elizabeth Dr./ Jeffery Ave./ Tidey Ave./ Tyler Ave./ Nelson Crt./ Scene St.
	Highway #25 (10 Sdrd to 5 Sdrd)
	Dublin Line (North of 5 Sdrd)
	5 Sdrd (Dublin Line to 6th Line)
	5 Sdrd (10th Line to Winston Churchill Blvd)
	Winston Churchill Blvd. (south of Steeles Avenue to 401 off ramp)
	27 Sdrd (10th Line to Winston Churchill Blvd.) and Leslie Hill Rd.
	Prince St. (10th Line to dead-end at subdivision)
	25 sdrd (Hwy #25 to Townline)
	3rd Line (5 Sdrd north to Tx. D03X046)
	** Consider testing poles marked for retest in past reports.

Year	Location(s)
2020	Guelph Street/ along C.N.R. Tracks (Crewson's Corners to Eastern Avenue Substation), north side of tracks poles 1182 to 1260. Also test poles on south side of Guelph Street west of Acton, pole 915 to 991.
	Dublin Line (32nd SDRD to 17th SDRD), P# 6049 to P# 3625.
	Highway #7/ Guelph Street (Churchill Road North in Acton to Norval PMU), including Trafalgar Road from 27 Sdrd to Hwy #7, Main Street North in Georgetown from Hwy #7 to Guelph Street, Poles 658 to 566, 668 to 482, 471 to 422, 420 to 270.
	Main Street, Georgetown (HWY #7 to Guelph Street), Inc. above.
	Trafalgar Road (27 SDRD to HWY #7), Inc. above.
	27 SDRD (Trafalgar Road to Dead-end at West), Inc. above.
	Trafalgar Road (HWY #7 to 15SDRD), Poles 481 to 731.
	Lindsay Court, Georgetown
	32nd SDRD (Trafalgar Road to 8th Line), Poles 3743 to 6413
	Hornby Road, Poles 871 to 14845.
	Armstrong Avenue - Mountainview Road to Sinclair Ave., Poles 18153 to 18217.
	Todd Road, Poles 18303 to 18345.
	Armstrong Ave., Guelph Street to MS#19., Poles 18301 to 18255.
	Private Road off Trafalgar Road (C08F272)
	Trafalgar Road, 32nd Sdrd to 27 Sdrd, poles 3743 to 3853.
	Highway #25 (32nd SDRD to CNR Tracks), poles 992 to 1238 & Scene Street in Acton, poles 6103 to 6111.

Appendix F, 2015-2027 FLEET VEHICLE REPLACEMENT SCHEDULE

#	Make	Model	Year	Description	PURCHASE YEAR	AGE IN BUDGET YEAR 2015	LIFE EXPT	Dept	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
101	FORD	RANGER	2010	PICK UP 4X4	2010	5	10	OPER						$35,000							
102	JEEP	CHEROKEE	2014	PASSENGER 4X4	2013	2	10	ENG										$37,000			
103																					
104																					
105																					
106	FORD	F150	2010	PICK UP 4X4 EXT. CAB	2010	5	10	OPER						$45,000							
107	INTERNATIONAL	POSIPLUS	2014	68' DOUBLE BUCKET	2014	1	12	OPER											$110,000	$290,000	
108	INTERNATIONAL	WAJAX	2008	SMALL RBD	2008	7	12	OPER						$110,000	$290,000						
109									$325,000												$100,000
110	INTERNATIONAL	WAJAX	2004	LARGE RBD	2003	12	12	OPER		$110,000	$290,000										
111																					
112										$35,000						$35,000					
113	INTERNATIONAL	POSIPLUS	2008	46 SINGLE MHAD	2008	7	5	OPER				$100,000	$225,000								
114	CHEVROLET	FULL SIZE	2008	AWD VAN	2008	7	10	OPER				$37,000									
115	FORD	RANGER EXT	2011	PICK UP 4X4 EXT. CAB	2011	4	10	ENG								$32,000					
116																					
117	INTERNATIONAL	POSIPLUS	2010	68' DOUBLE BUCKET	2010	5	12	OPER								$110,000	$290,000				
118	CHEVROLET	FULL SIZE	2009	AWD VAN	2009	6	10	METER					$37,000								
119	INTERNATIONAL	POSIPLUS	2012	46 SINGLE MHAD	2012	3	12	OPER										$100,000	$225,000		
120																					
121																					
122	JEEP	LIBERTY	2010	JEEP 4X4	2010	5	10	ENG						$37,000							
123																					
124																					
125	FORD	F250	2010	PICK UP 4X4 CREW	2010	5	10	OPER						$50,000							
126																					
127																					
128																$50,000					
129																					
130	FORD	F250	2013	PICK UP 4X4 CREW	2013	2	10	OPER										$50,000			
131	FORD	F450	2011	DUMP TRUCK	2011	4	12	OPER								$60,000					
140	FORD	F550/VERSALIFT	2007	42'SINGLE BUCKET	2013	8	7	SWE													
		TOTAL LICENSE FEE																			
	TRAILERS																				
201	TIMBERLAND	TRAILER	1998	REEL TRAILER	1998	17	20	OPER				$90,000									
202	BOBCAT	SKID STEER						OPER	Evaluate					Evaluate					Evaluate		
203																					
204	LIFT KING	FORKLIFT		LARGE FORKLIFT				OPER	Evaluate					Evaluate					Evaluate		
205																					
206	TIMBERLAND	TRAILER	2009	REEL TRAILER	2010	5	20	OPER													
207																					
208	GENERATOR	GEN TRAILER	1985	43 Alice St backup generator	1985	30	30	OPER	Evaluate					Evaluate					Evaluate		
209	POLE TRAILER	TRAILER	2007	POLE TRAILER - LARGE	2008	7	20	OPER													
210	NISSAN	FORKLIFT	1992	SMALL FORKLIFT	1992	23	25	OPER			Evaluate			Evaluate					Evaluate		
211	POLE TRAILER	TRAILER	2011	POLE TRAILER - SMALL	2011	4	20	OPER													
212	COLEMAN	POWER SPORT	2000	SMALL GENERATOR	2000	15	20	OPER						$1,000							
213	SNOWBEAR	TRAILER	2004	UTILITY TRAILER	2004	11	15	OPER					$4,000								
214	KUBOTA		2000	LARGE GENERATOR	2000	15	20	OPER						$2,000							
215	FMG Contracting	TRAILER	2011	Material/Reel Trailer	2011	4	20	OPER													
216	RIGID 7000	Honda GX390 motor	2013	LARGE GENERATOR	2013	2	20	OPER													

NORTHWEST GREATER TORONTO AREA INTEGRATED REGIONAL RESOURCE PLAN

Part of the GTA West Planning Region | April 28, 2015

ieso
Independent Electricity System Operator

Integrated Regional Resource Plan

Northwest Greater Toronto Area Sub-Region

This Integrated Regional Resource Plan ("IRRP") was prepared by the IESO pursuant to the terms of its Ontario Energy Board licence, EI-2013-0066.

This IRRP was prepared on behalf of the Northwest Greater Toronto Area Working Group, which included the following members:

- Independent Electricity System Operator
- Hydro One Brampton
- Milton Hydro
- Halton Hills Hydro
- Hydro One Networks Inc. (Distribution) and
- Hydro One Networks Inc. (Transmission)

The Northwest Greater Toronto Area Working Group assessed the adequacy of electricity supply to customers in the Northwest Greater Toronto Area Sub-Region over a 20-year period; developed a flexible, comprehensive, integrated plan that considers opportunities for coordination in anticipation of potential demand growth scenarios and varying supply conditions in the Northwest Greater Toronto Area Sub-Region; and developed an implementation plan for the recommended options, while maintaining flexibility in order to accommodate changes in key assumptions over time.

Northwest Greater Toronto Area Working Group members agree with the IRRP's recommendations and support implementation of the plan through the recommended actions. Northwest Greater Toronto Area Working Group members do not commit to any capital expenditures and must still obtain all necessary regulatory and other approvals to implement recommended actions.

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List of Abbreviations

Abbreviation	Description
CDM	Conservation Demand Management
DESN	Dual Element Spot Network
DG	Distributed Generation
DR	Demand Response
EA	Environmental Assessment
FIT	Feed-in Tariff
GS	Generating Station
IESO	Independent Electricity System Operator
IPSP	2007 Integrated Power System Plan
IRRP	Integrated Regional Resource Planning
kV	Kilovolt
LAC	Local Advisory Committee
LDC	Local Distribution Company
LTEP	2013 Long-Term Energy Plan
MTO	Ministry of Transportation
MTS	Municipal Transformer Station
MVA	Megavolt ampere
MW	Megawatt
OEB	Ontario Energy Board
OPA	Ontario Power Authority (merged with IESO as of January 1st 2015)
ORTAC	Ontario Resource and Transmission Assessment Criteria
PPS	Provincial Policy Statement
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Plan
SIA	System Impact Assessment
TS	Transformer Station
Working Group	

1. Introduction

This Integrated Regional Resource Plan ("IRRP") addresses the electricity needs of the Northern sub-region of the West Greater Toronto Area Region ("NW GTA" or "Northwest GTA") over the next 20 years. The report was prepared by the Independent Electricity System Operator ("IESO") on behalf of a Technical Working Group composed of the IESO, Hydro One Brampton, Milton Hydro, Halton Hills Hydro, Hydro One Distribution and Hydro One Transmission ("Working Group").

The NW GTA sub-region includes the municipalities of Brampton, Milton, Halton and the southern portion of Caledon. The other sub-region within the West Greater Toronto Area Region – Southwest GTA – underwent a Needs Screening and Scoping Assessment, which determined that needs in the area existed, but that they would be best addressed by the applicable distributors and transmitter for local capacity needs and through a bulk planning study for local restoration needs, rather than through an IRRP process.

Over the last 10 years, electrical demand in this sub-region has grown on average by 2.2% per year. Increasing electrical demand in densely populated urban areas and high growth rates in greenfield residential and commercial/industrial subdivisions have made this sub-region's growth rate one of the highest in Ontario. The official plans issued by the sub-region's municipalities indicate that this growth is expected to continue over the next 20 years in accordance with the province's "Places to Grow" policy.[1] There is a strong need for integrated regional electricity planning to ensure that the electricity system can support the pace of development in the long term.

In Ontario, planning to meet the electrical supply and reliability needs of a large area or region is done through regional electricity planning, a process that was formalized by the Ontario Energy Board ("OEB" or "Board") in 2013. In accordance with the OEB regional planning process, transmitters, distributers and the IESO are required to carry out regional planning activities for the 21 electricity planning regions at least once every five years.

This IRRP identifies and co -ordinates the options to meet customer needs in the sub-region over the next twenty years. Specifically, this IRRP identifies investments for immediate implementation to meet near- and medium-term needs in the region, respecting the lead time

[1] Growth Plan for the Greater Golden Horseshoe, June 2013 Consolidated, https://www.placestogrow.ca/index.php?option=com_content&task=view&id=359&Itemid=14

for development. This IRRP also identifies options to meet long-term needs, but given forecast uncertainty, the potential for technological change and the longer development lead-time, the plan maintains flexibility for long-term options and does not commit specific projects at this time. Instead, the long-term plan identifies near-term actions to develop alternatives and engage with the community, to gather information and lay the groundwork for future options. These actions are intended to be completed before the next IRRP cycle, scheduled for 2020 or sooner, depending on demand growth, so that the results can inform a decision should one be needed at that time.

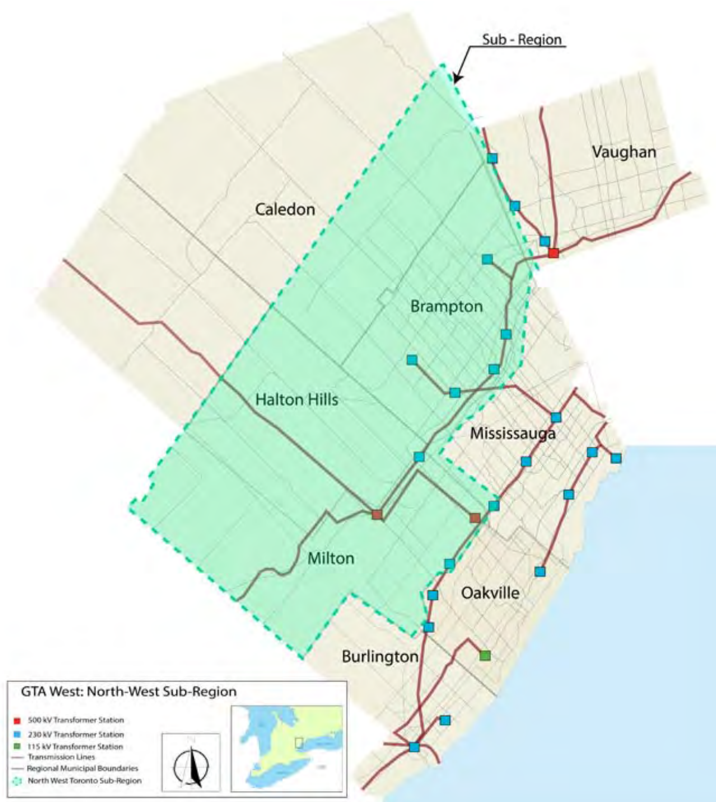
This report is organized as follows:

- A summary of the recommended plan for NW GTA is provided in Section 2
- The process and methodology used to develop the plan are discussed in Section 3
- The context for electricity planning in NW GTA and the study scope are discussed in Section 4
- Demand forecast scenarios, as well as conservation and distributed generation assumptions, are described in Section 5
- Near- and long-term electricity needs in NW GTA are presented in Section 6
- Alternatives and recommendations for meeting near- and medium-term needs are addressed in Section 7
- Options for meeting long-term needs are discussed and near-term actions to support development of the long-term plan are provided in Section 8
- A summary of community, aboriginal and stakeholder engagement to date in developing this IRRP and moving forward is provided in Section 9
- A conclusion is provided in Section 10.

2. The Integrated Regional Resource Plan

The Northwest GTA IRRP addresses the region's electricity needs over the next 20 years based on the IESO's Ontario Resource and Transmission Assessment Criteria ("ORTAC"). The IRRP identifies needs that are forecast to arise in the near and medium term (0-10 years) and in the longer term (10-20 years). These two planning horizons are distinguished in the IRRP to reflect the level of commitment required over these time horizons. Plans for both timeframes are coordinated to ensure consistency. The IRRP was developed based on consideration of planning criteria, including reliability, cost and feasibility, and, in the near-term, it seeks to maximize the use of the existing electricity system where it is economic to do so. The NW GTA sub-region is highlighted in green in Figure 2-1, below.

Figure 2-1: West GTA Northern Sub-region (NW GTA)

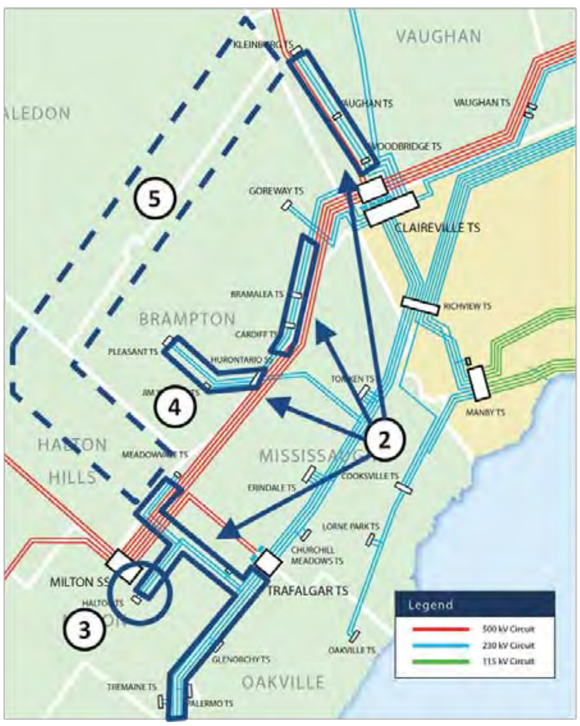


For the near and medium term, the IRRP identifies specific investments to be implemented. This is necessary to ensure that they are in service in time to address the region's more urgent needs, respecting the lead time for their development.

For the long term, the IRRP identifies a number of alternatives to meet needs. However, as these needs are forecast to rise further in the future, it is not necessary (nor would it be prudent given forecast uncertainty and the potential for technological change) to commit to specific projects at this time. Instead, near-term actions are identified to develop alternatives, keep key options open and engage with the communities, to gather information and lay the groundwork for future options. These actions are intended to be completed before the next IRRP cycle so that their results can inform a decision at that time.

The needs or recommended actions comprising the near- to medium-term and long-term plans are summarized below and shown in Figure 2-2 below.

Figure 2-2: Summary of Plan Elements



Near/ Medium Term

1. Conservation achievement (entire region)
2. Restoration needs *(left to right)*
   - Halton radial pocket
   - Pleasant TS
   - Cardiff/ Bramalea supply
   - Kleinburg radial pocket
3. Halton TS (capacity needs)
4. Supply to Pleasant TS (capacity needs)

Long Term

5. Secure long term transmission corridor rights

The sections below provide more details on plan elements shown in the map. They have been sorted according to near/medium term and long term.

2.1 Near- / Medium-Term Plan

There are a number of elements that comprise the near- and medium-term plan. The first element of the plan is to maximize achievement of conservation targets. The plan also identifies several pockets in the study area that are currently at risk for not meeting targeted load restoration levels and recommends a course of action for addressing these needs. Two new step-down transmission facilities are recommended in the near term to ensure new customer connections can be accommodated in the Halton Hills and Milton service territories. Over the medium term, a transmission line upgrade is recommended to address emerging capacity needs in the Pleasant TS service area. The recommendations that comprise the near- and medium-term plan are described in further detail below.

> **Near-/Medium-Term Needs**
>
> - Load restoration criteria exceeded in Northwest GTA—**2015**
> - Provide additional transformer station supply capability within the Halton TS service territory—**2018 for Halton Hills Hydro and 2020 for Milton Hydro**
> - Increase supply meeting capability of H29/30 circuits (supply to Pleasant TS) — **early-to-mid 2020s**
> - Address overloads on T38/39B (supply to Halton TS, Meadowvale TS, Trafalgar TS and Tremaine TS) — **early-to-mid 2020s**

Recommended Actions:

1. Implement conservation and distributed generation

Meeting the provincial conservation targets established in the 2013 Long-Term Energy Plan ("LTEP") is a key component of the near-term plan. Peak-demand impacts associated with the provincial targets were assumed before identifying any residual needs, when developing the demand forecast. This is consistent with the provincial Conversation First Policy. These peak-demand impacts amount to approximately 130 megawatts ("MW") or 33% of the forecast demand growth during the first 10 years of the study. To ensure that these savings materialize, the local distribution companies' ("LDCs") conservation efforts should focus on measures that will balance the needs for energy savings to meet the Conservation First policy, while maximizing peak-demand reductions.

Monitoring conservation success, including measuring peak-demand savings, will be an important element of the near-term plan. This will lay the foundation for the long-term plan by reviewing the actual performance of specific conservation measures in the region and assessing potential for further conservation efforts.

Provincial programs that encourage the development of distributed generation ("DG"), such as the Feed-in Tariff ("FIT"), microFIT and Combined Heat and Power Standard Offer programs, can also contribute to reducing peak demand in the region. This will depend in part on local interest and opportunities for development. The LDCs and the IESO will continue their activities to support these initiatives and monitor their impacts.

2. Address restoration and T38/39B needs through bulk system study

A bulk system study is underway in the West GTA Region to address anticipated overloads on the bulk transmission system resulting from changes in provincial generation patterns and overall growth across the GTA in general and the West GTA Region in particular. Options considered as part of the bulk system study have the potential to provide benefits related to improving local restoration capabilities throughout the area as well as the medium-term T38/39B capacity needs. As a result, the Working Group agreed that these regional needs should be considered as part of the bulk system study. If these needs are not adequately addressed through the bulk system study and a bulk system plan, they will be revisited as part of the regional planning process.

3. Develop two new step-down stations to relieve Halton TS overloads

Action is required to provide additional supply capacity in the area served by Halton TS. This station is located on the south side of Highway 401 in the Town of Milton and supplies 27.6 kilovolt ("kV") power throughout Milton and southern Halton Hills. Based on current forecasts, additional 27.6 kV supply is required in the general vicinity of Halton TS by approximately 2018 for Halton Hills Hydro's service area and 2020 for Milton Hydro's service area.

Following the analysis included as Appendix E and summarized in Section 7.1.3, the most economic course of action is to construct two stations: one at the site of the current Halton Hills Generating Station ("GS") to supply Halton Hills Hydro by 2018 and one at the existing Halton TS to supply Milton Hydro loads by 2020. Based on the anticipated needs and assuming a three-year lead time for development and construction, it is recommended that Halton Hills Hydro begin development of the Halton Hills MTS at this time. Commencement of development and construction of Halton TS #2 (for supply to Milton Hydro) does not need to be initiated until 2017.

4. Upgrade H29/30 circuits (supply to Pleasant TS) to a higher rating

When load at Pleasant TS exceeds approximately 417 MW and one of the H29/30 circuits that supplies Pleasant TS is out of service, there is a potential for overloads on the companion circuit. Under the Expected Growth forecast, relief is anticipated to be required by about 2026, or as early as 2023 under the Higher Growth forecast. Hydro One has indicated that this line can be upgraded to accommodate over 500 MW of electrical demand at Pleasant TS, enough to accommodate the full rating of the station's step-down facilities, and deferring need until the long term. Assuming a two-year lead time for the replacement of these conductors, action is not expected to be required until the early 2020s.

Peak load should continue to be monitored at Pleasant TS and action pursued when actual demand increases from the current level of approximately 375 MW to approximately 400 MW. Assuming five to ten megawatts of demand growth per year, peak load is expected to occur approximately two years before the need date of 2026.

2.2 Long-Term Plan

Long-Term Needs
• Provide additional transformer and transmission line capacity in northern Brampton/southern Caledon to meet forecast demand growth

The long term plan assumes near-/medium-term needs are addressed as recommended in Section 2.1, above. If that is not done, the long-term plan will likely have to be modified. In the long term, continued load growth is expected to be significant, increasing peak summer demand in Northwest GTA from 1,220 MW to 1,580 MW during the study period. This is expected to trigger capacity needs in the northern Brampton/southern Caledon area. In broad terms, capacity needs refer to the ability of the power system to meet the peak electricity demands of end use customers. In this area, there are two main drivers that could trigger this capacity need:

- Overloads on the transformers at Pleasant TS and/or Kleinburg TS due to load growth beyond the step-down stations' capacity.
- An inability for the distribution system to deliver the required service quality as a result of limitations on the distribution network due to distances between transmission supply points (i.e., transformer stations) and new end-use customers located in northern Brampton and southern Caledon.

When new capacity is necessary in the northern Brampton/southern Caledon area, step-down transformer stations will be required in the general vicinity of the anticipated growth to supply new customer loads. Due to a lack of available transmission supply in the area, a new transmission corridor will also be required to provide supply to any future stations.

Recommended Actions:

5. Continue Ongoing Work to Establish a New Transmission Corridor through Peel, Halton Hills and Northern Vaughan

The Ministry of Transportation ("MTO") recently began Phase 2 of an environmental assessment ("EA") to establish a new 400-series highway corridor running from the Highway 401/407 junction near Milton, north along the Halton Hills/Brampton border, through southern Caledon and northern Vaughan, terminating at Highway 400. The IESO and Hydro One have been working with MTO and municipal government staff to consider the establishment of a future transmission corridor in the general vicinity of this highway, consistent with government policy on coordinated and efficient use of land, resources, infrastructure and public service facilities in Ontario communities, outlined in the Provincial Policy Statement ("PPS"). This transmission corridor would provide supply capacity for northern Halton, northern Peel, and York Region in the long term and also enhance the capability of the West GTA bulk supply system.

To ensure the future viability of this option, the IESO and Hydro One will continue working with the Ministries of Energy, Transportation, Infrastructure and Municipal Affairs and Housing and related regional and municipal government staff.

6. Monitor Demand Growth, CDM Achievement and Distributed Generation Uptake

On an annual basis, the IESO will coordinate a review of conservation and demand management ("CDM") achievement, the uptake of provincial distributed generation projects and actual demand growth within the Northwest GTA sub-region. This review will be used to track the expected timing of the following needs to determine when a decision on implementation is required:

- Construction of Halton TS #2
- Upgrade of H29/30 circuits (supply to Pleasant TS) to a higher rating
- A new NW GTA electricity corridor

3. Development of the IRRP

3.1 The Regional Planning Process

In Ontario, planning to meet the electricity needs of customers at a regional level is done through regional planning. Regional planning assesses the interrelated needs of a region - defined by common electricity supply infrastructure over the near, medium and long term and develops a plan to ensure cost-effective, reliable, electricity supply. Regional plans consider the existing electricity infrastructure in an area, forecast growth and customer reliability, evaluate options for addressing needs and recommend actions.

Regional planning has been conducted on an as needed basis in Ontario for many years. Most recently, the Ontario Power Authority ("OPA") carried out regional planning activities to address regional electricity supply needs. The OPA conducted joint regional planning studies with distributors, transmitters, the IESO and other stakeholders in regions where a need for coordinated regional planning had been identified.

In 2012, the Ontario Energy Board convened the Planning Process Working Group ("PPWG") to develop a more structured, transparent and systematic regional planning process. This group was composed of industry stakeholders including electricity agencies, utilities and stakeholders. In May 2013, the PPWG released the Working Group Report to the Board, setting out the new regional planning process. Twenty-one electricity planning regions in the province were identified in the Working Group Report and a phased schedule for completion was outlined. The Board endorsed the Working Group Report and formalized the process timelines through changes to the Transmission System Code and Distribution System Code in August 2013, as well as through changes to the OPA's licence in October 2013. The OPA licence changes required it to lead a number of aspects of regional planning, including the completion of comprehensive IRRPs. Following the merger of the IESO and the OPA on January 1, 2015, the regional planning responsibilities identified in the OPA's licence were transferred to the IESO.

The regional planning process begins with a Needs Screening process performed by the transmitter, which determines whether there are needs requiring regional coordination. If regional planning is required, the IESO then conducts a scoping assessment to determine whether a comprehensive IRRP is required, which considers conservation, generation, transmission and distribution solutions, or whether a straightforward "wires" solution is the best option. If the latter applies, then a transmission- and distribution-focused Regional

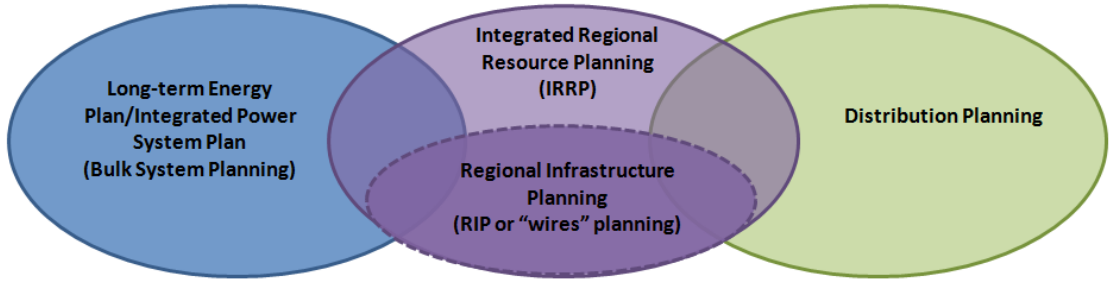
Infrastructure Plan ("RIP") is developed. The scoping assessment process also identifies any sub-regions that require assessment. There may also be regions where infrastructure investments do not require regional coordination and can be planned directly by the distributor and transmitter, outside of the regional planning process. At the conclusion of the scoping assessment, the IESO produces a report that includes the results of the Needs Screening process – identifying whether an IRRP, RIP or no regional coordination is required – and a preliminary Terms of Reference. If an IRRP is the identified outcome, then the IESO is required to complete the IRRP within 18 months. If a RIP is required, the transmitter takes the lead and has six months to complete it. Both RIPs and IRRPs are to be updated at least every five years.

The final IRRPs and RIPs are to be posted on the IESO and relevant transmitter websites and can be used as supporting evidence in a rate hearing or leave to construct application for specific infrastructure investments. These documents may also be used by municipalities for planning purposes and by other parties to better understand local electricity growth and infrastructure requirements.

Regional planning, as shown in Figure 3-1, is just one form of electricity planning that is undertaken in Ontario. There are three types of electricity planning in Ontario:

- Bulk system planning
- Regional system planning
- Distribution system planning

Figure 3-1: Levels of Electricity System Planning



Bulk System Planning

- 500 kV & 230 kV transmission
- Interconnections
- Inter-area network transfer capability
- System reliability (security and adequacy) to meet NERC, NPCC, ORTAC
- Congestion and system efficiency
- System supply and demand forecasts
- Incorporation of large generation
- Typically medium- and long-term focused

Regional Planning

- 230 kV & 115 kV transmission
- 115/230 kV autotransformers and associated switchyard facilities
- Customer connections
- Load supply stations
- Regional reliability (security and adequacy) to meet NERC, NPCC & ORTAC
- ORTAC local area reliability criteria
- Regional/local area generation & CDM resources
- Typically near- & medium-term focused

Distribution Network Planning

- Transformer stations to connect to the transmission system
- Distribution network planning (e.g. new & modified Dx facilities)
- Distribution system reliability (capacity & security)
- Distribution connected generation & CDM resources
- LDC demand forecasts
- Near- & medium-term focused

Planning at the bulk system level typically considers the 230 kV and 500 kV network. Bulk system planning considers the major transmission facilities and assesses the resources needed to adequately supply the province. Bulk system planning is typically carried out by the IESO in accordance with government policy. Distribution planning, which is carried out by local distribution companies, looks at specific investments on the low voltage, distribution system.

Regional planning can overlap with bulk system planning. For example, overlap can occur at interface points where regional resource options may also address a bulk system issue. Similarly, regional planning can overlap with the distribution planning of LDCs. An example of this is when a distribution solution addresses the needs of the broader local area or region. Therefore, to ensure efficiency and cost effectiveness, it is important for regional planning to be coordinated with both bulk and distribution system planning.

By recognizing the linkages with bulk and distribution system planning and coordinating multiple needs identified within a given region over the long term, the regional planning process provides an integrated assessment of needs. Regional planning aligns near and long-term solutions and allows specific investments recommended in the plan to be understood as part of a larger context. Furthermore, regional planning optimizes ratepayer interests by avoiding piecemeal planning and asset duplication and allows Ontario ratepayers' interests to be represented along with the interests of LDC ratepayers. Where IRRPs are undertaken, they allow an evaluation of the multiple options available to meet needs, including conservation, generation and "wires" solutions. Regional plans also provide greater transparency through engagement in the planning process and by making plans available to the public.

3.2 The IESO's Approach to Regional Planning

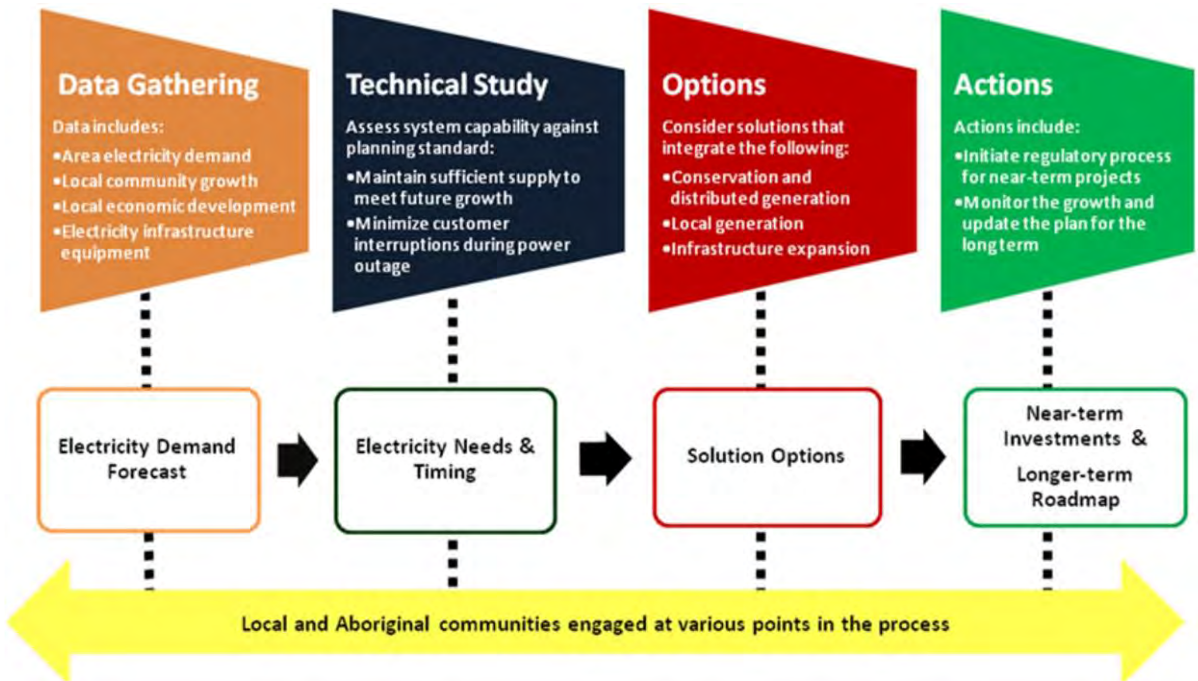
IRRPs assess electricity system needs for a region over a 20-year period. The 20-year outlook anticipates long-term trends so that near-term actions are developed within the context of a longer-term view. This enables coordination and consistency with the long-term plan, rather than simply reacting to immediate needs.

In developing an IRRP, a different approach is taken to developing the plan for the first 10 years of the plan—the near- and medium-term—than for the longer-term period of 10-20 years. The plan for the first 10 years is developed based on best available information on demand, conservation and other local developments. Given the long lead time to develop electricity infrastructure, near-term electricity needs require prompt action to enable the specified solutions in a timely manner. By contrast, the long-term plan is characterized by greater forecast uncertainty and longer development lead time, as such solutions do not need to be committed to immediately. Given the potential for changing conditions and technological development, the IRRP for the long term is more directional, focusing on developing and maintaining the viability of options for the future and continuing to monitor demand forecast scenarios.

In developing an IRRP, the IESO and regional working group (see Figure 3-2 below) carry out a number of steps. These steps include electricity demand forecasts; technical studies to determine electricity needs and the timing of these needs; the development of potential options; and a recommended plan including actions for the near and long term. Throughout this process, engagement is carried out with stakeholders and First Nation and Métis communities who may have an interest in the region. The steps of an IRRP are illustrated in Figure 3-2 below.

The IRRP report documents the inputs, findings and recommendations developed through the process described above and provides recommended actions for the various entities responsible for plan implementation. Where "wires" solutions are included in the plan recommendations, the completion of the IRRP report is the trigger for the transmitter to initiate an RIP process to develop those options. Other actions may involve: development of conservation, local generation, or other solutions; community engagement; or information gathering to support future iterations of the regional planning process in the region.

Figure 3-2: Steps in the IRRP Process



3.3 Northwest GTA Working Group and IRRP Development

Through 2012, the IESO and area LDCs discussed local conditions, recent and expected customer growth trends and anticipated challenges. The participants for this planning process were:

- IESO
- Hydro One Brampton
- Milton Hydro
- Halton Hills Hydro
- Hydro One Distribution
- Hydro One Transmission

Based on these discussions, the IESO and area LDCs agreed that an Integrated Regional Resource Planning process was appropriate for the area. The participants in the planning process became the Working Group that developed this IRRP.

The NW GTA IRRP process started in 2013 in response to strong growth in peak electrical demand throughout the sub-region. A major consideration for triggering an IRRP was the location of new growth: urban boundaries have been expanding northward throughout Halton and Peel regions, which has placed additional strain on a transmission system that is largely concentrated in the southern portion of the region.

The Northwest GTA IRRP is a "transitional" IRRP in that it began prior to the development of the OEB's regional planning process; some of the work was completed before the new process and its requirements were known. Much of the work completed in the early days of the study focused on development of the load forecast and identifying needs and options. The approaches used in conducting these elements of the study were consistent with the new OEB process. As a result, the Terms of Reference were not revised, but an explanatory note was added to communicate the updated planning framework. These Terms of Reference are available on the IESO's Regional Planning website.[2]

[2] http://powerauthority.on.ca/sites/default/files/planning/NW-GTA-Terms-of-Reference.pdf

4. Background and Study Scope

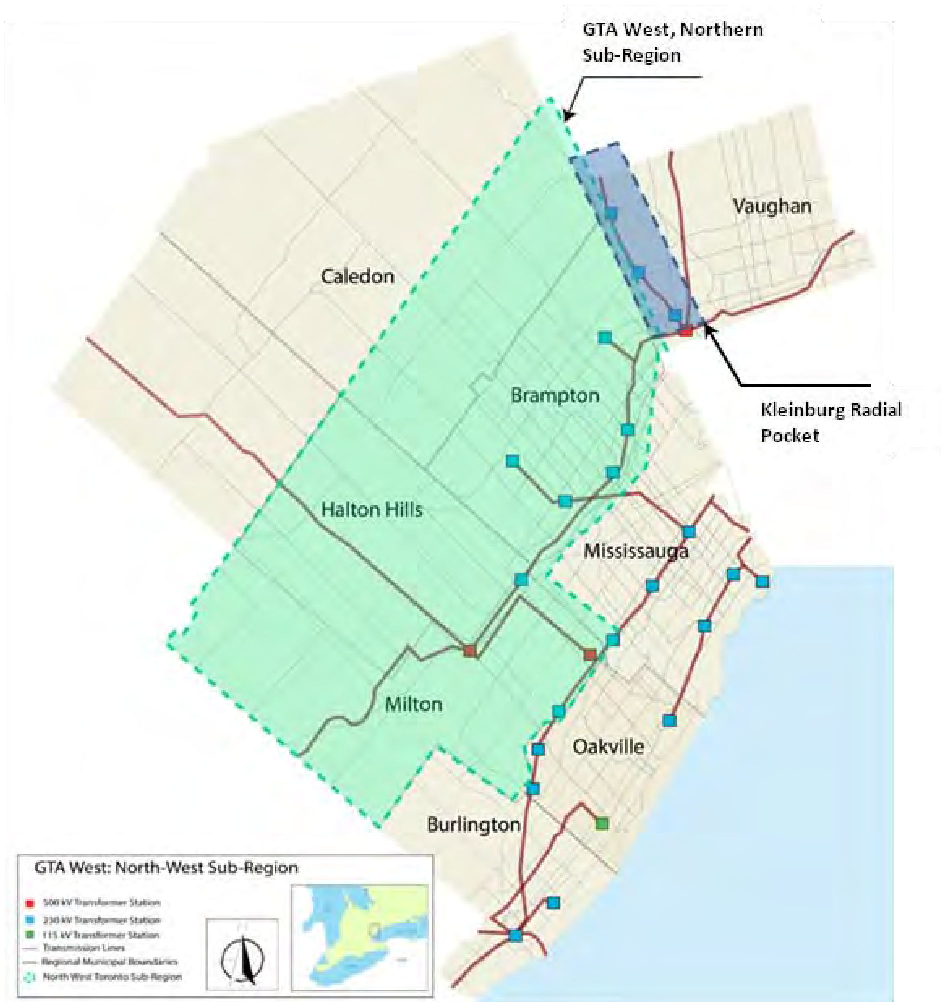
This report presents an integrated regional electricity plan for NW GTA for the 20-year period from 2014 to 2033. The planning process leading to this IRRP began in 2013, in recognition of the high electrical demand growth observed over the previous 10 years, expanding urban boundaries, limited existing electrical infrastructure and the requirement for coordination with ongoing bulk system planning in this sub-region.

To set the context for this IRRP, the scope of this IRRP and the region's existing electricity system are described in Section 4.1, the recommendations and implementation of the 2006 West GTA Supply Study are summarized in Section 4.2 and a brief introduction to the ongoing bulk system study is provided in Section 4.3.

4.1 Study Scope

The West Greater Toronto Area Region ("West GTA") roughly encompasses the municipalities of Mississauga, Oakville, Brampton, Milton, southern Halton Hills (including Georgetown and Acton) and southern Caledon (including Bolton and the areas south of the Greenbelt). Based on an early review of growth and existing infrastructure, this region was broken into two sub-regions: Northwest GTA, highlighted in green in Figure 4-1, below and Southwest GTA.

Figure 4-1: Northwest GTA Planning Sub-region



The Northwest GTA sub-region is roughly defined by the municipalities of Brampton, Milton, southern Halton Hills and southern Caledon. It is the focus of this IRRP.

Immediately adjacent to the Northwest GTA boundary is a short radial circuit (V43/44), which runs radially from Claireville TS and terminates at Kleinburg TS (Kleinburg radial pocket, highlighted in blue, above). Although the Kleinburg radial pocket is located within the GTA North Region, this pocket was included within the scope of the Northwest GTA IRRP for the following reasons:

- Electrical demand growth in this pocket is driven largely by new customers in southern Caledon, in particular the Town of Bolton. As a result, any capacity needs would have greater implications for customers in the Northwest GTA sub-region.

- The Northwest GTA sub-region is characterized by a large number of similarly configured radial pockets, meaning that restoration needs would be a common issue addressed across the entire planning area. The fact that there are so many radial pockets provides an opportunity for investigating common solutions.

The Southern sub-region of West GTA ("Southwest GTA") is not included in this IRRP. A separate Needs Assessment and Scoping Assessment were carried out for this sub-region in 2014. These assessments concluded that the sub-region's capacity needs would be best addressed directly by the distributor and transmitter, and restoration needs through a bulk transmission system study under development by the IESO. Some restoration needs for the Southwest GTA sub-region were also identified as part of the Scoping Assessment and will be considered as part of the bulk transmission system study already underway for West GTA (see Section 4.3, below, for more details). If these restoration needs are not resolved through the bulk transmission system study, they will be revisited as part of the regional planning process. Information on the Southwest GTA study, including links to the Needs Assessment and Scoping Assessment reports, is available on the IESO Regional Planning webpage.[3]

Growth in Peel region is expected to continue to expand northward into the undeveloped greenfield areas of north Brampton and south Caledon, farther from existing transmission assets. Within Halton region, the municipalities of Halton Hills and Milton are expected to see growth along underdeveloped areas to the north and south of Highway 401, the vicinity of James Snow Parkway and through southern Georgetown. The blue and orange highlighted areas in Figure 4-2 show these growth clusters:

[3] http://www.powerauthority.on.ca/power-planning/regional-planning/gta-west/southern-sub-region

Figure 4-2: Anticipated Growth Clusters, by Municipality

The continued high growth shown in this forecast is consistent with the *Places to Grow Growth Plan for the Greater Golden Horseshoe* (2013 consolidated), which projects an additional 790,000 people living in the Peel and Halton regions by 2031. This represents an average annual population increase of 1.84% per year.

4.2 2006 West GTA Supply Study

The 2006 West GTA Supply Study was a joint study undertaken by Enersource Hydro Mississauga, Halton Hills Hydro Inc., Hydro One Brampton, Hydro One Networks Inc. Distribution, Milton Hydro and Hydro One Networks Inc. Transmission. This study was initiated in 2004, before the establishment of the OPA, but had a similar purpose to the current regional planning initiative, namely to identify the need for transmission capacity and voltage stability in West GTA and assess the capability of the transmission system to meet the load requirements for a 10-year study period (from 2005 to 2015). Several new transmission reinforcements were recommended and ultimately adopted, including:

- Extension of circuits V72/73R from Cardiff TS to Pleasant TS tap and construction of Hurontario SS with radial supply to Jim Yarrow MTS
- Construction of Winston Churchill MTS
- Construction of a third set of step down transformers (Dual Element Spot Network, or "DESN") at Pleasant TS
- Construction of a second DESN at Goreway TS

The measures undertaken as a result of the 2006 study have supported the continued electrical load growth in this area over the past decade. This IRRP builds upon the previous planning initiatives in this area, including the 2006 West GTA study, to ensure that the forecast electrical load growth in the area can continue to be met.

A copy of the report is available on Hydro One's Regional Planning website.[4]

4.3 Bulk Transmission System Study

A bulk system study was initiated by the IESO for West GTA in 2014 to identify and recommend solutions to address emerging bulk transmission system needs. These needs differ from those driving the regional plan, as they are impacted by changes in the broader Ontario electricity system, rather than the local system. These needs include planned refurbishment and retirement of nuclear generation facilities, incorporating renewable generation in southwest Ontario and changes in electricity consumption patterns across the GTA. Due to the potential for overlaps between bulk and regional planning, as described in Section 3.1, it is important for regional planning to be coordinated with bulk system planning, particularly in the case of West GTA. The bulk system study will therefore account for regional needs that may be more efficiently solved through bulk system solutions.

The West GTA region is supplied by the 500 kV and 230 kV bulk transmission network with 500-230 kV transformation facilities at Claireville TS and Trafalgar TS. Load supply stations and major generating stations in the area are connected to the 230 kV network. The 500 kV transmission network is the backbone of the Ontario system and the 500-230 kV transformers provide the link between the 500 kV and the 230 kV networks. Milton SS, which is located in

[4] http://www.hydroone.com/RegionalPlanning/GTAWest/Documents/GTA%20West%20Supply%20Study%202006.pdf

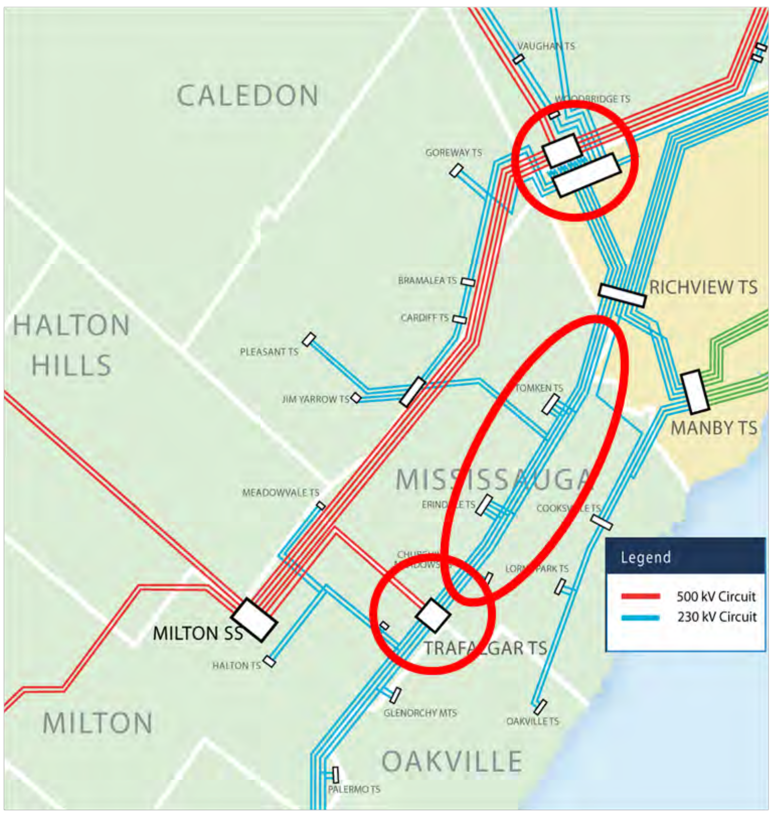
the area, provides switching for 500 kV circuits. Currently there are no 500-230 kV transformation facilities at this station.

The bulk system studies conducted indicate that the following facilities may require relief from overloads within the next 10 years:

- 500-230 kV transformers at Trafalgar TS
- 500-230 kV transformers at Claireville TS
- Trafalgar to Richview 230 kV lines

These three facilities are highlighted on the map below:

Figure 4-3: West GTA Bulk Facilities with Potential Needs



The two primary factors driving the overloads on the 500-230 kV transformers and the Trafalgar to Richview 230 kV lines are load growth in the GTA and changes in generation patterns across Ontario. While all growth within the GTA has some impact on the bulk system, growth within West GTA (the municipalities of Mississauga, Oakville, Milton, Halton Hills, Brampton and Caledon) has the greatest contribution due to proximity to the affected bulk facilities.

Specific contributors to changes in provincial generation patterns, particularly those driving bulk system needs in West GTA, include the completion of refurbishment of nuclear units at Bruce GS, significant uptake of renewable generation in southwestern Ontario, the planned retirement of nuclear generation at Pickering GS and the scheduled refurbishment of nuclear generation at Darlington GS. These changes are expected to result in increased inter-regional power flows into the GTA from the west towards the east through transmission facilities in West GTA. These higher inter-regional power flows contribute to overloads of the 500-230 kV transformers at Trafalgar TS and the Trafalgar-to-Richview 230 kV lines.

Based on the early results of the bulk system study, upgrades to the bulk transmission system in the area may be needed by 2020. These may include installing new autotransformers at Milton SS and new transmission infrastructure along existing transmission corridors. Because solutions to these bulk system needs are also capable of addressing several needs identified in this IRRP, in particular those associated with restoration capability, the scope of the bulk system study will include consideration for these local restoration needs. More details on the restoration needs within the Northwest GTA IRRP are available in Section 6.2. The Scoping Assessment for Southwest GTA is located on the IESO Regional Planning webpage.[5]

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[5] http://www.powerauthority.on.ca/power-planning/regional-planning/gta-west/southern-sub-region

5. Load Forecast

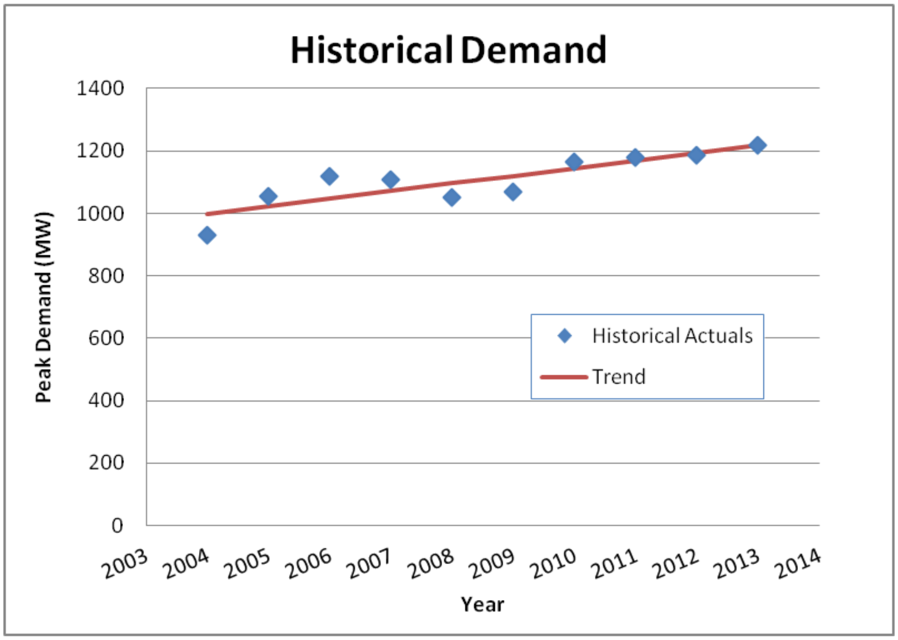
This section outlines the forecast of electricity demand within the Northwest GTA sub-region. It highlights the assumptions made for peak-demand load forecasts, the contribution of conservation to reducing peak demand and the role of distributed generation resources in supplying demand in this area. The resulting net demand forecast is used in assessing the electricity needs of the area over the planning horizon.

To evaluate the adequacy of the electric system, the regional planning process involves measuring the demand observed at each station for the hour of the year when overall demand in the study area is at a maximum. This is called "coincident peak demand" and represents the moment when assets are most stressed and resources most constrained. This is different from a non-coincident peak, which is measured by summing each station's individual peak, regardless of whether the stations' peaks occur at different times. Within Northwest GTA, the peak loading hour for each year typically occurs in mid-afternoon of the hottest weekday during summer, driven by the air conditioning loads of residential and commercial customers. This typically occurs on the same day as the overall provincial peak, but may occur at a different hour in the day.

5.1 Historical Demand

Growth within Northwest GTA has been strong over the past decade, largely driven by expanding urban boundaries and intensifying downtown cores. Within the study area, peak electrical demand has grown at an average of 2.2% over the past 10 years, representing an increase of approximately 220 MW for the study area after applying regression (see Figure 5-1, below):

Figure 5-1: 10-year Historical Peak Demand, with Trend Line



Growth has been particularly pronounced over the past five years, averaging 2.7% for the study area as a whole. Actual coincident peak demand for each LDC in the study area is shown below for the past five years, along with the resulting average percent growth:

Table 5-1: 5-year Historical Peak Demand and Average Percent Growth, by LDC (in MW)

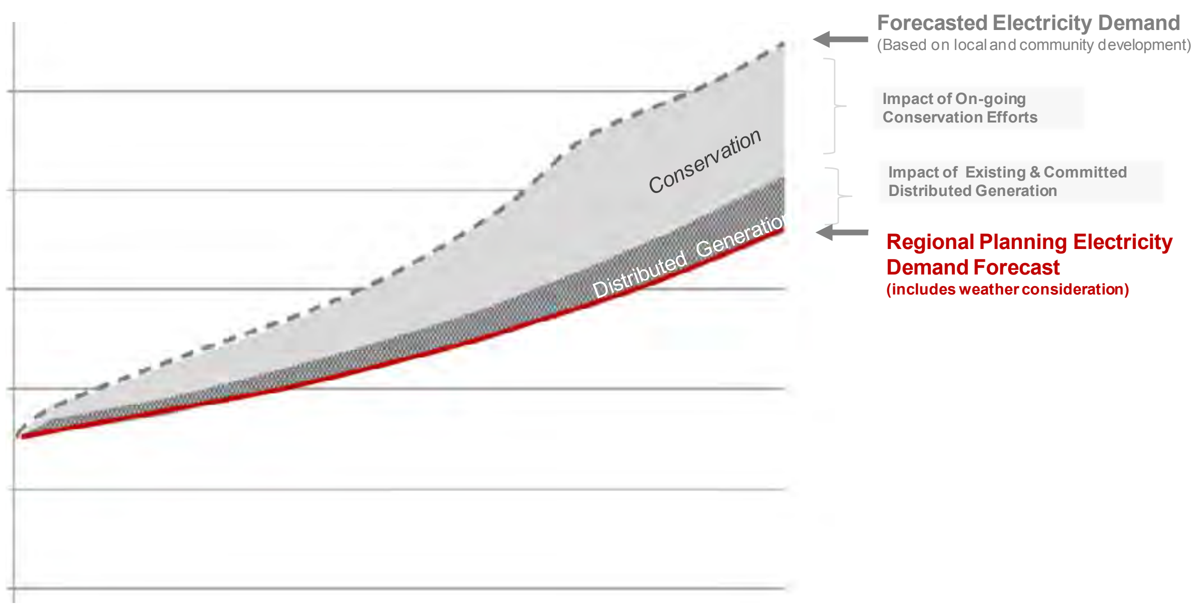
LDC	2009	2010	2011	2012	2013	Avg % Growth
Hydro One Brampton	739.35	800.67	807.70	810.65	825.55	2.32 %
Milton Hydro	130.82	143.42	156.18	156.93	168.28	6.05 %
Halton Hills Hydro	85.67	93.67	92.69	92.83	97.09	2.41 %
Hydro One Distribution (Caledon)	114.39	128.42	123.28	125.45	126.44	1.73 %
TOTAL	1070.24	1166.17	1179.85	1185.86	1217.36	2.74 %

5.2 Demand Forecast Methodology

Regional electricity needs are driven by the limits of the infrastructure supplying an area, which is sized to meet peak-demand requirements. Regional planning typically focuses on growth in regional-coincident peak demand. Energy adequacy is usually not a concern of regional planning, as the region can generally draw upon energy available from the provincial electricity grid, with energy adequacy for the province being planned through a separate process.

A regional peak-demand forecast, illustratively shown in Figure 5-2, was developed for the 20-year planning horizon. LDCs provided gross demand forecasts, which were modified by the IESO to reflect (1) the impact that provincial conservation targets and distributed generation programs have on peak demand and (2) extreme weather conditions. Using a planning forecast that is net of provincial conservation targets provides consistency with the province's Conservation First policy by reducing demand requirements before assessing any growth-related needs.[6]

Figure 5-2: Development of Expected Growth Scenario



To account for the uncertainty associated with applying conservation assumptions based on long-term energy targets, two net demand forecast scenarios were developed to reflect a range of possible outcomes:

- An "Expected Growth" scenario was developed to reflect the full allocation of energy savings from targeted conservation, with assumptions made for the translation of

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[6] This assumes that the conservation targets will be met and that the targets, which are energy-based, will produce estimated local peak demand impacts. Monitoring the actual peak demand impacts of conservation programs delivered by LDCs will be an important aspect of plan implementation.

energy to peak-demand savings. This scenario was the default forecast primarily used to identify regional needs.

- A "Higher Growth" scenario was developed assuming some combination of Higher Growth or lower projected peak-demand savings, resulting in a higher net electrical demand throughout the 20-year study period. More details on the assumptions used to develop this scenario are included in Section 5.4.

5.3 Gross Demand Forecast

Each participating LDC prepared gross demand forecasts at the transformer station level or bus level for multi-bus stations. Since LDCs have the most direct experience with customers and applicable local growth expectations, their information is considered the most accurate for regional planning purposes. Most LDCs had cited alignment with municipal and regional Official Plans as a primary source for input data. Other common considerations included known connection applications and typical electrical demand intensity for similar customer types.

The gross demand forecasts provided by the LDCs are provided in Appendix A.

5.4 Conservation Assumed in the Forecast

Conservation plays a key role in maximizing the utilization of existing infrastructure and maintaining reliable supply by keeping demand within equipment capability. It is achieved through a mix of program-related activities, behavioural changes by customers and mandated efficiencies from building codes and equipment standards. These approaches complement each other to maximize results. The conservation savings forecast for West GTA are applied to the gross peak-demand forecast, along with distributed generation resources, to determine the net peak demand for the region.

In December 2013 the Ministry of Energy released a revised Long-Term Energy Plan that outlined a provincial conservation target of 30 terawatt-hours of energy savings by 2032. To represent the effect of these targets within regional planning, the IESO developed an annual forecast for peak-demand savings resulting from the provincial energy savings target, which was then expressed as a percentage of demand in each year. These percentages were applied to the LDCs' demand forecasts to develop an estimate of the peak-demand impacts from the provincial targets in Northwest GTA. The resulting conservation assumed in the Expected Growth forecast is shown in Table 5-2. Additional conservation forecast details are provided in Appendix A.

Table 5-2: Peak MW Offset Due to Conservation Targets from 2013 LTEP, Select Years

	2013	2015	2017	2019	2021	2023	2025	2027	2029	2031
Total	0.9 %	2.2 %	3.1 %	5.0 %	6.8 %	8.0 %	9.5 %	10.9 %	12.3 %	13.7 %
MW assumed	11.0	29.8	42.7	72.8	104.4	127.7	158.0	189.1	218.8	249.6

It is assumed existing demand response ("DR") already in the base year will continue. Assumptions related to potential DR projects that do not yet have a contract will be handled when considering solutions to needs and not during development of the load forecast.

For the Higher Growth forecast, half of the peak-demand reduction shown in Table 5-2 was accounted for in the forecast. Applying this uncertainty was done for several reasons:

- Conservation targets used to develop this forecast were based on the 2013 LTEP and were only developed for annual energy consumption. Converting annual energy savings into summer peak-demand savings requires several assumptions regarding load profiles, customer type and end-use of future conservation measures and activities. These additional assumptions all carry associated uncertainties, especially over a 20-year planning horizon.
- Historical achievement of peak-demand conservation targets has varied greatly across different years and programs. The OPA's 2013 Annual Conservation and Demand Management Report, submitted to the OEB in October 2014, showed that while energy targets have been largely successful, only 48% of the 2014 peak-demand target was achieved by the end of 2013. In a follow-up letter to LDCs sent December 17, 2014, the OEB noted that "A large majority of distributors cautioned the Board that they do not expect to meet their peak demand targets," and that, "the Board will not take any compliance action related to distributors who do not meet their peak demand targets."
- Similar higher net growth sensitivity scenarios have been developed for other planning initiatives to manage risk of insufficient power system capacity due to higher underlying growth or lower peak-demand effect of conservation initiatives. This is a practice that has been used successfully within other regional plans and has been used as evidence at rate hearings and other regulatory submissions.

5.5 Distributed Generation Assumed in the Forecast

The effect of existing distributed generation is assumed to be represented in the historical data points used by LDCs to develop their gross demand forecasts. The IESO accounted for future DG projects in cases where a contract was signed, but the project had not yet reached commercial operation as of the peak-demand date used by LDCs to build their forecasts.[7] The in-service date for future DG projects is based on the milestone date for commercial operation listed on the contract.

The IESO applied capacity factors for solar and wind technologies based on the data used in the most recent Methodology to Perform Long Term Assessment. All other generation types are assumed to be fully operational at peak. Based on the May 2013 Long Term Assessment,[8] wind and solar peak capacity factors were assumed at:

- Wind: 13.6%
- Solar: 34.0%

The resulting effective capacity of all new DGs was subtracted from the forecast load at the connecting station, as shown below:

Table 5-3: DG Capacity Assumed by Station

Station	Effective kW
BRAMALEA TS	1,538
GOREWAY TS	2,231
HALTON TS	510
JIM YARROW MTS	697
KLEINBURG TS	420
PLEASANT TS	1,705
TRAFALGAR TS	85
WOODBRIDGE TS	216

5.6 Planning Forecasts

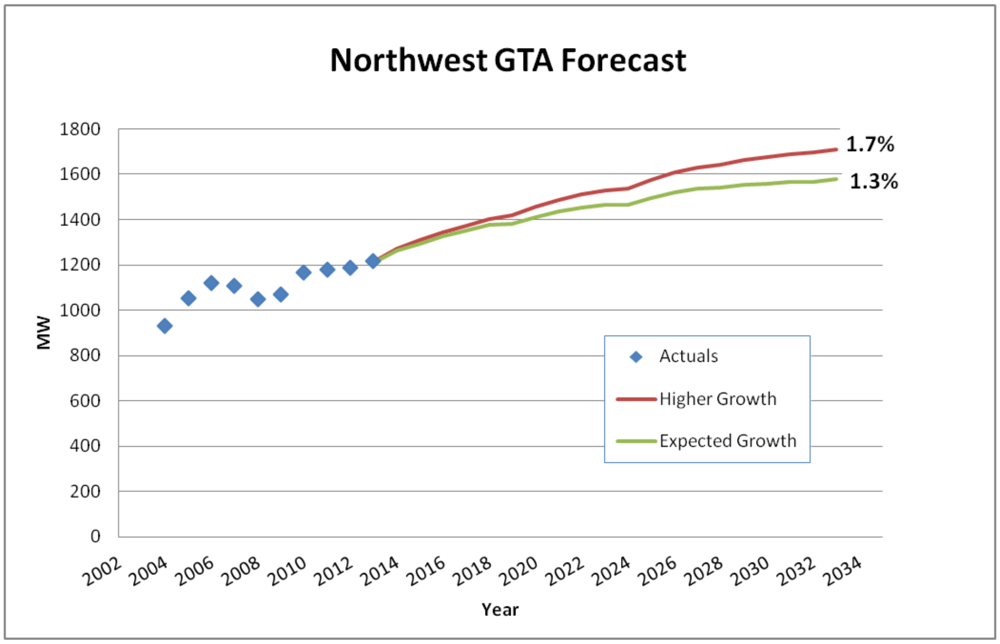
As described above, the IESO developed two planning forecasts:

- an Expected Growth forecast that considered the combined expected impact of conservation and distributed generation by station across the study area
- a Higher Growth forecast that was developed assuming half the peak conservation impact used in the Expected Growth forecast.

[7] For example, if the summer peak of July 17, 2012, was used to build the Gross Forecast and a FIT contract had come into service in September 2012, the contribution of this project would need to be accounted for in the net forecast.
[8] http://www.ieso.ca/imoweb/pubs/marketReports/Methodology_RTAA_2013may.pdf.

The final forecasts were adjusted to account for typical LDC station loading and operational practices. Figure 5-3 shows both planning forecasts, along with historic demand in the area. Annual load by station is provided in Appendix A.

Figure 5-3: Historical Demand and Expected and Higher Growth Forecasts



Under the Expect Growth forecast, growth averages 1.68% per year in the near and medium term, but drops to 0.82% per year for the second decade. For the Higher Growth forecast, growth averages 2.06% per year for the first decade and drops to an average of 1.18% per year for the long term. Over the 20-year planning period, the Expected and Higher Growth forecasts average 1.3% and 1.7% per year, respectively.

6. Needs

Based on the demand forecasts, system capability and application of provincial planning criteria, the Northwest GTA Working Group identified electricity needs in the near-to-medium term and in the long term. This section describes these identified needs, grouped into three major categories: step-down capacity, supply security, and restoration and transmission line capacity. Each section begins with a brief description of the category, including how needs are identified, followed by details on each identified need.

6.1 Step-down Capacity Needs

Step-down transformer stations convert high voltage electricity from the transmission system into lower-voltage electricity for delivery through the distribution system to end-use customers. Several factors limit the amount of electricity that can be supplied to customers, including a step-down transformer's rating, the number of available distribution feeders and their capacity. These needs are identified by comparing the net station forecast to the ratings of the station's facilities (i.e., transformers and feeders). Where multiple LDCs or customers share electrical capacity at the same station, the amount of effective feeder capacity remaining for each is considered, as this may be a limiting factor. For this reason, if only a limited amount of capacity remains for a transformer, two LDCs may hit their supply limit at different times based on the amount of capacity remaining on their respective feeders.

The table below shows the anticipated years when load at several NW GTA stations is expected to reach installed capacity, based on the Expected Growth forecast and under the Higher Growth forecast.

Table 6-1: Step-down Capacity Need Dates, by Station and LDC

Station	LDC	Expected Growth	Higher growth
Halton 27.6 TS	Halton Hills Hydro	2018	2018
	Milton Hydro	2020	2019
Pleasant 44 kV TS	Hydro One Brampton, Halton Hills Hydro, Hydro One Distribution	2033	2026
Kleinburg 44 kV TS	Hydro One Distribution, Powerstream	--	2033

When a step-down station's capacity is reached, options for offloading the limiting station or asset include reducing net growth in the supply area (e.g., through enhanced conservation and/or DG measures), transferring loads through the distribution system to nearby stations with surplus capacity, or building a new step-down supply station to serve incremental growth. Typically, measures to reduce or transfer net demand growth are not able to defer the need for a new station indefinitely, so the cost of these measures must be compared to the value of deferring construction of a new station. These assessments are done by comparing the cost per megawatt of the added capacity provided by the various options.

Additional information on capacity-related needs for the identified stations is provided in the sections below.

6.1.1 Halton 27.6 kV TS

Halton TS is a 207 megavolt ampere ("MVA") capacity 27.6 kV station, with 12 feeders each capable of supplying about 15.5 MW to nearby loads (effective station capacity is therefore approximately 186 MW, based on LDC feeder loading practices). Three feeders are allocated to Halton Hills Hydro and nine to Milton Hydro. The highest peak experienced on this station within the past five years was 166 MW (in 2011), an increase of over 30 MW since 2006. Most recent peaks, namely 2013, were slightly lower as a result of temporary load transfers made by Milton Hydro to a new transformer station (Glenorchy MTS), which is providing temporary relief in the southern part of its service territory.

Figure 6-1: Halton TS and Surrounding Service Territory

Based on current forecasts, remaining capacity on the Halton Hills Hydro supply feeders will be exhausted by 2018. The remaining capacity allocated to Milton Hydro will be exceeded in 2020:

Table 6-2: Halton TS Station Loading by LDC, Expected Demand (in MW)

LDC	Max Capability	2014	2015	2016	2017	2018	2019	2020
Halton Hills Hydro	46.5	33.9	36.9	39.6	44.9	50.0	54.6	58.2
Milton	139.5	92.1	101.0	109.1	118.8	127.8	134.8	141.8

This forecast assumes that Milton Hydro makes full use of available load transfers to nearby stations. However, long-term supply from these adjacent stations is not a preferred option, as Milton's existing and future load centres are located close to Halton TS. Transporting energy through long distribution lines is not efficient, resulting in higher losses and lowering customer reliability. Likewise, near-term Halton Hills load growth is expected close to Halton TS, immediately north of Highway 401, followed by longer-term growth in the south Georgetown area, located approximately 10 km farther north. Figure 6-1, above, shows the existing transmission system assets in the vicinity of Halton TS, the approximate location of the near-term Halton Hills growth area, Milton growth area and Highway 401.

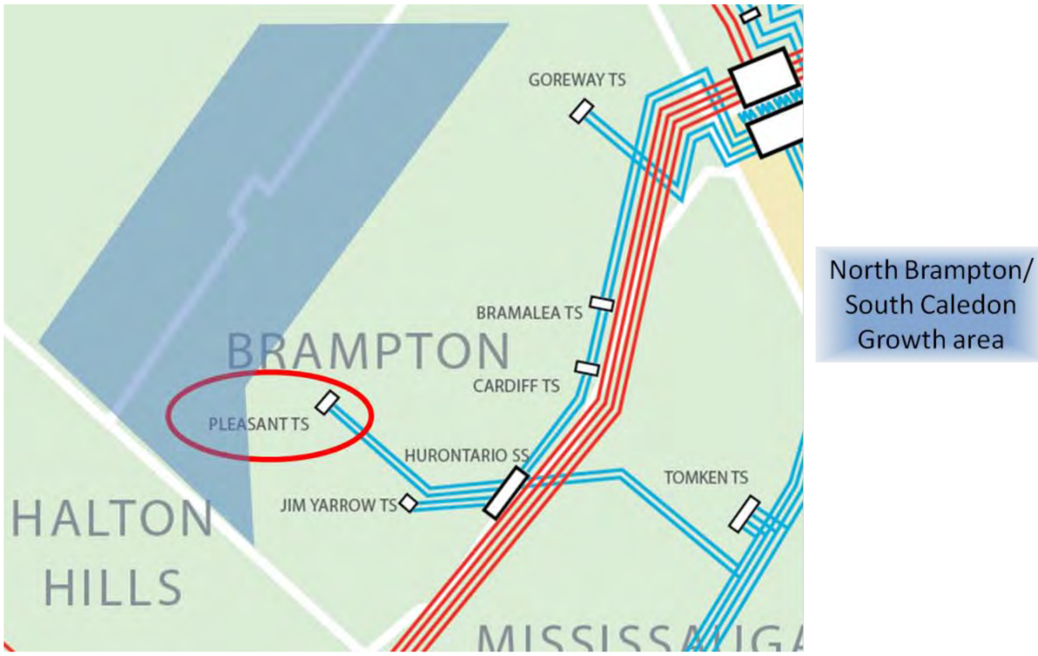
The following constraints must be accounted for when developing options for providing relief to Halton TS:

- **Lack of air rights over Highway 401.** Highway 401 bisects the Halton Hills/Milton growth pocket, with Halton TS (which currently supplies the majority of load in the area) located on the south side along with most of Milton's existing and anticipated customer load. The municipality of Halton Hills is located on the north side of Highway 401 and in the past, has received supply from Halton TS via several distribution feeders spanning over the highway. However, Halton Hills Hydro has informed the IESO that obtaining air rights for additional overhead distribution feeders represents a significant challenge. As an example, the 230 kV TransCanada transmission connection for Halton Hills Hydro GS (located close to Halton TS, but on the north side of Highway 401) was pursued as an undergrounded connection given the associated commercial challenges of spanning over Highway 401. As a result, it is assumed that future feeder crossings will be required to tunnel underneath the highway. The underground option is estimated to cost approximately $2 million per feeder.
- **Distribution voltages.** Step-down stations in the study area provide electrical supply at a voltage of either 27.6 kV or 44 kV. The selection of voltage is based on economics and technical requirements, such as how much electricity customers consume and the distance between major supply points and customer demand. Typically, 27.6 kV service is used for denser urban areas, while 44 kV service is used for rural areas and industrial zones. Almost all growth in the Milton/Halton growth pocket is expected to be served at the 27.6 kV level, which will require supply from a station capable of providing this voltage.
- **Transmission system connection availability and proximity to load centres.** Step-down transformer stations are supplied by high-voltage transmission lines and so must be directly connected to a high voltage circuit capable of providing the incremental forecast demand. To reduce reliance on long distribution lines, step-down stations are typically located close to growth centres.

6.1.2 Pleasant TS (44 kV)

Pleasant TS is a transformer station with two 230/27.6 kV step-down facilities and one 230/44 kV facility. This station is located in northern Brampton and supplies power to northwest Brampton, southwest Caledon and parts of Georgetown.

Figure 6-2: Pleasant TS and Surrounding Growth Areas



While electrical demand on the 27.6 kV system is expected to continue to grow, adequate 27.6 kV capacity is available for supplying the incremental 27.6 kV growth in the Pleasant TS service territory over the long term; however, this is not the case for the 44 kV system. Based on growth forecasts, an alternative supply may be required by 2033. The sensitivity analysis on the need date has shown it is very sensitive to small changes in net growth rates and could potentially move forward several years. For example, under the Higher Growth forecast, the need date is advanced to 2026, as shown in Table 6-3, below.

Table 6-3: Pleasant TS (44 kV) Transformer Capacity Demand in MW (by Need Dates)[9]

	Maximum Capability	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Expected Growth	148.1	138.0	139.9	141.1	141.8	142.0	142.7	143.8	144.7	145.8	148.4
Higher Growth	148.1	144.9	147.3	149.1	150.6	151.6	152.8	154.5	156.2	158.1	161.0

[9] Note that these needs are only related to the capacity of the transformers at Pleasant TS. This station is also potentially limited by the ability of transmission circuits to deliver high-voltage power, as described in Section 6.3.1, below.

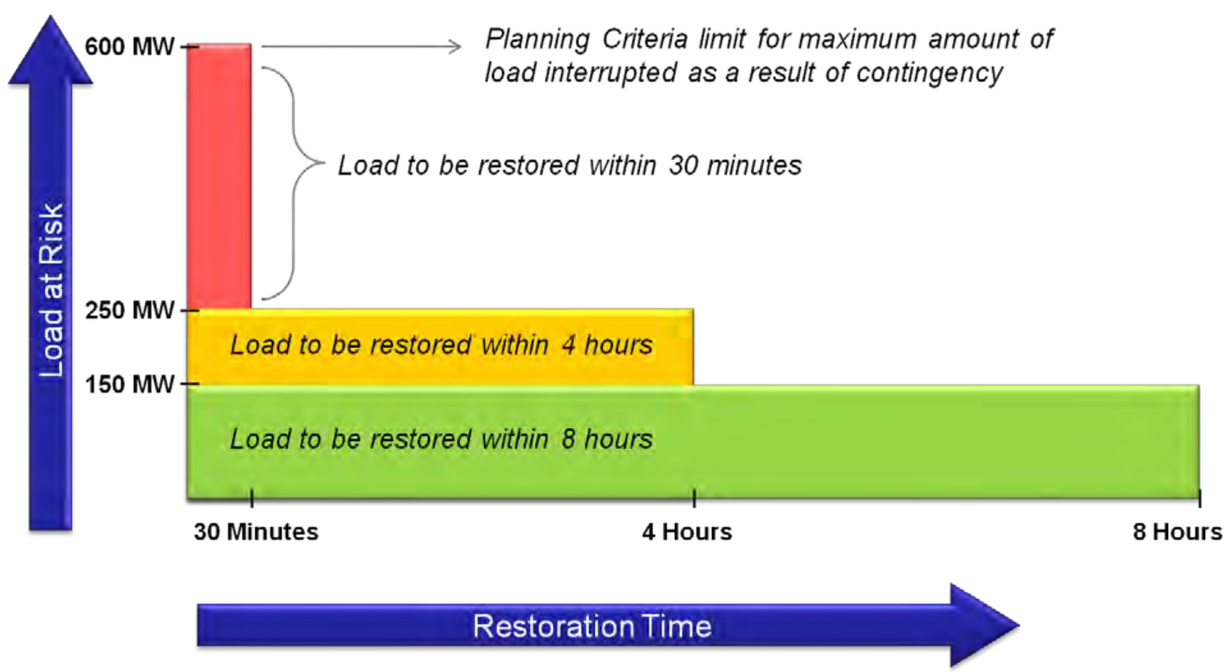
Actual loading on the 44 kV Pleasant TS will need to be reviewed during the next regional planning cycle given that the actual need date may vary from 2033. If new loads cannot be fully offset through conservation and DG initiatives, a new transmission line will be required to enable incremental capacity to be served, since there is no available transmission line capacity in the area that is able to accommodate a new step-down station.

6.2 Supply Security and Restoration Needs

Several areas within the NW GTA study area have been identified as being at risk for not meeting restoration levels as defined in the Ontario Resource and Transmission Assessment Criteria. ORTAC requires that, for the loss of two elements, any load in excess of 250 MW should be restored within 30-minutes and any load in excess of 150 MW should be restored within four hours. The assessment must also consider restoration of all loads within eight hours. These restoration levels are summarized in Figure 6-3, below.

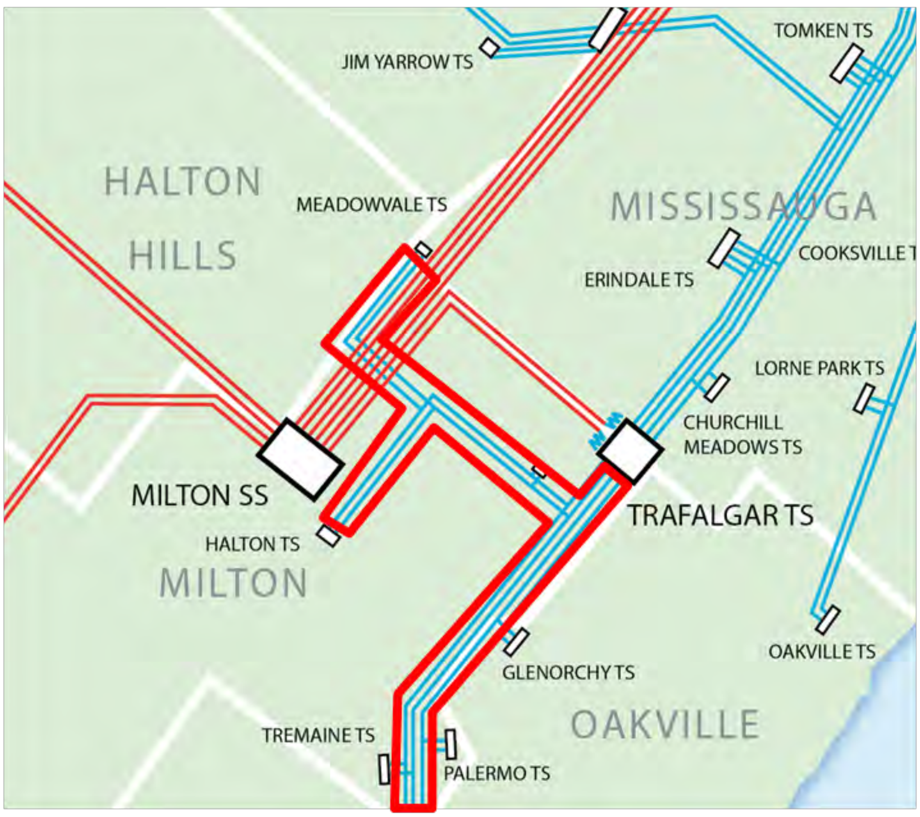
Because NW GTA is a densely populated area, it is assumed that sufficient maintenance and operations workforce are nearby to perform necessary repairs and restore loads within eight hours for expected failure modes. As a result, this analysis will only focus on 30-minute and four-hour restoration capability.

Figure 6-3: ORTAC Load Restoration Criteria



Whenever the loss of two major power system elements has the potential to interrupt over 600 MW of load, the security criteria specified in ORTAC is not met. The IESO analyzed the security and restoration capabilities of the system in the study area by taking the sum of net forecasts from stations that would lose supply following the loss of two major power system elements. In this study area, the security criteria are not expected to be met in 2026 under the Expected Growth forecast for circuits T38/39B. These circuits run from Burlington to Trafalgar TS and supply the stations of Tremaine TS, Trafalgar DESN, Meadowvale TS and Halton TS. These facilities are shown in the following figure:

Figure 6-4: T38/39B and Surrounding Area



Because the majority of these stations serve the northern section of Halton and the transmission is configured in a largely radial path (no redundancy to restore loads through transmission), this area is referred to as the “Halton Radial Pocket.” The table below shows the forecast peak load for this pocket, under the Expected Growth and Higher Growth scenarios:

Table 6-4: Halton Radial Pocket: T38/39B Station Loading (in MW)

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Expected Growth	432	444	456	472	482	486	492	507	521	574	584	598	610
Higher Growth	435	449	462	478	487	495	510	527	543	599	613	629	645

The analysis performed shows that the Halton Radial Pocket may exceed ORTAC security criteria in the medium term. Given the high initial loads in the area, the need date is only mildly sensitive to assumptions in net growth rates, as demonstrated by a small (two-year) gap between the two scenarios.

Of the remaining restoration criteria, the 30-minute/250 MW restoration point is typically the most limiting, as it largely relies on the availability of remotely controlled equipment rather than manual actions by field operations staff.

Several sections of the study area are currently at risk of being unable to meet the 30-minute restoration criteria associated with loss of two power system elements. This is due in part to the configuration of the transmission system in the area, which relies on long radial circuits to connect northern loads to the more reinforced transmission grid to the south. The areas identified as being at risk for not meeting restoration criteria are shown in blue in Figure 6-5 below, with areas potentially at risk of not meeting security criteria (e.g., Halton Radial Pocket) over the next decade highlighted in red:

Figure 6-5: Areas with Potential Restoration Needs Within the Study Area

The extent of the restoration shortfall depends on the amount of load that can be restored through emergency distribution load transfers following a contingency. LDCs provided estimates of the load-transfer capability currently available to any given step-down station following the loss of transmission supply.

Table 6-5 below shows the forecast load levels and amount of available distribution load-transfer capability within 30-minutes of the loss of station supply for the four load pockets identified as having potential restoration needs. Also included is the restoration shortfall as per the ORTAC criteria. Results are provided for the most recent summer peak and the 2023 forecast under the Expected Growth and Higher Growth assumptions:

Table 6-5: 30-minute Restoration Capability and Needs (in MW)

Load Pockets	2013			2023 Expected Growth		2023 Higher Growth	
	Actual Demand	Available 30-minute Restoration	30-Minute restoration shortfall	Forecast	30-Minute restoration shortfall	Forecast	30-Minute restoration shortfall
1. Halton Radial Pocket: T38/39B Halton TS, Meadowvale TS, Trafalgar DESN TS, Tremaine TS, Halton CGS	409	146	13	574	178	599	203
2. Pleasant Radial Pocket: H29/30 Pleasant TS	354	52	52	398	96	418	116
3. Bramalea/ Cardiff Supply: Bramalea TS, Cardiff TS, Sithe Goreway	438	140	48	447	57	466	76
4. Kleinburg Radial Pocket: V43/44 Kleinburg TS, Vaughan 3 MTS, Woodbridge TS	380	122	8	458	86	467	95

It is also acceptable under ORTAC for distributors and transmitters to agree to a lower level of reliability, where it is agreed that "satisfying the security and restoration criteria on facilities not designated as part of the bulk system is not cost justified."[10] Solutions considered to address restoration needs in NW GTA must ensure that any investment developed to rectify the need

[10] http://www.ieso.ca/imoweb/pubs/marketadmin/imo_req_0041_transmissionassessmentcriteria.pdf

can be economically justified by accounting for the relative cost and benefit from the customer's perspective. This is discussed further in Section 7.1.3.2.

6.3 Transmission Capacity Needs

Transmission capacity needs arise when the electrical demands exceeds the capability of the transmission line to deliver the electrical energy. Facility limitations can manifest as constrained energy carrying capability (often referred to as thermal limitations) or the inability to deliver electrical service at the required power quality (such as voltage levels). These types of needs are triggered by growth in net load at stations within the study area. The Northwest GTA IRRP has identified two areas with potential transmission capacity needs emerging within the next 10 years: H29/30 circuits providing supply to Pleasant TS and T38/39B circuits providing supply to Halton TS, Meadowvale TS, Trafalgar TS and Tremaine TS. These areas and needs are described in greater detail below.

6.3.1 Supply to Pleasant TS

Pleasant TS has three step-down stations located at the same facility in northwest Brampton. Two of the step-down stations output at 27.6 kV and one at 44 kV. Combined, these three stations reached an all-time peak demand of 375 MW in 2012. Although these assets have a maximum rated capacity of 515 MW, the transmission line serving this station (circuits H29/H30) is not capable of supplying this load.

Figure 6-6: H29/30 Supply to Pleasant TS

Based on the assessment carried out as part of the NW GTA IRRP, the maximum carrying capacity of the transmission line to Pleasant TS is approximately 417 MW. Since the need is dependent on the total loading of all three step-down facilities supplied by this line, the actual need date is sensitive to assumptions about the net growth rate. The table below summarizes forecast need dates under the Expected and Higher Growth scenarios:

Table 6-6: H29/30 Circuit Capacity Need Dates, Based on Net Load at Pleasant TS (in MW)

	Maximum loading	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Expected Growth	417	396	398	395	404	408	411	408	409	410	410	411	417
Higher Growth	417	414	418	418	431	439	445	446	449	452	455	458	465

Although the Expected Growth forecast shows a need date of 2033 (in red, above), growth is assumed to be offset by new conservation measures between the years 2026 and 2032, with peak demand stable between 408 MW and 410 MW (shown in orange). Given the risk that the energy-based conservation may not affect peak demand to this extent, it is recommended that solutions be pursued assuming a need date of 2026 for the Expected Growth forecast and 2023 for Higher Growth forecast. This recommended advancement is shown in Figure 6-7:

Figure 6-7: Recommended Advancement of H29/30 Supply to Pleasant TS Need Date

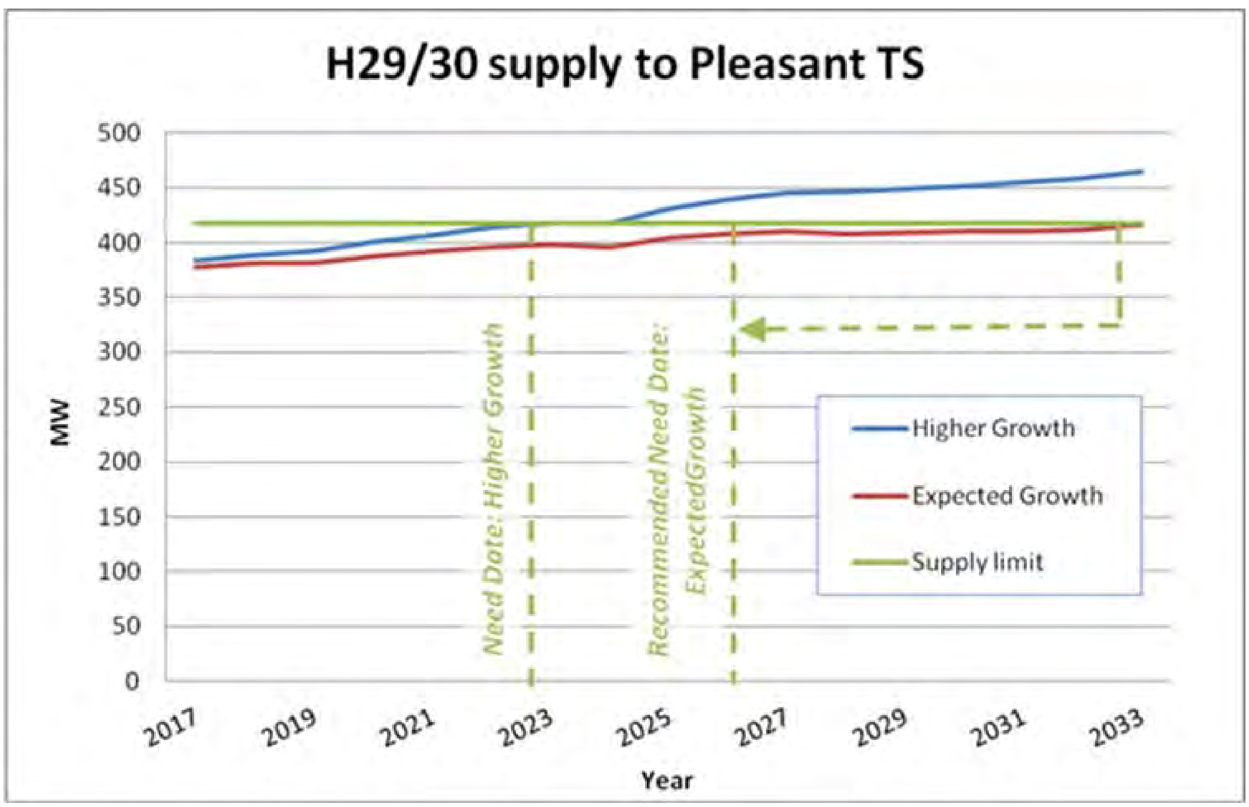


Figure 6-7 also shows that the need date under the Higher Growth forecast is less sensitive to small variations in demand, due to a stronger annual growth rate. As a result, it is not recommended that the need date be advanced under the Higher Growth forecast.

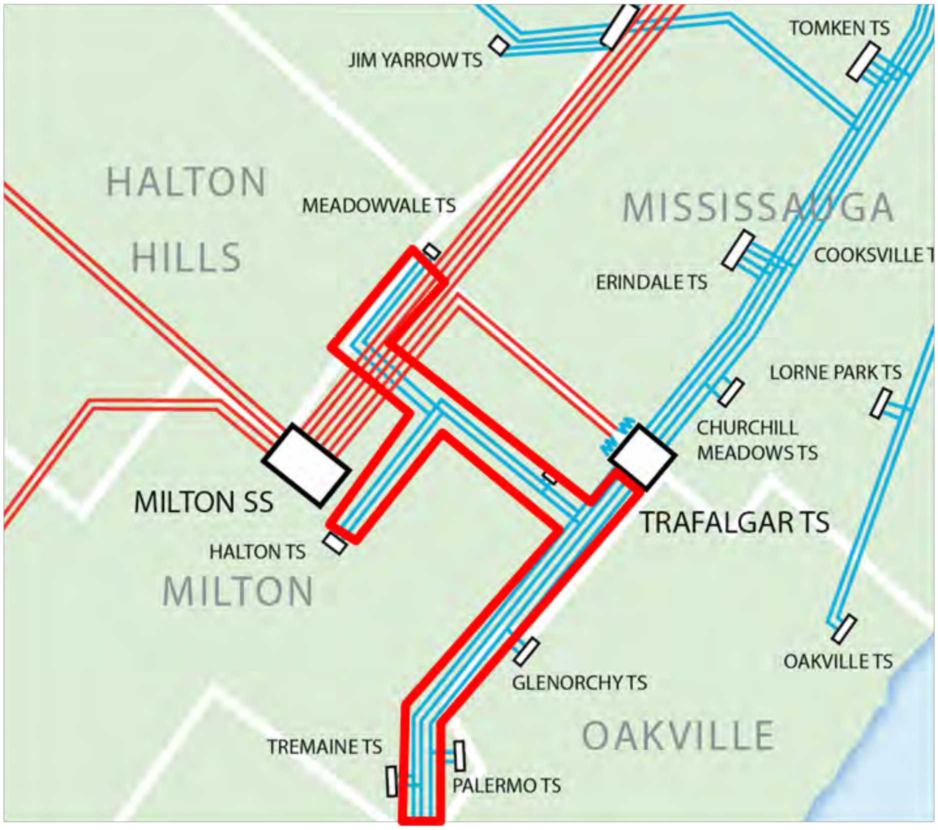
The H29/30 supply need was previously identified in 2007 through the System Impact Assessment ("SIA") for the third step-down station installed at Pleasant TS. The SIA conclusions noted that the supplying transmission lines (circuits H29/30) were expected to hit their thermal limit when the combined Pleasant TS loads hit approximately 408 MW.[11] The SIA required that a plan be put in place to mitigate this issue before load reached 408 MW. A second SIA prepared shortly thereafter for the Hurontario SS to Jim Yarrow MTS 230 kV transmission connection repeated this need, with a revised capacity for the transmission line of 412 MW.[12] Note that small variations in transmission line capability may occur between different studies, due to different assumptions used for running system models (as shown in the difference between H29/30 limits in the two SIAs and this IRRP).

6.3.2 Halton Radial Pocket

A large section of Halton region is currently supplied by two circuits, T38/39B, which span between Burlington TS and Trafalgar TS and contain a long radial section stretching north towards the Town of Milton. The peak load supplied by these two circuits was 410 MW, in 2013, representing the combined loads of Halton TS, Meadowvale TS, Trafalgar TS and Tremaine TS. Growth among these stations is forecast to continue to increase at a net rate of over 3% per year for the coming 10 years. As a result, this area is expected to exceed ORTAC security criteria in the mid-2020s, once total load is above 600 MW (see Section 6.2, above). In addition, there is also a risk of exceeding line capacity (thermal constraints) beginning in the early-to-mid 2020s.

[11] http://www.ieso.ca/Documents/caa/caa_SIAReportFinalDraft_2006-231_R2.pdf.
[12] http://www.ieso.ca/Documents/caa/caa_SIAReportFinalDraft_2006-248_R2.pdf

Figure 6-8: T38/39B Halton Radial Pocket



Following the loss of either T38B or T39B, the companion circuit must be able to supply all the electrical demand of the connected stations. While the capacity to transmit power varies at different sections of the circuit (typical for long and branching circuits), load flows show that potential needs are observed when Halton Hills GS is out of service and the total radial pocket load exceeds approximately 528 MW. Table 6-7 shows the total net forecast demand of all stations supplied by the T38/39B circuits, with potential needs highlighted:

Table 6-7: T38/39B Circuit Loading (in MW)

	2014	2015	2016	2017	2018	2019	2020	2021	2022
Expected Growth	432	444	456	472	482	486	492	507	521
Higher Growth	435	449	462	478	487	495	510	527	543

Overloading on the companion T38/39B circuit can be avoided by running Halton Hills GS, a 620 MW gas-fired power plant, during hours when the total area load exceeds 528 MW. This generation facility is located in southern Halton Hills and, in electrical terms, is at the furthest end of the T38/39B radial pocket. This means that any power output by Halton Hills GS reduces the amount of power transmitted into the area. T38/39B's potential overloading is one of the reasons Halton Hills GS was constructed in this area in 2010.

Due to the presence of local generation, the risk of exceeding the line capacity on T38/39B only occurs when there is a single circuit contingency and Halton Hills GS is unavailable. If either T38B or T39B and local generation are out of service, up to 150 MW of load shedding is permitted to prevent system overloads. ORTAC criteria allow this practice, given the low probability of occurrence. Applying this control action would eliminate the risk of system overloads for the duration of the study period under the Expected Growth forecast and until 2029 under the Higher Growth forecast. To ensure that any load interruptions have a minimal impact on customers, Special Protection Schemes can be designed in advance to ensure that critical loads are not impacted.

6.4 Needs Summary

The NW GTA is a rapidly growing area with an electrical system characterized by heavily loaded radial supply circuits. Within the near-to-medium term, growth is expected to continue northward into greenfield areas, further stressing a radial transmission system that is concentrated to the south. Both step-down stations and the supplying lines are expected to exceed their rated limits within the next decade and will require relief. Additionally, several restoration needs have been identified and will continue to worsen as electrical demand increases, potentially triggering a supply security need in the mid-2020s, when electrical demand in the radial pocket is forecast to exceed 600 MW. In the longer term, significant supply capacity is expected to be needed across a wide range of north Brampton and south Caledon, where no supporting power system infrastructure currently exists.

Table 6-8: Summary of Needs

	Near Term (2014-2018)	**Medium Term (2019-2023)**	**Long Term (2024-2033)**
Step-down Station Capacity	Halton TS • Halton Hills Hydro	Halton TS • Milton Hydro	Pleasant TS Kleinburg TS (Higher Growth)
Transmission Capacity	--	Supply to Pleasant TS (Higher Growth)	Supply to Pleasant TS (Expected Growth)
Supply Restoration	Halton Radial Pocket Pleasant Radial Pocket Cardiff/Bramalea supply Kleinburg Radial Pocket	--	--
Supply Security	--	--	Halton Radial Pocket

7. Alternatives for Meeting Near- and Medium-Term Needs

This section describes the alternatives considered in developing the near-term plan for Northwest GTA, provides details of and rationale for the recommended plan, and outlines an implementation plan.

7.1 Alternatives Considered

In developing the near-term plan, the Working Group considered a range of integrated options. The Working Group considered technical feasibility, cost and consistency with long-term needs and options in Northwest GTA when evaluating alternatives. Solutions that maximized the use of existing infrastructure were given priority.

The following sections detail the alternatives considered and comment on their performance in the context of the criteria described above. The alternatives are grouped according to three major solution categories: (1) conservation, (2) local generation and (3) transmission and distribution.

7.1.1 Conservation

Conservation was considered as part of the planning forecast, which includes the local peak-demand effects of the provincial conservation targets (see Section 5.4). Across the planning area, the LTEP energy reduction targets account for approximately 130 MW, or 33% of the forecast demand growth during the first 10 years of the study. Achieving the estimated peak-demand reductions of the provincial conservation targets defers several needs, including transmission line supply to Pleasant TS and Pleasant TS transformer capacity (more details provided below). Given the power system and customer benefits, conservation efforts should focus first on encouraging energy-saving measures that also offset peak demand. Maximizing savings in locations where there is potential to defer longer-term solutions should be a secondary consideration.

Although current LDC conservation targets are based on energy savings, peak-demand savings are required to defer the need for new infrastructure, especially in areas like Northwest GTA where new growth is outstripping the ability of the existing system to meet demand. As part of the Conservation First Framework 2015-2020, all Ontario LDCs are required to produce a conservation and demand management plan by May 1, 2015, outlining how they intend to meet their mandated energy savings targets within their allocated CDM budget.

Details on these plans have been provided by LDCs in Appendix D.

This IRRP will help inform the development and implementation of conservation programs by:

1. Identifying areas in the Northwest GTA where conservation will be most beneficial, and
2. Quantifying the expected benefit of achieving different levels of peak-demand reduction.

The latter is useful for determining whether the incremental cost of targeting peak-demand savings in one particular area is cost effective, given the expected societal benefit from the deferred investment.

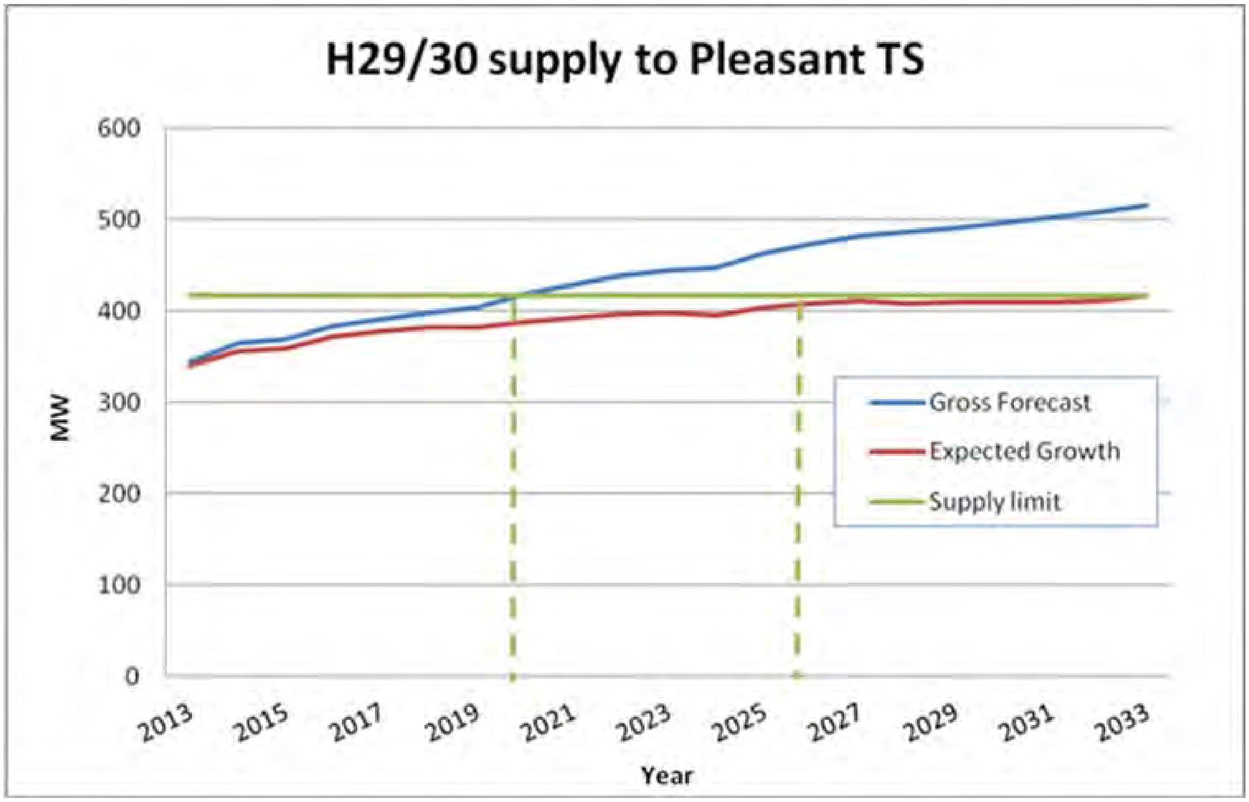
The examples below demonstrate the expected economic benefit from the achievement of the expected peak-demand savings from the LTEP energy reduction targets in two key areas in Northwest GTA: the Pleasant TS and Kleinburg TS service territories. While Pleasant TS and Kleinburg TS have been highlighted, peak-demand reductions will also benefit other parts of the study area, for example, by offsetting the need for distribution expansion. A breakdown of economic assumptions and calculations are provided in Appendix C.

Pleasant TS – Transmission line and step-down transformer needs

Pleasant TS has three step-down stations located at the same facility in northwest Brampton. As mentioned in Sections 6.1.2 and 6.3.1, there are two potential capacity needs associated with this station: (1) limits on the transmission lines that supply electricity to the station and (2) limits on the step-down transformers that convert high voltage electricity from the transmission system to lower voltages for distribution to customers. Both of these needs can be deferred several years by reducing peak demand, as the gap in need dates under the different forecasts demonstrates.

The Expected Growth forecast assumes 65 MW of peak-demand reduction within the Pleasant TS service territory by 2026, primarily from conservation measures. Achieving these reductions successfully defers the need for relief on the H29/30 circuits supplying Pleasant TS by six years, from 2020 to 2026. As described in Section 7.1.3.3, once the capacity limit on H29/30 is reached, these circuits will need to be upgraded to a higher carrying capacity, which is estimated to cost approximately $6.5 million. The expected present day economic value of deferring this investment from 2020 to 2026 is approximately $1.45 million.

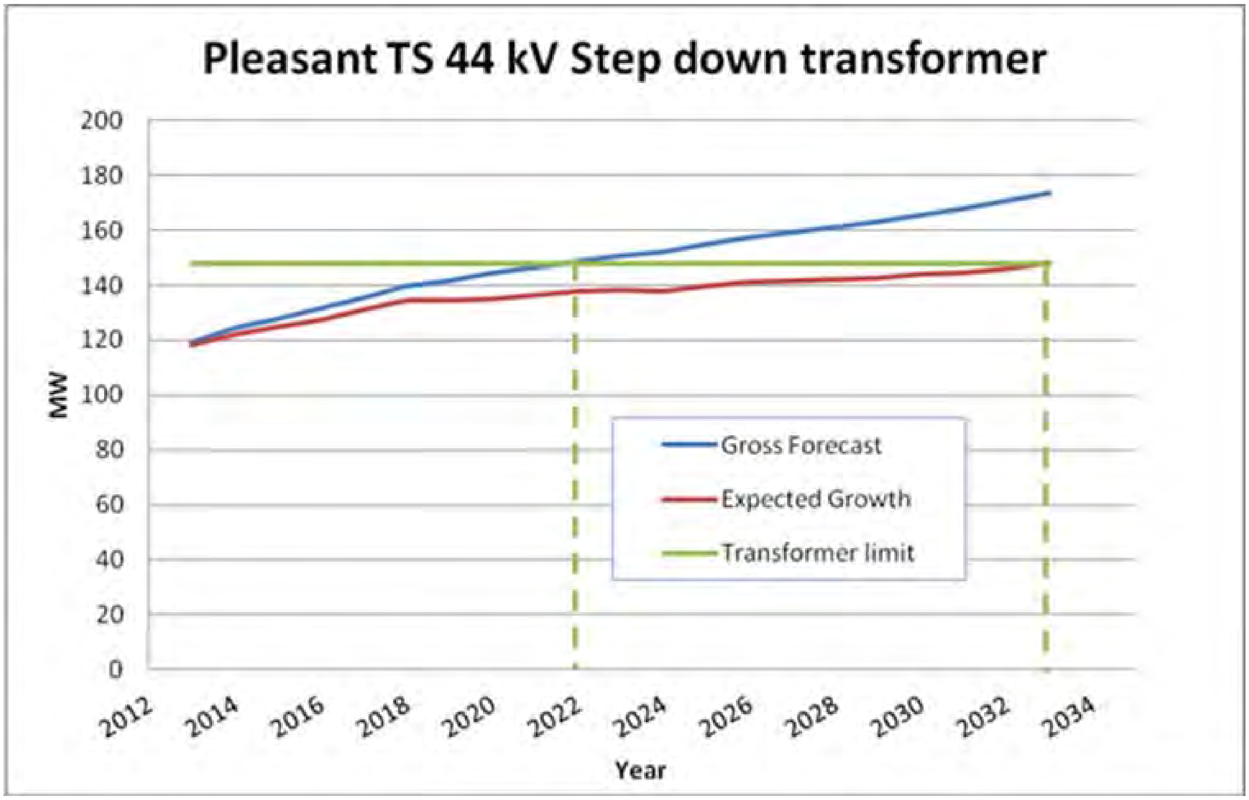
Figure 7-1: Effect of Conservation on H29/30 Needs



Of the three step-down facilities at Pleasant TS, the 44 kV transformers are expected to reach their maximum capacity first. While the LDCs' initial gross extreme weather forecast (the "Gross Forecast") originally anticipated a need date of 2022, the 25 MW of peak-demand reduction applied by the IESO in developing the Expected Growth forecast successfully defers the need for relief by 11 years. Assuming that the H29/30 needs are resolved through other means, such as upgrading the transformers, the expected present day economic value (based strictly on transmission infrastructure deferment) of the peak-demand effects of achieving provincial energy targets is approximately $11.60 million.

Note that this estimate is based only on deferring a $30 million step-down station and does not consider other system upgrades that may be required to ensure the new step-down station has adequate transmission supply. Thus, the actual benefit of deferring is expected to be higher, as new transmission facilities would be required to enable the connection and operation of this step-down station. Long-term supply options are described in greater detail in Section 8.1.1.

Figure 7-2: Effect of Conservation on Pleasant TS 44 kV Transformer Needs

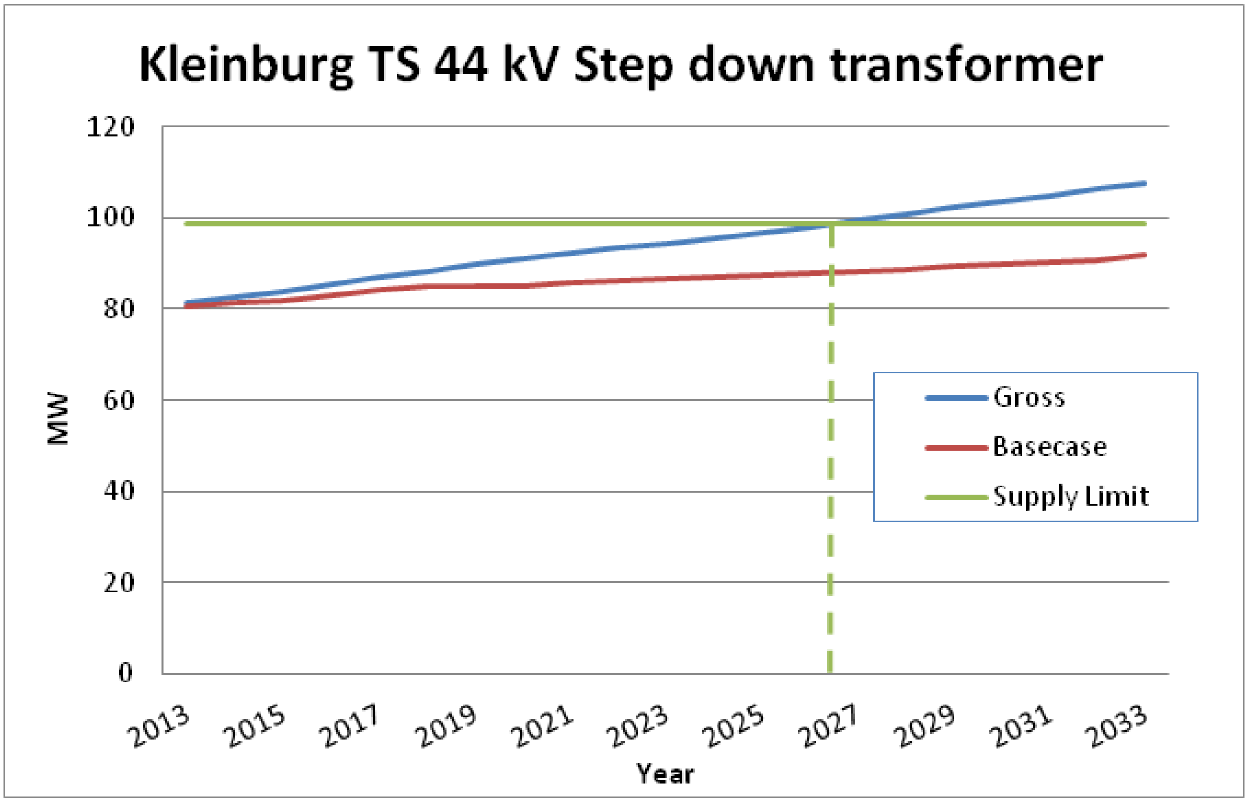


Kleinburg TS – Step-down transformer needs

Kleinburg TS has two step-down stations located at the same facility in northwest Vaughan, close to the boundary with Caledon. The station has a total load serving capacity of approximately 195 MW, shared between 27.6 kV and 44 kV loads. Demand on the station currently peaks at around 130 MW, or about 67% capacity. Load from Kleinburg TS primarily serves Hydro One Distribution customers, particularly in southern Caledon and the town of Bolton, which is expected to drive most new growth over the study period.

Based on the Gross Forecasts provided by LDCs, the 44 kV facilities at Kleinburg TS may hit their limit as early as 2027. In order to defer station overload needs beyond the current planning horizon, 10 MW of peak-demand reduction measures are required. The Expected Growth forecast developed in this IRRP already assumes that conservation programs will provide 15 MW of peak-demand reduction. The expected economic value of the peak-demand effects of achieving provincial energy targets estimated in the Kleinburg 44 kV service territory is approximately $6.53 million, assuming that achieving these targets successfully defers the need for a new $30 million step-down station from 2027 to 2034.

Figure 7-3: Effect of Conservation on Kleinburg TS 44 kV Transformer Needs



Although the Expected Growth forecast does not anticipate that Kleinburg TS (44 kV and 27.6 kV transformers) will reach their capacity limit before the end of the study period, relatively small changes in development levels could have a large effect on this facility's need date, due to the large greenfield areas within the Kleinburg TS service territory and a lack of alternate step-down stations to serve growth. As a result, actual loading on both step-down stations at this facility should be reviewed during the next regional planning cycle and needs revisited as required.

7.1.2 Local Generation

Large, transmission-connected generation and small-scale distribution-connected DG options were ruled out as viable alternatives for meeting near- and medium-term needs in Northwest GTA.

The most pressing near-term needs are associated with low voltage feeder capacity and step-down transformer capacity for Halton Hills Hydro and Milton Hydro (Halton TS). A transmission-connected generation project would not address this need given that the problem is at the distribution voltage level. Distribution-connected DG projects were determined to be technically, logistically and economically infeasible because the DG options would need to be optimally dispersed across a number distribution feeders such that existing feeder capacity is freed up to enable carrying forecast growth in electrical demand across the service territory. Developing and implementing such a complex solution within the time period of the need in this high-growth area was not determined to be practical.

A second set of identified needs for this sub-region are associated with restoration capability in four transmission/restoration pockets, as discussed in Section 6.2. Addressing restoration needs through large transmission-connected generation would require the implementation of a generation facility within Halton radial pocket, Pleasant TS, Cardiff/Bramalea and Kleinburg radial pocket. This solution was determined to be impractical from a technical and economic perspective, given the scale and number of facilities that would therefore be required within the region.

Transmission line capacity to Pleasant TS was also identified as a need in the 2023-2026 time period. Addressing this need through large-scale transmission-connected generation would require the implementation of a major facility in close proximity to Pleasant TS, which is located within a highly developed area of central Brampton. As discussed in Section 7.1.3.3, this need can best be met by upgrading an existing transmission line, with minimal cost and community impact. Since the large scale generation option would cost substantially more than the line upgrade option and result in significantly higher community impact, this option was not considered further.

In addition, because local generation would contribute to the overall generation capacity for the province, the generation capacity situation at the provincial level must be considered. Currently, the province has a surplus of generation capacity, and no new capacity is forecast to be needed until the end of the decade at the earliest. This was an additional consideration in ruling out local generation for meeting the near-term needs.

Small-scale, distributed generation was also rejected as a viable alternative for meeting the transmission line capacity need at Pleasant TS. Existing DG projects have already been accounted for in the forecast and contracted DG projects that are not yet in service have been assumed in the forecast based on their contracted in-service date. These future DG projects were applied by netting their expected contribution at peak load times, in a similar manner as conservation. Meeting the need for transmission line capacity to Pleasant TS through DG was rejected due to the availability of a low-cost, low community impact transmission solution (upgrading an existing line) as discussed in Section 7.1.3.3. This upgrade would be more economic and easier to implement than the option of small scale, DG.

Potential for meeting long-term needs, such as step-down transformer capacity needs at Pleasant TS or Kleinburg TS, will be reviewed as part of regular regional planning cycles closer to these facilities' expected need dates, while actual uptake will be monitored on a yearly basis.

7.1.3 Transmission and Distribution

A number of transmission and distribution, or "wires," alternatives were considered by the Working Group to meet the near-term needs. Wires infrastructure solutions can refer to new or upgraded transmission or distribution system assets, including lines, stations, or related equipment. These solutions are often characterized by high upfront capital costs, but have high reliability over the lifetime of the asset.

7.1.3.1 Halton TS Capacity Relief (Step-down Transformers and LDC Feeders)

There is a near-term need for additional step-down capacity to relieve overloading at Halton TS. Due to the near-term need, a separate product was prepared by the IESO and relevant LDCs concurrent to the IRRP process, to ensure a preferred solution could be identified, discussed and ultimately recommended with as short a lead time as possible. This paper, entitled "Transmission and Distribution Options and Relative Costs for Meeting Near-Term Forecast Electrical Demand within the NW GTA Study Area", is attached in Appendix E and considered three alternatives for meeting this need:

1. Distribution load transfers
2. Single step-down station (with enhanced distribution connections)
3. Two new step-down stations.

The two station solution, further described below, was ultimately recommended as the least costly of the feasible alternatives.

Distribution load Transfers

As an alternative to building new step-down stations to supply growing load in the vicinity of Halton TS, a number of neighbouring stations were considered for their ability to supply local demand through extensions of the low voltage (distribution) feeder network (See Figure 7-4). These options were rejected for the following reasons:

- **Palermo TS**: No remaining capacity is available at this station and as a result this station cannot be considered for providing load-transfer capability.
- **Glenorchy MTS**: This station is located too far south from the anticipated growth centers in Milton (approximately 9 km) to make this a preferable long-term supply option. However, this station can provide valuable flexibility in meeting near-term electrical demand. To minimize costs in the area, Oakville Hydro (the owner and operator of this station) has entered into a short-term leasing agreement with Milton Hydro, allowing Milton Hydro to use up to 40 MW of capacity until the year 2023, after which time Oakville Hydro anticipates requiring this capacity to meet their own growth. The 40 MW of Milton load currently being supplied by Glenorchy MTS will then require a suitable step-down station to provide this supply.
- **Trafalgar TS** (step-down facilities): Although approximately 30 MW of capacity remains at this station, it is approximately 12 km removed from Milton Hydro's growth centre and, as a result, is too far removed to be considered a suitable candidate. However, this station should be considered for meeting any long-term Milton Hydro load growth that may occur in the (currently largely rural) south eastern section of the municipality.
- **Tremaine TS**: This station is too far away to meet anticipated near-term growth in central Milton Hydro territory (the station is approximately 15 km from the growth centre) and, as a result, is not suitable for providing load-transfer capability to relieve Halton TS. Instead, Milton Hydro has been allocated two feeders (approximately 35 MW), which will be used to supply south Milton loads, primarily belonging to lower density and slower-growing customer pockets.
- **Jim Yarrow MTS**: This station is approaching its maximum capacity and is expected to be fully loaded by 2020. As a result, it was not considered a suitable station for transferring Halton TS area loads. Additionally, Jim Yarrow MTS is located too far from anticipated Milton and Halton Hills load centres to provide reliable service at the 27.6 kV level.
- **Pleasant TS**: Any load transfers to this station would advance thermal overloads anticipated on the supplying circuit in the mid-2020s. Additionally, Hydro One Brampton has indicated that new feeder egress is extremely limited and space for accommodating all anticipated feeders to serve Hydro One Brampton has already been obtained, limiting options for supply to other LDCs. Pleasant TS is also located too far

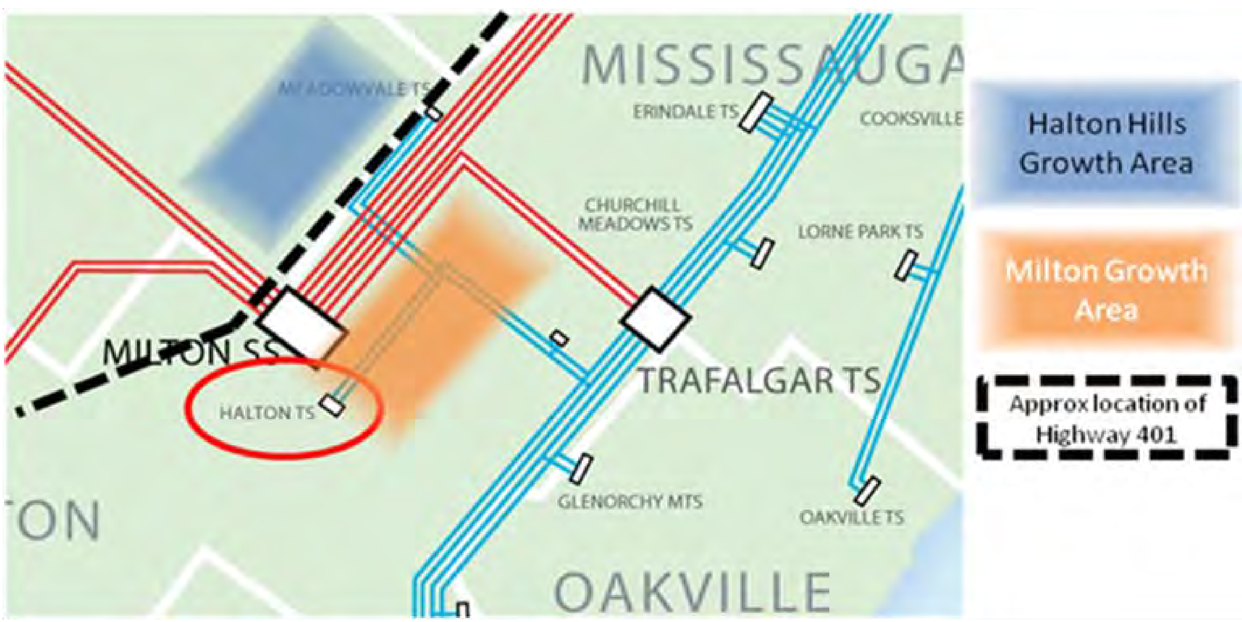
from anticipated Milton and Halton Hills load centres to provide reliable service at the 27.6 kV level. For these reasons, load transfers to Pleasant TS were not considered.
- **Meadowvale TS**: This station outputs at the 44 kV distribution level and so is not suitable for meeting growth currently supplied at the 27.6 kV level from Halton TS.

In addition to the specific reasons mentioned above, all distribution transfer options would require customers to be supplied by longer distribution connections than had they been supplied by a newer, closer station. Longer feeder connections result in poorer reliability, have the potential to trigger power quality issues and will require a greater investment in distribution infrastructure. Due to the unavailability of suitable stations, distribution load transfers were not considered as a potential solution to the Halton TS capacity need.

Single new step-down station (with enhanced distribution connections)

Under this alternative, a single step-down station is constructed on the south side of Highway 401 to meet load growth in both the Halton Hills Hydro and Milton Hydro service territories. Due to the challenges of acquiring air rights over Highway 401, it is assumed that the feeders for serving Halton Hills Hydro customers must be tunneled under the highway at a cost of $2 million per feeder.

Figure 7-4: Halton TS and Nearby Elements



Over the next 20 years, expected load growth in the Halton Hills territory will require the tunneling of eight distribution feeders. Additionally, under the Higher Growth forecast, a single step-down station will not provide sufficient capacity to meet expected long-term load growth in Milton and Halton Hills, so a second station would be required in 2028. As a result, the single station alternative performs poorer under high growth conditions than the two station alternative, as the latter allows the stations to be optimally sited for meeting growth and avoids the need for costly distribution investments.

This alternative also performs poorer than the two station alternative from the perspective of land use, as there would be a greater reliance on distribution infrastructure, especially through the eastern portions of Milton. Using more distribution lines can also contribute to lower customer reliability, as they are more prone to outages than equivalent transmission assets.

Two new step-down stations

This alternative consists of building two new step-down stations: one to provide long-term supply for Halton Hills Hydro loads and a second for Milton Hydro. The Halton Hills Hydro station is required in 2018 and would be located on the north side of Highway 401, while the Milton station, required in 2020, would be located on the south side. This solution eliminates the need to run distribution feeders across Highway 401, which would otherwise present a major technical and financial barrier to integrating a single new station. A suitable location has been found in existing electrical infrastructure facilities for both proposed stations: a new station north of Highway 401 located on the grounds of the TransCanada Halton Hills Gas Generation facility and a new station on the south side located within the existing Milton SS and Halton TS grounds.

After carrying out a net present value cost comparison (summarized in Table 7-1, below), the two station option proved more economic than the single station alternative and was adopted as the recommended outcome for meeting this need. A full list of economic assumptions and methodology is available in Appendix E.

Table 7-1: Cost of Providing Halton TS Capacity Relief, Alternative and Load Growth Scenarios

Alternative	Cost of Alternative, in $M 2014 (Expected Growth)	Cost of Alternative, in $M 2014 (Higher Growth)
Distribution load transfers	Not technically feasible	Not technically feasible
One new step-down station (Halton TS #2, and Halton TS #3 required under Higher Growth forecast)	$51.6	$67.9
Two new step-down stations (Halton Hills Hydro MTS + Halton TS #2)	$48.5	$49.9

Under the Expected Growth forecast, the cost of a second step-down station is also slightly less when considering the cost of additional feeders, including tunneling, required to supply Halton Hills Hydro loads from a single station located south of Highway 401. As a result, the two station alternative is slightly more economic. Under the Higher Growth forecast, a second station is required regardless, meaning the initial two station solution is much more economic since it eliminates the need for distribution expansion.

7.1.3.2 Restoration needs

As described in Section 6.2, four areas in the Northwest GTA sub-region are at risk for not meeting restoration criteria following the loss of two transmission elements. These are:

1. Halton radial pocket
2. Pleasant radial pocket
3. Bramalea/Cardiff supply
4. Kleinburg radial pocket

Figure 7-5: Areas with Potential Restoration Needs Within the Study Area

Possible infrastructure solutions were investigated and their conclusions discussed below.

Bulk transmission study underway

As described in Section 4.3, a bulk system study is underway for West GTA to address overload issues on the 500 kV and some 230 kV transmission assets in the area. Since the bulk transmission study will investigate major changes to the transmission system that can impact restoration capability, the regional restoration needs for the Halton radial pocket, Bramalea/Cardiff supply and the Kleinburg radial pocket will be factored into the bulk system analysis. If these restoration needs are not adequately addressed through the bulk transmission study, they will be revisited as part of the regional planning process.

Restoration needs for Pleasant TS are not being considered as part of the bulk study, as this pocket is not directly linked to any bulk system assets. The Pleasant TS restoration needs were considered separately as part of this NW GTA IRRP (see below).

Pleasant TS Restoration

Pleasant TS is served by a radial 230 kV two-circuit overhead transmission line that supplies approximately 375 MW of electrical demand during summer peak. The station itself includes three step-down transformers facilities (DESNs): one serving 44 kV distribution loads and two serving 27.6 kV loads. Growth in electricity demand in the area served by this station is expected to increase this demand to 400 MW by 2023 and 415 MW by 2033, the end of the study period. Under the Higher Growth forecast, electrical demand in these same years is forecast at 420 MW and 465 MW, respectively. Table 6-5 summarizes the ORTAC load restoration criteria and the degree to which these criteria are exceeded for the four areas with potential issues, including Pleasant TS. The Pleasant TS restoration need stems from the occurrence of a double circuit outage to the transmission line supplying the transformer station, which is a low probability event.

As mentioned in Section 6.2, the restoration criteria within ORTAC provide flexibility in cases where "satisfying the security and restoration criteria on facilities not designated as part of the bulk system is not cost justified." Since the radial supply facilities to Pleasant TS do not form part of the integrated bulk transmission system, a cost justification assessment was undertaken. Several jurisdictions within the electricity industry take guidance on cost justification for low probability/high-impact events by accounting for the cost risk (probability and consequence) of the failure event and determining if mitigating solutions can reduce the overall cost to customers. This is accomplished by:

1. Assessing the probability of the failure event occurring
2. Estimating the expected magnitude and duration of outages to customers served by the supply lines
3. Monetizing the cost of a supply interruptions to the affected customers
4. Determining the cost of mitigating solutions and their impact on supply interruptions to the affect customers.

If the customer cost impact associated with the mitigating solutions exceeds the cost of customer supply interruptions under the status quo, the mitigating solutions are not considered cost-justified.

The assessment for the Pleasant TS supply situation found that mitigating solutions were estimated to be significantly more costly to customers in the area than the status quo. This is primarily due to the low probability of the event occurring. As a result, it is not economically prudent to pursue a transmission- or distribution-based solution at this time. Details of this assessment can be found in Appendix C.

The existing long-term forecast indicates that the service area immediately to the north of Pleasant TS is expected to grow substantially over the next 20 years. As described in Section 8.1.1, supplying this long-term growth area will require the introduction of a new transmission supply line and transformer station in the 2026-2033 time period. Once this new supply point is introduced, it is expected that more economic restoration options for the low probability failure event to Pleasant TS would become available. This will be reviewed in updates to this plan.

7.1.3.3 Supply to Pleasant TS

As described in Section 6.3.1, the H29/30 circuits that supply Pleasant TS (shown below) are expected to reach their capacity limit in approximately 2026 under the Expected Growth forecast, or 2023 under the Higher Growth forecast. Conservation and distributed generation can reduce peak demand and defer this need, but a transmission-based solution is expected to be required in the medium to long term.

Figure 7-6: H29/30 Supply to Pleasant TS

Two transmission-based solutions are considered below: upgrading the existing H29/30 circuits to a higher rating and advancing the construction of a new transmission supply path into the area.

Upgrading circuits H29/30

The H29/30 circuits supplying Pleasant TS are currently rated at 1090 A,[13] which limits the maximum load-carrying capacity to approximately 417 MW. Based on a preliminary assessment performed by Hydro One, the asset owner, the existing towers are able to support a conductor large enough to carry 1400 A, or supply loads of over 500 MW. Since replacing the conductors would not require changes to the existing tower structures, the estimated preliminary cost of this upgrade is around $6.5 million.

This upgrade would fully address this need and allow the step-down transformer facilities at Pleasant TS to be loaded up to their maximum rated capacity.

Advancement of long-term transmission solution

As described in Section 8.1.1, there is a long-term need for new transmission infrastructure in northern Brampton/southern Caledon. As an alternative to upgrading circuits H29/30,

[13] Summer Long Term Emergency planning rating.

transmission investment could be made earlier to provide an alternative point of supply to serve growing loads in the current Pleasant TS service territory. Note that this option would require limiting the loading at Pleasant TS step-down facilities below their maximum ratings to avoid overloading the supplying circuits.

Based on high level planning estimates for the cost of new transmission infrastructure to supply the area north of Pleasant TS and the need dates from the Expected Growth forecast, the cost of advancing this investment to 2026 from 2033 is approximately $25 million:

Table 7-2: Cost of Advancing West GTA Transmission Corridor, Expected Growth Forecast

Investment	Capital Cost (excludes financing) ($M)	2026 in-service date (2014 $M)	2033 in-service date (2014 $M)
25 km new 2x230 kV transmission	$75	$54.3	$38.2
New step-down transformer	$30	$23.2	$16.3
Reconfigure Kleinburg, other circuit terminations	$10	$7.7	$5.4
TOTAL	**$115**	**$85.3**	**$59.9**
Advancement Cost:			**$25.4**

Under the Higher Growth forecast, this infrastructure is required in 2023 to address overloads on H29/30, a three-year advancement from the 2026 need date if H29/30 were upgraded:

Table 7-3: Cost of Advancing West GTA Transmission Corridor, Higher Growth Forecast

Investment	Capital Cost (excludes financing) ($M)	2023 in service (2014 $M)	2026 in service (2014 $M)
25 km new 2x230 kV transmission	$75	$62.7	$54.3
New step-down transformer	$30	$26.8	$23.2
Reconfigure Kleinburg, other circuit terminations	$10	$8.9	$7.7
TOTAL	**$115**	**$98.5**	**$85.3**
Advancement Cost:			**$13.2**

Based on this assessment, the cost of advancing the need date for a major new transmission corridor is two to four times more costly than upgrading the H29/30 conductors to a higher rating (estimated to be $6.5 million). Therefore, upgrading the H29/30 conductors is the recommended alternative.

Details on economic assumptions used in this analysis are available in Appendix C.

7.2 Recommended Near-Term Plan

The Working Group recommends the actions described below to meet the near-term electricity needs of NW GTA. Successful implementation of this plan will address the region's electricity needs until the early-to-mid 2020s.

7.2.1 Conservation

As achieving demand reductions associated with the conservation targets is a key element of the near-term plan, the Working Group recommends that LDCs' conservation efforts focus on peak-demand reductions. Monitoring conservation success, including measuring peak-demand savings, is an important element of the near-term plan and will lay the foundation for the long-term plan by gauging conservation measures' performance and assessing the potential for further conservation efforts.

Particular attention should be directed to the areas with the highest value conservation potential, namely for reducing peak demand in the service areas supplied by Pleasant TS and, in the longer term, by Kleinburg TS.

Details on each LDC's conservation plan are provided in Appendix D.

7.2.2 Two Station Solution: Halton Hills Hydro MTS and Halton TS #2

Halton Hills Hydro should proceed to gain the necessary approvals to construct, own and operate a new step-down station at the Halton Hills Gas Generation facility. Based on technical and economic analysis, the Working Group believes that building this facility is the least-cost option for serving growth within Halton Hills. Currently analysis recommends a targeted in-service date of 2018.

The Working Group recommends the transmitter, Hydro One, should initiate technical and engineering work for the development of Halton TS #2, at the site of the existing Halton TS, with a tentative in-service date of 2020. Based on the current load forecast and a typical three-year lead time from initiation of approvals to in-service date, construction of Halton TS #2 is not yet required. The Working Group recommends that actual load growth be monitored on an annual basis before a RIP is initiated.

7.2.3 Reinforcement of H29/30

The Working Group recommends the transmitter, Hydro One, should proceed with the preliminary work required to validate the technical, feasibility and cost for the replacement of conductors on the H29/30 circuits to a summer LTE planning rating of 1400 A. It is recommended that this measure be implemented before peak loads at Pleasant TS exceed approximately 417 MW. Based on the current load forecast, this may occur as soon as 2023 under the Higher Growth scenario. The Working Group recommends that actual load growth be reviewed annually and this issue be reassessed during the next iteration of the regional planning cycle.

7.2.4 Restoration Needs

Four pockets in the study area are at risk for not meeting ORTAC restoration criteria. The ongoing bulk system study will consider solutions to address these needs at three of the four pockets. If these restoration needs are not adequately addressed through the bulk transmission study, they will be revisited as part of the regional planning process. The fourth pocket, Pleasant TS, was considered as part of this IRRP; pursuing transmission- or distribution-based solution at this time is not economically prudent. Opportunities will be reassessed in updates to this plan.

7.3 Implementation of Near-Term Plan

To ensure that the near-term electricity needs of Northwest GTA are addressed, it is important that the near-term plan recommendations be implemented in a timely manner. Table 7-4 shows the plan's deliverables, timeframe for implementation and the parties responsible for implementation.

The Northwest GTA Working Group will continue to meet at regular intervals as this IRRP is implemented to monitor developments in the region and to track progress toward these deliverables. In particular, the actions and deliverables in Table 7-4 with estimated timeframes for completion will require annual monitoring of system conditions to determine when projects must be initiated. Preliminary engineering and design work should be initiated at an appropriate time to ensure that the plan can be implemented as required.

Table 7-4: Implementation of Near-Term Plan for Northwest GTA

Recommendation	Action(s)/Deliverable(s)	Lead Responsibility	Timeframe
1. Implement conservation and distributed generation	Develop CDM plans	LDCs	May 2015
	LDC CDM programs implemented	LDCs	2015-2020
	Conduct Evaluation, Measurement and Verification of programs, including peak-demand impacts and provide results to Working Group	LDCs	Annually
	Continue to support provincial distributed generation programs	LDCs/IESO	Ongoing
2. Develop new step-down station in Halton Hills	Design, develop and construct new step-down station in southern Halton Hills, at the Halton Hills GS site	Halton Hills Hydro	In-service spring 2018
3. Develop new step-down station in Milton	Design, develop and construct new step-down station in Milton at the existing Halton TS site	Hydro One	In-service spring 2020 (estimated)
4. Upgrade H29/30 conductors	Upgrade H29/30 circuits to higher rated conductors	Hydro One	2023-2026 (estimated)

8. Options for Meeting Long-Term Needs

The following sections describe various approaches for meeting the long-term electricity needs of Northwest GTA. The purpose in describing different approaches is not to advocate for one over another, but to present the factors that must be balanced when forming long-term electricity plans.

In the case of Northwest GTA, long-term needs are characterized by constraints on a system largely built to the south, while new development continues to expand northward, beyond the existing system's ability to meet new demand. These needs are not limited to the electricity system, as all forms of infrastructure will be challenged to accommodate expanding development. One major infrastructure initiative already underway is the development of the West GTA transportation corridor, led by the Ministry of Transportation. This project is working to identify and secure land for the development of a 400-series highway and transitway extending from Highway 400 (between Kirby Road and King-Vaughan Road) in the east to the Highway 401/407 ETR interchange area in the west, passing along the south Caledon border with Brampton and along the eastern Halton border with Peel.

More information on this project is available at http://www.gta-west.com/.

This proposed route aligns well with the long term electricity infrastructure needs described in this IRRP and provides the opportunity to plan for a transmission corridor in the general vicinity to meet the transmission needs. The coordination of these infrastructure facilities is consistent with the 2014 Provincial Policy Statement ("PPS").[14] The PPS reinforces the link between electricity infrastructure planning and land use planning. It also promotes the efficient and coordinated use of land, resources, infrastructure and public service facilities in Ontario communities. Regardless of the approach pursued to meet long-term electrical demand growth in Northwest GTA, there will remain a long-term need for new transmission infrastructure. Establishing the corridor at this time is recommended due to the unique opportunity provided by the simultaneous planning of the West GTA transportation corridor.

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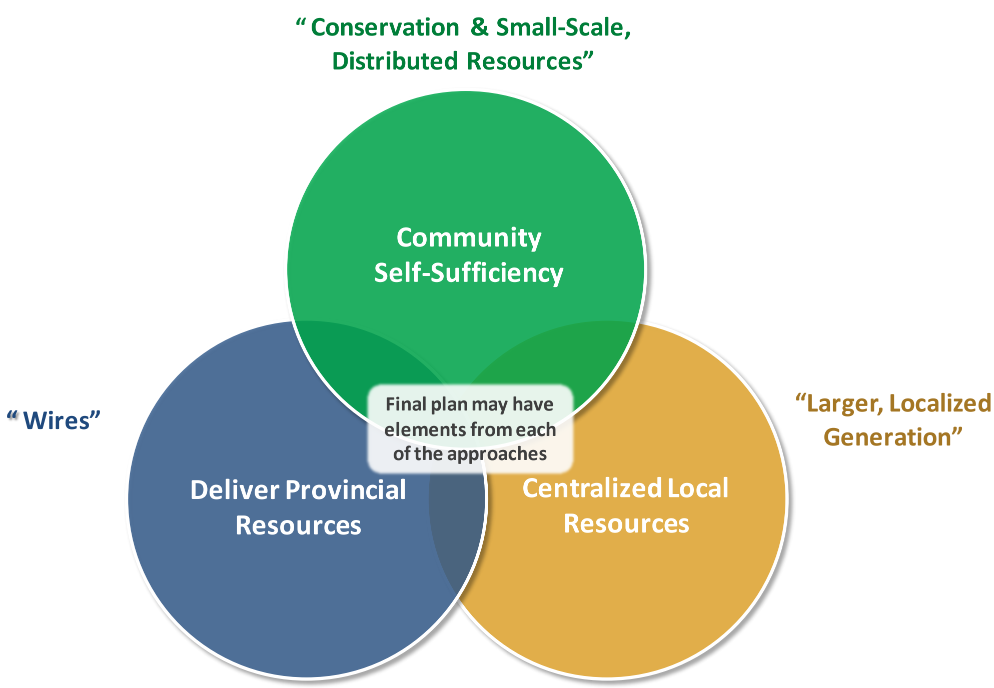
[14] http://www.mah.gov.on.ca/AssetFactory.aspx?did=10463

8.1 Approaches to Meeting Long-Term Needs

In recent years, a number of trends, including technology advances, policy changes supporting distributed generation, greater emphasis on conservation as part of electricity system planning and increasing community interest and desire for involvement in electricity planning and infrastructure siting, are changing the landscape for regional electricity planning. Traditional, "wires"-based approaches to electricity planning, while still technically feasible, may not be the best fit for all communities. New approaches that acknowledge and take advantage of these trends should also be considered.

To facilitate discussions about how a community might plan its future electricity supply, three conceptual approaches for meeting a region's long-term electricity needs provide a useful framework (see Figure 8-1). Based on regional planning experience across the province over the last 10 years, it is clear that different approaches are preferred in different regions, depending on local electricity needs and opportunities and the desired level of involvement by the community in planning and developing its electricity infrastructure.

Figure 8-1: Approaches to Meeting Long-Term Needs



The intent of this framework is to identify which approach is to be emphasized in a particular region. In practice, certain elements of electricity plans will be common to all three approaches and there will necessarily be some overlap between them. For example, provincially mandated conservation targets will be an element in all regional electricity plans, regardless of which planning approach is adopted for a region. In fact, it is likely that all plans will contain some combination of conservation, local generation, transmission and distribution elements. Once a decision on the basic approach is made, the plan is developed around that approach, which affects the relative balance of conservation, generation and "wires" in the plan.

The three approaches are as follows:

- **Delivering provincial resources**, or "wires" planning, is the traditional regional electricity planning approach associated with the development of centralized electric power systems over many decades. This approach involves using transmission and distribution infrastructure to supply a region's electricity needs, taking power from the provincial electricity system. This model takes advantage of generation that is planned at the provincial level, with generation sources typically located remotely from the region. In this approach, utilities (transmitters and distributors) play a lead role in development.
- The **centralized local resources** approach involves developing one or a few large, local generation resources to supply a community. While this approach shares the goal of providing supply locally with the community self-sufficiency approach below, the emphasis is on large central-plant facilities rather than smaller, distributed resources.
- The **community self-sufficiency** approach entails an emphasis on meeting community needs largely with local, distributed resources, which can include: aggressive conservation beyond provincial targets; demand response; distributed generation and storage; smart grid technologies for managing distributed resources; integrated heat/power/process systems; and electric vehicles. While many of these applications are not currently in widespread use, for regions with long-term needs (i.e., 10-20 years in the future) there is an opportunity to develop and test out these options before long-term plan commitment decisions are required. The success of this approach depends on early action to explore potential and develop options and on the local community taking a lead role. This could be through a municipal/community energy planning process, or an LDC or other local entity taking initiative to pursue and develop options.

Details of how these three approaches could be developed to meet the specific long-term needs of Northwest GTA are provided in the following sections.

8.1.1 Delivering Provincial Resources

Under a "wires"-based approach, the traditional approach taken to address regional electricity needs, the long-term needs of Northwest GTA would be met primarily through transmission and distribution system enhancements. Due to the continued northern expansion of urban growth throughout the study area in general and through northern Brampton and southern Caledon in particular, it is anticipated that new transmission infrastructure will be required in this area in the long term. As described earlier, this could be triggered by one of three needs:

- Overloads on the H29/30 circuits providing supply to Pleasant TS
- Overloads on the transformers at Pleasant TS and/or Kleinburg TS and
- Limitations on the distribution network due to distances between transmission supply points (transformer stations) and new end use customers located in northern Brampton and southern Caledon.

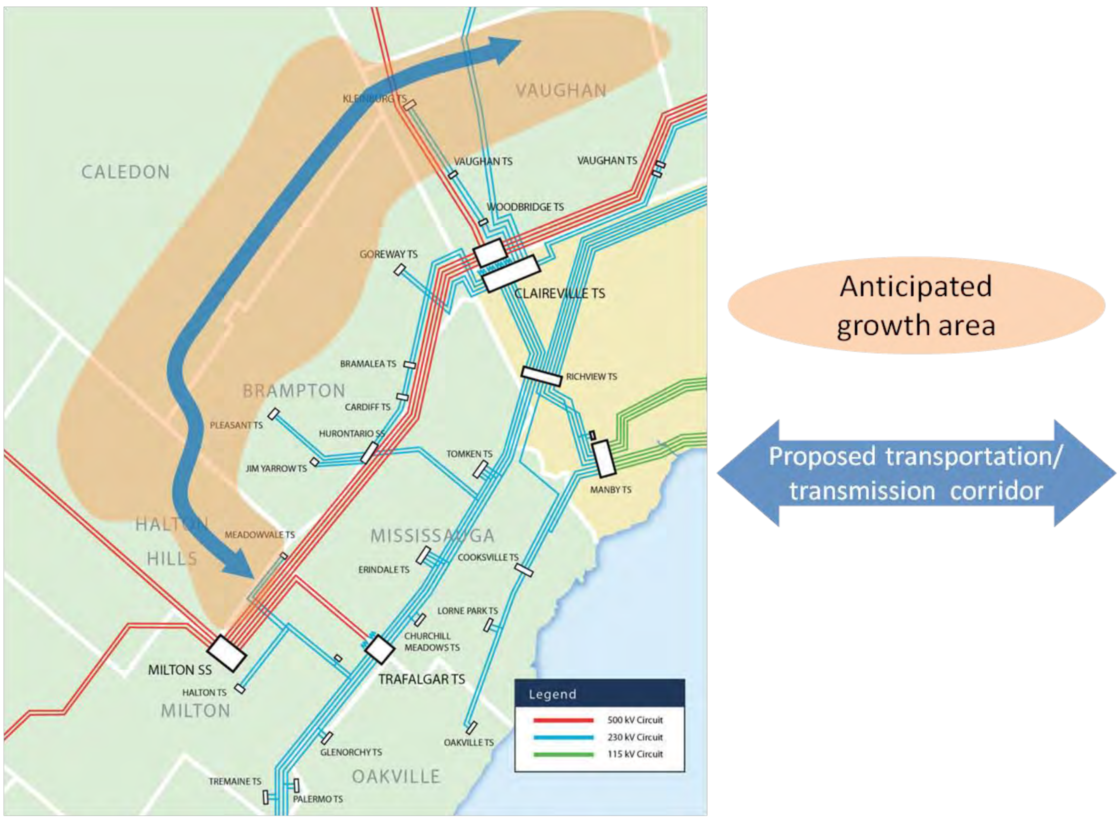
If peak reduction efforts, including conservation and distributed generation, are unable to defer these capacity needs (both circuit and transformer) and distribution solutions such as load transfers prove technically or economically infeasible, a new step-down transformer station will be required in the general northern Brampton/southern Caledon area. Since existing circuits are unable to supply this additional station demand, a new transmission corridor will also be required in this general service area.

In addition to these potential capacity issues, the need for new transmission infrastructure could also be triggered as a result of an inability to provide adequate power quality for new customers located in new development lands in northern Brampton and southern Caledon. These new development lands, shown in Figure 8-2, below, are distant from existing supply points such as Pleasant TS and Goreway TS, resulting in long distribution feeders that impact reliability and voltage performance. Hydro One Brampton has already experienced challenges in providing adequate voltage on the long feeders extending from Pleasant TS and Goreway TS to the existing growth areas in north Brampton. As loads to the north of existing transmission infrastructure develop further, there is a potential for distribution voltage performance to worsen.

When capacity needs arise in the northern Brampton/southern Caledon area, new step-down transformer stations will be required in the general vicinity of anticipated growth to supply new customer loads. Due to a lack of available transmission supply in the area, a new transmission corridor will also be required to provide supply to any future stations.

A suitable location for this future transmission corridor is being assessed in the general vicinity of the proposed West GTA transportation corridor, currently under development by the Ministry of Transportation.[15] The alignment of these infrastructure facilities is consistent with the 2014 PPS.[16] The 2014 PPS reinforces the link between electricity infrastructure planning and land use planning. It also promotes the efficient and coordinated use of land, resources, infrastructure and public service facilities in Ontario communities.

Figure 8-2: Approximate West GTA Transportation Corridor Route and Greenfield Growth Areas



Long-term population projections and development plans are based on the *Places to Grow Growth Plan for the Greater Golden Horseshoe* (2013 consolidated), which projects an additional 473,000 people living in the Peel Region in 2031 than in 2011. The majority of this increase is expected in the northern municipalities of Brampton and Caledon, which collectively estimate a

[15] Up to date information on this project is available at http://www.gta-west.com/.
[16] http://www.mah.gov.on.ca/AssetFactory.aspx?did=10463

population increase of over 360,000 between 2011 and 2031, based on a draft update to the Region of Peel official plan.

Figure 8-2 identifies the area of anticipated greenfield growth throughout Brampton and Caledon, in addition to the neighbouring municipalities of Halton Hills and Vaughan, both of which are also expected to support the West GTA transportation corridor.

Given the location of expected growth and other infrastructure developments in the area, the IESO recommends that a transmission corridor be planned in the vicinity of the proposed West GTA transportation corridor.

8.1.2 Large, Localized Generation

Addressing Northwest GTA's long-term needs primarily with large local generation would require that the size, location and characteristics of local generation facilities be consistent with the needs of the region. As the requirements are for additional capacity during times of peak demand, a large generation solution would need to be capable of being dispatched when needed and to operate at an appropriate capacity factor. This would mean that peaking facilities, such as a single-cycle combustion turbine technology, would be more cost-effective than technologies designed to operate over a wider range of hours, or that are optimized to a host facility's requirements.

Based on the anticipated long-term needs for this area, this type of investment would likely only provide marginal benefit and would not be suitable for meeting capacity-related needs (those expected to trigger the need for new transmission infrastructure). This is because siting any large generator in the areas expected to experience capacity needs would still require the same basic transmission infrastructure to connect this facility to the grid. This means that enabling large, localized generation to meet long-term load growth would also require a duplication of the infrastructure needs described in Section 8.1.1, above, plus the added cost of the generator itself, with little additional benefit to the area.

8.1.3 Community Self-Sufficiency

Addressing the long-term needs of Northwest GTA through a community self-sufficiency approach requires leadership from the community to identify opportunities and implement solutions. As this approach relies to a great degree on emerging technologies, there will be a need to develop and test out solutions to establish their potential and cost-effectiveness, so that they can be appropriately assessed in future regional plans.

One promising tool for identifying and studying emerging technologies in a region is through the development of a municipal energy plan. A municipal energy plan is a comprehensive long-term plan to improve energy efficiency, reduce energy consumption and greenhouse gas emissions. A number of municipalities across the province are undertaking energy plans to better understand their local energy needs, identify opportunities for energy efficiency and clean energy, and develop plans to meet their goals. Municipal energy plans take an integrated approach to energy planning by aligning energy, infrastructure and land use planning. Innovative measures that have been investigated in similar urban settings include:

- Advanced fuel cell technologies
- Advanced storage technologies – particularly in combination with fuel cells
- Aggressive demand response programs – particularly residential and small commercial demand response programs enabled by aggregators
- Aggressive conservation programs targeted at residential consumers and enabled by next-generation home area networks
- Battery electric vehicle storage capabilities, especially for load intensification cluster applications
- Enhanced renewable generation opportunities enabled by next-generation storage technologies
- Micro-grid and micro-generation technologies coupled with next-generation storage technologies
- Combined heat and power opportunities
- Renewed consideration of the load serving entity/aggregator market model

The Working Group recognizes significant risks associated with this strategy, the most crucial being the necessity to successfully meet the growth in electricity demand with new and unproven load management and storage technologies.

Other key risks include demonstrating consumer value, cost recovery certainty for innovative technologies and the associated risk of asset stranding, risk/reward incentives and technological obsolescence as a causal factor for asset replacement.

Given the magnitude of the long-term capacity needs expected throughout northern Brampton, southern Caledon and parts of the neighbouring municipalities of Halton Hills and Vaughan, it is not expected that emerging or innovative technologies will be able to provide a technically feasible alternative to conventional infrastructure in the long term. As a result, it is recommended that while measures could be encouraged where a sound business case is available, a commitment to community self-sufficiency cannot replace the need for acquiring corridor rights for future transmission infrastructure in this area.

8.2 Recommended Actions and Implementation

There is a long-term need to provide electrical service to a significant new development area within the northern Brampton/southern Caledon area. Due to a lack of transmission in this area, new step-down stations cannot be accommodated until additional transmission infrastructure is built. Given the long lead times associated with this type of investment and the benefits of coordinating the planning of linear infrastructure corridors, it is recommended that work continue to establish a corridor for a future transmission near the planned West GTA transportation corridor. Coordinated planning for linear infrastructure corridors is consistent with the direction provided in the PPS. Actual construction of the transmission facilities would not be triggered until the need for the supply path and associated step-down capacity is identified within a near- to medium-term planning horizon. This may occur as a result of the need for additional step-down capacity to relieve existing stations (Pleasant TS and Kleinburg TS), or, as a result of power quality issues on the distribution system that may arise when customer loads are served by long feeders.

In November 2014, the OPA provided a letter to Hydro One supporting the long term need for this project, provided in Appendix F. Based on the analysis described in this letter, it was estimated that growth across these four municipalities will require the availability of new transmission infrastructure to support the increase in electrical demand (beyond the currently available system capacities) of 300-570 MW by 2031 and 570-950 MW by 2041. Given that the timeline is beyond the typical planning horizon for the IRRP and the affected area extends beyond the Northwest GTA, these electrical demand forecasts were based on the Places To Grow official plan and a range of demand per capita coefficients. Even under the most conservative of estimates, growth of this magnitude would require significant new transmission infrastructure to reliably serve new customer demand. As a result, it was recommended that sufficient corridor width be preserved to allow for the economic, safe and reliable construction, operation and maintenance of two double circuit 230 kV lines. The corridor may be required over the next 20 years, depending on the timing and location of the development in the area.

The use of undergrounded transmission lines (cables), as opposed to overhead lines, was not recommended as they are significantly more costly with costs ranging from five to ten times higher. Instead, cables are typically reserved for situations where overhead options are not feasible, such as in densely populated areas with no remaining right-of-way allowances. Identifying and preserving transmission rights-of-way early and well ahead of the forecast need can help electricity customers avoid costs associated with underground cables in the future. Allowing the area to develop without reserving an overhead transmission corridor and attempting to incorporate underground transmission facilities at a later date could result in hundreds of millions of dollars in additional costs when upgrading the system and is inconsistent with the PPS.

The IESO will continue to work with Hydro One and relevant municipal, regional and provincial entities to consider the planning of this long-term strategic asset.

Table 8-1: Summary of Solutions Considered for Near-, Medium- and Long-term Needs

Needs	Conservation	DR	DG	Wires Infrastructure
Near-term Needs				
Halton TS capacity relief	--	--	--	Yes
Restoration	--	--	--	Yes
Medium-term Needs				
Supply to Pleasant TS	Yes	Yes	Yes	Yes
Long-term Needs				
Pleasant TS capacity relief	Yes	Yes	Yes	--
Kleinburg TS capacity relief	Yes	Yes	Yes	--
New northern Brampton/southern Caledon supply	--	--	--	Yes

9. Community, Aboriginal and Stakeholder Engagement

Community engagement is an important aspect of the regional planning process. Providing opportunities for input in the regional planning process enables the views and preferences of the community to be considered in the development of the plan, and helps lay the foundation for successful implementation. This section outlines the engagement principles as well as the activities undertaken to date for the NW GTA IRRP and those that will take place to discuss the long-term needs identified in the plan and obtain input in the development of options.

A phased community engagement approach has been developed for the NW GTA IRRP based on the core principles of creating transparency, engaging early and often, and bringing communities to the table. These principles were established as a result of the IESO's outreach with Ontarians to determine how to improve the regional planning process, and they are now guiding the IRRP outreach with communities and will ensure this dialogue continues and expands as the plan moves forward.

Figure 9-1: Summary of NW GTA IRRP Community Engagement Process

Creating Transparency:

Creation of NW GTA IRRP Information Resources

- Dedicated NW GTA IRRP webpage created on IESO (former OPA) website providing background information, the IRRP Terms of Reference and listing the Working Group members
- Dedicated webpage added to Hydro One website and information posted on LDC websites
- Self-subscription service established for NW GTA IRRP for subscribers to receive regional specific updates
- Status: complete

Engaging Early and Often:

Municipal, First Nation & Métis Outreach

- Presentation and discussion at three group meetings with municipal planners from across the planning region
- Information provided to First Nation communities who may have an interest in the planning area
- Presentation and discussion with First Nation communities as requested
- Information provided to Métis Nation of Ontario
- Status: initial outreach complete; dialogue to continue

Bringing Communities to the Table:

Broader Community Outreach

- Presentation at Municipal Councils, First Nation community meetings and Métis Nation of Ontario as requested
- Webinar to discuss electricity needs, near-term solutions and formation of a Local Advisory Committee ("LAC")
- Formation of LAC to discuss longer-term options, including new transmission right of way
- Broader community outreach to be undertaken; feedback from this phase on community values and preferences will inform the decisions to be made in the next planning cycle
- Status: beginning in May 2015; no time limit

Creating Transparency

To start the dialogue on the NW GTA IRRP and build transparency in the planning process, a number of information resources were created for the plan. A dedicated webpage was created on the IESO (former OPA) website to provide a map of the regional planning area, information on why the plan was being developed, the Terms of Reference for the IRRP and a listing of the organizations involved was posted on the websites of the Working Group members. A dedicated email subscription service was also established for the NW GTA IRRP where communities and stakeholders could subscribe to receive email updates about the IRRP.

Engaging Early and Often

The first step in the engagement of the NW GTA IRRP was meeting with representatives from the municipalities and First Nation communities in the region. For the municipal meetings, presentations were made to the NW GTA area municipal planners and CAOs at three group meetings held in Halton Hills, Brampton and Milton. The IESO held a separate meeting with representatives of the Six Nations Elected Council.

During these meetings, key topics of discussion involved confirmation of growth projections for the area, addressing near- and medium-terms needs through the development of two new step-down stations, and the recommendation of a future transmission corridor to provide for longer-term capacity needs as a result of continued growth in the northern Brampton, southern Caledon, and Halton Hills area. Invitations to meet to discuss the NW GTA IRRP were also extended to the Mississaugas of the New Credit First Nation and to the Haudenosaunee Confederacy Chiefs Council. The IESO remains committed to responding to any questions or concerns from these communities.

Also discussed was a bulk system study that has been initiated for West GTA to identify and recommend solutions to address emerging bulk transmission system needs, primarily driven by the retirement of Pickering Nuclear GS.

Bringing Communities to the Table

This engagement will begin with a public webinar hosted by the working group to discuss the plan and potential approaches of possible long-term options. Presentations on the NW GTA IRRP will also be made to Municipal Councils and First Nation communities on request.

To further continue the dialogue, a West GTA local advisory committee will be established as an advisory body to the NW GTA Working Group, as well as the broader West GTA Region. The purpose of the committee is to establish a forum for members to be informed of the regional planning processes. Their input and recommendations, information on local priorities, and ideas on the design of community engagement strategies will be considered throughout the engagement, and planning processes. LAC meetings will be open to the public and meeting information will be posted on the IESO website. Note that LACs are formed on a regional basis, and will therefore encompass the entire West GTA planning region, including the municipalities of Mississauga and Oakville, which were not part of the NW GTA IRRP. Information on the formation of the West GTA LAC is available on the NW GTA IRRP main webpage.

Strengthening processes for early and sustained engagement with communities and the public were introduced following an engagement held in 2013 with 1,250 Ontarians on how to enhance regional electricity planning. This feedback resulted in the development of a series of recommendations that were presented to, and subsequently adopted by the Minister of Energy. Further information can be found in the report entitled "Engaging Local Communities in Ontario's Electricity Planning Continuum"[17] available on the IESO website.

Information on outreach activities for the NW GTA IRRP can be found on the IESO website and updates will be sent to all subscribers who have requested updates on the NW GTA IRRP.

[17] http://www.powerauthority.on.ca/stakeholder-engagement/stakeholder-consultation/ontario-Regional-energy-planning-review

10. Conclusion

This report documents an IRRP that has been carried out for NW GTA, a sub-region of the West GTA OEB planning region, and, combined with the planning activities for Southwest GTA, largely fulfils the OEB requirement to conduct regional planning in the West GTA Region.[18] The IRRP identifies electricity needs in the region over the 20-year period from 2014 to 2033, recommends a plan to address near- and medium-term needs and identifies actions to develop alternatives for the long term.

Implementation of the near-term plan is already underway, with the LDCs developing CDM plans consistent with the Conservation First policy and with development work initiated for a new step-down transformer station being developed by Halton Hills Hydro. A transmission solution to address additional capacity needs for Halton TS is required for 2020 under the Expected Growth forecast. This will be planned further by the transmitter through the RIP process. Additionally, the RIP should consider a "wires" solution to address overloading needs on H29/30, with a potential need date of 2023-2026.

To support development of the long-term plan, a number of actions have been identified to develop alternatives, engage with the community and monitor growth in the region. Responsibility has been assigned to appropriate members of the Working Group for these actions. Information gathered and lessons learned as a result of these activities will inform development of the next iteration of the IRRP for NW GTA.

The planning process does not end with the publishing of this IRRP. Communities will be engaged in the development of the options for the long term. In addition, the NW GTA Working Group will continue to meet regularly throughout the implementation of the plan to monitor progress and developments in the area and will produce annual update reports that will be posted on the IESO website. Of particular importance, the Working Group will track closely the expected timing of the needs that are forecast to arise in the long term under the Expected Growth forecast. If demand grows as anticipated, it may not be necessary to revisit the plan until 2020, in accordance with the OEB-mandated 5-year schedule. This would allow more time to develop alternatives and to take advantage of advances in technology in the next planning cycle.

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[18] A bulk planning process underway for West GTA will consider the restoration needs described in this report.

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March 23, 2015

Matthew Wright, C.E.T.
System Planning Supervisor
Halton Hills Hydro Inc.
43 Alice St.
Acton, ON L7J 2A9

Dear Mr. Wright:

Subject: Regional Planning Status

In reference to your request for a Regional Planning Status Letter, please note that Halton Hills Hydro Inc. ("Halton Hills Hydro") belongs to the GTA West Region – Northwestern Subregion, and Kitchener-Waterloo-Cambridge-Guelph ("KWCG") Region. Both Regions are in Group 1. A map showing details with respect to the 21 Regions/Groups and a list of Local Distribution Companies (LDC) in each Region is attached in Appendix A and B respectively.

GTA West Region – Northwestern Subregion

The planning activity for GTA West Region – Northwestern Subregion was already underway prior to the new regional planning process and was deemed to be in the Integrated Regional Resource Planning ("IRRP") phase of the process. This IRRP led by the IESO (formerly OPA) is expected to be completed by Q2 2015.

Two transmission projects have been identified to address the near- and medium-term needs in this Region: the Halton Hills Hydro MTS project, and reinforcement of 230kV circuits H29 and H30 that supply Pleasant TS. Halton Hills Hydro is an embedded LDC at Pleasant TS. Work on the first project is already underway, led by Halton Hills Hydro. As the need for the second project is not until 2023, the study team will monitor the load growth and reassess this issue during the next regional planning cycle.

KWCG Region

The planning activity for KWCG Region was already underway prior to the new regional planning process and was deemed to be in the Integrated Regional Resource Planning ("IRRP") phase of the process. This IRRP led by the IESO (formerly OPA) is expected to be completed by Q2 2015.

Two transmission projects have been identified to address the near- and medium-term needs in this Region: the first being the Guelph Area Transmission Reinforcement ("GATR") project, and the second being the installation of switches on circuits M20D and M21D. Execution of the first project is already underway while the second in the project development phase.

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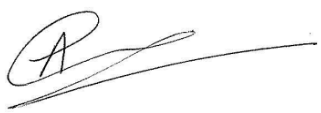
Halton Hills Hydro is an embedded LDC in this Region and is also served by Fergus TS. Halton Hills Hydro has recently expressed concerns regarding load growth and single supply reliability to Acton from Fergus TS feeder M4. This is primarily a distribution planning activity and Halton Hills Hydro and Hydro One Distribution have agreed to assess and develop a plan to address these reliability concerns. Ultimately, this may result in some distribution investments for Halton Hills Hydro.

Hydro One looks forward to working with Halton Hills Hydro in executing the new regional planning process. If you have any further questions, please feel free to contact me.

Sincerely,



Ajay Garg, Manager – Regional Planning Coordination
Hydro One Networks Inc.

Appendix A: Map of Ontario's Planning Regions

Northern Ontario

Southern Ontario

Greater Toronto Area (GTA)

Group 1	Group 2	Group 3
Burlington to Nanticoke	East Lake Superior	Chatham/Lambton/Sarnia
Greater Ottawa	London area	Greater Bruce/Huron
GTA East	Peterborough to Kingston	Niagara
GTA North	South Georgian Bay/Muskoka	North of Moosonee
GTA West	Sudbury/Algoma	North/East of Sudbury
Kitchener- Waterloo-Cambridge-Guelph (“KWCG”)		Renfrew
Metro Toronto		St. Lawrence
Northwest Ontario		
Windsor-Essex		

Appendix B: List of LDCs for Each Region

[Hydro One as Upstream Transmitter]

Region	LDCs
1. Burlington to Nanticoke	• Brant County Power Inc. • Brantford Power Inc. • Burlington Hydro Inc. • Haldimand County Hydro Inc. • Horizon Utilities Corporation • Hydro One Networks Inc. • Norfolk Power Distribution Inc. • Oakville Hydro Electricity Distribution Inc.
2. Greater Ottawa	• Hydro 2000 Inc. • Hydro Hawkesbury Inc. • Hydro One Networks Inc. • Hydro Ottawa Limited • Ottawa River Power Corporation • Renfrew Hydro Inc.
3. GTA North	• Enersource Hydro Mississauga Inc. • Hydro One Brampton Networks Inc. • Hydro One Networks Inc. • Newmarket-Tay Power Distribution Ltd. • PowerStream Inc. • PowerStream Inc. [Barrie] • Toronto Hydro Electric System Limited • Veridian Connections Inc.
4. GTA West	• Burlington Hydro Inc. • Enersource Hydro Mississauga Inc. • Halton Hills Hydro Inc. • Hydro One Brampton Networks Inc. • Hydro One Networks Inc. • Milton Hydro Distribution Inc. • Oakville Hydro Electricity Distribution Inc.

5. Kitchener- Waterloo-Cambridge-Guelph ("KWCG")	• Cambridge and North Dumfries Hydro Inc. • Centre Wellington Hydro Ltd. • Guelph Hydro Electric System - Rockwood Division • Guelph Hydro Electric Systems Inc. • Halton Hills Hydro Inc. • Hydro One Networks Inc. • Kitchener-Wilmot Hydro Inc. • Milton Hydro Distribution Inc. • Waterloo North Hydro Inc. • Wellington North Power Inc.
6. Metro Toronto	• Enersource Hydro Mississauga Inc. • Hydro One Networks Inc. • PowerStream Inc. • Toronto Hydro Electric System Limited • Veridian Connections Inc.
7. Northwest Ontario	• Atikokan Hydro Inc. • Chapleau Public Utilities Corporation • Fort Frances Power Corporation • Hydro One Networks Inc. • Kenora Hydro Electric Corporation Ltd. • Sioux Lookout Hydro Inc. • Thunder Bay Hydro Electricity Distribution Inc.
8. Windsor-Essex	• E.L.K. Energy Inc. • Entegrus Power Lines Inc. [Chatham-Kent] • EnWin Utilities Ltd. • Essex Powerlines Corporation • Hydro One Networks Inc.
9. East Lake Superior	N/A → This region is not within Hydro One's territory

10. GTA East	• Hydro One Networks Inc. • Oshawa PUC Networks Inc. • Veridian Connections Inc. • Whitby Hydro Electric Corporation
11. London area	• Entegrus Power Lines Inc. [Middlesex] • Erie Thames Power Lines Corporation • Hydro One Networks Inc. • London Hydro Inc. • Norfolk Power Distribution Inc. • St. Thomas Energy Inc. • Tillsonburg Hydro Inc. • Woodstock Hydro Services Inc.
12. Peterborough to Kingston	• Eastern Ontario Power Inc. • Hydro One Networks Inc. • Kingston Hydro Corporation • Lakefront Utilities Inc. • Peterborough Distribution Inc. • Veridian Connections Inc.
13. South Georgian Bay/Muskoka	• Collingwood PowerStream Utility Services Corp. (COLLUS PowerStream Corp.) • Hydro One Networks Inc. • Innisfil Hydro Distribution Systems Limited • Lakeland Power Distribution Ltd. • Midland Power Utility Corporation • Orangeville Hydro Limited • Orillia Power Distribution Corporation • Parry Sound Power Corp. • Powerstream Inc. [Barrie] • Tay Power • Veridian Connections Inc. • Veridian-Gravenhurst Hydro Electric Inc. • Wasaga Distribution Inc.

14. Sudbury/Algoma	• Espanola Regional Hydro Distribution Corp. • Greater Sudbury Hydro Inc. • Hydro One Networks Inc.
15. Chatham/Lambton/Sarnia	• Bluewater Power Distribution Corporation • Entegrus Power Lines Inc. [Chatham-Kent] • Hydro One Networks Inc.
16. Greater Bruce/Huron	• Entegrus Power Lines Inc. [Middlesex] • Erie Thames Power Lines Corporation • Festival Hydro Inc. • Hydro One Networks Inc. • Wellington North Power Inc. • West Coast Huron Energy Inc. • Westario Power Inc.
17. Niagara	• Canadian Niagara Power Inc. [Port Colborne] • Grimsby Power Inc. • Haldimand County Hydro Inc.* • Horizon Utilities Corporation • Hydro One Networks Inc. • Niagara Peninsula Energy Inc. • Niagara-On-The-Lake Hydro Inc. • Welland Hydro-Electric System Corp. • Niagara West Transformation Corporation* *Changes to the May 17, 2013 OEB Planning Process Working Group Report
18. North of Moosonee	N/A → This region is not within Hydro One's territory

19. North/East of Sudbury	• Greater Sudbury Hydro Inc. • Hearst Power Distribution Company Limited • Hydro One Networks Inc. • North Bay Hydro Distribution Ltd. • Northern Ontario Wires Inc.
20. Renfrew	• Hydro One Networks Inc. • Ottawa River Power Corporation • Renfrew Hydro Inc.
21. St. Lawrence	• Cooperative Hydro Embrun Inc. • Hydro One Networks Inc. • Rideau St. Lawrence Distribution Inc.

IESO Letter of Comment

Halton Hills Hydro

Renewable Energy Generation Investments 2016 – 2020

March 6, 2015

Independent Electricity System Operator

Introduction

On March 28, 2013, the Ontario Energy Board ("the OEB" or "Board") issued its Filing Requirements for Electricity Transmission and Distribution Applications; Chapter 5 – Consolidated Distribution System Plan Filing Requirements (EB-2010-0377). Chapter 5 implements the Board's policy direction on 'an integrated approach to distribution network planning', outlined in the Board's October 18, 2012 Report of the Board - A Renewed Regulatory Framework for Electricity Distributors: A Performance Based Approach.

As outlined in the Chapter 5 filing requirements, the Board expects that the Ontario Power Authority[1] ("OPA") comment letter will include:

- the applications it has received from renewable generators through the FIT program for connection in the distributor's service area;
- whether the distributor has consulted with the OPA, or participated in planning meetings with the OPA;
- the potential need for co-ordination with other distributors and/or transmitters or others on implementing elements of the REG investments; and
- whether the REG investments proposed in the DS Plan are consistent with any Regional Infrastructure Plan.

Halton Hills Hydro Inc. – Distribution System Plan

On February 12, 2015 Halton Hills Hydro Inc. ("Halton Hills Hydro") provided its Renewable Energy Generation Investments Information ("Plan") to the IESO as part of its 5-year Distribution System Plan. The IESO has reviewed Halton Hills Hydro's Plan and has provided its comments below.

OPA FIT/microFIT Applications Received

Halton Hills Hydro indicates that as of December 5, 2014 it has connected 6 FIT projects and 107 microFIT projects totalling 2.589 MW of generation capacity.

According to the IESO's information, as of December 31, 2014, the IESO offered contracts to 104 microFIT projects totalling 170 kW of capacity. The OPA has also offered contracts to 9 FIT projects representing a capacity of 2.705 MW, of which 6 FIT projects have come into service. The renewable energy generation connections information in Halton Hills Hydro's Plan is therefore reasonably consistent with that of the IESO.

[1] On January 1, 2015, the Ontario Power Authority ("OPA") merged with the Independent Electricity System Operator ("IESO") to create a new organization that will combine the OPA and IESO mandates. The new organization is called the Independent Electricity System Operator.

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Consultation / Participation in Planning Meetings; Coordination with Distributors / Transmitters / Others; Consistency with Regional Plans

The IESO notes that Halton Hills Hydro is part of “Group 1” and the Greater Toronto Area (“GTA”) West region for regional planning purposes. The GTA West region is divided into the Northwestern sub-region and the Southern sub-region. Halton Hills is a participant on the working group for the Northwestern GTA (“NWGTA) sub-region Integrated Regional Resource Plan (“IRRP”) that is currently underway. This IRRP that is to be finalized at the end of April, 2015 is being led by the IESO in partnership with Hydro One Transmission, Hydro One Brampton, Milton Hydro, Halton Hills Hydro, and Hydro One Distribution. The NWGTA sub-region IRRP will address the area’s needs over the 20-year planning horizon that will include the near- (0-5 years), medium- (5-10 years), and long-term (10-20+ years) timeframe, and with integrate potential solutions focused on conservation, demand response, generation, distribution, and transmission.

The IESO also notes that Halton Hills Hydro has indicated an established relationship with Hydro One Transmission in order to coordinate and address renewable energy generation connections and impacts such as capacity allocation issues.

IESO looks forward to continuing to work with Halton Hills Hydro on regional planning in the GTA West region and appreciates the opportunity to comment on the information provided as part of its Distribution System Plan at this time. For more information on the NWGTA sub-region IRRP please follow this link: http://powerauthority.on.ca/power-planning/regional-planning/gta-west/nwgta

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Appendix E, Pole Testing Policy/Procedure

Engineering – Pole Testing and Inspection	**Date: June 2010**
Procedure No HHCEC-ENG-005	**Revision:**
Issued by: Art Skidmore	**Title: President & CEO**

SCOPE OF PROCEDURE

The intent of this procedure is to cover the applicable requirements for pole testing. Halton Hills Hydro shall conduct pole testing as part of a preventative maintenance program to ensure its' utility poles are of sufficient capability to support the utilities distribution. Although this procedure covers pole testing, other preventative maintenance techniques relating to utility poles may be employed.

PROCEDURE DESCRIPTION

Halton Hills Hydro will, as part of its preventative maintenance program, inspect and test a portion of its' utility poles on a yearly basis. This shall entail:

- Each year, a minimum of 1200 poles shall be tested unless otherwise decided.
- An established pole testing company shall be hired to inspect and test the poles using applicable industry standards, from which a report shall be generated indicating the poles requiring replacement and the condition of all poles tested.
- All parties involved shall review the results of the pole testing.
- Each pole marked for replacement shall be inspected by hydro personnel.
- Each pole marked for replacement will be replaced in the same year as the inspection was completed or the following year. If time does not permit replacement within the aforementioned time frame, the pole shall be inspected by hydro to determine if any immediate danger exists by not replacing the pole.
- Pole replacements shall be done on a Like-for-Like replacement basis per O.Reg. 22/04 unless otherwise stated.

PERSONNEL REQUIREMENTS

The Engineering Personnel assigned to oversee the pole testing shall:

- Decide what poles are to be tested in that year based on annual schedule.
- Create a Job in Quadra under which the work will be carried out.
    - Engaged the services of an established pole testing company and arrange an initial meeting at the hydro office with this company to discuss the project.
    - Plot drawings of the areas where poles are to be tested and clearly identify those areas.
    - At the initial meeting, hydro shall provide drawings of the areas to be tested to the pole testing company along with any other pertinent information. Hydro, if they choose, shall ask the pole testing company to number each pole and tag each pole with that number. Hydro shall provide the pole numbering materials to the pole testing company at this meeting. Hydro will also state their expectation for a report from this company that should include a list of poles to be replaced, a list of all poles tested and their present condition with recommendations for retesting, and other pertinent information. Also, hydro shall indicate to that each pole indicated for replacement shall be clearly marked with an “X” to indicate “pole for replacement”.
    - At the initial meeting Hydro shall provide the pole testing company representative with a scope of work, identification badges, and vehicle magnets. Hydro shall also obtain names and contact information for those performing the testing as well as the make, model, and license plate of the vehicle(s) being used by the pole testing company.
    - Hydro personnel may elect to do a site visit to see how the testing is progressing.
    - Following completion of the pole testing, the pole testing company shall complete a report, which shall be provided to hydro for review and action. If another meeting is required, the hydro personnel overseeing the work shall set up a meeting between both parties.
    - Following receipt of the report, hydro personnel shall review the report, make note of each pole marked for replacement, visit each pole in field and make notes as necessary. After field inspection by hydro personnel, the personnel overseeing the pole testing shall put together work order, material lists, drawings, pictures, etc… Another field inspection may be necessary if pole staking or other actions need to be done.
    - A package will be prepared by Engineering personnel that will be given to the Operations Staff and will include:
        1. Job Summary and Instructions.
        2. Material Lists
        3. Drawings indicated what poles are to be replaced
        4. Standard Pole Framings
        5. Pictures of each Pole (if needed)
        6. Table of Poles to be Replaced
        7. Asset Alteration Report sheets
        8. Locates (where obtained before releasing the work order to Operations)
        9. Ministry of Labour Project Notification (projects exceeding $50,000.00) and/ or Registration of Constructors forms (for contract labour)

10. Other information/ documentation as applicable.

- The Engineering Personnel shall arrange a meeting with the Engineering Supervisor to review the information put together. Following that meeting, changes decided upon shall be made prior to a meeting with the Operations Staff.
- The Engineering Personnel shall arrange a meeting with the Manager of Operations and the Operations Foreman to discuss the poles to be replaced. At this meeting all documentation being provided to the Operations Staff shall be reviewed. If any changes are required those changes shall be made and forwarded to the Operations Staff.
- Hydro Operations Staff shall make arrangements to replace the poles marked for replacement within the same year of the testing or the following year provided no immediate danger exists from not replacing the poles immediately. Operations Staff or Engineering Personnel will arrange locates for each pole so as to allow for coordination with their work schedule. In replacing a pole, the Operations Staff shall move the pole number from the recovered pole to the new pole.

- Following replacement of a pole, the Operations Staff shall notify the Engineering Personnel overseeing the project of the replacement by returning the completed work order and Asset Alteration Report.
- Engineering Personnel shall make note in the pole-testing database/ asset management files that the pole was replaced and update the database(s) accordingly.

SUMMARY / CONCLUSION

Pole testing shall be carried out as part of a preventative maintenance program to ensure its utility poles are of sufficient capability to support the utilities distribution network. By following the above procedure, hydro personnel can be confident that aspects of pole testing have been achieved and furthermore, the utility can be confident that their utility poles are of sufficient strength to supports its distribution network.

Christopher Hale, Engineering Supervisor

Renewable Energy

Generation Investments 2016 - 2020

Prepared: February 12, 2015

Halton Hills Hydro

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1. EXECUTIVE SUMMARY

On March 28, 2013, the Board issued Chapter 5 of the Board's Filing Requirements for Electricity Transmission and Distribution Applications, entitled Consolidated Distribution System Plan Filing Requirements (the "DS Plan Filing Requirements") which reflect the Board's policy direction on an integrated approach to distribution network planning. Halton Hills Hydro has prepared its Distribution System Plan in accordance with the DS Plan Filing Requirements.

Section 5.1.4.2 of the DS Plan Filing Requirements requires that distributors submit information to the Independent Electricity System Operator (formerly the Ontario Power Authority) in relation to the Renewable Energy Generation investments identified in their Distribution System Plan. The Independent Electricity System Operator (the "IESO") is expected to provide a letter of comment with regards to these plans. Halton Hills Hydro's Renewable Energy Generation Investment Plan forms part of its overall Distribution System Plan. However, Halton Hills Hydro has separated its Renewable Energy Generation Investment Plan for the purpose of the obtaining IESO's review and letter of comment. The Board's expectations for the IESO's comment letter are provided in Appendix B.

The Renewable Energy Generation Investment Plan assesses the state of Halton Hills Hydro's existing distribution system, studies the current renewable-connected generation and near-term growth forecast, defines a strategy to accommodate the predicted renewable generation growth and describes Halton Hills Hydro's future Renewable Generation expenditures from 2016 through 2020.

The IESO launched the Feed-In Tariff ("FIT") program in 2009. The FIT/microFIT program has had a high level of uptake in Halton Hills Hydro's service area. Halton Hills Hydro's connected renewable generation is 2.589MW for microFIT and FIT programs combined as of December 5, 2014. Currently there are six FIT projects and 107 microFIT projects which have been connected to Halton Hills Hydro's distribution system. There is one 0.2MW FIT application having received a Connection Impact Assessment (CIA) and is pending connection expected in 2015. At the time of writing this, there are currently six (6) additional FIT applications in Halton Hills Hydro’s service area for which Halton Hills Hydro has performed Distribution Availability Tests (DAT) but has not received an application for connection. These applications are listed in Appendix A.

Halton Hills Hydro's distribution system is well positioned to accommodate further renewable energy micro-generation connections and small to mid-size renewable energy generation. Prior to the implementation of the IESO’s Feed-In-Tariff programs Halton Hills Hydro did not have renewable generation interconnected to the distribution system. Since the programs implementation, capacity at the individual feeder level was assessed and available limits determined. Halton Hills Hydro maintains a record of available and allocated capacity by feeder.

Based on Halton Hills Hydro’s experience with Feed-In-Tariff projects to date, it is estimated that the connection of renewable energy projects under FIT and microFIT programs will remain steady between 2016 and 2020. The calculated remaining capacity and the projected demand for renewable energy indicate that Halton Hills Hydro is ready to connect future renewable generation projects. Halton Hills Hydro has not included any capital expenditures related to renewable energy generation in its Distribution System Plan. In addition, there are no additional OM&A costs proposed related to renewable energy generation.

2. CURRENT ASSESSMENT

2.1 Halton Hills Hydro Distribution System

Halton Hills Hydro is a local distribution company responsible for the distribution of electricity to approximately 23,000 homes and businesses within the Town of Halton Hills. It is a subsidiary of Halton Hills Community Energy Corporation whose sole shareholder is the Town of Halton Hills. Halton Hills Hydro owns and operates 1,527 km of circuits to deliver energy and power to its customers. It receives power from Hydro One Networks Inc. from four (4) 44kV sub-transmission feeders and three (3) 16/ 27.6kV feeders. It delivers electricity to its customers via twelve 44kV step-down municipal substation and three aforementioned 16/ 27.6kV feeders.

2.2 Existing Distributed Generation

As of December 5, 2014, Halton Hills Hydro has connected 107 microFIT (10kW or less) and six small to mid-sized Feed-In Tariff (FIT) (less than 500kW) projects for a total of 2.589MW of renewable generation. In addition, Halton Hills Hydro is aware of six (6) pending small FIT applications from renewable generators in Halton Hills Hydro's service area, totaling 2.313MW. The total microFIT and FIT capacity allocations and connections by municipal substation feeder are shown in Table 1 below. In addition, Halton Hills Hydro has renewable energy generation projects connected direct to our 27.6kV and 44kV feeders. Presently Halton Hills Hydro has one net metered solar PV micro-generator actively interconnected to our distribution system. There exists a second net metered solar PV micro-generator that was interconnected to our distribution system. This micro-generator has since disconnected their system for repairs. At this time Halton Hills Hydro is unaware if this generator will reconnect. In that respect Halton Hills Hydro does not foresee capacity constraints that would prohibit the generator from reconnecting.

Table 1: Allocated/ Connected Capacity & Remaining Capacity on 4.16kV and 8.32kV Feeders

Substation Designator	Feeder	Feeder Capacity Limit (MW)	Total Feeder Capacity Allocated & Connected (MW)	Remaining Available Feeder Capacity (MW)
19	1	1.440	0.450	0.990
	2	1.440	0.014	1.426
	3	1.440	0	1.440
23	1	0.850	0.119	0.731
	2	0.850	0.027	0.8234
	3	0.850	0.020	0.83012
1	1	0.850	0.020	0.8301
	2	0.850	0	0.850
	3	0.850	0.007	0.8428
7	1	0.720	0.036	0.68433
	2	0.720	0.010	0.710
	3	0.720	0	0.720
13	1	1.440	0.010	1.430
	2	1.440	0.004	1.4357
	3	1.440	0.010	1.430
11	1	1.500	0.059	1.44112
	2	1.500	0.057	1.44329
	3	1.500	0.055	1.44524
17	1	1.440	0.027	1.41292
	2	1.440	0.006	1.434
	3	1.440	0.025	1.41475
21	1	0.850	0.020	0.830
	2	0.850	0.010	0.840
	3	0.850	0	0.850
15	1	1.440	0.502	0.93839
	2	1.440	0.058	1.3819
	3	1.440	0.006	1.4344
5	1	0.850	0.169	0.681137
	2	0.850	0.085	0.76487
	3	0.850	0.006	0.844
9	1	0.720	0.009	0.71054
	2	0.720	0.016	0.70398
	3	0.720	0.027	0.693
3	1	0.720	0.017	0.7028
	2	0.720	0	0.720
	3	0.720	0.004	0.7158

The connected and allocated capacity, as well as potential capacity based on recent IESO Distribution Assessment Tests, are shown in Table 2 below.

Table 2: Allocated/ Connected Capacity on 27.6kV and 44kV Feeders

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

Because our 44kV and 16/ 27.6kV feeders originate at a Hydro One owned transformer stations, Halton Hills Hydro has not included available or remaining capacity for these feeders as they are owned by Hydro One. Rather Halton Hills Hydro will utilize on-line resources provided by Hydro One to assess feeder capacity for new renewable energy generation.

In addition to the above station available capacity information, the cumulative generation connections are limited on an individual feeder basis as follows:

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

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

2.3 System Capability Assessment for Renewable Energy Generation

The estimated capability of Halton Hills Hydro's distribution system to accommodate renewable energy generation connection at each municipal substation is shown in Table 1. Table 1 lists the calculated feeder capacity at each of our 4.16kV and 8.32kV substations, the allocated capacity (i.e. connected capacity and not yet connected capacity), and the estimated remaining capacity on each feeder. The amount of available capacity in respect of each substation is derived from the Kilovolt-Amp rating of the transformer.

At this time Halton Hills Hydro is not aware of specific system limitations where constraints are expected to emerge that would constrain microFIT projects. Also, there are no anticipated constraints on main feeders for FIT projects (less than 0.5MW). With respect to FIT projects greater than 500kW Halton Hills Hydro may have capacity depending on the feeder and point of common coupling. With respect to large scale renewable energy projects (ie: greater than 10MW) Halton Hills Hydro does not anticipate such projects and at this time has not assessed its distribution system to determine if such sized projects could connect.

As well, Halton Hills Hydro is not aware of an capacity restrictions at Hydro One owned Pleasant TS DESN1, Fergus TS, and Halton TS and we believe there remains sufficient short-circuit capacity to accommodate the type of distributed generation that Halton Hills Hydro has seen so far. All of the renewable energy projects proposed in Halton Hills Hydro service area are inverter-based with limited fault contribution to Halton Hills Hydro's distribution system. It is unlikely that the fault contribution from the anticipated distributed generation will cause the transformer stations to reach the short-circuit capacity limits although as Halton Hills Hydro does not own the transformer stations from which we are supplied we shall coordinate efforts with Hydro One as necessary.

3. PLANNED DEVELOPMENT

3.1 Projected Renewable Generation Growth

To date, the Renewable Generation installations in Halton Hills Hydro's service area consist of rooftop solar PV smaller than 0.5MW. As indicated by the IESO's FAME website, there are six (6) small to mid-sized FIT applications under the current FIT program with a total proposed capacity of 2.313MW (refer to Appendix A). As these applications have received a pass for their respective Distribution Assessment Tests (DAT's), it is reasonable to estimate that most if not all applications will proceed to connection. It is also reasonable to estimate that the remaining customers who do not receive a FIT contract under the current FIT program may choose to pursue a contract at a later time.

Since the microFIT's program inception in 2009, Halton Hills Hydro has made approximately 18 connections per year with 2011 being our most significant year in which 31 microFIT projects were connected. This translates to an average of 0.149MW of microFIT connected on average per year since program inception. Based on our experience with application volume we expect to continue connecting 10 – 15 projects annually for microFIT projects totaling between 0.1MW to 0.15MW annually.

Based on Halton Hills Hydro's assessment of past volumes of connections and applications we have received over the past 12 months, Halton Hills Hydro anticipates the connection of renewable energy generation will remain steady through 2020. This estimate assumes that the IESO does not significantly change the program rules and rate calculation methodology.

Based on experience to date, it is estimated that Halton Hills Hydro has enough remaining station capacity and distribution infrastructure to accommodate the demand for renewable energy projects under FIT/microFIT program from 2016 to 2020. However, should microFIT or FIT connections become concentrated in specific areas such as commercial/industrial development's, Halton Hills Hydro will assess potential system limitations and work with the applicants to enable renewable energy connections provided such connections would not adversely affect the distribution system or create a hazard to the public.

3.2 IESO Consultation

Halton Hills Hydro consults with the IESO on a regular basis as new contracts are approved and will continue to do so in the future. The IESO's letter of comment with respect to Halton Hills Hydro's Renewable Energy Generation Plan is provided in Appendix B of this DS Plan.

3.3 Hydro One Networks Inc. Consultation

Halton Hills Hydro communicates regularly with Hydro One in respect of renewable energy generation projects. Since the inception of the Threshold Connection Impact Assessment, more recently termed Threshold Allocation Assessment, Halton Hill Hydro has worked with Hydro One to obtain and maintain allocated capacity for our 44kV feeders originating at Pleasant TS DESN1 in Brampton. On January 24, 2011 Hydro One allocated 2MW of capacity to Halton Hills Hydro and since that time we have renewed the allocated capacity to enable renewable generation connections. Such allocated capacity has enabled Halton Hills Hydro to work closely with generation proponents and communicate directly with Hydro One's Ontario Grid Control Center (OGCC) to coordinate pending connections. Halton Hills Hydro will continue to work with Hydro One to maintain capacity allocation for our dedicated feeders to enable renewable energy generation connections as long as capacity remains available.

4. PLANNED INVESTMENT

Under the rules for connecting renewable energy projects in the Distribution System Code, Halton Hills Hydro will be responsible for funding new feeder assets required to connect FIT generators to a maximum of $90,000 per MW. To date, FIT connections that have taken place in Halton Hills Hydro's service area have not required distribution system expansions.

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

- Feeder Extension and Upgrades – Such projects often include upgrading the size of distribution transformers and primary and secondary circuit wire along the main distribution circuit. These upgrades at the distribution level may more positively impact local smaller (micro) renewable generation often connected single phase 120/240V by increasing local capacity. Such upgrades could also benefit small to mid-sized generation that would be connected three phase 120/208V or 600/347V. Considerations such as upgrading transformers beyond what is needed for the load service where no prospect of renewable generation is apparent may not be cost effective both in respect of material costs as well as no-load and load losses inherent in the transformer due to energizing the primary coil.

- Converting 4.8/8.32Y kV distribution to 16/27.6Y kV – Halton Hills Hydro is planning to continue converting parts of our 4.8/ 8.32Y kV rural distribution system to 16/27.6Y kV in areas we foresee future development and to support our existing distribution system. In doing so parts of our 4.8/ 8.32Y kV that are presently single phase may be converted to 16/27.6Y kV three phase potentially enabling small- to mid-sized renewable generation (FIT) projects. Presently much of our rural service territory includes farm and residences serviced by single phase 120/240V stepped down from 4.8kV. The largest size of distribution transformer that can be connected to a single phase system is 167kVA. By upgrading a single phase circuit to three phase the ability to connect renewable generation in excess of 167kVA increases; however connection would be made three phase, not single phase, to better address potential phase balancing impacts.

Based on experience to date and projected future connected load, no investments specific to renewable energy generation for the period 2016 - 2020 are expected, in order to accommodate the renewable energy generation connections.

From an OM&A perspective Halton Hills Hydro has been able to manage the workload related to processing renewable energy applications using existing staff for responding to the microFIT inquiries, conducting the site visits, preparing the offers to connect and microFIT data entries. Halton Hills Hydro anticipates that the number of applications in the future will not increase workload such that additional resources are necessary and therefore has not included any OM&A costs in our Distribution System Plan.

4.1 Overall Assessment

Based on a calculated remaining maximum capacity and the projected generation projects that we are aware of, Halton Hills Hydro has capacity in place to accept future renewable generation projects.

Appendix A: Proposed small FIT applications

The proposed small FIT applications in Halton Hills Hydro service area as shown on the IESO FAME website are provided in the following table. These small FIT applications have received a pass with respect to the DAT test and therefore it is reasonable these projects will proceed to connection.

Number of Applications	Capacity (MW)	TS Name, Upstream Feeder Name, Voltage (as indicated by the applicant)
1	0.450	Pleasant TS DESN1, 42M28, 44kV
1	0.500	Pleasant TS DESN1, 42M28, 44kV
1	0.500	Pleasant TS DESN1, 42M28, 44kV
1	0.250	Pleasant TS DESN1, 42M28, 44kV
1	0.113	Pleasant TS DESN1, 42M28, 44kV
1	0.250	Pleasant TS DESN1, 42M23, 44kV

Appendix B: IESO Letter

As per Section 5.1.4.2 of the DS Plan Filing Requirements, the Board expects that the IESO comment letter will include:

- The applications it has received from renewable generators through the FIT program for connection in the distributor's service area;
- Whether the distributor has consulted with the IESO, or participated in planning meetings with the IESO;
- The potential need for co-ordination with other distributors and/or transmitters or others on implementing elements of the Renewable Energy Generation investments; and
- Whether the Renewable Energy Generation investments proposed in the DS Plan are consistent with any Regional Infrastructure Plan.

The Board may postpone processing an application where a comment letter from the IESO has not been filed in accordance with this requirement.

FLEET BUDGETING 2015 January 27, 2015

REVISED: **Jan 28, 2015**

#	Make	Model	Year	License Fees	Plate #	Description	PURCHASE YEAR	AGE IN BUDGET YEAR 2015	LIFE EXPT	Dept	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
101	FORD	RANGER	2010	$98.00	6732NZ	PICK UP 4X4	2010	5	10	OPER						$35,000							
102	JEEP	CHEROKEE	2014	$98.00	BSSY054	PASSENGER 4X4	2013	2	10	ENG										$37,000			
103																							
104																							
105																							
106	FORD	F150	2010	$98.00	6821YK	PICK UP 4X4 EXT. CAB	2010	5	10	OPER						$45,000							
107	INTERNATIONAL	POSI PLUS	2014	$1,628.00	AF71393	68' DOUBLE BUCKET	2014	1	12	OPER											$110,000	$290,000	
108	INTERNATIONAL	WAJAX	2008	$1,769.00	5485JK	SMALL RBD	2008	7	12	OPER						$110,000	$290,000						
109	INTERNATIONAL	AMADOR	1997	$1,978.00	5477JK	60 DOUBLE BUCKET	1996	19	12	OPER	$325,000												$100,000
110	INTERNATIONAL	WAJAX	2004	$1,769.00	5483JK	LARGE RBD	2003	12	12	OPER		$110,000	$290,000										
111																							
112												$35,000						$35,000					
113	INTERNATIONAL	POSI PLUS	2008	$505.50	2403XA	46 SINGLE MHAD	2008	7	5	OPER				$100,000	$225,000								
114	CHEVROLET	FULL SIZE	2008	$174.00	2235WP	AWD VAN	2008	7	10	OPER				$37,000									
115	FORD	RANGER EXT	2011	$98.00	7461ZW	PICK UP 4X4 EXT. CAB	2011	4	10	ENG								$32,000					
116																							
117	INTERNATIONAL	POSI PLUS	2010	$814.00	5043YK	68' DOUBLE BUCKET	2010	5	12	OPER								$110,000	$290,000				
118	CHEVROLET	FULL SIZE	2009	$174.00	8238XA	AWD VAN	2009	6	10	METER					$37,000								
119	INTERNATIONAL	POSI PLUS	2012	$1,011.00	AA78020	46 SINGLE MHAD	2012	3	12	OPER										$100,000	$225,000		
120																							
121																							
122	JEEP	LIBERTY	2010	$98.00	AJSA 956	JEEP 4X4	2010	5	10	ENG						$37,000							
123																							
124																							
125	FORD	F250	2010	$221.00	7779XZ	PICK UP 4X4 CREW	2010	5	10	OPER						$50,000							
126																							
127																							
128																		$50,000					
129																							
130	FORD	F250	2013	$221.00	AD68463	PICK UP 4X4 CREW	2013	2	10	OPER										$50,000			
131	FORD	F450	2011	$1,077.00	5856ZV	DUMP TRUCK	2011	4	12	OPER								$60,000					
140	FORD	F550/VERSALIFT	2007			42'SINGLE BUCKET	2013	8	7	SWE													
		TOTAL LICENSE FEE		$11,831.50																			
	TRAILERS																						
201	TIMBERLAND	TRAILER	1998		unplated	REEL TRAILER	1998	17	20	OPER				$90,000									
202	BOBCAT	SKID STEER			unplated					OPER	Evaluate					Evaluate					Evaluate		
203																							
204	LIFT KING	FORKLIFT			unplated	LARGE FORKLIFT				OPER	Evaluate					Evaluate					Evaluate		
205																							
206	TIMBERLAND	TRAILER	2009		F2543Z	REEL TRAILER	2010	5	20	OPER													
207																							
208	GENERATOR	GEN TRAILER	1985		Y25687	43 Alice St backup generator	1985	30	30	OPER	Evaluate					Evaluate					Evaluate		
209	POLE TRAILER	TRAILER	2007		EG2210	POLE TRAILER - LARGE	2008	7	20	OPER													
210	NISSAN	FORKLIFT	1992		unplated	SMALL FORKLIFT	1992	23	25	OPER			Evaluate			Evaluate					Evaluate		
211	POLE TRAILER	TRAILER	2011		J9489J	POLE TRAILER - SMALL	2011	4	20	OPER													
212	COLEMAN	POWER SPORT	2000			SMALL GENERATOR	2000	15	20	OPER						$1,000							
213	SNOWBEAR	TRAILER	2004		B9024A	UTILITY TRAILER	2004	11	15	OPER					$4,000								
214	KUBOTA		2000			LARGE GENERATOR	2000	15	20	OPER						$2,000							
215	FMG Contracting	TRAILER	2011		J3779S	Material/Reel Trailer	2011	4	20	OPER													
216	RIGID 7000	Honda GX390 motor	2013			LARGE GENERATOR	2013	2	20	OPER													

2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
$325,000	$145,000	$290,000	$227,000	$266,000	$280,000	$290,000	$287,000	$290,000	$187,000	$335,000	$290,000	$100,000

****NOTE: PROVINCIAL TAX INCLUDED IN VEHICLE PRICE**

45' SINGLE BUCKET ... $325,000
68 DOUBLE BUCKET or HEAVY DUTY DIGGER/DERRICK ... $400,000

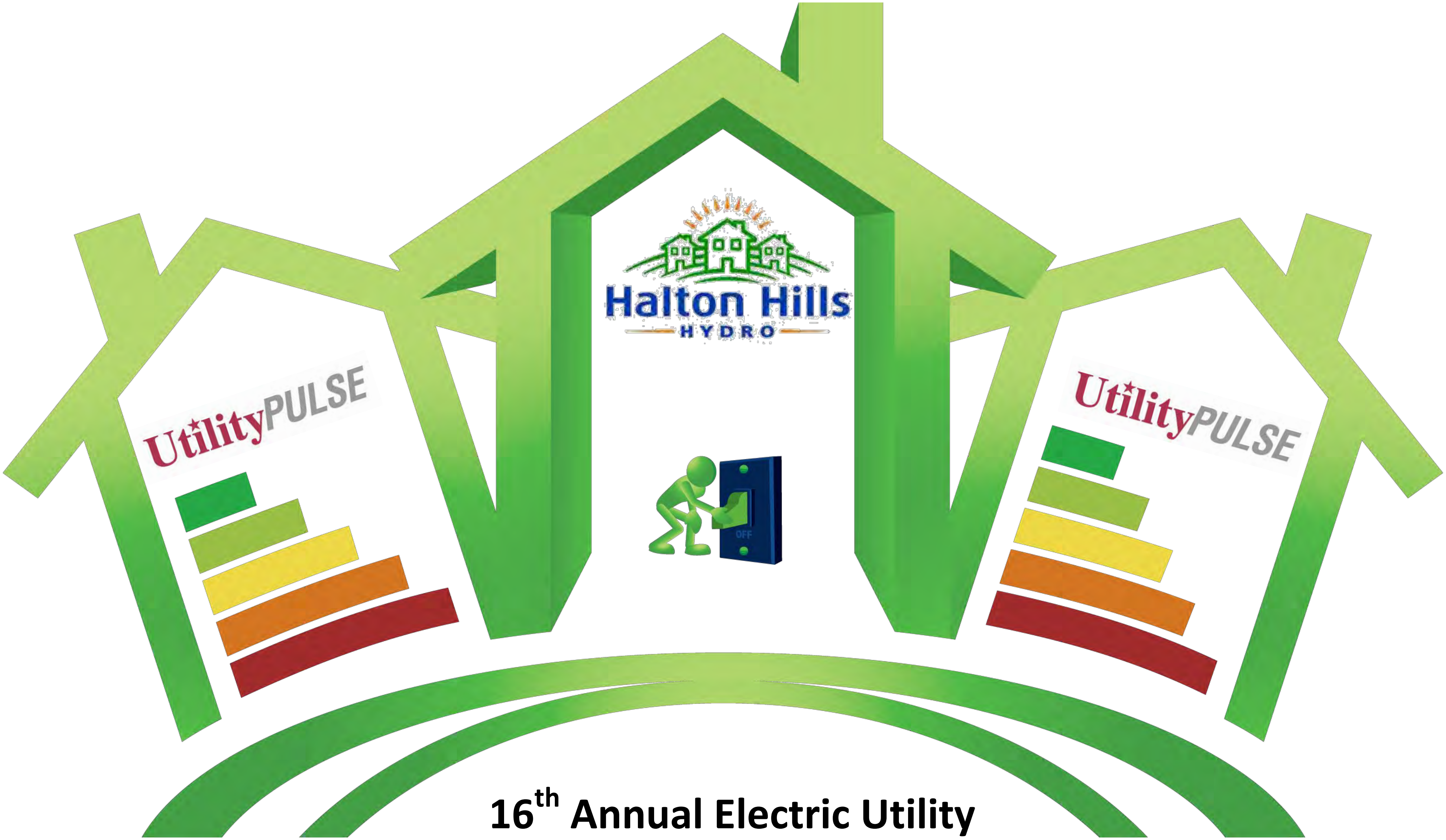
ONE (1) TON PICK UP ... $50,000
HALF TON PICK UPS ... $35,000

FULL SIZE VANS & JEEPS... $37,000

STRINGING MACHINE...$90,000
FORK LIFT...$80,000
POLE TRAILER $35,000

GENERATOR: SMALL - $1000, LARGE - $2000

Halton Hills Hydro Inc.



16th Annual Electric Utility
Customer Satisfaction Survey

The purpose of this report is to profile the connection between Halton Hills Hydro and its customers.

The primary objective of the Electric Utility Customer Satisfaction Survey is to provide information that will support discussions about improving customer care at every level in your utility.

The UtilityPULSE Report Card® and survey analysis contained in this report do not merely capture state of mind or perceptions about your customers' needs and wants - the information contained in this survey provides actionable and measurable feedback from your customers.

All comments and questions should be addressed to:

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Email: sidridgley@utilitypulse.com or sridgley@simulcorp.com

Executive summary

Rosemarie LeClair, Chair of the Ontario Energy Board, in a recent presentation (Ontario Energy Network, April 28, 2014) said the OEB's consumer centric regulatory framework defines the utility's obligation for planning, obligations for customer engagement and its responsibilities for monitoring and measuring performance results.

EB-2010-0379 Report of the Board: Scorecard Approach (ROB-SA) (March 5, 2014)

Throughout this report are connections to the OEB's Report of the Board. Where possible we have addressed the specifics in the document and, the "spirit" of the Scorecard Approach.

We believe that the data from interviewing over 10,000 electric utility customers so far, in 2014, supports 3 main conclusions:

1- Customers, almost universally, are concerned about the cost of electricity

2- Customers are resilient and can adapt to adversity, in fact, they are very tolerant when a utility goes through a very difficult situation

3- In a utility world that is used to "pushing information out", it has to invest in and hone its competencies in having 2-way interactions with customers.

Reasonable costs

9,943 Ontario survey respondents were asked if they agree or disagree with the following statement *"The cost of electricity is reasonable when compared to other utilities".* 50% agree in 2014, and 62% agreed in 2010. Satisfaction with the utility is about the same in those respective years.

We can also say that issues in the electricity industry, as a whole, show satisfaction ratings and other important measures lower in 2014 than they were in 2013. A customer may be upset with the amount that electricity costs, or what is going on in the industry, but that may not translate to being upset with their own local utility.

Data from the 2014 survey shows that respondents who give their utilities high marks for respect, trust, and social responsibility also give their utilities high marks for providing high quality services, and better marks for both cost efficiency and reasonableness of costs.

The attributes which help an LDC to be seen as trusted and highly credible are: knowledge, integrity, involvement and trust. On demonstrating Credibility and Trust, Halton Hills Hydro has done well. Overall, Halton Hills Hydro 83% [Ontario 77%; National 80%].

EB-2010-0379 ROB-SA: Comparability

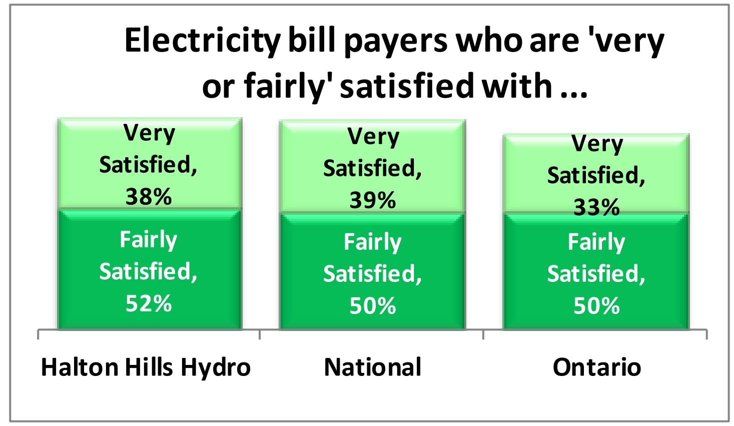
Your 2014 report contains data comparisons to:

- An Ontario-wide LDC benchmark
- A National LDC benchmark
- Previous year's ratings (where available)

- Ontario LDCs participating in the 2014 survey
- UtilityPULSE database

EB-2010-0379 ROB-SA: Customer Focus

There are 2 identified Performance Categories in the OEB Report, they are Customer Satisfaction & Service Quality. Performance measurements for these areas range from *'relatively easy to attain production statistics'* to '*harder to define and measure qualitative items'*. None-the-less this survey provides you with insights about how customers perceive performance of the utility.



Base: total respondents

EB-2010-0379 ROB-SA: Customer Focus - Customer Satisfaction - Satisfaction Survey Results

Customer satisfaction is one of the measures in the consumer centric regulatory framework. This rating is known as an effectiveness rating as it represents a sum total of perceptions and expectations that a customer has about their utility. Those expectations go far beyond "keeping the lights on", "billing me properly", and "restoring power quickly".

Halton Hills Hydro SATISFACTION SCORES – Electricity customers' satisfaction					
Top 2 Boxes: 'very + fairly satisfied'	**2014**	**2013**	**2012**	**2011**	**2010**
PRE: Initial Satisfaction Scores	90%	-	-	93%	-
POST: End of Interview	90%	-	-	92%	-

Base: total respondents / (-) not a participant of the survey year

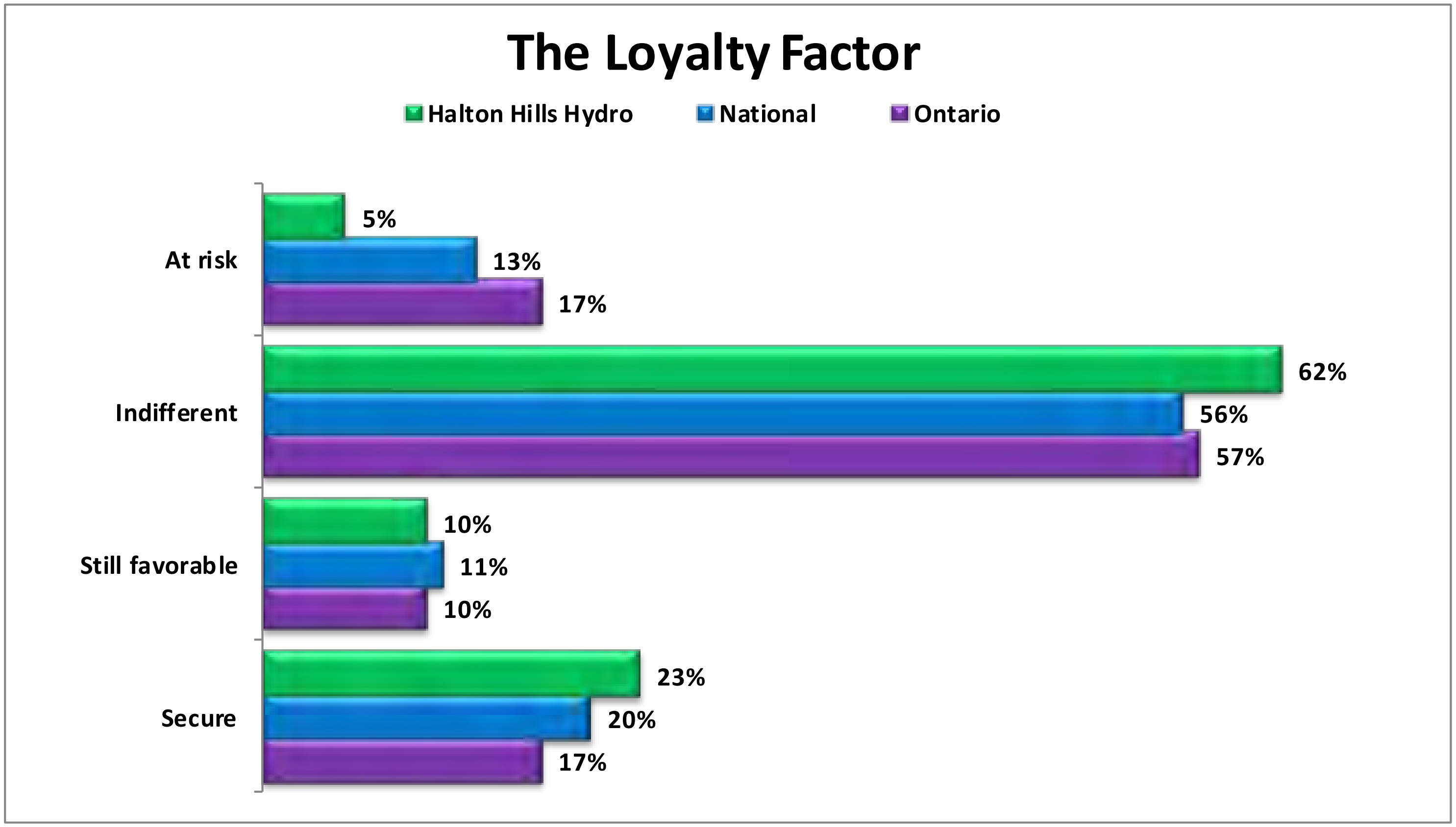
- ***Satisfaction*** *happens when utility core services meet or exceed customer's needs, wants, or expectations.*
- ***Loyalty*** *(Affinity) occurs when a customer makes an emotional connection with their electric utility on a diverse range of expectations beyond core services.*

Customer Affinity

Loyalty, for private industry, is a behaviourial metric. Loyalty, for natural monopolies (like LDCs) is an attitudinal metric.

Customer Loyalty Groups				
	Secure	**Favorable**	**Indifferent**	**At Risk**
Halton Hills Hydro				
2014	23%	10%	62%	5%
2013	-	-	-	-
2012	-	-	-	-
2011	29%	12%	55%	5%
2010	-	-	-	-

Base: total respondents / (-) not a participant of the survey year



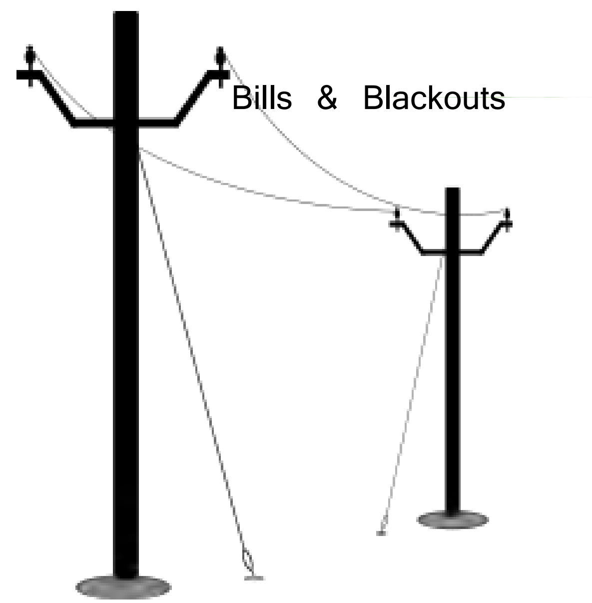
Base: total respondents

Utilities benefit from a trusted relationship with their empowered Customers. Higher levels of trust are the hallmarks of Secure customers. When people interact, either face-to-face, by telephone or on-line, if people do not trust each other, the interaction is not going to be efficient. Trust improves the speed at which the interaction can be accomplished. At Risk customers recall experiencing more outages and more billing problems than Secure customers. What makes matters worse is, At Risk customers are about 2X more likely to contact the utility to deal with it.

None-the-less problems will happen.

The Killer B's (Blackouts and Bills)

It is inevitable that there will be blackouts/power outages – the key is how a utility anticipates outages and more importantly, how it deals with them. It should also be noted that there is a disconnect between what a utility might call a "billing problem" and what a customer defines as a "billing problem". Though both viewpoints are valid, employees need to be trained to answer those which cause the most concern with customers.



Percentage of Respondents indicating that they had a Blackout or Outage problem in the last 12 months			
	Halton Hills Hydro	National	Ontario
2014	45%	47%	49%
2013	-	41%	35%
2012	-	44%	46%
2011	45%	43%	43%
2010	-	45%	41%

Base: total respondents / (-) not a participant of the survey year

Percentage of Respondents indicating that they had a Billing problem in the last 12 months			
	Halton Hills Hydro	**National**	**Ontario**
2014	14%	16%	25%
2013	-	8%	10%
2012	-	12%	13%
2011	10%	10%	16%
2010	-	10%	12%

Base: total respondents / (-) not a participant of the survey year

What method did you use to contact your electric utility when you had a problem?

Base: data from the full 2014 database

Customers may prefer a particular communication channel today (i.e., 88% telephone), however, that does not mean the customer who prefers the telephone will not want, or eventually want another channel for communications. In addition, there could be variances in preferences based on the type of issue or transaction.

EB-2010-0379 ROB-SA: Customer Focus – Customer Satisfaction – Billing Accuracy

There is a difference between what a customer believes is a billing problem versus a technical or production level measurement. Without the benefit of production level numbers, 85% of respondents 'agree strongly + somewhat' that the utility has "accurate billing". The Ontario benchmark rating is 77%.

EB-2010-0379 ROB-SA: Customer Focus – Customer Satisfaction – First Contact Resolution

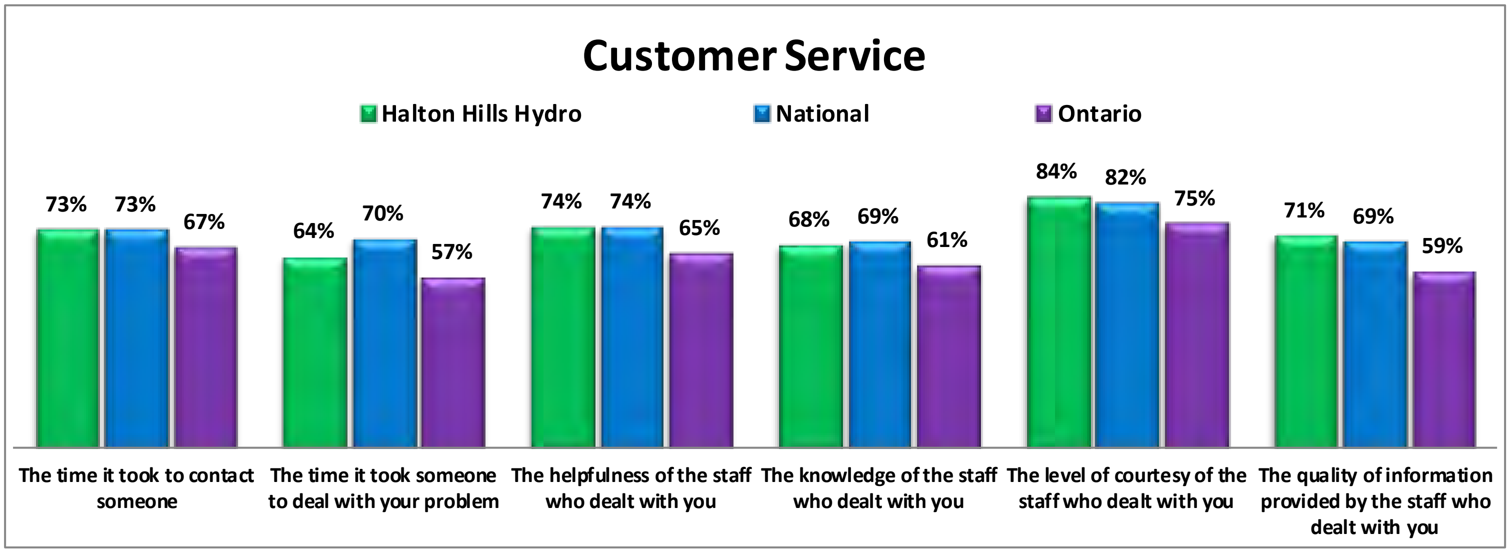
This performance measure is not defined in the EB-2010-0379 ROB-SA March 5, 2014 document. First contact resolution is an outcome base measurement which is affected by: type of problem, competency levels of staff, empowerment levels of staff, and organization culture to name a few.

Your 2014 survey gives you the following information from respondents:

1- Satisfaction with the contact experience
2- A problem solved rating
3- A Customer Experience Performance rating (CEPr)

Satisfaction with the contact experience

When there are problems, how they are handled can validate or invalidate a customer's perception about the utility's competency in handling the problem, and in running the operation. Here is how Customers, who contacted your LDC, rated their one-on-one transaction.



Base: total respondents who contacted the utility

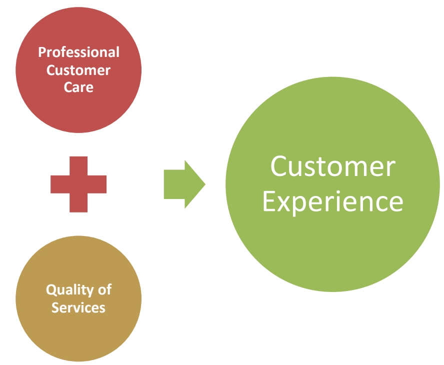
Customer expectations are on the rise and continue to change. Customers expect their utility to have customer care practices and services that are in-line with any other organization that is important to their everyday life. Setting realistic expectations and consistently delivering to those expectations are keys to higher levels of Customer satisfaction. The setting of customer expectations is tough, but the harder part is to deliver consistency.

Overall satisfaction with most recent experience			
	Halton Hills Hydro	**National**	**Ontario**
Top 2 Boxes: 'very + fairly satisfied'	66%	75%	62%

Base: total respondents who contacted the utility

Problem solved rating

Respondents who said that they contacted the utility were also asked "Do you consider the problem solved or not solved?" 66% of your LDC's respondents said the problem was solved. The Ontario benchmark rating is 61%.



Customer Experience Performance rating (CEPr)

What do customers anticipate contact will be with their local utility when they have a problem? Will it be adversarial, or cooperative, or pleasant, etc. High numbers in CEPr indicate that a large majority of customers would agree that their next contact will be a good or positive one.

Customer Experience Performance rating (CEPr)			
	Halton Hills Hydro	**National**	**Ontario**
CEPr: all respondents	84%	82%	79%

Base: total respondents

EB-2010-0379 ROB-SA: Customer Focus – Service Quality

The three performance measures identified are all time based measures. They are: New Residential Services Connected on Time; Scheduled Appointments Met on Time; and, Telephone Calls Answered on Time. These are good examples of efficiency measures. In addition to time, there are other dimensions of Service Quality that Customers value.

Customer Service Quality

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

Base: total respondents with an opinion

EB-2010-0379 ROB-SA: Operational Effectiveness

With the exception of the Public Safety measure, which is yet to be defined, performance measures would typically take the form of a monitoring and measuring (quantitative) rating. Though customers may not have the benefit of numbers, they do have a perception.

Management Operations

Top 2 boxes, 'strongly + somewhat agree'	Halton Hills Hydro	National	Ontario
Provides consistent, reliable electricity	89%	89%	86%
Quickly handles outages and restores power	82%	86%	83%
Makes electricity safety a top priority for employees and contractors	88%	89%	87%
Operates a cost effective electricity system	75%	69%	62%
Overall the utility provides excellent quality services	85%	83%	80%

Base: total respondents with an opinion

UtilityPULSE Report Card®

The purpose of the UtilityPULSE Report Card is to provide your utility with a snapshot of performance – it represents the sum total of respondents' ratings on 6 categories of attributes that research has shown are important to customers in influencing satisfaction and affinity levels with their utility.

Halton Hills Hydro's UtilityPULSE Report Card®

Performance

	CATEGORY	Halton Hills Hydro	National	Ontario
1	**Customer Care**	**B+**	**B+**	**B**
	Price and Value	B	B	C+
	Customer Service	A	B+	B
2	**Company Image**	**A**	**B+**	**B+**
	Company Leadership	A	B+	B+
	Corporate Stewardship	A	A	B+
3	**Management Operations**	**A**	**A**	**A**
	Operational Effectiveness	A	A	B+
	Power Quality and Reliability	A	A	A
	OVERALL	**A**	**B+**	**B+**

Base: total respondents

Corporate Image

Reputation, image, brand have to be actively managed. Positive impressions beget positive perceptions. Marketing communication includes positioning the utility in a way that makes customers want your utility and its services. Every utility has a brand, why not have the brand you want?

Attributes strongly linked to a hydro utility's image

	Halton Hills Hydro	National	Ontario
Is a respected company in the community	88%	81%	78%
A leader in promoting energy conservation	82%	78%	77%
Keeps its promises to customers and the community	84%	79%	76%
Is a socially responsible company	85%	78%	77%
Is a trusted and trustworthy company	86%	82%	77%
Adapts well to changes in customer expectations	77%	71%	68%
Is 'easy to do business with'	85%	79%	75%
Provides good value for your money	70%	67%	63%
Overall the utility provides excellent quality services	85%	83%	80%
Operates a cost effective hydro-electric system	75%	69%	62%

Base: total respondents with an opinion

Customers, as human beings, are both rational and emotional. The rational side of the customer holds the LDC accountable for doing its job (as contracted), thereby fulfilling the customer's basic needs. The emotional side of the customer is about fulfilling expectations. Meeting rational needs – at best – gets the customer to a neutral state and at worst creates dissatisfaction. Emotional needs, when met, assuming base level rational needs are met, can move a customer from neutral to higher levels of satisfaction. The industry is obsessed with rational concerns about customer behaviour, but the real motivation for customer behaviour is emotional, not rational.

What do customers think about electricity costs?

Ask a utility customer – anywhere in the province of Ontario – what do they think about electricity, there is a very high probability they will say electricity costs are too high or too expensive. For customers who said that they had a billing problem in the last 12 months, and stated that the problem was “high bills” or “high rates or charges”, there was very little variability between customers who could be called Secure, Favourable, Indifferent or At Risk. There was also very little variability between age groupings or income groupings.

Our survey database shows 50% more customers in 2014 citing complaints with “high bills” or “high rates or charges” than in 2010. There is a growing concern over electricity costs, especially as it relates to its portion of a household budget. This means the industry needs to monitor “ability to pay”.

Is paying for electricity a worry or major problem …

	Halton Hills Hydro	National	Ontario
Not really a worry	70%	69%	59%
Sometimes I worry	17%	20%	26%
Often it is a major problem	7%	7%	11%
Depends	2%	3%	2%

Base: total respondents

Supplemental Insights

Recognizing that customers' interests and needs continue to shift, we have provided data and insights, on a number of subjects such as e-care, e-billing, conservation and more.

Electric Industry Knowledge & SMART Grid

Beyond knowing that they need electricity to maintain their day to day activities, does the average person feel that they are actually knowledgeable about the electric utility industry?

Knowledge level about the electric utility industry	
	Ontario
Extremely knowledgeable	2%
Very knowledgeable	11%
Moderately knowledgeable	47%
Slightly knowledgeable	26%
Not very knowledgeable	14%
Don't know	1%

Base: total respondents in the Ontario Benchmark survey

Two-thirds (60%) of those polled in the Ontario Benchmark survey considered themselves moderately to extremely knowledgeable about the electric industry.

While it is evident that the SMART grid is still not a much talked about concept, only 34% have a basic or good understanding of what it is, oddly enough, 60% still think that it is important to pursue SMART grid implementation. It is also clear that the majority of respondents are very + somewhat supportive of the utility working with neighbouring utilities on SMART grid initiatives.

Level of knowledge about the SMART Grid	
	Ontario
I have a fairly good understanding of what it is and how it might benefit homes and businesses	9%
I have a basic understanding of what it is and how it might work	25%
I've heard of the term, but don't know much about it	36%
I have not heard of the term	29%
Don't know	1%

Base: total respondents in the Ontario Benchmark survey

Efforts to reduce energy consumption

Do customers believe there is a real pay-off for trying to reduce their energy consumption? Does this impact overall efforts to reduce consumption? Respondents were asked *"How active have you been in trying to reduce your electricity consumption?"* (Base: total respondents in the Ontario Benchmark survey)

- 94% feel they are "very + somewhat active" in trying to reduce electricity consumption, and
- 81% of those do believe their efforts have resulted in reduced energy consumption, of which
- 44% estimate that they were able to offset an energy consumption reduction of more than 10%, and
- 72% believe that these efforts translated to savings on their electricity bills.

Level of Activity in trying to reduce electricity consumption	Ontario
Very active	52%
Somewhat active	42%
Neither proactive or inactive	0%
Not active	2%
Not very active	3%

Base: total respondents in the Ontario Benchmark survey

Estimate of percentage reduction in consumption	Ontario
1 – 2 %	5%
3 – 5 %	10%
6 – 8 %	4%
9 – 10 %	15%
More than 10%	44%
Don't know	21%

Base: total respondents in the Ontario Benchmark survey whose active efforts have reduced consumption

Active efforts have reduced energy consumption

81%

16%

Base: total respondents in the Ontario Benchmark survey who have been active in trying to reduce energy consumption

Efforts to conserve have translated into savings on your electricity bill

72%

24%

Base: total respondents in the Ontario Benchmark survey whose active efforts have reduced consumption

Energy Conservation & Efficiency

Energy efficiency can be broken down into two areas: *better use of energy through improved energy-efficient technologies;* and *energy saving through changes in customer awareness and behaviour.*

Efforts to conserve energy

Halton Hills Hydro	Yes	No	Already Done	Don't Know
Install energy-efficient light bulbs or lighting equipment	21%	9%	69%	1%
Install timers on lights or equipment	14%	46%	39%	1%
Shift use of electricity to lower cost periods	23%	15%	59%	3%
Install window blinds or awnings	14%	27%	58%	1%
Install a programmable thermostat	13%	22%	64%	1%
Have an energy expert conduct an energy audit	8%	75%	15%	2%
Removing old refrigerator or freezer for free	16%	43%	39%	2%
Join the peaksaverPLUS™ program	10%	52%	20%	18%
Replacing furnace with a high efficiency model	12%	37%	48%	3%
Replacing air-conditioner with a high efficiency model	13%	43%	39%	6%
Use a coupon to purchase qualified energy saving products	31%	39%	23%	7%

Base: 90% of total respondents from the local utility

E-care and E-billing

Technology – specifically the internet—has allowed people access to far more information than ever before and the ability to do more than ever before.

Do you have access to the internet?		
	Ontario LDCs	**Halton Hills Hydro**
Yes	87%	86%
No	13%	14%

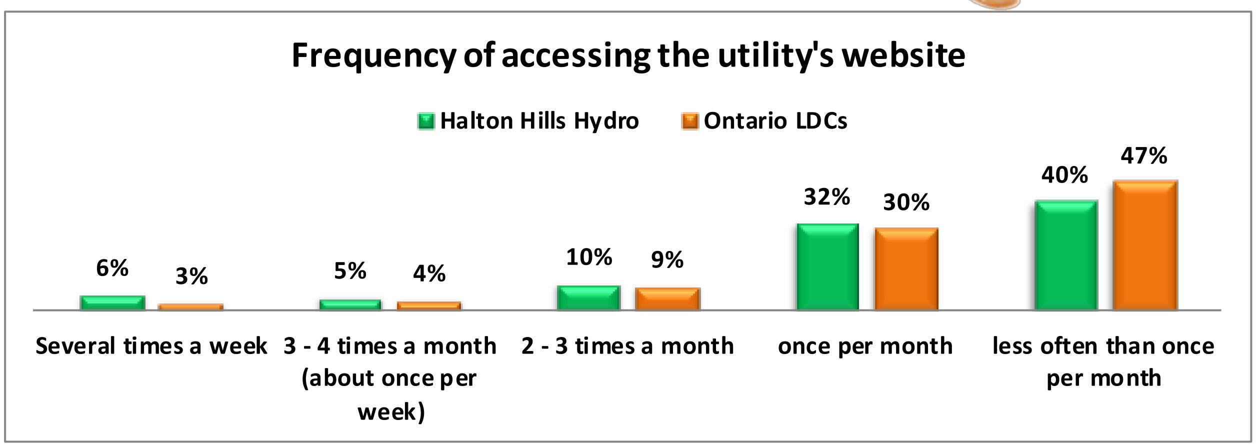
Base: 90% of total respondents from the local utility

Over the past six months have you accessed your local utility website?

43%

57%

Base: 90% of total respondents from the local utility



Base: An aggregate of respondents from 2014 participating LDCs / 90% of total respondents from the local utility

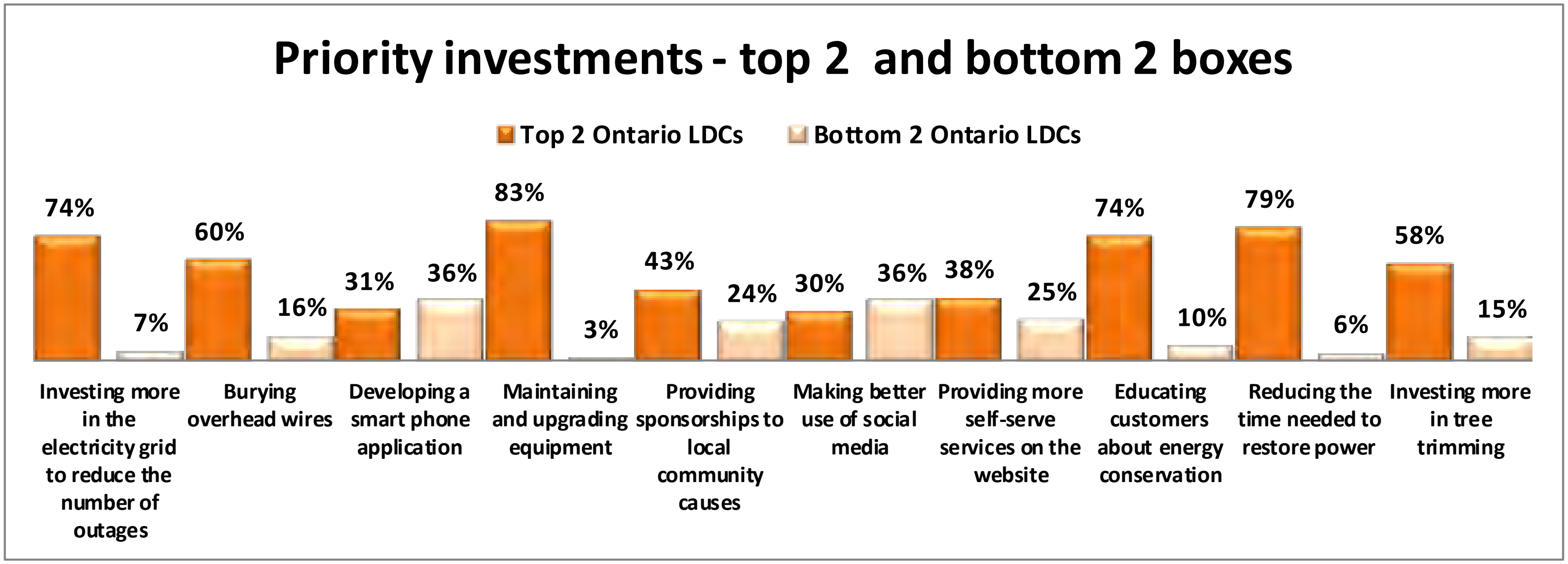
Likelihood of using the internet for future customer care needs for things such as:		
Top 2 Boxes: ‘very + somewhat likely’	**Ontario LDCs**	**Halton Hills Hydro**
Setting up a new account	31%	28%
Arranging a move	38%	34%
Accessing information about your bill	55%	54%
Accessing information about your electricity usage	54%	51%
Accessing energy saving tips and advice	45%	41%
Accessing information about Time Of Use rates	51%	44%
Maintaining information about your account or preferences	51%	49%
Paying your bill through the utility’s website	32%	25%
Getting information about power outages	47%	52%
Arranging for service	40%	36%

Base: An aggregate of respondents from 2014 participating LDCs / 90% of total respondents from the local utility

As society becomes increasingly more familiar with technology it will become a more popular medium for giving and receiving information. One could also say, demographics will also put more pressure on the technology channels. Unfortunately, customers adopt technology on their own timetable. This causes the utility to continue to improve existing channels while building the technological channels wanted by some today, but by the year 2020, demanded by many. Will your utility be ready?

Priority Investments

While regulation and reliability are top concerns in the utility industry, aging infrastructure is now a top operational concern. Customers agree with industry insiders that infrastructure renewal is a high priority. This year, respondents were asked for their views about prioritizing investments.



Base: An aggregate of respondents from 2014 participating LDCs

Some findings shown above correlate with some of the suggestions made by respondents on things the utility could do to improve. Percentage of comments received from all Ontario respondents were:

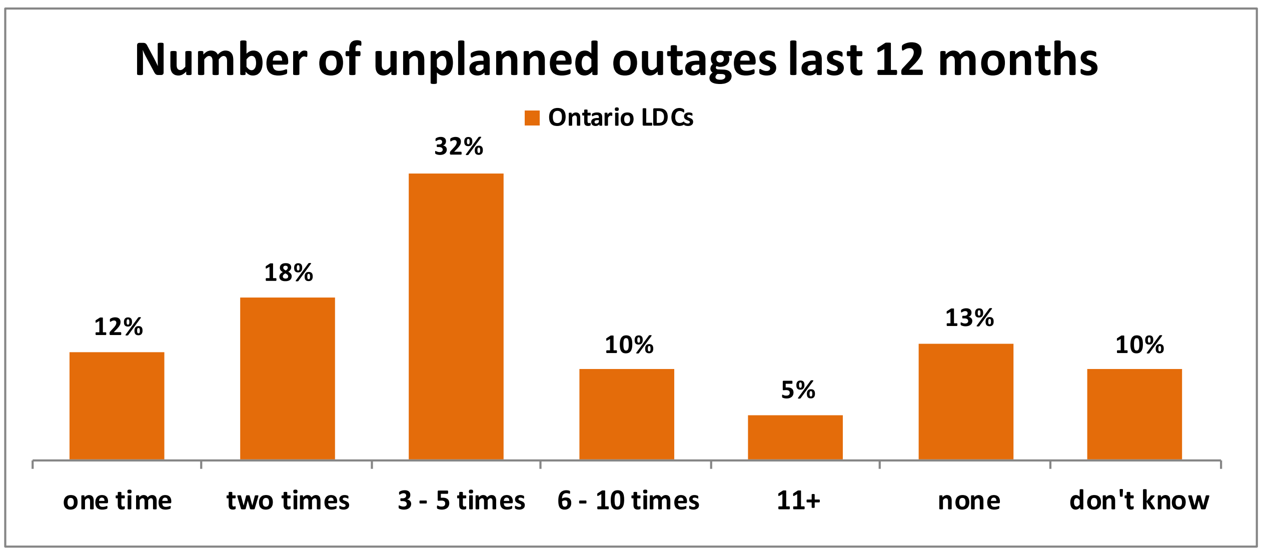
- 14% improve reliability (10% in 2010)
- 11% better maintenance (3% in 2010)

- 10% better communication (7% in 2010)

Outage Management

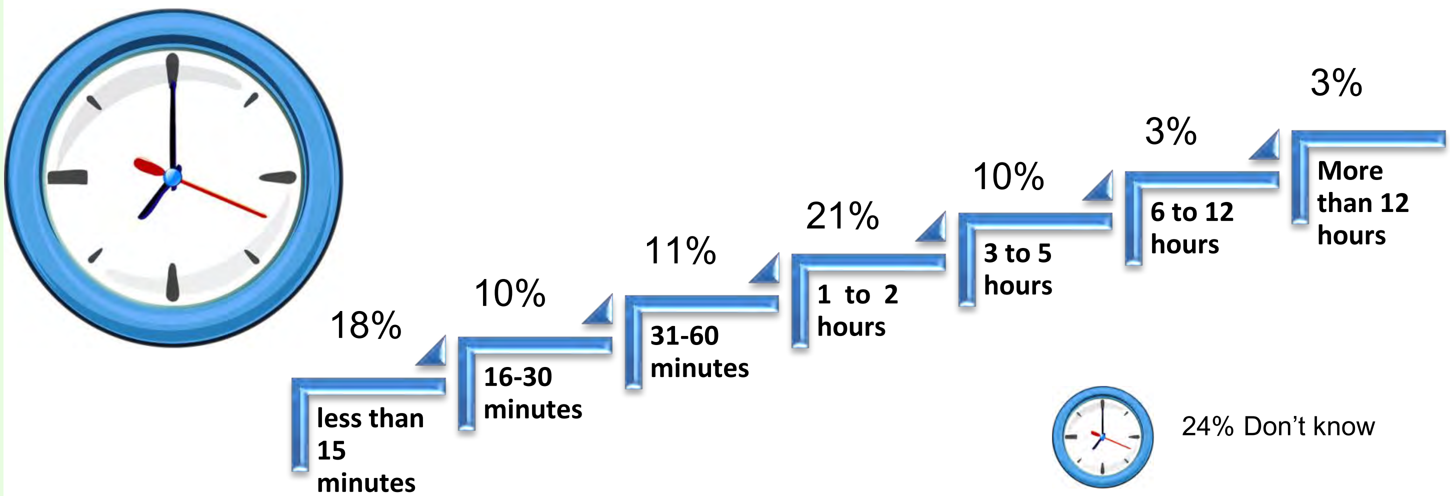
Whether an outage is planned or unplanned, the reality is that it is going to cause disruption and inconvenience under best case scenario and under worst case scenarios there could be safety and financial consequences.

However, one thing for certain, no matter what the scenario happens to be, customers are expecting their utility to keep them continually updated on the status of outages. Most importantly, and top priority, is to know the estimated restoration time. They also want to know the cause of the outage because they do not want to be a frequent outage customer.



Base: An aggregate of respondents from 2014 participating LDCs

When an unplanned outage occurs, how long, on average, is the outage?



Base: An aggregate of respondents from 2014 participating LDCs

How a utility chooses to handle, manage and communicate with customers during an outage situation does affect customers' satisfaction with their utility. Customers want timely, accurate and relevant information about an outage and customers expect a utility to use various communication channels to ensure their message is getting out there. This means not only obtaining information via the call centre and IVR but customers have increasing expectations for proactive two-way communication through social media, utility websites and modern communication devices (e.g. tablets, smartphones) and apps.

Inability to provide the above information accurately and in a timely manner will result in customer complaints, increased call volumes to your call centres, create unwanted public and media attention, and negatively impact customer satisfaction.

Utility's effectiveness during an unplanned outage	
Top 2 Boxes: 'very + somewhat effective'	**Ontario LDCs**
Responding to questions	61%
Providing a reason for the outage	61%
Providing an estimate when power will be restored	60%
Responding to the power outage	81%
Restoring power quickly	85%
Communicating updates periodically	64%
Posting information to the website	35%
Using media channels for providing updates	53%

Base: An aggregate of respondents from 2014 participating LDCs

On December 20, 2013, a severe ice storm struck the central and eastern portions of Canada and the northeastern United States. The storm's devastation caused major damage to utility distribution lines, towers, transformers, poles and entire substations and resulted in large scale outages and blackouts for long periods of time. The data suggests that customers are both tolerant and understanding when major outages take place.

At least 50% of all Ontario respondents surveyed indicated they were affected by the 2013 ice storm.

Percentage of Respondents who contacted their utility about the ice storm power outage

	Halton Hills Hydro
Yes	31%
No	68%

Base: total respondents affected by the ice storm

Halton Hills Hydro
Length of outage (during Ice Storm 2013)

Less than 2 hours	2 – 4 hours	4+ hours or ½ day	12-18 hours or ½ - ¾ day	19-24 hours or 1 day	1 to 1.5 days	1.6 to 2 days	More than 2 days
0%	2%	7%	2%	11%	10%	10%	53%

Base: total respondents affected by the ice storm

Halton Hills Hydro
Method used to contact electric utility about outage during the 2013 ice storm

Telephone	E-mail	Website	Twitter	facebook	In person	Don't know
80%	2%	9%	2%	1%	2%	5%

Base: total respondents affected by the ice storm who said they contacted the utility about the outage during the storm

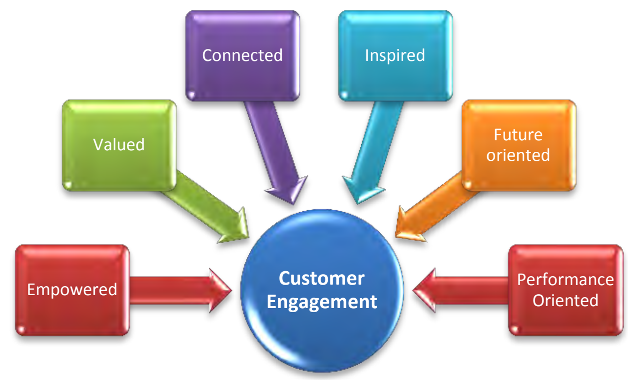
In your view, what is an acceptable period of time to go without electricity in situations like the ice storm?

Base: total respondents affected by the ice storm

•None (the power shouldn't be going out)	7%
•Less than 2 hours	2%
•2 - 4 hours	3%
•4+ hours or 1/2 day	8%
•12 - 18 hours or 1/2 day to 3/4 day	7%
•19 - 24 hours or 1 day	12%
•1 to 1.5 days	8%
•1 .6 to 2 days	15%
•More than 2 days	16%

Customer Centric Engagement Index (CCEI)

The EB-2010-0379 ROB-SA report includes the following: “better engage with their customers to better understand and respond to their needs…” Conducting surveys (like this one), holding town hall meetings, focus groups, etc. are examples of engaging your customers. We call this an activity based definition of engagement. Asking 100 people to complete a survey is an engagement activity. This survey also provides you with an emotional look at engagement.



The CCEI index is a gauge of the amount of goodwill that has been generated. High numbers in CCEI suggests that there is a high level of goodwill amongst your customers – this is important for two reasons. First when something goes awry for the utility, goodwill helps the utility to be resilient. Second, goodwill encourages active participation in requests to participate in engagement activities or program offerings from the utility.

Utility Customer Centric Engagement Index (CCEI)			
	Halton Hills Hydro	**National**	**Ontario**
CCEI	81%	79%	76%

Base: total respondents

In a world of chaos and confusion what will a customer do? Find someone to help. In the electricity industry, the vast majority of customers turn to, and rely on, their local utility. Knowing that customers will turn to their electric utility requires utilities to really know their customers. Not easy when customer expectations continue to shift.

The shift is on. 15 years ago a utility could think about their customers in terms of usage, now they have to think about them in terms of personas (i.e., customer type). Currently, customer segmentation, for most utilities, consists of a number of "personas". While this may be adequate today, in order to achieve high customer participation in programs and to optimize business processes there will be a need for granular targeting of communications.

Most utilities are quite comfortable "pushing" out communications in a one-way world. However, the shift is on because the new channels are 2-way; even without the new channels customers are expecting 2-way dialogue. The impact on a utility's marketing-communications is significant.

Value is what a customer perceives they get in exchange for what they give up. The real challenge is educating customers on the value they receive. In the absence of a value proposition the primary thing people will talk about is cost.

We recommend having meaningful two-way dialogue with employees (and others) to leverage the results from your 2014 customer satisfaction survey derived from speaking with 413 Halton Hills Hydro customers [March 27 - April 3, 2014]. The electric utility business has demanding customers with high expectations.

UtilityPULSE

Sid Ridgley

Simul/UtilityPULSE

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June, 2014

Good things happen when work places work. You'll receive both strategic and pragmatic guidance about how to improve Customer satisfaction & Employee engagement with leaders that lead and a front-line that is inspired. We provide: training, consulting, surveys, diagnostic tools and keynotes. The electric utility industry is a market segment that we specialize in. We've done work for the Ontario Electrical League, the Ontario Energy Network, and both large and small utilities. For sixteen years we have been talking to 1000's of utility customers in Ontario and across Canada and we have expertise that is beneficial to every utility.

Culture, Leadership & Performance – Organizational Development	**Focus Groups, Surveys, Polls, Diagnostics**	**Customer Service Excellence**
Leadership development	Diagnostics ie. Change Readiness, Leadership Effectiveness, Managerial Competencies	Service Excellence Leadership
Strategic Planning	Surveys & Polls	Telephone Skills
Teambuilding	Customer Satisfaction and Loyalty Benchmarking Surveys	Customer Care
Organizational Culture Transformation	Organization Culture Surveys	Dealing with Difficult Customers

Benefit from our expertise in Customer Satisfaction, Leadership development, Strategy development or review, and Front-line & Top-line driven-change. We're experts in helping you assess and then transform your organization's culture to one where achieving goals while creating higher levels of customer satisfaction is important. Call us when creating an organization where more employees satisfy more customers more often, is important.

Your personal contact is:

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Halton Hills Hydro

Halton Hills HYDRO

2015 Electric Utility Customer Engagement Survey

UtilityPULSE

The purpose of this report is to profile the connection between Halton Hills Hydro and its customers.

The primary objective of this report based on a telephone survey, an online survey, and focus groups is to provide information supporting Halton Hills Hydro's 5 year distribution system plan.

In addition to the specific telephone and online surveys with Halton Hills Hydro customers, this report includes data from the 2015 Ontario and National Benchmark Surveys, the 2015 17th Annual UtilityPULSE Customer Satisfaction Survey and from the UtilityPULSE database.

All comments and questions should be addressed to:

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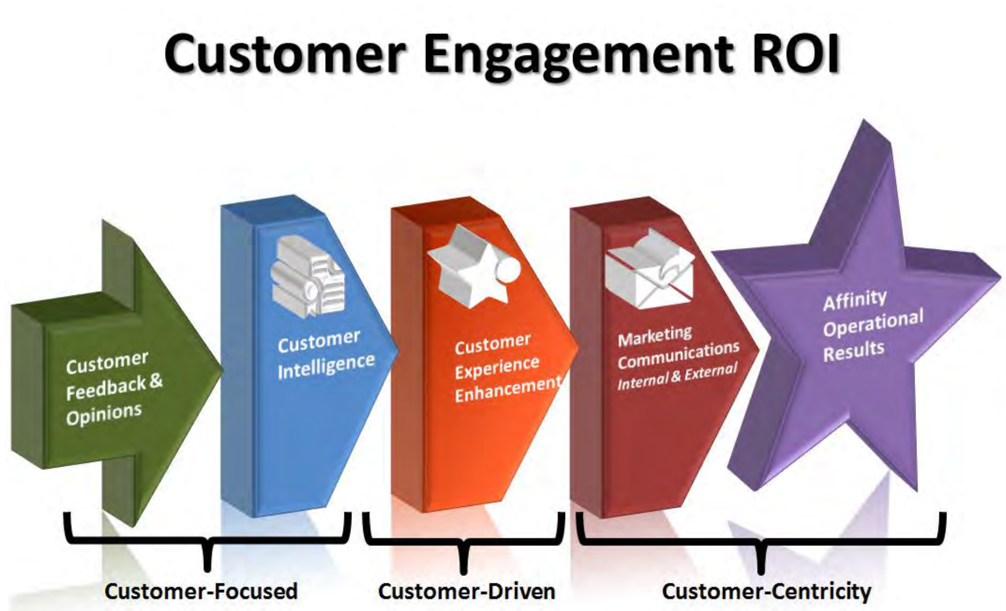
Survey Observations & Insights

Customer engagement is a key driver for the successful development of Halton Hills Hydro's capital and operational expenditures plan. The key to effective engagement lies in understanding customers' attitudes, wants, needs, motivations, and in recognizing that customer opinions matter. Customer engagement is crucial for the longer term success of the LDC.

Chapter 5 of the Ontario Energy Board publication *"Filing Requirement's for Electricity Transmission and Distribution Applications"* (March 28, 2013) set out the requirements for performance outcomes in a number of areas. One of those areas, Customer Focus is defined as "*services are provided in a manner that responds to identified customer preferences".* Another area is Operational Effectiveness: *"continuous improvement in productivity and cost performance is achieved; and utilities deliver on system reliability and quality objectives."*



Survey methods, data analysis and reporting

In an effort to engage with its customers, Halton Hills Hydro Inc. commissioned UtilityPULSE to interview its customers via a telephone survey, an online survey and through focus group sessions.

As a result, the telephone survey contains data from 426 HHH customers. With a customer base of approximately 22,000 customers, this sample size would have a margin of error of +/- 4.6%, 19 times out of 20. The online survey contains data from 930 customers and it would have a margin of error of +/- 3.1%, 19 times out of 20. With a combined 1,356 interviews the margin of error is +/- 2.6%, 19 times out of 20. Smaller data samples within the survey will have wider margins of error.

For the telephone survey HHH provided UtilityPULSE with a customer list from which people were contacted in random order. For the online survey, HHH staff sent emails to residential and commercial customers. 4,050 emails were received by residential customers and 315 emails were received by commercial customers. Out of a total of 4,365 received emails, an impressive 930 or 21.3% of customers who did receive the email, did complete the online survey.

While there are differences in methodology i.e., online and telephone, the online questionnaire and the telephone script were kept as consistent as possible. That is, whenever possible survey questions were presented or asked in a consistent manner both in terms of language and in sequence. This helps with comparability. We're pleased to say the consistency of the data between the 2 methods was very high.

Focus Groups

Seven commercial customers participated in a focus group session while 20 residential customers participated in a focus group session. The primary purpose of the focus groups was to gain a better understanding of the issues around Operational and Capital expenses.

Who attended the Business Customers Focus Group?

Six of seven attendees described themselves as a Senior Manager, Owner, President or General Manager – these individuals are decision makers for their respective businesses/organizations.

Five of seven indicated that their business had been in its current location for more than 20 years.

Who attended the Residential Customers Focus Group?

Twenty residential customers attended the focus group session. Of those participants who volunteered their age, the data showed attendees represented a broad range of ages beginning from age 25.

Participants, who volunteered the annual income of their household, showed representation from all income groups including the under $20,000 per year.

There was a brief education style presentation provided by Art Skidmore, President & CEO of Halton Hills Hydro Inc. The purpose of the brief presentation was to thank participants, provide education on how the system works, and provide information about various capital and operational plans. No Halton Hills Hydro staff member attended the focus group sessions beyond the initial welcome and brief presentation.

The item which most surprised both the residential and business attendees of the respective focus groups was the portion of the electricity bill that actually gets designated to Halton Hills Hydro to deliver electricity to homes and businesses. The Residential Focus Group stated they were not aware that the Halton Hills Hydro portion of the bill for residential customers was about 20% -- they all thought it was higher. The Business Focus Group participants were also surprised at the amount of the hydro bill, typically in the 10-15% range, which goes to Halton Hills Hydro.

Comparability

Your 2015 report contains data comparisons where applicable to:

- An Ontario-wide LDC benchmark
- Ontario LDCs participating in the 2015 UtilityPULSE 17th Annual Customer Satisfaction Survey
- UtilityPULSE database

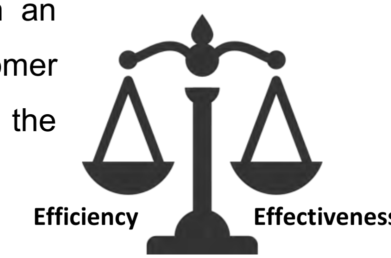
Customer Satisfaction

In Ontario, the Ontario Energy Board (OEB) has made it clear Customer Satisfaction measurement will be part of an Electricity Distributor's reporting. Of the many reasons why every LDC should place a premium on satisfying customers, here are some of the important ones:

1. Every utility has an obligation to satisfy its customers
2. Economically, high levels of satisfaction lead to less customer complaints and less scrutiny (hence less cost)
3. As an effectiveness measure it prompts discussion about policies, procedures, planning, use of technology, and more
4. When things go wrong (and they do), customers with high levels of satisfaction handle the problem far better than customer with very low levels of satisfaction
5. For employees there is a morale boost when working in an organization with a high level of customer satisfaction
6. Customers (as well as others) have growing levels of expectations which means the things that satisfy customers today may not tomorrow.

A focus on satisfaction prompts an organization to continue to evolve in ways that make sense to those that pay the bills. A focus on satisfaction is a focus on effectiveness in the delivery of service to the customer. Satisfied customers who trust their LDC may be more likely to seek advice i.e. energy efficiency methods, and may be more receptive to important messages i.e. safety, new capital projects, etc.

A word of caution to readers, please do not assume that great performance in an efficiency rating (such as answering the phone in 30 seconds) will lead to customer satisfaction. It will not. Answering the phone in 20 seconds but not solving the customer's problem is not going to ameliorate the customer's perception about the transaction.



Efficiency ratings won't lead to satisfaction but they can lead to dissatisfaction. Taking 90 seconds to answer the phone will create an agitated customer who, for the most part starts off being dissatisfied with the service – before you've even had a chance to deal with or solve their problem.

The following chart shows the satisfaction scores for residential and small commercial customers conducted via a telephone interview in 2014.

Halton Hills Hydro SATISFACTION SCORES – Electricity customers' satisfaction

Top 2 Boxes: 'very + fairly satisfied'	2014	2013	2012	2011	2010
PRE: Initial Satisfaction Scores	90%	-	-	93%	-
POST: End of Interview	90%	-	-	92%	-

Base: total respondents / (-) not a participant of the survey year

- ***Satisfaction*** *happens when utility core services meet or exceed customer's needs, wants, or expectations.*
- ***Loyalty*** *(Affinity) occurs when a customer makes an emotional connection with their electric utility on a diverse range of expectations beyond core services.*

SATISFACTION SCORES – COMMERCIAL CUSTOMERS 2015			
Top 2 Boxes: 'very + fairly satisfied'	**Halton Hills Hydro**	**Ontario Benchmark**	**Ontario LDCs**
Small Commercial Customers	92%	86%	90%
Large Commercial Customers	91%	--	89%

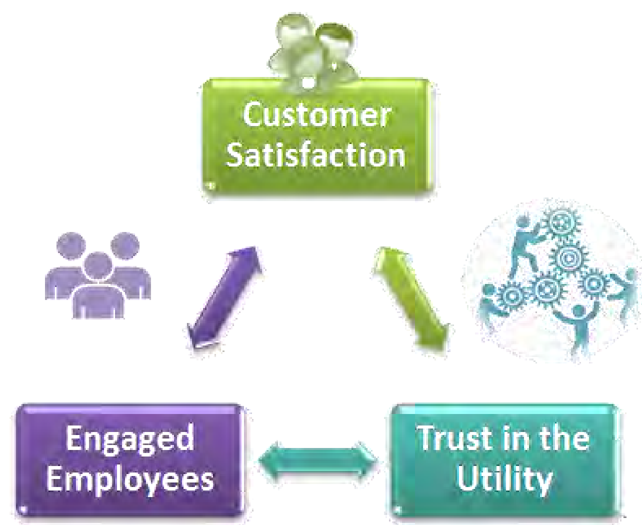
Base: total respondents, participating LDCs 2015 Customer Survey, Ontario benchmark participants

Customer expectations of their electricity LDC have evolved past the "provide electricity reliably, safely and billed both accurately with fair pricing". They do expect their LDC to be ethical, forward-thinking, competent and trustworthy.

In a nutshell:

- Satisfaction is not a program, it is an outcome.
- ***Efficiency*** *is about achieving objectives with the minimum amount of people, time, money and other resources.*
- ***Effectiveness*** *ratings are measures that keep the organization and its people more future focused than efficiency ratings*

Finding the right balance between efficiency and effectiveness measures is difficult.



Outage Management

Customers have increased their expectations as it relates to getting information about outages. What makes the dissemination of information challenging for the LDC is the need to provide the information via multiple media channels and in a timely manner whilst trying to get the power restored. The perception of competency and value of the LDC are certainly linked to the frequency and duration of power outages.

Recognizing the importance of this topic to customers, a question about LDC reliability standards was asked in the survey.

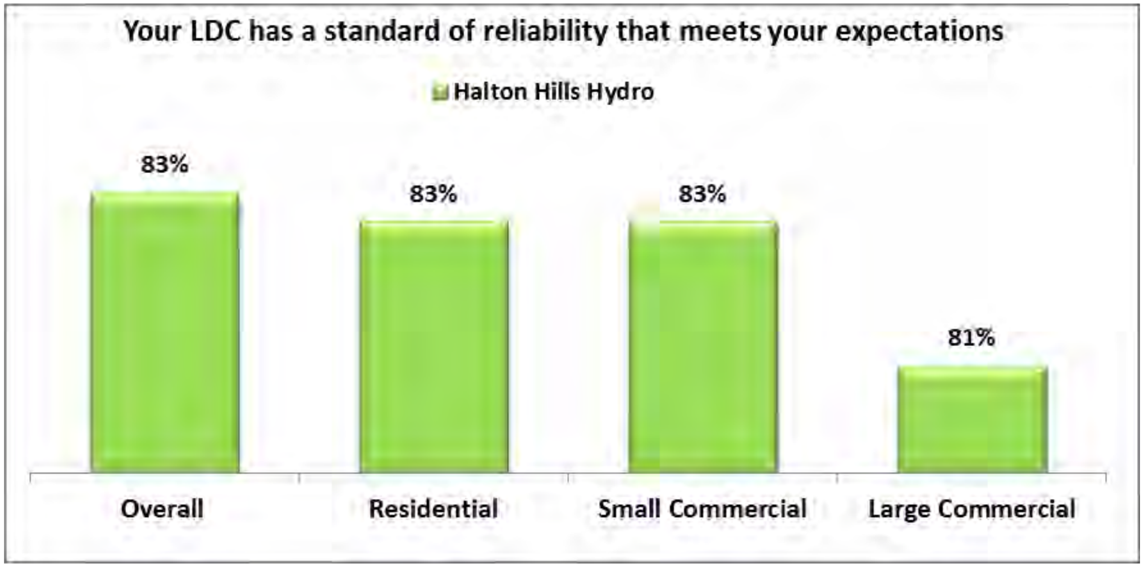
Your LDC has a standard of reliability that meets your expectations

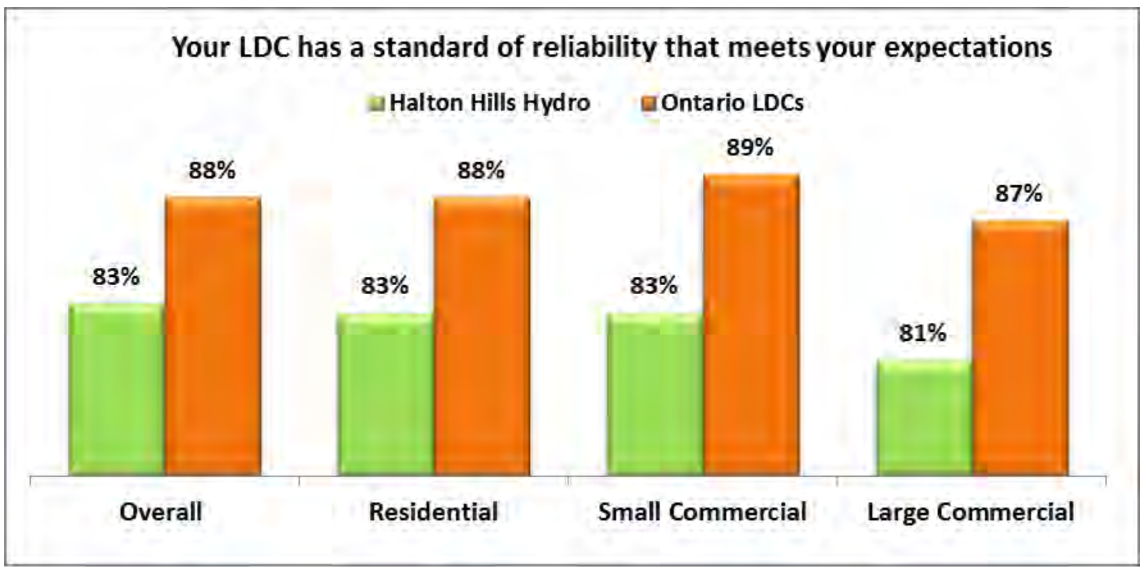
	Halton Hills Hydro	Ontario LDCs
Overall	83%	88%
Residential	83%	88%
Small Commercial	83%	89%
Large Commercial	81%	87%

Base: total respondents

An outage management system helps LDC employees to discover, locate and resolve power outages in a more informed, orderly, efficient and timely manner.

It is worth noting that 44% of the Customers surveyed were willing to pay more for such a system.





POWER OUTAGES

It is important to note Halton Hills Hydro experienced a 100% outage with the December 2013 ice-storm. The memory of such an event is still on the minds of customers. Both the residential & commercial customer focus groups made mention of the event. They also gave kudos to the staff of Halton Hills Hydro in the handling of the massive outage.

In addition, spring 2015 saw more outages as a result of a number of pole fires.

Base: Extract from 2015 UtilityPULSE 17th Annual Customer Satisfaction Survey Ontario LDCs / total respondents

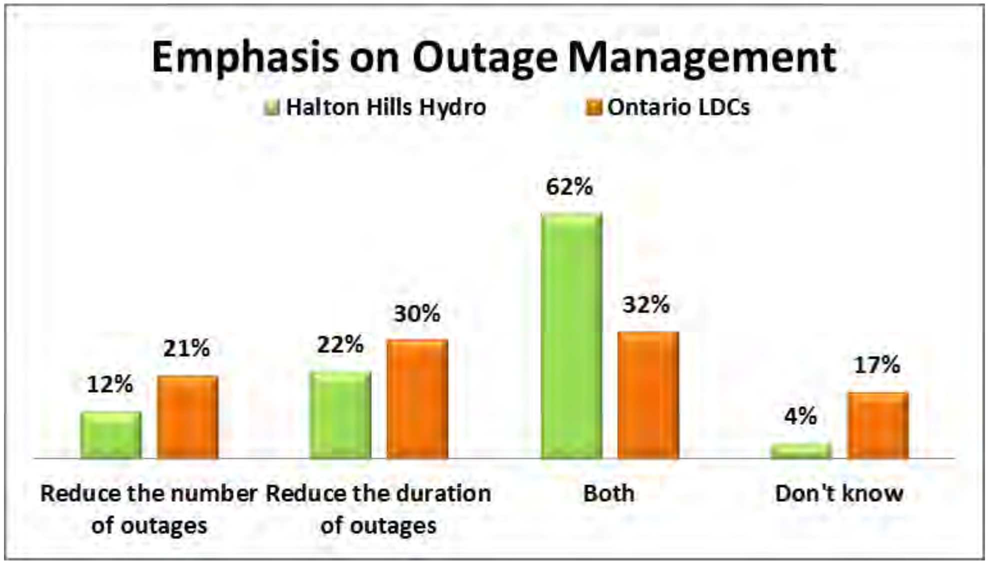
How many outages are acceptable over 12 months?		
	Halton Hills Hydro	**Ontario LDCs**
None	19%	23%
One	20%	15%
Two	31%	26%
Three	17%	13%
Four	5%	5%
Five or more	5%	7%
Don't Know	3%	9%

Reasonable amount of time for an unplanned outage?		
	Halton Hills Hydro	**Ontario LDCs**
Less than 15 minutes	16%	14%
16-30 minutes	20%	15%
31-60 minutes	26%	13%
1 to 2 hours	28%	29%
3 to 5 hours	8%	13%
6 to 12 hours	1%	5%
More than 12	1%	3%
Don't Know	1%	8%

Base: Extract from 2015 UtilityPULSE 17th Annual Customer Satisfaction Survey Ontario LDCs / total respondents

Customers were asked if the utility were to improve reliability should they put more emphasis on reducing the number of or unplanned outages or reducing the duration of the unplanned outage? Or both which requires an increase.

Base: Extract from 2015 UtilityPULSE 17th Annual Customer Satisfaction Survey Ontario LDCs / total respondents



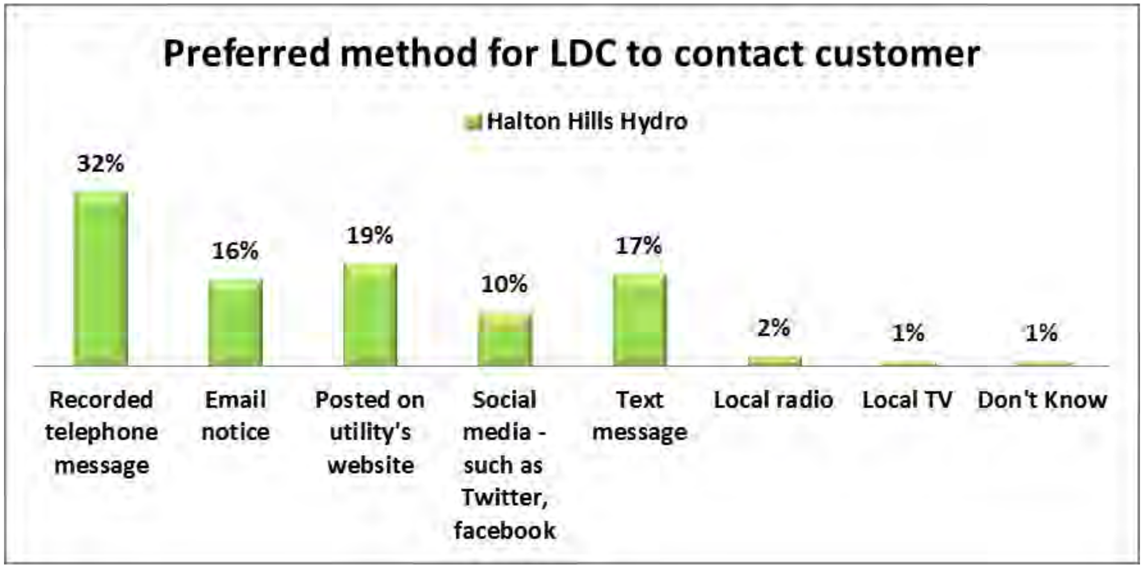
Which communication channel do customers prefer to use? The UtilityPULSE data base information from over 9,000 residential and small commercial customer interviews between March – May, 2015, shows the telephone is the most used and preferred method to contact the LDC to communicate with customer care representatives.

	Telephone	Email	Utility Website	Social Media	Text Message	In Person
Ontario LDCs	84%	5%	2%	1%	0%	0%
Halton Hills Hydro	58%	6%	15%	8%	11%	1%

Base: Extract from 2015 UtilityPULSE 17th Annual Customer Satisfaction Survey Ontario LDCs / total respondents

The Business Focus Group emphasized the importance of using technology – but they also recognized that not everyone is comfortable with the technology. Residential Focus Group members also talked about technology and the need to help customers understand how to use the technology.

While the telephone is still the communication channel most would prefer to use to communicate with or to be communicated to, customers do have an expectation for the LDC to use varied methods to contact them. Communication channels other than the telephone received higher preference scores when asked about the utility contacting the customer versus the customer's use of such channels to contact the utility. This indicates that the onus is on the utility to find a way to contact a customer when necessary and that should use various means to ensure the message is communicated. Proactive communication channels which include recorded calls, emails and SMS (text messaging) are increasingly being used by utilities to reach customers affected by outages.



Base: total respondents

Top 4 methods:

- **Recorded Telephone Message**
- **Email notice**
- **Posted on website**
- **Text message**

Responding to outages and making sure power is restored quickly is a priority item with customers as well as communications during outage events. Being effective during an outage situation from the point of view of a customer requires that:

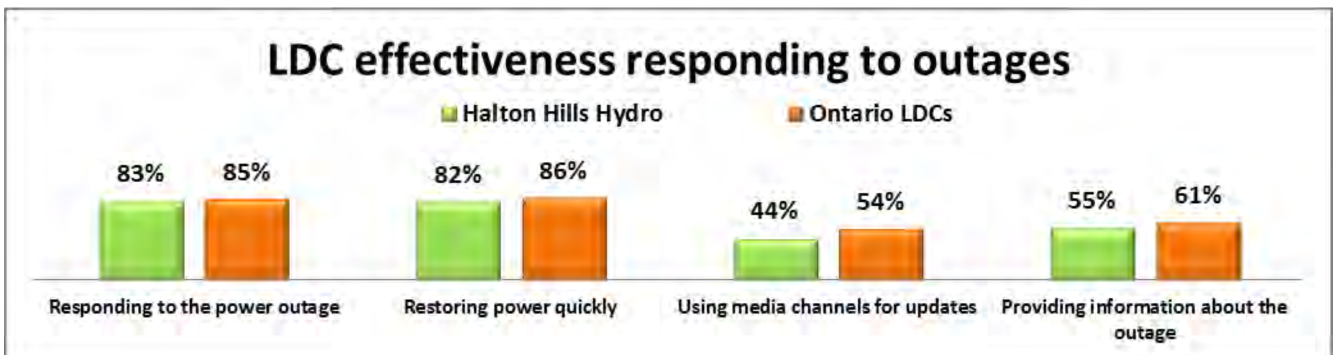
- timely information on outages is provided
- utilities understand that even a short outage in duration is impactful
- in large scale events, utilities should proactively provide tips on how to prepare for extended outages

- being kept informed about what is going on during an outage makes customers feel valued.

LDC effectiveness responding to outages		
	Halton Hills Hydro	**Ontario LDCs**
Responding to the power outage	83%	85%
Restoring power quickly	82%	86%
Using media channels for updates	44%	54%
Providing information about the outage	55%	61%

Base: Extract from 2015 UtilityPULSE 17th Annual Customer Satisfaction Survey Ontario LDCs / total respondents

It is important to note, for Halton Hills Hydro there isn't a daily newspaper, nor is there a local radio or television station.



Base: Extract from 2015 UtilityPULSE 17th Annual Customer Satisfaction Survey Ontario LDCs / total respondents

The types of information that customers require during an outage include:

- *When will their power be restored?*
- *What areas are affected?*
- *How many customers are impacted?*
- *Have work crews been dispatched to the affected area and is the utility working to restore power?*
- *What was the cause of the power outage?*
- *What can customers do to cope during the outage?*

Operating & Capital Expenses

UtilityPULSE has been conducting research in the LDC industry in Ontario for 17 years. However, members of UtilityPULSE have been doing customer research for much longer. It is true, customers (but not all) can tell you what they want, but they have a very difficult time telling you what they need. On the one hand, many customers *"want"* lower prices, but they *"need"* reliability and responsiveness. Hence, it is up to the professionals in the LDC to use their experience and judgment to determine what needs to be done and when it should be done. No easy task.

UtilityPULSE asked customers: *"As it relates to replacing equipment electric utilities typically follow 2 main practices which are: let equipment run-to-failure OR pro-actively replace equipment. Which of the following best represents your view on equipment replacement?"*

Strategy for replacing equipment

	Halton Hills Hydro	Ontario LDCs
Run-to-failure when there are limited customers affected ensures full-value is received from the equipment	37%	27%
Pro-active replacement, even though it may cost more, should ensure reliable power	62%	65%
Don't Know	2%	8%

Base: Extract from 2015 UtilityPULSE 17th Annual Customer Satisfaction Survey Ontario LDCs / total respondents

60% of Halton Hills Hydro respondents chose the statement “Pro-active replacement, even though it may cost more…” as the statement that best describes their view about replacing equipment.

The Business Focus Group was passionate about the length of time of the outage. For example, one participant said that when the estimated time to get the electricity back up and running is 3 hours or more, they send staff home. And when the repair only takes 1 hour (though the estimate was 3), they have really lost productivity as staff have now gone home. In a follow up question, this Business Focus Group made it clear that working on the duration of the outage was the first priority however every effort should be made to do both.

Those from the Residential Focus Group who were rural customers said they had more outages than urban customers. Much like the Business Focus Group they cited concerns about the length of time of the outages and felt there was a difference in the outage depending on time of year. The Residential Focus Group thought that customers would expect Halton Hills Hydro to work on both the number of outages and the length of time of the outage. However, there was more dialogue around the length of time. As one participant said, *“I worry about food loss -- except, of course, in the wintertime.”*

While the majority of both rural and urban survey respondents chose “pro-active replacement…”, 72% of urban customers said they were willing to pay more for “replacing aging equipment” while 62% of rural customers said that they would pay more per month.

Halton Hills Hydro is responsible for customers in a 280 sq km territory, and it has a very large rural to urban split. Of those 280 sq km only 25km are urban.

Operational Items

Much has been written, and reported on, regarding the cost of electricity. A goal of customer engagement, in addition to understanding wants & needs, is to reduce the worry that customers have about the reliability and future costs of electricity. What readers may not know is, Halton Hills Hydro has to focus on day-to-day operations while it builds, re-builds, re-furbishes and prepares the organization for a changed future. In addition, LDCs need to think in terms of decades, not just today, this week, this month, or this quarter. They need to do so in a regulated environment that is a 5 year planning environment. Respondents were asked to identify the items they were willing to pay more for and, they were asked "how much" they would be willing to pay.

Which of the following items are you willing to pay more for per month … (Operational items)				
Halton Hills Hydro	**Yes**	**No**	**Not sure**	**Depends**
A proactive outage management communication system	44%	38%	18%	0%
Increased self-service options on the website	24%	60%	16%	0%
Extended office hours	6%	82%	12%	0%
Increased tree trimming to improve reliability	53%	32%	15%	0%
Educating customers about energy conservation	26%	60%	13%	0%
Educating customers and the public about electricity safety	18%	68%	15%	0%

Base: total respondents

Which of the following items are you willing to pay more for per month … (Operational items)				
Halton Hills Hydro	**Rural**	**Urban**	**Small Commercial**	**Large Commercial**
A proactive outage management communication system	36%	46%	53%	56%
Increased self-service options on the website	18%	25%	37%	19%
Extended office hours	6%	6%	7%	9%
Increased tree trimming to improve reliability	51%	52%	66%	78%
Educating customers about energy conservation	23%	25%	42%	53%
Educating customers and the public about electricity safety	14%	17%	29%	38%

Base: total respondents

Which of the following items are you willing to pay more for per month … (Operational items)					
Halton Hills Hydro	**Yes**	**Telephone**	**Online**	**Focus Group Business**	**Focus Group Residential**
A proactive outage management communication system	44%	47%	43%	86%	45%
Increased self-serve options on the website	24%	25%	23%	29%	30%
Extended office hours	6%	8%	5%	0%	0%
Increased tree-trimming to improve reliability	53%	60%	50%	86%	40%
Educating customers about energy conservation	26%	38%	21%	43%	20%
Educating customers and the public about electricity safety	18%	31%	12%	43%	20%

Base: total respondents

The above charts can certainly fuel debate between industry professionals, regulators, interveners and customers. Could an LDC ignore investing in self-service options on their website? Do the raw scores from the survey represent what the LDC needs to do? If the LDC didn't invest in increased self-service options what might happen to operational costs? What might happen to the perceived brand of the LDC i.e., being seen as a modern enterprise?

For those who said they would pay more…

Willing to pay how much more per month for … (Operational items)

Halton Hills Hydro	1 item	2 items	3 or more items
$0.50 or less	49%	38%	27%
$0.51 – $1.00	27%	29%	18%
$1.01 – $3.00	16%	18%	24%
$3.01 – $5.00	3%	7%	13%
$5.01+	4%	8%	18%

Base: total respondents

Respondents were not guided by the interviewer providing various ranges of rates.

Respondents were simply asked to give an amount of $.

Their answers were categorized into one of the rate ranges shown in the table.

Findings from Halton Hills Hydro's customer engagement surveys are consistent with our findings from the 2015 UtilityPULSE 17th Annual Customer Satisfaction Survey for Ontario LDCs. That is, there isn't a proportional difference in the amounts a customer is willing to pay based on 1 item, 2 items or, 3 or more items, though there is a difference. However the data does tell us that it would be easier to get customer support for an increase of $3.00 or more when there are 3 or more items being improved.

How much more per month -- 3 or more Operational items			
Halton Hills Hydro	**ALL**	**Residential**	**Commercial**
$0.50 or less	27%	25%	47%
$0.51 - $1.00	18%	20%	6%
$1.01 - $3.00	24%	27%	4%
$3.01 - $5.00	13%	13%	12%
$5.01+	18%	15%	35%

Base: total respondents

Customers were probed about their willingness to pay more per month for the OPERATIONAL items listed below:

- A proactive outage management system
- Increased self-service options on the website
- Extended office hours
- Increased tree trimming to improve reliability
- Educating customers about energy conservation
- Educating customers and the public about electricity safety

How much more per month -- 3 or more Operational items					
Halton Hills Hydro	**ALL**	**Telephone**	**Online**	**Focus Group Business**	**Focus Group Residential**
.50 or less	27%	27%	27%	0%	20%
$0.51 - $1.00	18%	4%	29%	29%	25%
$1.01 - $3.00	24%	17%	29%	29%	10%
$3.01 - $5.00	13%	17%	10%	29%	15%
$5.01+	18%	35%	5%	14%	0%

Base: total respondents

Capital Items

Customers were also asked about the following capital items:

Which of the following items are you willing to pay more for per month …

Halton Hills Hydro	Yes	No	Not sure	Res Yes	Comm Yes
Replacing aging equipment to improve safety and reliability	71%	16%	13%	70%	78%
Upgrading equipment to accommodate future growth in the community	36%	41%	23%	34%	57%
Adding automation and technology to reduce outage time	51%	28%	21%	50%	66%

Base: total respondents

Which of the following items are you willing to pay more for per month …

Halton Hills Hydro	Yes	Telephone	Online	Focus Group Business	Focus Group Residential
Replacing aging equipment to improve safety and reliability	71%	73%	70%	86%	70%
Upgrading equipment to accommodate future growth in the community	36%	54%	28%	14%	10%
Adding automation and technology to reduce outage time	51%	59%	49%	86%	55%

Base: total respondents

Willingness to pay per month

Willing to pay how much more per month for … Capital items			
Halton Hills Hydro	**1 item**	**2 items**	**3 items**
$0.50 or less	36%	22%	25%
$0.51 - $1.00	20%	19%	11%
$1.01 - $3.00	26%	30%	21%
$3.01 - $5.00	12%	14%	17%
$5.01+	6%	14%	26%

Base: total respondents

How much more per month -- 3 Capital items			
Halton Hills Hydro	**ALL**	**Residential**	**Commercial**
.50 or less	25%	20%	62%
$0.51 - $1.00	11%	12%	0%
$1.01 - $3.00	21%	23%	2%
$3.01 - $5.00	17%	19%	6%
$5.01+	26%	25%	30%

Base: total respondents

Customers were probed about their willingness to pay more per month for the Capital items listed below:

- Replacing aging equipment to improve safety and reliability
- Upgrading equipment to accommodate future growth in the community
- Adding automation and technology to reduce outage time

How much more per month -- 3 Capital items					
Halton Hills Hydro	**ALL**	**Telephone**	**Online**	**Focus Group Business**	**Focus Group Residential**
.50 or less	25%	32%	18%	0%	15%
$0.51 - $1.00	11%	3%	19%	0%	20%
$1.01 - $3.00	21%	9%	33%	43%	35%
$3.01 - $5.00	17%	14%	21%	29%	5%
$5.01+	26%	41%	10%	29%	10%

Base: total respondents

The amount customers are willing to pay for 1 item versus 3 items did not translate into a proportional increase. While customers recognize 3 items would necessitate more money than 1 item, fewer customers were willing to pay that much more for 3 items. However, they are more willing to pay for items that provide a direct benefit to themselves.

When all 3 capital items are selected by survey participants, Halton Hills Hydro data no significant difference amounts based on age or income. 57% of the 18-34 year old respondent selected a number of $3.00 or less, it was 56% of respondent who identified themselves as 55+. 54% of respondents with a household income of <$40,000 selected a number of $3.00 or less, it was 53% of respondents with an income of $70,000+.

Both the Business and Residential Focus Groups were not supportive of increased fees to support economic growth in the community. As one Business Focus Group member said: *"Let the growth pay."* A Residential Focus Group member said: *"I need to know what it does for me before I can support an increase for growth."*

Elasticity in willingness to pay more per month

It is true, self-interest will drive the choices that people make. If an operational or capital item directly affects the respondent, then there is a willingness to support paying more per month. For example, 53% said they would pay more for tree-trimming. If a customer can see a benefit then there is higher level of support for paying more money. For example, respondents in the 18-34 age range are 50% more likely to be willing to pay more for "increased self-service options on the website" than respondents in the 55+ age range. Receptivity for paying more increases when there is a direct benefit to the customer or the customer sees the cost as a means to avoid adverse consequences (pain).

At the time of writing (June 2015) we have data from 5,380 Ontarians who were asked if they were willing to pay more for any of the operational items, 21% were not willing to pay more for ANY of the operational items. The equivalent number in Halton Hills Hydro is 28%. Proof there is a significant number of people not willing to pay more for anything. It is extremely important that increases in rates are tied to customer benefits.

It is also important to note that data from all sources shows survey respondents do not have a sense of what things cost. Telling a customer that an item/project costs $12,000,000 means little, but telling them it would increase their bill by $1.50 does. It is not the amount of the investments, it is the impact of the investment that matters most.

Confidence

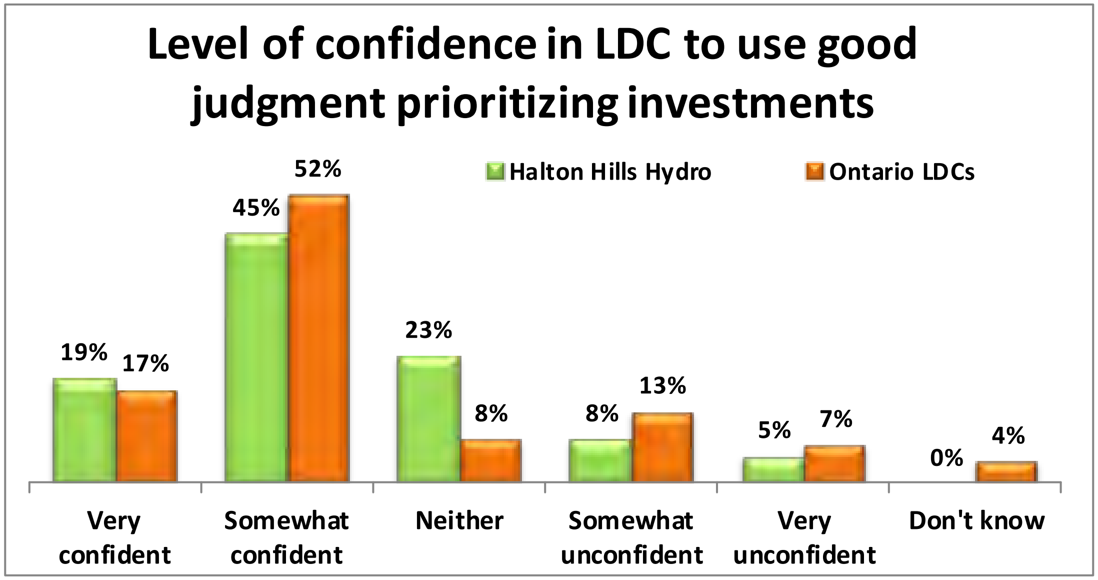
Data from all sources tells us that most customers have difficulty understanding costs, investments and value. Customers are certainly “worried” about costs. Our research clearly shows less price sensitivity when customers have a high affinity level towards their LDC. For all survey methods of customer engagement, customers were asked about the “level of confidence you have in the people at Halton Hills Hydro to use good judgment when prioritizing expense projects”. Halton Hills Hydro fared well. Interestingly online survey participants provided lower scores on this question.

What is your level of confidence in the people at Halton Hills Hydro to use good judgment when prioritizing expense projects?

Halton Hills Hydro	ALL	Telephone	Online	Ontario LDCs
Top 2 boxes: ‘Very + Somewhat Confident’	64%	78%	58%	69%
Very Confident	19%	22%	18%	17%
Somewhat Confident	45%	56%	40%	52%
Neither	23%	10%	29%	8%
Somewhat Unconfident	8%	8%	8%	13%
Very Unconfident	5%	4%	5%	7%

Base: total respondents

A participant in the Residential Customer Focus Group said: *“We expect those that are being paid will make good decisions.”*



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Base: Extract from 2015 UtilityPULSE 17th Annual Customer Satisfaction Survey Ontario LDCs / total respondents

Business Focus Group participants felt there was a need for more communication to everyone i.e., education about HHH. They also felt it was important to be pro-actively communicating instead of only when there is a problem or crisis situation at large.

The Residential Focus Group was more direct about what could be done to increase the level of confidence. Comments received include: *"Communicate whose side are you on when rates go up." "Show us a comparison of rates." "Talk to me about how you spend the money." "Tell us more about the things you do to benefit us."*

Additional Observations, Insights & Commentary

In 2011, 2014 and 2015 Halton Hills Hydro actively collected customer feedback and opinion through various UtilityPULSE surveys. Data from all of Halton Hills Hydro surveys shows a strong connection between the utility and its customers. For example, 25% of customers contacted by telephone completed the survey, and 21% of customers who were invited via email completed an online survey. It is clear Halton Hills Hydro customers want their opinion heard and it is equally clear Halton Hills Hydro staff want to hear them.

The data from our Ontario benchmark survey on the importance of “feedback” tells us customers want their voice heard. We believe this is completely in sync with what experts call, customer centricity. However asking for feedback, but not acting on that feedback or not using the feedback in a constructive way could have some adverse consequences for the LDC i.e., lower levels of trust, credibility and customer affinity. Ensuring future customer communications from Halton Hills Hydro about increases is tied to the work done to garner feedback and opinion is more than a “nice to do”.

It is important to note there are 2 sides of customer engagement. One side is getting customer participation in various activities while the other is about getting higher levels of emotional connection (affinity). Conducting surveys (like the telephone and online survey), holding town hall meetings, focus groups, etc. are examples of engaging your customers that is, getting your customers to participate in something.

Engagement is how customers think, feel and act towards the organization. Customer engagement is not about making customers “happy” with the costs or the service that is being provided by their LDC. Nor is customer engagement about making the industry regulator “happy”. The purpose of engaging customers is to gather usable information that will help Halton Hills Hydro be more effective and efficient with higher levels of customer affinity.

Keeping the lights on, billing customers properly and restoring power quickly is the core offering that must be provided by all LDCs in a competent and efficient manner. Halton Hills Hydro covers 280 sq. km and accomplishes much with a small staff. But circumstances will affect the system. While staff can't control everything, they can control the quality of the experience. Making operational and capital investments certainly is important, however how a problem is handled can validate or invalidate a customer's perception about the utility's competency in providing excellent quality services.

We recommend having meaningful two-way dialogue with employees (and others) to leverage the results from your 2015 customer engagement survey derived from 1,356 Halton Hills Hydro Customers [April 21 - May 21, 2015]. Ensuring customers are everyone's priority in the LDC through words, behaviours, actions and interactions creates an improved organization which can better meet tomorrow's challenges while keeping costs in check.

UtilityPULSE

Sid Ridgley
Simul/UtilityPULSE
Email: sidridgley@utilitypulse.com or sridgley@simulcorp.com
June, 2015

Method

The findings in this report are based on telephone interviews and an online survey conducted for Simul Corp. / UtilityPULSE by the Logit Group between April 21 - May 7, 2015, with 426 telephone survey respondents who pay or look after the electricity bills from a list of residential and small and medium-sized business customers supplied by Halton Hills Hydro.

The sample of phone numbers chosen was drawn randomly to insure that each business or residential phone number on the list had an equal chance of being included in the poll.

The sample was stratified so that 85% of the interviews were conducted with residential customers and 15% with commercial customers.

In addition an online survey was also developed. Halton Hills Hydro sent an invitation to participate email to customers where they had an email address. 4,050 emails were received by residential customers and 315 emails were received by commercial customers. 930 customers responded to the online survey.

In sampling theory, in 19 cases out of 20 (95% of polls in other words), the results based on a random sample of 426 telephone plus 930 online customers for a total of 1,356 respondents will differ by no more than ±2.6 percentage points where opinion is evenly split.

This means you can be 95% certain that the survey results do not vary by more than 2.6 percentage points in either direction from results that would have been obtained by interviewing all Halton Hills Hydro customers.

The margin of error for the sub samples is larger. To see the error margin for subgroups use the calculator at http://www.surveysystem.com/sscalc.htm.

Interviewers for the telephone survey reached 1,672 households and businesses from the customer list supplied by Halton Hills Hydro. The 426 who completed the interview represent a 25% response rate.

The findings for the Simul/UtilityPULSE National Benchmark of Electric Utility Customers are based on telephone interviews conducted February 20 through February 27, 2015, with adults throughout the country who are responsible for paying electric utility bills. The ratio of 85% residential customers and 15% small and medium-sized business customers in the National study reflects the ratios used in the local community surveys. The margin of error in the National poll is ±2.7 percentage points at the 95% confidence level.

For the National study, the sample of phone numbers chosen was drawn by recognized probability sampling methods to insure that each region of the country was represented in proportion to its population and by a method that gave all residential telephone numbers, both listed and unlisted, an equal chance of being included in the poll.

The data were weighted in each region of the country to match the regional shares of the population.

The margin of error refers only to sampling error; other non-random forms of error may be present. Even in true random samples, precision can be compromised by other factors, such as the wording of questions or the order in which questions were asked.

Random samples of any size have some degree of precision. A larger sample is not always better than a smaller sample. The important rule in sampling is not how many respondents are selected but how they are selected. A reliable sample selects poll respondents randomly or in a manner that insures that everyone in the population being surveyed has an equal chance of being selected.

How can a sample of only several hundred truly reflect the opinions of thousands or millions of electricity customers within a few percentage points?

Measures of sample reliability are derived from the science of statistics. At the root of statistical reliability is probability, the odds of obtaining a particular outcome by chance alone. For example, the chances of having a coin come up heads in a single toss are 50%. A head is one of only two possible outcomes.

The chance of getting two heads in two coin tosses is less because two heads are only one of four possible outcomes: a head/head, head/tail, tail/head and tail/tail.

But as the number of coin tosses increases, it becomes increasingly more likely to get outcomes that are either close to or exactly half heads and half tails because there are more ways to get such outcomes. Sample survey reliability works the same way but on a much larger scale.

As in coin tosses, the most likely sample outcome is the true percentage of whatever we are measuring across the total customer base or population surveyed. Next most likely are outcomes very close to this true percentage. A statement of potential margin of error or sample precision reflects this.

Some pages in the computer tables also show the standard deviation (S.D.) and the standard error of the estimate (S.E.) for the findings. The standard deviation embraces the range where 68% (or approximately two-thirds) of the respondents would fall if the distribution of answers were a normal bell-shaped curve. The spread of responses is a way of showing how much the result deviates from the "standard mean" or average.

Beneath the S.D. in the tables is the standard error of the estimate. The S.E. is a measure of confidence or reliability, roughly equivalent to the error margin cited for sample sizes. The S.E. measures how far off the sample’s results are from the standard deviation. The smaller the S.E., the greater the reliability of the data.

In other words, a low S.E. indicates that the answers given by respondents in a certain group (such as residential bill payers or women) do not differ much from the probable spread of the answers "predicted" in sampling and probability theory.

Good things happen when work places work. You'll receive both strategic and pragmatic guidance about how to improve Customer satisfaction & Employee engagement with leaders that lead and a front-line that is inspired. We provide: training, consulting, surveys, diagnostic tools and keynotes. The electric utility industry is a market segment that we specialize in. Both large and small utilities have received actionable insights. For seventeen years we have been talking to 1000's of utility customers in Ontario and across Canada and we have expertise that is beneficial to every utility.

Culture, Leadership & Performance – Organizational Development	**Focus Groups, Surveys, Polls, Diagnostics**	**Customer Service Excellence**
Leadership development	Diagnostics ie. Change Readiness, Leadership Effectiveness, Managerial Competencies	Service Excellence Leadership
Strategic Planning	Surveys & Polls	Telephone Skills
Teambuilding	Customer Satisfaction and Loyalty Benchmarking Surveys	Customer Care
Organizational Culture Transformation	Organization Culture Surveys	Dealing with Difficult Customers

Benefit from our expertise in Customer Satisfaction, Leadership development, Strategy development or review, and Front-line & Top-line driven-change. We're experts in helping you assess and then transform your organization's culture to one where achieving goals while creating higher levels of customer satisfaction is important. Anyone can present data, or design programs – we believe having an understanding of the industry before doing so is cruicial. Call us when creating an organization where more employees satisfy more customers more often, is important.

Your personal contact is:

Sid Ridgley, CSP

Phone: (905) 895-7900 Fax: (905) 895-7970 E-mail: sidridgley@utilitypulse.com or sridgley@simulcorp.com

Halton Hills HYDRO	**CAPITAL PLAN**	**ENGINEERING**		**2016**
			System Type	**SYSTEM ACCESS**
	Job Request / Number:			**34**
	Project Name:	**9th Line, Steeles Avenue to 10 Side Road (Widening).**		
	Project Category:			**Customer Directed**

Reference

Quadra Division:				CAP - CUSTDIRECT
Job Request Number:				34
Job Number:				
Project Name:				9th Line, Steeles Avenue to 10 Side Road (Widening).
Project Category:				Customer Directed
System Type:				SYSTEM ACCESS
Priority Ranking:				4
Risk Ranking:	*Impact:*	4	*Probability:* 2	8
Customer Attachments/Load:				
Project Designer/Manager:				
Start Date:				
In Service Date:				

Estimated Costs

Description		Estimated Cost	Notes			Estimated Expenditure Timing
Labour:	$	497,357		Q1	$	193,774
Materials:	$	350,941		Q2	$	658,734
Equipment:	$	293,961		Q3	$	381,533
Contract Labour:	$	169,290		Q4	$	38,755
Other:	$	-				
				Carry-over:	$	38,755
Non-construct capital						
Total Estimated Cost	**$**	**1,311,549**		Total:	$	1,311,549
Recoverable:	$	480,304				
HHHI Estimated Cost	**$**	**831,245**		Control	-$	480,304
					-$	480,304

General Information

Project Summary/Description:
This project invloves relocating our utility poles, wires, anchors, and related equipment along Steeles Avenue between Steeles Avenue and 10 Side Road to accommodate Region of Halton intersection improvement plans. Halton Hills Hydro will install new distribution infrastructure following a final design that is approved by the Region of Halton. Halton Hills Hydro is obligated to perform this work per the Government of Ontario's Public Service Works on Highways Act, R.S.O. 1990, Chapter 49, Section 2 (2), Halton Hills Hydro is required to take up, remove or change the location of our infrastruture when requested by the road authority.

Comparative Information on Equivalent Historical Projects (if any):
Halton Hills Hydro has performed relocations for municipal road improvements in recent years such as Steeles Avenue, at Trafalgar Road and 5 Side Road, and 10 Side Road at 10th Line. The latter two examples were relocations to accommodate Regional intersection improvement plans. Like those projects, the planned relocations at Trafalgar Road and 10 Side road is based on a designed prepared by Halton Hills Hydro, approved by the Region of Halton, and coordinated with third party PUCC members. Historical experience has taught us that while in construction, The Region of Halton may ask us to alter our relocation plans. Such requests force the utility spend addtional resources to revise its already approved drawings and relocate infrastructure that had already been relocated at the Region of Halton's request. Such changes are normally borne by the requestor fully at their expense.

Risks to Completion and Risk Mitigation:
The primary risk to completion is if we begin construction prior to land and easement acquisition, part of the work may be delayed until Region of Halton can acquire the necessary land and easements. Halton Hills Hydro generally will not commence construction until we receive confirmation that land and easements are acquired or we have received permission to enter and construct our work. A secondary risk to completion is the Region of Halton requesting further changes once construction has commenced. To mitigate this second risk Halton Hills Hydro works closely with the Region to evaluate such requests to determine if they are necessary.

Total Capital and OM&A Costs for Renewable Energy Generation portion of project (if any):
n/a.

1. Efficiency, Customer Value, Reliability

Main Driver:
The main driver for this project is Region of Halton road improvement plans conflicting with existing pole and anchor locations.

Priority & Reasons for Priority:
This project has been given a medium priority. If the Region of Halton acquires the land as they say they will for 2016, Halton Hills Hydro will be expected to commence with construction and be complete before Regional road forces begin their work. However, given past experience with land acquisition delays Halton Hills Hydro has reason to doubt such claims until we see factual evidence from the Region.

Qualitative & Quantitative Analysis of Project and Project Alternatives:
Subject to the Government of Ontario's Public Service Works on Highways Act, R.S.O. 1990, Chapter 49, Section 2 (2), Halton Hills Hydro is required to take up, remove or change the location of our infrastruture when requested by the road authority (region of Halton). Halton Hills Hydro will be seeking cost recovery under the provincial for 50% of the labour and equipment portions of this project. Cost recover is shown in the above financial metrics.

Other:
n/a.

Evaluation Criteria and Information	
	2. Safety Halton Hills Hydro's construction will be done in accordance with approved utility standards which will protect general public and promote safe working environments for line staff. Poles will be of sufficient strength to support the load applied to them. Halton Hills Hydro lines staff will be working on a very busy road for which they are trained to follow certain rules and set-up requirements (MTO Book 7). Such training is managed through Halton Hills Hydro's implementation of our Empower safety program with Springboard Management.
	3. Cyber-security, Privacy n/a.
	4. Coordination, Interoperability Halton Hills Hydro will coordinate our relocation efforts with the Region of Halton to ensure completion prior to road work commences. We will also coordinate with telecommunication companies to ensure their attachments are relocated to our new poles.
	5. Economic Development Renewed infrastructure when properly planned can offer a stronger back bone for the distribution system supporting current business and be flexible to support load growth.
	6. Environmental Benefits Asset records indicate that some poles along 9th Line may have creosote treatment. Removing this poles will lessen potential impacts on the environment.
	7. Customer Control (Smart Grid Objective) **Access:** n/a. **Visibility:** n/a. **Control:** n/a. **Participation in Renewables:** Customers will have the ability to participate in renewable generation. The relocation work invloves replacing our distribution circuits and infrastructure to current standards and practices which ensures the system is flexible and reliable. On this section of road we have one (1) microFIT customer whom will be able to be connected to the new infrastructure once built. **Customer Choice:** n/a. **Education:** Projects like these allow the utility to speak directly with customers affected by the work, communicate our plans and answer questions. We also notify our customers about our projects in writing ahead of the project commencing. Customer engangement is crutial to mitigating the risk if public resistance to the project.
	8. Power System Flexibility (Smart Grid Objective) **Distributed Renewables:** n/a. **Visibility:** n/a. **Control and Automation:** n/a. **Quality:** This project will ensure Halton Hills Hydro's infrastructure is sufficient to support current load and load growth.
	9. Adaptive Infrastructure (Smart Grid Objective) **Flexibility:** n/a. **Forward Compatibility:** This project will provide sufficient pole space to install a 27.6kV distribution circuit from Steeles Avenue into Georgetown and interconnect to our existing 41M21 circuit along 10 Side Road. Such flexability allows Halton Hills Hydro to proactively support future load growth projected by the Town of Halton Hills Vision Georgetown while not resulting in unnecessary additional costs at present. **Encourage Innovation:** n/a.
	1. Customer Focus **Service Quality:** n/a. **Customer Satisfaction:** n/a.
	2. Operational Effectiveness **Safety:** This project will be constructed to Halton Hills Hydro standards and in doing so the project will protect the general public from undue hazards related to the distribution system. Halton Hills Hydro staff is trained in proper working procedures and job site set-up. Training for staff is managed by Springboard Management as part of Halton Hills Hydro's Empower safety program. Halton Hills Hydro will need to employ traffic control duing construction as there is little to no shoulder and few spots to work from along side along 9th Line, a two lane rural road. **System Reliability:** System reliability will be maintained through use of current standards that improve the overall structural integrity of the distribution system and accommodate current and future load growth. Integrated in any major project like this is key switching points whereby Halton Hills Hydro can utilize those switching points to re-route the supply of power to customers. As well, planning for future circuits ensures the installed infrastructure will not ahve to be replaced for to accommodate additional/ future growth and needed capacity. **Asset Management:** n/a.

Outcomes	**Cost Control:** Halton Hills Hydro will monitor costs for this project during construction and periodically invoice the Region of Halton as construction progresses. Should costs seem to be deviating from the estimate Halton Hills Hydro will take proactive measures to determine overall impacts to the job and cost sharing with the Region of Halton. A competative bid process for transformers will allow Halton Hills Hydro to select transformers that meet our timing requirements and have the lowest total ownership cost when considering the up-front cost as well as the cost related to losses. In instances where two or more transformers can be replaced by one transformer to serve our customers, Halton Hills Hydro can expect additional savings related to transformer losses as well as up-front capital costs.
	3. Public Policy Responsiveness **CDM** Halton Hills Hydro will review transformer bids from manufacturers and generally the select transformer manufacturer produces a transformer having the lowest losses of the bids we receive. As well, in instances where two or more transformers can be replaced by one transformer to serve our customers, Halton Hills Hydro can expect additional savings related to transformer losses as well as up-front capital costs. **Connection of Renewable Generation** Although the driver for this project is a municipally road widening, Halton Hills Hydro's infrastructure that will be installed will accommodate renewable generation.
	4. Financial Performance **Financial Implications** This project will permit the installation of a future circuit. Because Regional municipalities do not pay for materials as per Section 2 of the Public Service Works on Highways Act, Halton Hills Hydro believes it to be ecomonically responsbile to ensure the infastructure we pay for is sufficient for current and future uses where such future uses may exist. In doing so we demonstrate financial viability through planning and construction that will enable the utility to build for future load growth without incurring additional expenditures for more infrastructure or to rebuild infrastructure.
Third Party Planning	***1. Regional (IESO Regions)*** n/a.
	2. Regional (geographic) Halton Hills Hydro will work with the Region of Halton to ensure our construction work is coordinated with their plans and that we received municipal consent.
	3. Municipal Halton Hills Hydro will advise the Town of Halton Hills of our work. However, we will not seek municipal consent from the Town as both Trafalgar Road and 10 Side Road are Regional roads and the Town would not be able to issue a municipal consent.
	4. Other Halton Hills Hydro will circulate our PUCC group to advise the utilities of our work and coordinate relocation efforts. Where telecommunication companies are attached to our poles being removed, we will advise them to prepare transfer designs as required by O.Reg. 22/04 and coordinate their attachment transfers. Halton Hills Hydro will also coordinate outages, when necessary, with our microFIT customer on 9th Line as power interruptions will force their renewable generator off-line so that we can conduct work safety.
	5. Transmitter Halton Hills Hydro will coordinate with the upstream transmitter, Hydro One, where necessary when performing switching procedures on our 44kV, 27.6kV, and 8.32kV circuits to electrically isolate the intersection/ work area.
Other Information	***1. Factors Affecting Project Timing*** The primary factor affecting timing is when the Region acquires the land and easements needed to facilitate relocations. Hatlon Hills Hydro will not commence relocations until we are assured that land is available to begin construction.
	2. Implications of NOT Implementing If this project were not to commence our utility poles and anchors would be indirect conflict with Regional road improvements. This would be a violation of the requirements of the Public Service Works on Highways Act and could put the Region is a position to serve Halton Hills Hydro with a notice to relocate in 60 days.
	3. Alternatives Considered & Reason for Not Implementing During the design phase, consideration was given to installing poles that would be suitable for only the existing circuits. However, given Halton Hills Hydro's plans with respect to growing our 27.6kV distribution system to accommodate future load growth the present plan is to install infrastructure and design to accommodate a 27.6kV circuit. If we do not designed for an additional circuit, Halton Hills Hydro would have been faced with difficulty in extending our 27.6kV and may have had to replace part of the newly installed infrastructure. Because cost recovery does not include materials (defined in the Ontario's Public Service Works on Highways Act, R.S.O. 1990, Chapter 49) we believe it makes financial sense to install infrastructure for future growth and system reliability as we do recoupe 50% of labour and equipment costs.

Images

Project Authorization

Prepared by:

Date:

Authorized By:

Assigned To:

Assigned Date:

Completion Date:

Change History					
Date	Section	Change		Reason	Change Authorized by:

Halton Hills HYDRO	**CAPITAL PLAN**	**ENGINEERING**			**2016**
				System Type	**SYSTEM ACCESS**
	Job Request / Number:				**33**
	Project Name:	**Make Ready Work**			
	Project Category:				**Customer Directed**

Reference

Quadra Division:				CAP - CUSTDIRECT
Job Request Number:				33
Job Number:				
Project Name:				Make Ready Work
Project Category:				Customer Directed
System Type:				SYSTEM ACCESS
Priority Ranking:				4
Risk Ranking:	*Impact:* 3		*Probability:* 2	6
Customer Attachments/Load:		N/A		
Project Designer/Manager:				
Start Date:				
In Service Date:				

Estimated Costs

Description	**Estimated Cost**	**Notes**		**Estimated Expenditure Timing**
Labour:	$ 7,300		Q1	$ -
Materials:	$ 4,265		Q2	$ 4,356
Equipment:	$ 2,438		Q3	$ 13,068
Contract Labour:	$ 3,420		Q4	$ -
Other:	$ -			
			Carry-over:	$ -
Non-construct capital				
Total Estimated Cost	**$ 17,424**		Total:	$ 17,424
Recoverable:	$ 2,000			
HHHI Estimated Cost	**$ 15,424**		Control	-$ 2,000
				-$ 2,000

General Information

Project Summary/Description:
This project invloves the analysis and replacement of overloaded infrastructure and stems primarily from third party telecommunication recommendations. When a telecommunications company wants to install a new attachment, overlash on existing attachments, or perform work on their plant attached to our poles they must submit a design compliant with Ontario Regulation 22/04. In some cases the third party indicates that the utility needs to perform some work called "Make Ready". In some cases the Make Ready is required to enable the third party to perform their work. In other cases they notify the utility of potentially overloaded utility infrastructure. Halton Hills Hydro performs its due diligence, reviews the request and determines if suh Make Ready is required. If so, a work package will be assembled for the Make Ready.

Comparative Information on Equivalent Historical Projects (if any):
Halton Hills Hydro received many applications annually from third party telecommunications companies requesting to perform work on our poles. In the past where we are notified of Make Ready work we have assessed the requested work. If for instance the work is required to accommodate the third party Halton Hills Hydro invices the third party for the work as it is recoverable. In other instances we may be notified a guy wire is overloaded. In those cases we analyze the pole and loading on the guy wire using software to substaniated the claim. Where the claim can be substaniated, Halton Hills Hydro performs the Make Ready work to ensure our system is structurally sound. Costs for such work are not billed to the third party if our infrastructure was already overloaded (ie: the third parties work does not trigger an overloaded device).

Risks to Completion and Risk Mitigation:
The primary risk to completion is other projects taking precident such as municipally directed projects. Such risks can be mitigated by scheduling the work to accommodate all projects. Generally the Make Ready type project involves 1/2 days work at a given location, maybe less. If mulitple Make Ready projects can be scheduled on the same day risk to completion is reduced by having a crew dedicated for the day.

Total Capital and OM&A Costs for Renewable Energy Generation portion of project (if any):
n/a.

1. Efficiency, Customer Value, Reliability

Main Driver:
The main driver for Make Ready is third party applications to perform work on our utility poles.

Priority & Reasons for Priority:
This project has been given a low priority. The reason for such a priority is that Make Ready work often relates to determinations of overloaded guy wire. Halton Hills Hydro will continue to perform its due diligence to address such Make Ready notification but such Make Ready notifications do not mean the piece of equipment identified will fail immediately.

Qualitative & Quantitative Analysis of Project and Project Alternatives:
Subject to the requirements of CSA C22.3 No.1-10 "Overhead Systems" Halton Hills Hydro will perform non-linear analysis to ensure poles and their supporting devices (guy wires and anchors) are sufficient to support the distribution system. Where improvements are necessary, Halton Hills Hydro will perform upgrades. Make Ready work often results in strengthening of supporting guying and in doing so poles are better supported which means there is less potential for failure of devices causing increased O&M for repair work.

Other:
n/a.

2. Safety
Halton Hills Hydro's construction will be done in accordance with approved utility standards which will protect general public and promote safe working environments for line staff. Some Make ready work msut be performed so that it is safe for third parties to perform their work.

3. Cyber-security, Privacy
n/a.

Evaluation Criteria and Information	***4. Coordination, Interoperability*** Halton Hills Hydro coordinates with third party telecommunication companies to ensure Make Ready work is addressed so as to not impede the third parties schedule.
	5. Economic Development n/a.
	6. Environmental Benefits n/a.
	7. Customer Control (Smart Grid Objective) **Access:** n/a. **Visibility:** n/a. **Control:** n/a. **Participation in Renewables:** n/a. **Customer Choice:** n/a. **Education:** n/a.
	8. Power System Flexibility (Smart Grid Objective) **Distributed Renewables:** n/a. **Visibility:** n/a. **Control and Automation:** n/a. **Quality:** n/a.
	9. Adaptive Infrastructure (Smart Grid Objective) **Flexibility:** n/a. **Forward Compatibility:** n/a. **Encourage Innovation:** n/a.
Outcomes	***1. Customer Focus*** **Service Quality:** n/a. **Customer Satisfaction:** n/a.
	2. Operational Effectiveness **Safety:** This project will be constructed to Halton Hills Hydro standards and in doing so the project will protect the general public from undue hazards related to the distribution system. Halton Hills Hydro staff is trained in proper working procedures and job site set-up. Training for staff is managed by Springboard Management as part of Halton Hills Hydro's Empower safety program. **System Reliability:** System reliability will be maintained as Make Ready work often involves strengthening th supporting structures of the distribution system. **Asset Management:** n/a. **Cost Control:** Halton Hills Hydro will analyze third party requests/ Notifications for Make Ready work and determine if we feel such work in necessary. Where the work is necessary we will perform it. Where we do not believe the work is necessary, we will not spend capital funds to construct unecessary work.
	3. Public Policy Responsiveness **CDM** n/a. **Connection of Renewable Generation** n/a.
	4. Financial Performance **Financial Implications** Make Ready work demonstrates financial responsibility by ensuring our system is structurally sound. A system that is structurally weak is open to risk factors that can have financial implications on O&M expenditures. By properly analyzing and planning Make Ready work, system upgrades and enhancements can be performed in a financially responsbile manner that ensures the viability of the utility through renewed infrastructure that supports the existing infrastructure.
ty Planning	***1. Regional (IESO Regions)*** n/a.
	2. Regional (geographic) Halton Hills Hydro will work with the Region of Halton to obtain municipal consents when working on Regional roads.
	3. Municipal Halton Hills Hydro will work with the Town of Halto Hills to obtain municipal consents when working on Town roads.

Third Pa[rty]

4. Other

Halton Hills Hydro will ccoordinate our Make Ready work with the requesting third party and other third parties attached to the utility poles. Halton Hills Hydro may also coordinate/ advise neighbouring utilities where the Make Ready work is not be performed on a jointly owned or cohabitated pole line.

5. Transmitter

n/a.

Other Information

1. Factors Affecting Project Timing

The primary factor affecting timing is scheduling this work among other porjects especially if we need to react to a municipal project..

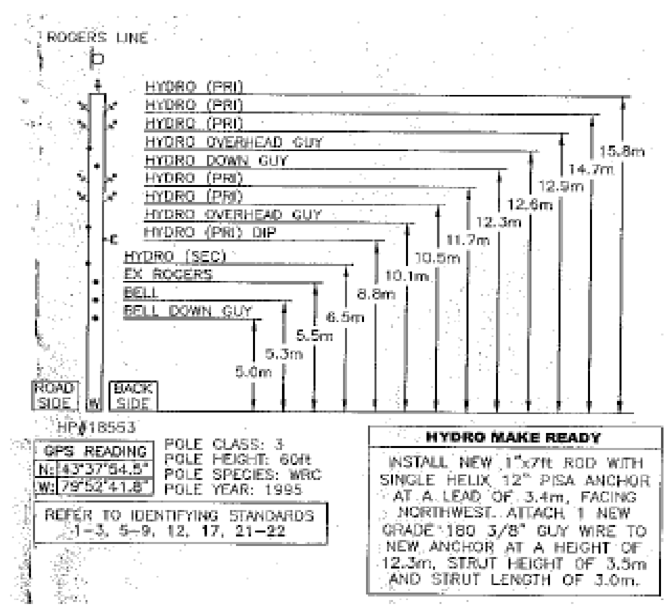
2. Implications of NOT Implementing

If we do not implement Make Ready work two outcomes may result. (1) Halton Hills Hydro may not be operating in conformance with third party agreements and third parties may not be able to perform their work safely or at all. (2) The distribution system may be at risk if portions of it are overloaded and in danger of failing.

3. Alternatives Considered & Reason for Not Implementing

An alternative to perfoming analysis in house would be to contract the work to an external engineering firm. Halton Hills Hydro prefers to keep such work in house as it promotes staff development and maintains competency. Although we have not compared in house costs to perceived external costs, Make-Ready analysis and design generally takes less than 8 hours per site to design and prepare a work package. Engineering firms will cost siginficantly more than our staff rates just due to their higher rates in general plus travel expenses, potential re-design where the original does not conform to Halton Hills Hydro's methods of design, and consider hydro staff will still have to prepare a bill of materials, work instructions, and coordinate with third parties and municipalties. For such reasons we prefer to conduct this design work in house.

Images



Project Authorization

Prepared by:		Authorized By:	
Date:		Assigned To:	
		Assigned Date:	
		Completion Date:	

Change History					
Date	Section	Change		Reason	Change Authorized by:

CAPITAL PLAN	**ENGINEERING**		**2016**
		System Type	SYSTEM ACCESS
Job Request / Number:			
Project Name:	General Service >50 kW Metering Upgrade		
Project Category:			Customer Directed

Reference

Quadra Division:			CAP - HHHDIRECT
Job Request Number:			
Job Number:			
Project Name:			General Service >50 kW Metering Upgrade
Project Category:			Customer Directed
System Type:			SYSTEM ACCESS
Priority Ranking:			5
Risk Ranking:	*Impact:* 4	*Probability:* 3	12
Customer Attachments/Load:			
Project Designer/Manager:			
Start Date:			
In Service Date:			

Estimated Costs

Description		Estimated Cost	Notes			Estimated Expenditure Timing
Labour:	$	5,626		Q1	$	-
Materials:	$	37,200		Q2	$	44,726
Equipment:	$	1,900		Q3	$	-
Contract Labour:	$	-		Q4	$	-
Other:	$	-				
				Carry-over:	$	-
Non-construct capital						
Total Estimated Cost	**$**	**44,726**		Total:	$	44,726
Recoverable:	$	-				
HHHI Estimated Cost	**$**	**44,726**		Control	$	-
					$	-

General Information

Project Summary/Description:
This project includes costs associated with installing new smart meters for general service >50 kW class customers. This requirement is mandated by the Ontario Energy Board

Comparative Information on Equivalent Historical Projects (if any):
A similar project would be the residential smart metering program although on a much smaller scale.

Risks to Completion and Risk Mitigation:
Failure to complete would mean regulatory non-compliance
Total Capital and OM&A Costs for Renewable Energy Generation portion of project (if any):
n/a

Criteria and Information

1. Efficiency, Customer Value, Reliability
Main Driver:
The main driver for this project is a mandated service obligation by the Ontario Energy Board.

Priority & Reasons for Priority:
Priority ranking is listed at 5 since this project must be completed to maintain regulatory compliance
Qualitative & Quantitative Analysis of Project and Project Alternatives:
Benefit to the customer would be the ability to obtain time of use billing on actual consumption rather than on the net system load shape

Other:
N/A

2. Safety
Safety will be ensured by installing meters that meet the latest RF emmission standards.

3. Cyber-security, Privacy
Cyber-security will be maintained by communicating over the new mesh network utilizing VPN technology with data residing within Canada.

4. Coordination, Interoperability
The new meters will interoperate with the existing communications infrastructure

5. Economic Development
Time of use metering will enable better customer control over

6. Environmental Benefits
Remote meter reading will eliminate manual reads and vehicle emmisions.

7. Customer Control (Smart Grid Objective)
Access:
A customer account portal will be made available for viewing consumption data
Visibility:
Online consumption data will be made available to customers where previously this option didn't exist.
Control:
Customers will beable to better manage and control their electricity consumption

Evaluation (	**Participation in Renewables:** n/a **Customer Choice:** n/a **Education:** n/a
	8. Power System Flexibility (Smart Grid Objective) **Distributed Renewables:** Smart metering technology will enable renewable generation monitoring **Visibility:** Generated energy will be able to be viewed online **Control and Automation:** smart metering technoloy will bring future advancements and features to enable control and future automation integration **Quality:** Power quality options are available for newer smart meters to allow for better logging capabilities and reporting mechanisms.
	9. Adaptive Infrastructure (Smart Grid Objective) **Flexibility:** Smart meters included on mesh networks allow for adaptive data network paths and outage reporting. **Forward Compatibility:** The software and firmware used for smart meters is normally upgradable at time of reverification **Encourage Innovation:** Advanced power quality monitoring and outage reporting capability can be leveraged to provide new services to customers such as outage management, bill presentment, CDM.
Outcomes	***1. Customer Focus*** **Service Quality:** Power quality options may be made available to customers **Customer Satisfaction:** improved outage reporting capability will improve utility responsiveness and increase customer satisfaction
	2. Operational Effectiveness **Safety:** n/a **System Reliability:** Reliability will be realized through faster outage response. Customer loading information may be used for system planning purposes to improved constrained areas of the distribution system **Asset Management:** Transformer loading may be monitored, trended and analyzed to optimize equipment life cycles **Cost Control:** Costs will be controlled by buying in large quantities, and leveraging existing data network systems.
	3. Public Policy Responsiveness **CDM** n/a **Connection of Renewable Generation** n/a
	4. Financial Performance **Financial Implications** More accurate consumption and billing of actual consumption used will contribute to reliable revenue collection.
hird Party Planning	***1. Regional (IESO Regions)*** n/a
	2. Regional (geographic) Halton Hills Hydro will seek municipal consent where required for installations.
	3. Municipal Halton Hills Hydro will seek municipal consent where required for installations.
	4. Other Halton Hills Hydro will advise telecommunication companies of the project and if necessary coordinate any relocation work with affected parties.

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5. Transmitter
n/a

Other Information

1. Factors Affecting Project Timing
The main factor affecting timing will be the timeframe mandated by the Ontario Energy Board

2. Implications of NOT Implementing
Not implementing will assure regulatory non compliance

3. Alternatives Considered & Reason for Not Implementing
Not implementing is not an option

Images

Project Authorization

Prepared by:
Date:

Authorized By:
Assigned To:
Assigned Date:
Completion Date:

Change History					
Date	**Section**	**Change**		**Reason**	**Change Authorized by:**

Halton Hills HYDRO	CAPITAL PLAN	ENGINEERING	2016
		System Type	SYSTEM ACCESS
	Job Request / Number:		
	Project Name:	Metering Residential and Interval	
	Project Category:		Customer Directed

Reference

Quadra Division:			CAP - HHHDIRECT
Job Request Number:			
Job Number:			
Project Name:			Metering Residential and Interval
Project Category:			Customer Directed
System Type:			SYSTEM ACCESS
Priority Ranking:			4
Risk Ranking:	*Impact:* 3	*Probability:* 4	12
Customer Attachments/Load:			
Project Designer/Manager:			
Start Date:			
In Service Date:			

Estimated Costs

Description		Estimated Cost	Notes			Estimated Expenditure Timing
Labour:	$	3,024		Q1	$	-
Materials:	$	89,900		Q2	$	114,824
Equipment:	$	1,900		Q3	$	-
Contract Labour:	$	20,000		Q4	$	-
Other:	$	-				
				Carry-over:	$	-
Non-construct capital						
Total Estimated Cost	**$**	**114,824**		Total:	$	114,824
Recoverable:	$	-				
HHHI Estimated Cost	**$**	**114,824**		Control	$	-
					$	-

General Information

Project Summary/Description:
This project includes costs associated with installing residential and interval meters. Regular exchanges must be made as interval meter seals expire. As smart meter seal expiries approach, the utility will need to begin group sampling to cost effectively manage the smart meter seal extensions. Also included are the costs of instrument transformers. These are required for larger commercial and industrial service installations

Comparative Information on Equivalent Historical Projects (if any):
These projects costs are generally equal year over year with some fluctuations based on economic development & the number of new customer connections based on new residential and commercial developments. Residential smart meters stalled the group sampling program and so this initiative will see a re-start of group sampling.

Risks to Completion and Risk Mitigation:
Possible risks include inadequate supply, new technology upgrades associated with smart meters and regulatory changes.

Total Capital and OM&A Costs for Renewable Energy Generation portion of project (if any):
n/a

1. Efficiency, Customer Value, Reliability

Main Driver:
The main driver with metering is regulatory requirements.

Priority & Reasons for Priority:
Priority is high at 4 due to the strict enforcement of meter seal periods and revenue requirements

Qualitative & Quantitative Analysis of Project and Project Alternatives:
Benefit to the customer would be the ability to obtain time of use billing, online web presentment of consumption and interval data. Alternatives would factor into the types of meters used and types of data collection methods

Other:
N/A

2. Safety
Safety will be ensured by installing meters that meet the latest RF emmission standards.

3. Cyber-security, Privacy
Cyber-security will be maintained by communicating over the new mesh network utilizing VPN technology with data residing within Canada.

4. Coordination, Interoperability
The new meters will interoperate with the existing communications infrastructure

5. Economic Development
Online consumption and data presentment enables customers to better manage their energy use, new online tools will empower local businesses to make wise energy choices and attract new business opportunities

on

Evaluation Criteria and Informati	***6. Environmental Benefits*** Remote meter reading will eliminate manual reads and vehicle emmisions.
	7. Customer Control (Smart Grid Objective) **<u>Access:</u>** A customer account portal will be made available for viewing consumption data **<u>Visibility:</u>** Online consumption data will be made available to customers where previously this option didn't exist. **<u>Control:</u>** Customers will beable to better manage and control their electricity consumption **<u>Participation in Renewables:</u>** New meter technology will enable customers to connect renewables such as solar, wind, etc. and monitor revenues generated **<u>Customer Choice:</u>** Customer choice will be enabled through data access **<u>Education:</u>** n/a
	8. Power System Flexibility (Smart Grid Objective) **<u>Distributed Renewables:</u>** Smart metering technology will enable renewable generation monitoring **<u>Visibility:</u>** Energy use at the point of sale will be available to grid operators as technology advances and is rolled out **<u>Control and Automation:</u>** Advanced control features are becoming more available such as remote disconnect and reconnect at the meter. **<u>Quality:</u>** Smart metering systems are now including upgrades to allow for advanced power quality logging, voltage monitoring, sag/swell/interruption data
	9. Adaptive Infrastructure (Smart Grid Objective) **<u>Flexibility:</u>** Smart meters include multiple registers to capture power flow in multiple directions. This will allow for the future capture of energy stored and utilized in new ways ie. electric vehicles. **<u>Forward Compatibility:</u>** The software and firmware used for smart meters is normally upgradable at time of reverification **<u>Encourage Innovation:</u>** Advanced power quality monitoring and outage reporting capability can be leveraged to provide new services to customers such as outage management, bill presentment, CDM.
Outcomes	***1. Customer Focus*** **<u>Service Quality:</u>** Power quality options may be made available to customers **<u>Customer Satisfaction:</u>** improved outage reporting capability will improve utility responsiveness and increase customer satisfaction
	2. Operational Effectiveness **<u>Safety:</u>** n/a **<u>System Reliability:</u>** Reliability will be realized through faster outage response. Customer loading information may be used for system planning purposes to improved constrained areas of the distribution system **<u>Asset Management:</u>** Transformer loading may be monitored, trended and analyzed to optimize equipment life cycles **<u>Cost Control:</u>** Costs will be controlled by buying in large quantities, and leveraging existing data network systems.
	3. Public Policy Responsiveness **<u>CDM</u>** n/a **<u>Connection of Renewable Generation</u>** n/a
	4. Financial Performance **<u>Financial Implications</u>** More accurate consumption and billing of actual consumption used will contribute to reliable revenue collection.
arty Planning	***1. Regional (IESO Regions)*** n/a
	2. Regional (geographic) Halton Hills Hydro will seek municipal consent where required for installations.
	3. Municipal Halton Hills Hydro will seek municipal consent where required for installations.

Third P

4. Other
Halton Hills Hydro will advise telecommunication companies of the project and if necessary coordinate any relocation work with affected parties.

5. Transmitter
n/a

Other Information

1. Factors Affecting Project Timing
The main factor affecting timing will be verification of an accurate system model from the utility GIS system

2. Implications of NOT Implementing
Not implementing will assure regulatory non compliance

3. Alternatives Considered & Reason for Not Implementing
Not implementing is not an option

Images

Project Authorization

Prepared by:		**Authorized By:**	
Date:		**Assigned To:**	
		Assigned Date:	
		Completion Date:	

Change History

Date	Section	Change		Reason	Change Authorized by:

Halton Hills HYDRO	CAPITAL PLAN	ENGINEERING		2016
			System Type	SYSTEM ACCESS
	Job Request / Number:			
	Project Name:	Subdivisions		
	Project Category:			Customer Directed

Reference

Quadra Division:			CAP - CUSTDIRECT
Job Request Number:			
Job Number:			
Project Name:			Subdivisions
Project Category:			Customer Directed
System Type:			SYSTEM ACCESS
Priority Ranking:			4
Risk Ranking:	*Impact:* 4	*Probability:* 3	12
Customer Attachments/Load:	N/A		
Project Designer/Manager:	Meg Gonzales		
Start Date:			
In Service Date:			

Estimated Costs

Description	Estimated Cost	Notes		Estimated Expenditure Timing
Labour:	$ 50,500		Q1	$ 20,700
Materials:	$ 42,000		Q2	$ 82,800
Equipment:	$ 4,500		Q3	$ 82,800
Contract Labour:	$ 110,000		Q4	$ 20,700
Other:	$ -			
			Carry-over:	$ -
Non-construct capital				
Total Estimated Cost	**$ 207,000**		Total:	$ 207,000
Recoverable:	$ 207,000			
HHHI Estimated Cost	**$ -**		Control	-$ 207,000
				-$ 207,000

General Information

Project Summary/Description:
This project involves the design and connection of subdivisions to Halton Hills Hydro's distribution system. It represents the cost and risk involved with subdivisions and the assets associated with such services. Halton Hills Hydro is mandated by the OEB Distribution System Code Section 6 - Distributors' Responsibilities, in which subsection 6.1.1 states "A distributor shall make every reasonable effort to respond promptly to a customer's request for connection. In any event a distributor shall respond to a customer's written request for a customer connection within 15 calendar days. A distributor shall make an offer to connect within 60 calendar days of receipt of the written request, unless other necessary information is required from the load customer before the offer can be made." As well, the Electricity Act 1998 C.15, Section 28 directs the distributors in having an obligation to connect if the building lines along any of the lines of the distributor's distribution system and the owner, occupant, or other person in charge of the build requests a connection.

Comparative Information on Equivalent Historical Projects (if any):
Halton Hills Hydro receives applications each year for new subdivisions and has many years of experience designing, managing, and connecting subdivisions. Subdivisions are customer driven, they design the street networks, house locations, and perform the civil work involved with installing hydro distribution infrastructure. Our years of experience have taught staff to be vigilant in the management of subdivisions, correspond regularly with the developer and our inspectors, and ensure costs are accounted for billed regularly. Two (2) years following the connection of a subdivision, Halton Hills Hydro performs a final inspection and once all is acceptable assumes ownership of the distribution infrastructure up to the demarcation points specified in our conditions of service.

Risks to Completion and Risk Mitigation:
Projects are customer driven and often customers have their own timelines. Customer driven timelines may or may not incorporate coordination with the utility and in some cases the customer is making an application near when they want power. Halton Hills Hydro works with our customers to mitigate potential timing issues by advising customers of expected timeframes for preparing a service layout package and estimate as well as timeframes for ordering and receiving transformers. A close working relationship is necessary to ensure customer driven target service dates are met.

Total Capital and OM&A Costs for Renewable Energy Generation portion of project (if any):
n/a.

1. Efficiency, Customer Value, Reliability

Main Driver:
The main driver for this project is customer requests for electrical distribution and services.

Priority & Reasons for Priority:
This project has a priority reflective of the impacts to our business process. Impacts to Halton Hills Hydro are low as most of the work is performed by the developer. Halton Hills Hydro requires a letter of credit from developers so that if the developer cannot finish construction, Halton Hills Hydro will have funds available to complete the work. Our business process for subdivisions is structured such that Halton Hills Hydro is not negatively impacted (financially) by transpiring's of the developer. Halton Hills Hydro is well equipped to manage multiple subdivision projects.

Qualitative & Quantitative Analysis of Project and Project Alternatives:
By undertaking these projects Halton Hills Hydro ensures compliance with the Electricity Act 1998 C.15 section 28 and the OEB Distribution System Code section 6. The costs associated with these projects are predominantly funded by the developer based on calculated estimates for design, inspection, and connection.

Other:
n/a.

Evaluation Criteria and Information	***2. Safety*** Halton Hills Hydro's construction will be done in accordance with approved utility standards which will protect general public and promote safe working environments for line staff. The developers installation of what will become Halton Hills Hydro's distribution system is inspected by our contract inspectors to ensure compliance with our standards. Inspectors are training in Halton Hills Hydro's Construction Verification Program (O.Reg. 22/04).
	3. Cyber-security, Privacy n/a.
	4. Coordination, Interoperability Halton Hills Hydro's new construction is performed to approved Engineering and Construction Standards with respect to O.Reg. 22/04. Halton Hills Hydro coordinates with other parties such as the municipality and other utilities (telecom and gas) to ensure our respective installations conform to Town of Halton Hills lot service standards. Where necessary due to limited municipal right-of-way, Halton Hills Hydro employs joint-use step trenches permitting all utilities to be installed in the same trench, at different elevations to meet CSA C22.3 No.7 "Underground Systems".
	5. Economic Development Installation of new subdivisions results in new hydro distribution where there was no distribution before. Often in subdivisions there are blocks for schools and commercial business opportunities. This development will see new employment opportunities for commercial retail and service industries as well as educators.
	6. Environmental Benefits n/a.
	7. Customer Control (Smart Grid Objective) **Access:** Smart meters are installed on residential and some commercial services. Customers can set-up an account on-line at Halton Hills Hydro's website and monitor their power usage, see the effects of changes they make in there consumption, and perform comparative analysis of TOU and RPP rates. **Visibility:** Customers can set-up an account on-line at Halton Hills Hydro's website and monitor their power usage, see the effects of changes they make in there consumption, and perform comparative analysis of TOU and RPP rates. **Control:** Customers can view their consumption habits and make informed decisions about making changes in the way the consume power. **Participation in Renewables:** New subdivisions improve the potential for renewable connections by adding new distribution infrastructure where it had not existed previously. As such, new customers have the potential to apply for a renewable generation connection and provided there are no system capacity constraints they may be able to connect a renewable generation project. Similar can be said for service upgrades that include increasing transformation for the service(s). Increased transformation lends itself to the potential for increased renewable generation capacity. **Customer Choice:** Customers can choose to sign with a retailer. **Education:** New subdivisions provide an avenue to discuss renewable generation with interested customers. Halton Hills Hydro also distributes welcome packages to new customers letting them know who we are and what we do.
	8. Power System Flexibility (Smart Grid Objective) **Distributed Renewables:** Where capacity permits, the distribution system can accommodate renewable generation. **Visibility:** n/a. **Control and Automation:** n/a. **Quality:** Each project is constructed to current standards and in doing so quality of supply to new and upgraded customers can be maintained. New transformers have tap switches which allows the utility to control voltage at a local level.
	9. Adaptive Infrastructure (Smart Grid Objective) **Flexibility:** Infrastructure installed in subdivisions generally is not fully utilized and thus there can be the potential to permit service upgrades as well as accommodate renewable generation. **Forward Compatibility:** n/a. **Encourage Innovation:** Customers will have the opportunity to install innovative technologies such as electric vehicle car charges.
Outcomes	***1. Customer Focus*** **Service Quality:** n/a. **Customer Satisfaction:** n/a.
	2. Operational Effectiveness **Safety:** New subdivisions will be constructed to Halton Hills Hydro standards and in doing so the project will protect the general public from undue hazards related to the distribution system. **System Reliability:** New subdivisions are constructed to current standards are inherently reliable as new assets are used to construct new services. **Asset Management:** n/a. **Cost Control:** Final costs of the subdivision is determined from final costs post completion. Halton Hills Hydro designs and estimates subdivisions taking into consideration known factors and make experienced based decisions to lessen the potential for unexpected changes during construction.

	3. Public Policy Responsiveness **<u>CDM</u>** Halton Hills Hydro requires the developer submit at least three (3) transformer manufacturer quotations complete with upfront cost and losses. Halton Hills Hydro staff determines the total ownership cost of each manufacturers transformer and advises the developer of the approval transformer. Generally, the selected transformer has the lowest losses and low losses reduces the utilities overall loss factor. **<u>Connection of Renewable Generation</u>** Customers will have the opportunity to install renewable generation provide capacity exists.
	4. Financial Performance **<u>Financial Implications</u>** Subdivision projects demonstrate financial viability as construction costs are recouped from the developer. Furthermore new customers provide additional revenue for the utility through meter service charges. Long term operational effectiveness is attained through use of current construction standards and the use of new assets.
Third Party Planning	***1. Regional (IESO Regions)*** n/a.
	2. Regional (geographic) Halton Hills Hydro will coordinate with the Region of Halton for municipal consents.
	3. Municipal Halton Hills Hydro will coordinate with the Town of Halton Hills for municipal consents and ensure installations conform to municipal lot servicing standards.
	4. Other Halton Hills Hydro coordinates with telecommunication companies and gas companies to ensure services to the subdivision do not conflict with each other.
	5. Transmitter n/a.
Other Information	***1. Factors Affecting Project Timing*** The customer drives timing for the most part. Close coordination with the customer is necessary to ensure projects meet their target dates. Halton Hills Hydro prioritizes projects and material ordering to coincide with customer in-service target dates.
	2. Implications of NOT Implementing The implication of not implementing designs and utility related construction for subdivisions is a dissatisfied customer. Furthermore, Halton Hills Hydro would not be meeting it's regulated requirements in the Electrical Act 1998 C.15 section 28 or the OEB Distribution System Code section 6.
	3. Alternatives Considered & Reason for Not Implementing Projects are initiated by the customer. Halton Hills Hydro provides options relating to servicing the development and works with our customers to align the scope of work to satisfy the customers needs and meet our regulatory requirements.
Images	
Project Authorizat ion	**Prepared by:** **Date:** **Authorized By:** **Assigned To:** **Assigned Date:** **Completion Date:**

Change History					
Date	**Section**	**Change**		**Reason**	**Change Authorized by:**

Halton Hills HYDRO

CAPITAL PLAN	ENGINEERING		2016
		System Type	SYSTEM ACCESS
Job Request / Number:			
Project Name:	Technical Service Layouts		
Project Category:			Customer Directed

Reference

Quadra Division:			CAP - CUSTDIRECT
Job Request Number:			
Job Number:			
Project Name:			Technical Service Layouts
Project Category:			Customer Directed
System Type:			SYSTEM ACCESS
Priority Ranking:			4
Risk Ranking:	*Impact:* 4	*Probability:* 3	**12**
Customer Attachments/Load:			
Project Designer/Manager:			
Start Date:			
In Service Date:			

Estimated Costs

Description	Estimated Cost	Notes		Estimated Expenditure Timing
Labour:	$ 251,816		Q1	$ 41,604
Materials:	$ 80,000		Q2	$ 150,414
Equipment:	$ 44,220		Q3	$ 150,414
Contract Labour:	$ -		Q4	$ 33,604
Other:	$ -			
			Carry-over:	$ -
Non-construct capital				
Total Estimated Cost	**$ 376,035.71**		Total:	$ 376,036
Recoverable:	$ 296,035.71			
HHHI Estimated Cost	**$ 80,000.00**		Control	-$ 296,036
				-$ 296,036

General Information

Project Summary/Description:
This project involves the connection of any new or upgrades residential, general, and temporary service to Halton Hills Hydro's distribution system. It represents the cost and risk involved with customer services and the assets associated with such services. Halton Hills Hydro is mandated by the OEB Distribution System Code Section 6 - Distributors' Responsibilities, in which subsection 6.1.1 states "A distributor shall make every reasonable effort to respond promptly to a customer's request for connection. In any event a distributor shall respond to a customer's written request for a customer connection within 15 calendar days. A distributor shall make an offer to connect within 60 calendar days of receipt of the written request, unless other necessary information is required from the load customer before the offer can be made." As well, the Electricity Act 1998 C.15, Section 28 directs the distributors in having an obligation to connect if the building lines along any of the lines of the distributor's distribution system and the owner, occupant, or other person in charge of the build requests a connection.

Comparative Information on Equivalent Historical Projects (if any):
Halton Hills Hydro receives many applications each year for new services and service upgrades/ modifications. Each service application is an individual project and managed as such. Standard policies and procedures are applied uniformly to applications. Halton Hills Hydro assesses each application and determines the extent of work based on the customers servicing needs and electrical demand requirements.

Risks to Completion and Risk Mitigation:
Projects are customer driven and often customers have their own timelines. Customer driven timelines may or may not incorporate coordination with the utility and in some cases the customer is making an application near when they want power. Halton Hills Hydro works with our customers to mitigate potential timing issues by advising customers of expected timeframes for preparing a service layout package and estimate as well as timeframes for ordering and receiving transformers. A close working relationship is necessary to ensure customer driven target service dates are met.

Total Capital and OM&A Costs for Renewable Energy Generation portion of project (if any):
n/a.

1. Efficiency, Customer Value, Reliability

Main Driver:
The main driver for this project is customer requests for electrical services.

Priority & Reasons for Priority:
This project has a priority reflective of the impacts to our business process. Halton Hills Hydro is well equipped to manage multiple service layout requests provided the customer has contacted us well in advance of their target in-service date.

Qualitative & Quantitative Analysis of Project and Project Alternatives:
By undertaking these projects Halton Hills Hydro ensures compliance with the Electricity Act 1998 C.15 section 28 and the OEB Distribution System Code section 6. The costs associated with these projects are predominantly funded by the applying customer based on calculated estimates for connection with the expectation of the transformer as transformation is provided by Halton Hills Hydro and is a capital investment.

Other:
n/a.

2. Safety
Halton Hills Hydro's construction will be done in accordance with approved utility standards which will protect general public and promote safe working environments for line staff. Poles will be of sufficient strength to support the load applied to them.

3. Cyber-security, Privacy
n/a.

4. Coordination, Interoperability
Halton Hills Hydro's new construction is performed to approved Engineering and Construction Standards with respect to O.Reg. 22/04. Halton Hills Hydro coordinates with other parties such as the municipality for consent to perform work in the public right-of-way. We also coordinate with telecommunication companies where such need exists.

Evaluation Criteria and Information

5. Economic Development

Installation of service and upgrades services allows for local development, creation of jobs, and overall economic growth of the municipality.

6. Environmental Benefits

n/a.

7. Customer Control (Smart Grid Objective)

<u>Access:</u>

Smart meters are installed on residential and some commercial services. Customers can set-up an account on-line at Halton Hills Hydro's website and monitor their power usage, see the effects of changes they make in there consumption, and perform comparative analysis of TOU and RPP rates.

<u>Visibility:</u>

Customers can set-up an account on-line at Halton Hills Hydro's website and monitor their power usage, see the effects of changes they make in there consumption, and perform comparative analysis of TOU and RPP rates.

<u>Control:</u>

Customers can view their consumption habits and make informed decisions about making changes in the way the consume power.

<u>Participation in Renewables:</u>

New services will be associated with a transformer. As such, new customers have the potential to apply for a renewable generation connection and provided there are no system capacity constraints they may be able to connect a renewable generation project. Similar can be said for service upgrades that include increasing transformation for the service(s). Increased transformation lends itself to the potential for increased renewable generation capacity.

<u>Customer Choice:</u>

n/a.

<u>Education:</u>

New service provide an avenue to discuss renewable generation and customer involvement with interested customers.

8. Power System Flexibility (Smart Grid Objective)

<u>Distributed Renewables:</u>

Where capacity permits, the distribution system can accommodate renewable generation.

<u>Visibility:</u>

n/a.

<u>Control and Automation:</u>

n/a.

<u>Quality:</u>

Each project is constructed to current standards and in doing so quality of supply to new and upgraded customers can be maintained.

9. Adaptive Infrastructure (Smart Grid Objective)

<u>Flexibility:</u>

n/a.

<u>Forward Compatibility:</u>

n/a.

<u>Encourage Innovation:</u>

n/a.

Outcomes

1. Customer Focus

<u>Service Quality:</u>

n/a.

<u>Customer Satisfaction:</u>

n/a.

2. Operational Effectiveness

<u>Safety:</u>

This project will be constructed to Halton Hills Hydro standards and in doing so the project will protect the general public from undue hazards related to the distribution system.

<u>System Reliability:</u>

New services that are constructed to current standards are inherently reliable as new assets are used to construct new services.

<u>Asset Management:</u>

n/a.

<u>Cost Control:</u>

Final costs of each service installation is determined from final costs post completion. Halton Hills Hydro designs and estimates service layouts taking into consideration known factors and make experienced based decisions to lessen the potential for unexpected changes during construction. Control of costs is also achieved through a competitive bid process for transformers to ensure the upfront capital expenditure as well as the total ownership costs are as low as reasonably possible. Where changes are initiated by the customer, additional expenditures are recovered form the customer.

3. Public Policy Responsiveness

<u>CDM</u>

n/a.

<u>Connection of Renewable Generation</u>

n/a.

4. Financial Performance

<u>Financial Implications</u>

Technical service layout projects demonstrate financial viability as construction costs are recouped from the customer. Furthermore new customers provide additional revenue for the utility through meter service charges. Long term operational effectiveness is attained through use of current construction standards and the use of new assets.

ty Planning

1. Regional (IESO Regions)

n/a.

2. Regional (geographic)

Halton Hills Hydro will coordinate with the Region of Halton for municipal consents.

3. Municipal

Halton Hills Hydro will coordinate with the Town of Halton Hills for municipal consents.

Third Par

4. Other
Halton Hills Hydro will advise telecommunication companies that are attached to our poles being removed/ relocated/ replaced, we will advise them to prepare transfer designs as required by O.Reg. 22/04 and coordinate their attachment transfers.

5. Transmitter
In some cases it may be necessary to advise Hydro One of new services being connected to our 44kV feeders that originate at Hydro One owned transformer stations.

Other Information

1. Factors Affecting Project Timing
The customer drives timing for the most part. Close coordination with the customer is necessary to ensure projects meet their target dates. Halton Hills Hydro prioritizes projects and material ordering to coincide with customer in-service target dates.

2. Implications of NOT Implementing
The implication of not implementing a customer service layout designs is a dissatisfied customer. Furthermore, Halton Hills Hydro would not be meeting it's regulated requirements in the Electrical Act 1998 C.15 section 28 or the OEB Distribution System Code section 6.

3. Alternatives Considered & Reason for Not Implementing
Projects are initiated by the customer. Halton Hills Hydro provide options relating to servicing the customers and works with our customers to align the scope of work to satisfy the customers needs and meet our regulatory requirements.

Images

Project Authorization

Prepared by:
Date:

Authorized By:
Assigned To:
Assigned Date:
Completion Date:

Change History

Date	Section	Change		Reason	Change Authorized by:

Halton Hills HYDRO	**CAPITAL PLAN**	**ENGINEERING**		**2016**
			System Type	**SYSTEM ACCESS**
	Job Request / Number:			**15**
	Project Name:	**Trafalgar Road at 10 Side Road (Intersection Widening).**		
	Project Category:			**Customer Directed**

Reference

Quadra Division:				CAP - CUSTDIRECT
Job Request Number:				15
Job Number:				
Project Name:				Trafalgar Road at 10 Side Road (Intersection Widening).
Project Category:				Customer Directed
System Type:				SYSTEM ACCESS
Priority Ranking:				4
Risk Ranking:	*Impact:* 5		*Probability:* 3	**15**
Customer Attachments/Load:				
Project Designer/Manager:				
Start Date:				
In Service Date:				

Estimated Costs

Description	Estimated Cost	Notes		Estimated Expenditure Timing
Labour:	$ 115,180		Q1	$ 89,324
Materials:	$ 150,037		Q2	$ 267,971
Equipment:	$ 67,454		Q3	$ -
Contract Labour:	$ 24,624		Q4	$ -
Other:	$ -			
			Carry-over:	$ -
Non-construct capital				
Total Estimated Cost	**$ 357,295**		Total:	$ 357,295
Recoverable:	$ 103,629			
HHHI Estimated Cost	**$ 253,666**		Control	-$ 103,629
				-$ 103,629

General Information

Project Summary/Description:
This project invloves relocating our utility poles, wires, anchors, and related equipment at the intersection of Trafalgar Road and 10 Side Road to accommodate Region of Halton intersection improvement plans. Halton Hills Hydro will install new distribution infrastructure as layed out in our design and approved by the Region of Halton. Halton Hills Hydro is obligated to perform this work per the Government of Ontario's Public Service Works on Highways Act, R.S.O. 1990, Chapter 49, Section 2 (2), Halton Hills Hydro is required to take up, remove or change the location of our infrastruture when requested by the road authority.

Comparative Information on Equivalent Historical Projects (if any):
Halton Hills Hydro has performed relocations for municipal road improvements in recent years such as Steeles Avenue, at Trafalgar Road and 5 Side Road, and 10 Side Road at 10th Line. The latter two examples were relocations to accommodate Regional intersection improvement plans. Like those projects, the planned relocations at Trafalgar Road and 10 Side road is based on a designed prepared by Halton Hills Hydro, approved by the Region of Halton, and coordinated with third party PUCC members. Historical experience has taught us that while in construction, The Region of Halton may ask us to alter our relocation plans. Such requests force the utility spend addtional resources to revise its already approved drawings and relocate infrastructure that had already been relocated at the Region of Halton's request. Such changes are normally borne by the requestor fully at their expense.

Risks to Completion and Risk Mitigation:
The primary risk to completion is if we begin construction prior to land and easement acquisition, part of the work may be delayed until Region of Halton can acquire the necessary land and easements. Halton Hills Hydro generally will not commence construction until we receive confirmation that land and easements are acquired or we have received permission to enter and construct our work. A secondary risk to completion is the Region of Halton requesting further changes once construction has commenced. To mitigate this second risk Halton Hills Hydro works closely with the Region to evaluate such requests to determine if they are necessary.

Total Capital and OM&A Costs for Renewable Energy Generation portion of project (if any):
n/a.

1. Efficiency, Customer Value, Reliability

Main Driver:
The main driver for this project is Region of Halton road improvement plans conflicting with existing pole and anchor locations.

Priority & Reasons for Priority:
This project has been given a high priority. If the Region of Halton acquires the land as they say they will for 2016, Halton Hills Hydro will be expected to commence with construction and be complete before Regional road forces begin their work.

Qualitative & Quantitative Analysis of Project and Project Alternatives:
Subject to the Government of Ontario's Public Service Works on Highways Act, R.S.O. 1990, Chapter 49, Section 2 (2), Halton Hills Hydro is required to take up, remove or change the location of our infrastruture when requested by the road authority (region of Halton). Halton Hills Hydro will be seeking cost recovery under the provincial for 50% of the labour and equipment portions of this project. Cost recover is shown in the above financial metrics.

Other:
n/a.

2. Safety
Halton Hills Hydro's construction will be done in accordance with approved utility standards which will protect general public and promote safe working environments for line staff. Poles will be of sufficient strength to support the load applied to them. Halton Hills Hydro lines staff will be working on a very busy road for which they are trained to follow certain rules and set-up requirements (MTO Book 7). Such training is managed through Halton Hills Hydro's implementation of our Empower safety program with Springboard Management.

Evaluation Criteria and Information	***3. Cyber-security, Privacy*** n/a.
	4. Coordination, Interoperability Halton Hills Hydro will coordinate our relocation efforts with the Region of Halton to ensure completion prior to road work commences. We will also coordinate with telecommunication companies to ensure their attachments are relocated to our new poles.
	5. Economic Development n/a.
	6. Environmental Benefits n/a.
	7. Customer Control (Smart Grid Objective) **Access:** n/a. **Visibility:** n/a. **Control:** n/a. **Participation in Renewables:** n/a. **Customer Choice:** n/a. **Education:** n/a.
	8. Power System Flexibility (Smart Grid Objective) **Distributed Renewables:** n/a. **Visibility:** n/a. **Control and Automation:** n/a. **Quality:** This project will ensure Halton Hills Hydro's infrastructure is sufficient to support current load and load growth.
	9. Adaptive Infrastructure (Smart Grid Objective) **Flexibility:** n/a. **Forward Compatibility:** This project will provide sufficient pole space to install our 27.6kV distribution system through the intersection and north on Trafalgar Road to connect to our 41M21 circuit that presently dead-ends about 3 pole spans north of the intersection. In the future Halton Hills Hydro will have the opportunity to complete this distribution loop. **Encourage Innovation:** n/a.
Outcomes	***1. Customer Focus*** **Service Quality:** n/a. **Customer Satisfaction:** n/a.
	2. Operational Effectiveness **Safety:** This project will be constructed to Halton Hills Hydro standards and in doing so the project will protect the general public from undue hazards related to the distribution system. Halton Hills Hydro staff is trained in proper working procedures and job site set-up. Training for staff is managed by Springboard Management as part of Halton Hills Hydro's Empower safety program. **System Reliability:** System reliability will be maintained on our 44kV and 8.32kV distribution systems as this relocation project will see our existing circuits continue to function in the same manner. However, this project will enable Halton Hills Hydro to install 27.6kV north on Trafalgar Road and connect it to our 41M21 whcih is dead-ended about 3 poles spans north of the intrsection. Extending our 27.6kV through the intersection will create a much needed distribution loop that will improve reliability for residential customers who are presently supplied via a radial feeder. **Asset Management:** n/a. **Cost Control:** Halton Hills Hydro will monitor costs for this project during construction and periodically invoice the Region of Halton as construction progresses. Should costs seem to be deviating from the estimate Halton Hills Hydro will take proactive measures to determine overall impacts to the job and cost sharing with the Region of Halton.
	3. Public Policy Responsiveness **CDM** n/a. **Connection of Renewable Generation** n/a.

4. Financial Performance

<u>Financial Implications</u>

This project includes sufficient pole space to install our 27.6kV through the intrsection. Becasuse the Region of Halton does not pay for materials (as per the Public Service Works on Highways Act) Halton Hills Hydro is taking a proactive measure to ensure we can take advantage of the construction for future work. This investment will save significant amounts of capital dollars as we will not have to construct additional infrastructure to extend complete a 27.6kV distribution loop. This financial efficiency was looked at as being significant enough to delay completing our 27.6kV loop completion.

Third Party Planning

1. Regional (IESO Regions)

n/a.

2. Regional (geographic)

Halton Hills Hydro will work with the Region of Halton to ensure our construction work is coordinated with their plans and that we received municipal consent.

3. Municipal

Halton Hills Hydro will advise the Town of Halton Hills of our work. However, we will not seek municipal consent from the Town as both Trafalgar Road and 10 Side Road are Regional roads and the Town would not be able to issue a municipal consent.

4. Other

Halton Hills Hydro will circulate our PUCC group to advise the utilities of our work and coordinate relocation efforts. Where telecommunication companies are attached to our poles being removed, we will advise them to prepare transfer designs as required by O.Reg. 22/04 and coordinate their attachment transfers.

5. Transmitter

Halton Hills Hydro will coordinate with the upstream transmitter, Hydro One, where necessary when performing switching procedures on our 44kV and 27.6kV circuits to electrically isolate the intersection/ work area.

Other Information

1. Factors Affecting Project Timing

The primary factor affecting timing is when the Region acquires the land and easements needed to facilitate relocations. Hatlon Hills Hydro will not commence relocations until we are assured that land is available to begin construction.

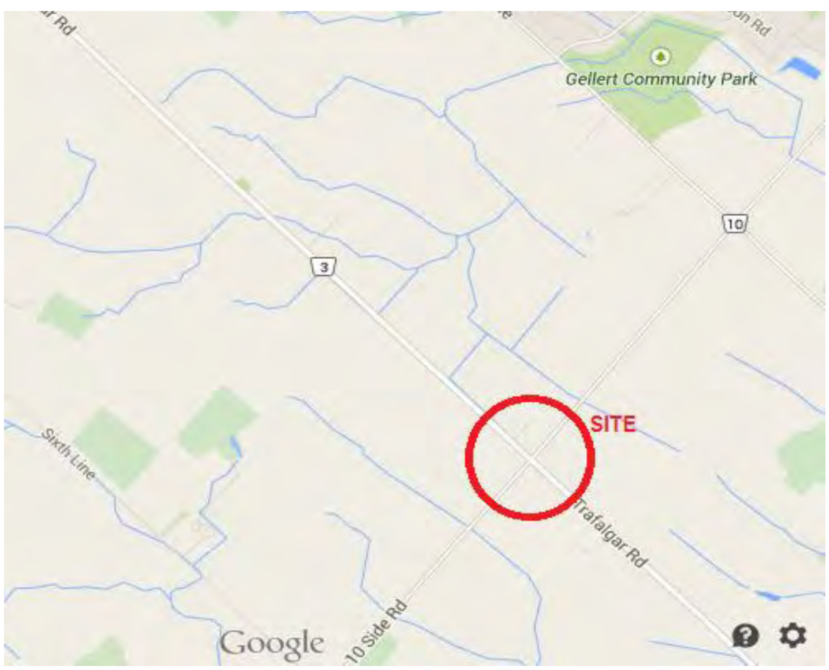
2. Implications of NOT Implementing

If this project were not to commence our utility poles and anchors would be indirect conflict with Regional road improvements. This would be a violation of the requirements of the Public Service Works on Highways Act and could put the Region is a position to serve Halton Hills Hydro with a notice to relocate in 60 days.

3. Alternatives Considered & Reason for Not Implementing

During the design phase, consideration was given to installing poles that would be suitable for only the existing circuits. However, given Halton Hills Hydro's plans with respect to growing our 27.6kV distribution system to accommodate future load growth and current reliability issue, the decision was made to install infrastructure and design to accommodate a 27.6kV circuit. If we had not designed for an additional circuit, Halton Hills Hydro would have been faced with difficulty in extending our 27.6kV through the intersection and may have had to replace part of the newly installed infrastructure. Because cost recovery does not include materials (defined in the Ontario's Public Service Works on Highways Act, R.S.O. 1990, Chapter 49) we believe it makes financial sense to install infrastructure for future growth and system reliability as we do recoupe 50% of labour and equipment costs.

Images



Project Authorization				
	Prepared by:		Authorized By:	
	Date:		Assigned To:	
			Assigned Date:	
			Completion Date:	

Change History					
Date	Section	Change		Reason	Change Authorized by:

Halton Hills HYDRO

CAPITAL PLAN	ENGINEERING		2016
		System Type	SYSTEM RENEWAL
Job Request / Number:			
Project Name:	Cross MS Switchgear Replacement		
Project Category:			Substation

Reference

Quadra Division:			CAP - HHHDIRECT
Job Request Number:			9
Job Number:			
Project Name:			Cross MS Switchgear Replacement
Project Category:			Substation
System Type:			SYSTEM RENEWAL
Priority Ranking:			5
Risk Ranking:	Impact: 4	Probability: 4	16
Customer Attachments/Load:			
Project Designer/Manager:			
Start Date:			
In Service Date:			

Estimated Costs

Description	Estimated Cost	Notes		Estimated Expenditure Timing
Labour:	$ 10,690		Q1	$ 3,551
Materials:	$ 700,000		Q2	$ -
Equipment:	$ 3,515		Q3	$ -
Contract Labour:	$ -		Q4	$ 710,654
Other:	$ -			
			Carry-over:	$ -
Non-construct capital				
Total Estimated Cost	**$ 714,205**		Total:	$ 714,205
Recoverable:	$ -			
HHHI Estimated Cost	**$ 714,205**		Control	$ -
				$ -

General Information

Project Summary/Description:
This project involves the replacement of a walk-in 4.16 kV switchgear that has reached end of life. Also supported is the reinforcement of the Georgetown 4.16kV system by adding an additional feeder circuit breaker and increased main bus with higher load capacity to fully support the existing power transformer rating.

Comparative Information on Equivalent Historical Projects (if any):
A similar switchgear was replaced at River MS in 2007 for reasons of asset end of life renewal

Risks to Completion and Risk Mitigation:
The main risk is manufacturer lead/delivery time.

Total Capital and OM&A Costs for Renewable Energy Generation portion of project (if any):
n/a

1. Efficiency, Customer Value, Reliability

Main Driver:
Asset renewal is the main driver for this project. The equipment has reached the end of it's useful life and will require ongoing repairs and refurbishment in order to keep the equipment in a fit operational state. A secondary driver is 4.16 kV system reinforcement by supporting increased load capacity to ensure adequate supply for future growth and the support of load transfers during peak loading periods or planned maintenance outages on the system.

Priority & Reasons for Priority:
The priority ranking reflects the present age of the switchgear and because it requires immediate capacity upgrades and feeder expansion to support reinforcing the 4.16 kV system. This project has also been deffered in previous years.

Qualitative & Quantitative Analysis of Project and Project Alternatives:
The investment would support reinforcement of the 4.16 kV system, reduction in overall feeder loading as well as a reduction in system losses. Benefits to the customer would be a reduction in operating costs and overall distribution charges.

Other:
N/A

2. Safety
Medium voltage distribution switchgear safety standards have changed dramatically over the last 10 years. Arc flash protection has been incorporated into manufacturing standards and offers better protection to utility personnel at a small cost compared to the overall cost of the equipment.

3. Cyber-security, Privacy
N/A

4. Coordination, Interoperability
Many local distribution companies automate their substations. Halton Hills Hydro's substations, when connected to our SCADA system, will be controlled remotely from our shared Control Room at Oakville Hydro by the operators.

5. Economic Development
Enabling the re-inforcement of the 4.16kV system will enable the ability to connect new load for infill developments, allowing for new residential and commercial growth.

6. Environmental Benefits
Expansion of an existing substation offers environmental benefits over siting new substations, by reducing land use needs and overal environmental impact.

7. Customer Control (Smart Grid Objective)

Access:
n/a

Visibility:

a and Information

Evaluation Criteri	n/a **Control:** n/a **Participation in Renewables:** Increased system capacity will allow for greater amounts of renewable generation in the denser urban areas. Customers will now have the ability to install generation with the utility being assured that appropriate feeder protection is in place. The utility will benefit by being able to better monitor feeders in real time. **Customer Choice:** Reinforcing the 4.16kV distribution system will provide customers with greater ability to connect renewable generation as well as request larger services if their demand load requires. **Education:** n/a
	8. Power System Flexibility (Smart Grid Objective) **Distributed Renewables:** The equipment contained in the switchgear will be automated and communicate with the utility SCADA system. It can be operated to restore power to areas affected by power interruptions. Such switching routines could enable renewable generation on affected feeders to be reconnected and continue operations. **Visibility:** Integrated instrument transformers that step voltage and current down from a higher level (4,160V) to a lower level (120V) to be used by protection and control equipment such as relays and meters. The voltage and load readings as well as breaker status (open/ closed) and fault conditions can be transmitted to the utility office via the utility SCADA system. **Control and Automation:** Additional switching functionality may enable early restoration of circuits on which renewable generation is connected thus enabling renewable generation to continue producing power. **Quality:** Metering equipment within the switchgear may be used for monitoring power quality and logged for review and improvement initiatives.
	9. Adaptive Infrastructure (Smart Grid Objective) **Flexibility:** Substation Automation provide flexibility by allowing the utility to restore power to areas affected by power interruptions. This can help the implementation of innovative technologies such as electric vehicle charging stations, public or private, and will help customers feel their utility power supply is supportive of innovative technologies that they already use or are considering purchasing. **Forward Compatibility:** The software and firmware used for substation automation is normally upgradable. **Encourage Innovation:** By using substation automation to restore power in an expedient manner, customers who are exploring innovative technologies such as electric vehicles may elect to purchase EV's knowing their power supply is reliable.
Outcomes	***1. Customer Focus*** **Service Quality:** Advanced feeder protection, control & metering provides the opportunity to monitor power quality at the source of a feeder. **Customer Satisfaction:** Improved system reliability and more timely attention to power quality issues will contribute to enhanced customer satisfaction
	2. Operational Effectiveness **Safety:** Crew safety will be enhanced by remotely monitoring the state of equipment **System Reliability:** Newer, modern distribution switchgear combined with automation can help reduce outage times by enabling quick restoration through automated routines or remote operations. **Asset Management:** Equipment upgrades and smart controls enable enhanced condion monitoring that can be used to support equipment life cycle decisions **Cost Control:** Vacuum breakers will reduce O&M expenditures by eliminating air as an arc interrupting medium. Reduced maintenance will be required throught the useful life of the asset. Remote switching will also reduce capital expenditures that normally result from time spent by field staff going to specific switch locations and manually operating switches to isolate a work zone or to place a holdoff.
	3. Public Policy Responsiveness **CDM** Reinforcement and lower load levels will reduce line loss. **Connection of Renewable Generation** This project will allow for increase renewable generation sources to be connected.
	4. Financial Performance **Financial Implications** Optimum balanced load levels on the 4.16 kV distribution feeders will result in lower system losses. This will enable better cost recovery and lower system operating costs.

Third Party Planning	***1. Regional (IESO Regions)*** n/a
	2. Regional (geographic) Halton Hills Hydro will seek municipal consent where required for installations.
	3. Municipal Halton Hills Hydro will seek municipal consent where required for installations.
	4. Other Halton Hills Hydro will advise telecommunication companies of the project and if necessary coordinate any relocation work with affected parties.
	5. Transmitter n/a
Other Information	***1. Factors Affecting Project Timing*** The main factor affecting timing will be receiving the switchgear on time. Delays can be averted by contacting the manufacturer to determine what the delivery lead time is and build that lead time into the project scope to ensure the switchgear is ordered in time.
	2. Implications of NOT Implementing Not implementing this project would lead to supply constraints to new infill developments and potential decrease in reliability .
	3. Alternatives Considered & Reason for Not Implementing Alternatives considered have been to add a fourth circuit breaker and upgrade the main bus capacity to support the increase capacity requirements. Considering the age of the existing insulation systems and cicuit breakers, future breaker failures & overhauls would be required in addition to the risk of bus insulation failure. Modern switchgear also incorporate advanced safety features at modest incremental cost vs. refurbishing older equipment.
Images	
Project Authorization	**Prepared by:** **Date:** **Authorized By:** **Assigned To:** **Assigned Date:** **Completion Date:**

Change History

Date	Section	Change		Reason	Change Authorized by:

CAPITAL PLAN	ENGINEERING		2016
		System Type	SYSTEM RENEWAL
Job Request / Number:			
Project Name:	Live Front Transformer Replacement		
Project Category:			HHHI Directed

Reference

Quadra Division:			CAP - HHHIDIRECT
Job Request Number:			
Job Number:			
Project Name:			Live Front Transformer Replacement
Project Category:			HHHI Directed
System Type:			SYSTEM RENEWAL
Priority Ranking:			2
Risk Ranking:	*Impact:* 4	*Probability:* 1	4
Customer Attachments/Load:			
Project Designer/Manager:			
Start Date:			
In Service Date:			

Estimated Costs

Description	Estimated Cost	Notes	Estimated Expenditure Timing	
Labour:	$ 18,202		Q1	$ 3,945
Materials:	$ 44,800		Q2	$ 49,345
Equipment:	$ 5,187		Q3	$ 45,400
Contract Labour:	$ 30,500		Q4	$ -
Other:	$ -			
			Carry-over:	$ -
Non-construct capital				
Total Estimated Cost	**$ 98,689.44**		Total:	$ 98,689
Recoverable:	$ -			
HHHI Estimated Cost	**$ 98,689.44**		Control	$ -
				$ -

General Information

Project Summary/Description:
This project involves the replacement of live front padmounted transformers with dead-front padmounted transformers. At the same time primary cables and concrete foundations will be replaced to renew the asset aged of the service. On average these units are over 40 years old and have surpassed their useful life. Live-front padmounted transformers supply multi-unit residential buildings, schools, and commercial business. The project address a concern that if a live front padmount transformer were to fail it would be difficult to replace it with dead-front transformer using the existed aged assets.

Comparative Information on Equivalent Historical Projects (if any):
n/a.

Risks to Completion and Risk Mitigation:
The project involves work in close proximity to existing customer services. Risks to completion are mitigated by working closely with affected customers to communicate project plans. Furthermore, careful planning and engineering will ensure projects are not delayed which might further inconvenience customers.

Total Capital and OM&A Costs for Renewable Energy Generation portion of project (if any):
n/a.

1. Efficiency, Customer Value, Reliability

Main Driver:
The main driver of this project is the need to replace aged assets that are in poor condition and will be difficult to replace if they fail. The risk to customers and the distribution system are factors that have been considered as well.

Priority & Reasons for Priority:
The priority level of this project reflects the risk of the aged assets but not the immediacy of the replacements.

Qualitative & Quantitative Analysis of Project and Project Alternatives:
Halton Hills Hydro has in the past few years replaced two (2) live front padmounted transformers and has comparative information with respect to the complications of replacing such units with dead front transformers.

Other:
n/a.

2. Safety
New service are constructed to current standards in respect of O.Reg. 22/04 and protect the public.

3. Cyber-security, Privacy
n/a.

4. Coordination, Interoperability
n/a.

5. Economic Development
Renewing aged assets for commercial services represent a commitment to customers that Halton Hills Hydro invests in its infrastructure to support local economic sustainment and growth.

6. Environmental Benefits
n/a.

tion

Evaluation Criteria and Informa	***7. Customer Control (Smart Grid Objective)*** **<u>Access:</u>** n/a. **<u>Visibility:</u>** n/a. **<u>Control:</u>** n/a. **<u>Participation in Renewables:</u>** n/a. **<u>Customer Choice:</u>** n/a. **<u>Education:</u>** n/a.
	8. Power System Flexibility (Smart Grid Objective) **<u>Distributed Renewables:</u>** New transformers are better equipped to accommodate renewable generation. Asset life of new transformers exceeds current government contract terms of 20 years. **<u>Visibility:</u>** n/a. **<u>Control and Automation:</u>** n/a. **<u>Quality:</u>** New transformers are built to current CSA standards that incorporate design efficiencies and enable the utility to adjust transformer output voltage. As well, new transformers are more efficient national standards developed by CSA specify loss requirements that transformers are not to be exceed when manufactured.
	9. Adaptive Infrastructure (Smart Grid Objective) **<u>Flexibility:</u>** n/a. **<u>Forward Compatibility:</u>** n/a. **<u>Encourage Innovation:</u>** n/a.
Outcomes	***1. Customer Focus*** **<u>Service Quality:</u>** n/a. **<u>Customer Satisfaction:</u>** n/a.
	2. Operational Effectiveness **<u>Safety:</u>** New transformers and related installations are constructed to current CSA standards and utility construction standards per O.Reg. 22/04. Such construction is based on specifications that meet national standards and are designed to ensure safe operation by line staff. **<u>System Reliability:</u>** New construction is done to current industry standards, new assets are manufactured to current industry standards, and this ensures the distribution is reliable. **<u>Asset Management:</u>** Halton Hills Hydro's Asset Management Plan addresses the risk and impact of live front padmounted transformers. This project is reflective of the Asset Management Program SP14-03 and addresses the risk represented by such units operating. **<u>Cost Control:</u>** Cost control is achieved through competitive bid processes for transformers. Further cost control can be can be achieved through competitive bid processes for contractual costs with respect to installation of the civil infrastructure.
	3. Public Policy Responsiveness **<u>CDM</u>** n/a. **<u>Connection of Renewable Generation</u>** n/a.
	4. Financial Performance **<u>Financial Implications</u>** Long term viability can be achieved through progressive replacement of live front padmounted transformers. Were a live front padmounted transformer to fail, Halton Hills Hydro's O&M expenditures would be effected.
Third Party Planning	***1. Regional (IESO Regions)*** n/a.
	2. Regional (geographic) Halton Hills Hydro will seek municipal consent from the Region of Halton where required.
	3. Municipal Halton Hills Hydro will seek municipal consent from the Town of Halton Hills where required.
	4. Other n/a.
	5. Transmitter n/a.

Other Information

1. Factors Affecting Project Timing

These assets are to be replaced over a number of years. Planning, engineering, and ordering materials will mitigate factors related to pre-construction timing. These projects are performed in close proximity to customer and as such communication with customers will help mitigate public resistance to planned work.

2. Implications of NOT Implementing

Not implementing this project leaves aged obsolete assets operating that cannot be readily replaced in operation and exposes the distribution system and customers to interruptions were a transformer to fail.

3. Alternatives Considered & Reason for Not Implementing

The alternative considered was replacing a live front padmounted transformer with dead front padmounted transformer. However, doing so presents potential problems as outlined in Halton Hills Hydro's Asset management Plan SP14-03 and include new transformers being larger than the ones being removed whereby the new transformer does not sit properly on the poured concrete foundation, primary cable may not be long enough to re-terminate and connect to the bushings of a new transformer, and old primary cable may not be compatible with current termination methods and approved equipment. As such, the alternative cannot be implemented.

Images

Project Authorization

Prepared by:

Date:

Authorized By:

Assigned To:

Assigned Date:

Completion Date:

Change History

Date	Section	Change		Reason	Change Authorized by:

CAPITAL PLAN — ENGINEERING — 2016

		System Type	SYSTEM RENEWAL
Job Request / Number:			
Project Name:	PoleTrans Replacements (Hillside Drive Area).		
Project Category:			HHHI Directed

Reference

Quadra Division:					CAP - HHHDIRECT
Job Request Number:					
Job Number:					
Project Name:					PoleTrans Replacements (Hillside Drive Area).
Project Category:					HHHI Directed
System Type:					SYSTEM RENEWAL
Priority Ranking:					4
Risk Ranking:	*Impact:*	4	*Probability:*	3	**12**
Customer Attachments/Load:					
Project Designer/Manager:	Meg Gonzales				
Start Date:					
In Service Date:					

Estimated Costs

Description	Estimated Cost	Notes		Estimated Expenditure Timing
Labour:	$ 38,500		Q1	$ -
Materials:	$ 63,400		Q2	$ 68,333
Equipment:	$ 7,725		Q3	$ 213,440
Contract Labour:	$ 390,375		Q4	$ 218,227
Other:	$ -			
			Carry-over:	$ -
Non-construct capital				
Total Estimated Cost	**$ 500,000**		Total:	$ 500,000
Recoverable:	$ -			
HHHI Estimated Cost	**$ 500,000**		Control	$ -
				$ -

General Information

Project Summary/Description:

This project involves the replacement of aged and obsolete PoleTrans transformers many of which we installed more than 30 years ago and are reaching the end of their useful life. PoleTrans are distribution transformers that are located at the base street light pole and are contained in the pole. Access to the transformer is gained by panels on the exterior of the street light pole. This system renewal project is aimed at replacing aged distribution equipment that is no longer made and for which parts are hard to obtain. While Pole Trans transformers continue to operate on our 2.4/4.16Y kV distribution system this proactive approach will prevent undue hardship to customers were a PoleTrans to fail and were not repairable. In such cases customers may be faced with a significant outage until alternate power arrangement can be made. The design of PoleTrans transformers presents a problem for field staff as the design does not accommodate installation of temporary working grounds on the incoming or outgoing medium voltage power cables and still allow for the front panel to be closed and locked. Further the design of PoleTrans transformers provides very little clearance within the main compartment which that they are adequate for 2.4/4.16Y kV but not higher voltages. This work relates directly to our Asset Management Plan as it address the plans direction to replace PoleTrans.

Comparative Information on Equivalent Historical Projects (if any):

This project is a continuation of Halton Hills PoleTrans asset renewal program. Similar projects have been executed consistently by Halton Hills Hydro over the past 5 years and we have seen improvement to our distribution system having undertaken this work. Much of the renewal work has been performed in Acton however this project constitutes our first major initiative in Georgetown.

Risks to Completion and Risk Mitigation:

This project involves the replacement of infrastructure close to customer property and other utility equipment. The risk to completion is mitigated through customer consultations and coordination with all affected parties is necessary to ensure effective installation and completion of the project. By consulting with customers and other utilities, Halton Hills Hydro can set forth our project plans and set realistic expectations for all impacted parties.

Total Capital and OM&A Costs for Renewable Energy Generation portion of project (if any):

n/a.

CAPITAL PLAN	ENGINEERING		2016
		System Type	SYSTEM RENEWAL
Job Request / Number:			
Project Name:	PoleTrans Replacements (Hillside Drive Area).		
Project Category:			HHHI Directed

Evaluation Criteria and Information

1. Efficiency, Customer Value, Reliability

Main Driver:
This project is driven by the necessity to replace end of life assets that are obsolete and present difficulties to operational staff working on the distribution system.

Priority & Reasons for Priority:
Replacement of PoleTrans receives significant priority to address issues related to age, obsolescence, and worker safety.

Qualitative & Quantitative Analysis of Project and Project Alternatives:
PoleTrans are significantly aged which makes them prone to failure. If aging infrastructure is not replaced the risk for extended local and feeder outages increases should a failure happen that produces faults that cause upstream fused cutouts to open. With no other method to supply customers from a failed PoleTrans, an extended outage could happen as Halton Hills Hydro will need to arrange for a padmounted transformer to be installed.

Other:
n/a.

2. Safety
Replacement of PoleTrans will improve worker safety when applying working ground to the distribution system while performing work.

3. Cyber-security, Privacy
n/a.

4. Coordination, Interoperability
Installation of new equipment shall be done in accordance with Halton Hills Hydro's construction standards a CSA C22.3 No.7 "Underground Systems" and CSA C227.3 "Low Profile Single Phase Padmounted Distribution Transformers". Halton Hills Hydro will advise municipality and other utilities of planned work. If other utilities want to replace their infrastructure at the same time, possibly in the same trench Halton Hills Hydro will apply our approved standards with respect to third party locations.

5. Economic Development
n/a.

6. Environmental Benefits
n/a.

7. Customer Control (Smart Grid Objective)
Access:
n/a.

Visibility:
n/a.
Control:
n/a.
Participation in Renewables:
Replacing PoleTrans with padmounted transformers will result in additional transformation capacity. This in turn may permit greater amounts of participation in renewable generation.
Customer Choice:
n/a.
Education:
n/a.

8. Power System Flexibility (Smart Grid Objective)
Distributed Renewables:
This project will see our distribution circuit loops maintained and improved. As such the distribution system flexibility to accept renewable generation will not decrease.

Visibility:
n/a.
Control and Automation:
n/a.
Quality:
New transformers with greater capacity will lessen the potential for localized system overloading that results in low voltage for customers.

9. Adaptive Infrastructure (Smart Grid Objective)
Flexibility:
n/a.
Forward Compatibility:
n/a.
Encourage Innovation:
n/a.

Halton Hills HYDRO

CAPITAL PLAN	ENGINEERING		2016
		System Type	SYSTEM RENEWAL
Job Request / Number:			
Project Name:	PoleTrans Replacements (Hillside Drive Area).		
Project Category:			HHHI Directed

Outcomes

1. Customer Focus

Service Quality:

n/a.

Customer Satisfaction:

n/a.

2. Operational Effectiveness

Safety:

New construction is performed to current Halton Hills Hydro standards. These standards meet or exceed minimum industry standards increasing safety for lines staff working on the system as well as improves reliability through new more efficient material and increased safety standards.

System Reliability:

System reliability is improved as new materials are used and are lessen prone to failure.

Asset Management:

This project directly ties to section 4.5 of our Asset Management Plan (SP14-03) and the phasing out of PoleTrans identified in that plan.

Cost Control:

Halton Hills Hydro takes proactive measures to ensure project costs remain on budget and accounts for additional expenditures where necessary due to unforeseen circumstances. One way in which costs can be controlled is through a competitive bid process for materials such as transformers. A competitive bid process will identify a manufactures transformer(s) that has a reasonable capital investment and total ownership cost when compared to alternatives. Competitive bid process for other aspects of the project may also result in cost efficiencies.

3. Public Policy Responsiveness

CDM

n/a.

Connection of Renewable Generation

Increased capacity will enable greater amount of renewable nameplate capacity/ generation.

4. Financial Performance

Financial Implications

As stated in Cost Control, this project can see cost efficiencies through competitive bid processes making the project viable. Long term planning will see our PoleTrans transformers replaced with padmounted transformers which will improve the utilities ability to resolve field issues in the affected areas. Viability is also established as underground primary cable will be replaced at the same time thus having both major assets (primary cable and transformers) of the same vintage and useful life.

Third Party Planning

1. Regional (IESO Regions)

n/a.

2. Regional (geographic)

Halton Hills Hydro will seek municipal consent from the Region of Halton.

3. Municipal

Halton Hills Hydro will seek municipal consent from the Town of Halton Hills.

4. Other

Halton Hills Hydro will coordinate our relocation efforts with third party telecommunication companies.

5. Transmitter

n/a.

Other Information

1. Factors Affecting Project Timing

Halton Hills Hydro incorporates sufficient planning and design time. Factors affecting timing may be attributed to contractor and material availability. Such factors can be mitigated by tendering for construction and material purchases well in advance of the expected date they are needed.

2. Implications of NOT Implementing

By not implementing this project, Halton Hills Hydro's distribution system can be at risk of extended outages should a PoleTrans fail. Furthermore, if the primary cable were to fault and being it is most likely direct buried (based on age of developments) a contractor would need to expose the primary cable and splice the primary cable together. Potential O&M increases would be expected in these cases.

3. Alternatives Considered & Reason for Not Implementing

The alternatives are do nothing or replace only PoleTrans transformers. This is not a proactive approach, it does not follow Halton Hills Hydro's Asset Management Plan SP14-03, and puts our distribution system at risk. By only replacing the PoleTrans transformers and not the primary cable there may be an incompatibility between utility approved equipment and old power cables (ie: approved equipment cannot be installed on old cable). Such incompatibility may affect timing of the project as well as increase Halton Hills Hydro's O&M costs if we need to stock specific material for a small portion of our distribution system, lessens material interoperability efficiencies.

CAPITAL PLAN	ENGINEERING		2016
		System Type	SYSTEM RENEWAL
Job Request / Number:			
Project Name:	PoleTrans Replacements (Hillside Drive Area).		
Project Category:			HHHI Directed

Images

Project Authorization

Prepared by:		Authorized By:	
Date:		Assigned To:	
		Assigned Date:	
		Completion Date:	

Change History					
Date	Section	Change		Reason	Change Authorized by:

Halton Hills HYDRO

CAPITAL PLAN

ENGINEERING

2016

System Type	**SYSTEM RENEWAL**
Job Request / Number:	**30**
Project Name:	**Vintage Underground Replacements/ Refurbishments (John St. Phase 1)**
Project Category:	**HHHI Directed**

Reference

Quadra Division:				CAP - HHHDIRECT
Job Request Number:				30
Job Number:				
Project Name:				Vintage Underground Replacements/ Refurbishments (John St. Phase 1)
Project Category:				HHHI Directed
System Type:				SYSTEM RENEWAL
Priority Ranking:				3
Risk Ranking:	*Impact:* 3		*Probability:* 2	**6**
Customer Attachments/Load:				
Project Designer/Manager:				
Start Date:				
In Service Date:				

Estimated Costs

Description		Estimated Cost	Notes			Estimated Expenditure Timing
Labour:	$	19,656		Q1	$	-
Materials:	$	28,289		Q2	$	15,681
Equipment:	$	9,261		Q3	$	150,623
Contract Labour:	$	247,380		Q4	$	138,281
Other:	$	-				
				Carry-over:	$	-
Non-construct capital						
Total Estimated Cost	**$**	**304,586**		Total:	$	304,586
Recoverable:	$	-				
HHHI Estimated Cost	**$**	**304,586**		Control	$	-
					$	-

General Information

Project Summary/Description:

This project invloves the replacement of aged end of useful life primary cable. The primary cable in the John Street area of Georgetown was installed in the mid 1970's and is approaching its end of useful life (Asset Management Plan, SP14-03, Table 4-1). This cable is direct burried, of a lesser rating that what current practices require to be installed, and is one of the older underground parts of our Georgetown urban center. The project investment level represents the risk associated with such infrastructure failing. Replacement of aged assets will be coordinated in a two (2) phase approach over the course of 2016 and 2017.

Comparative Information on Equivalent Historical Projects (if any):

n/a.

Risks to Completion and Risk Mitigation:

This project invloves the replacement of infrastructure close to customer property and other utility equipment. The risk to completion is mitiagted through customer consultations and coordination with all affected parties is necessary to ensure effective installation and completion of the project. By consulting with customers and other utilities, Halton Hills Hydro can set forth our project plans and set realistic expectations for all impacted parties.

Total Capital and OM&A Costs for Renewable Energy Generation portion of project (if any):

n/a.

Halton Hills HYDRO	CAPITAL PLAN	ENGINEERING	2016
		System Type	SYSTEM RENEWAL
	Job Request / Number:		30
	Project Name:	Vintage Underground Replacements/ Refurbishments (John St. Phase 1)	
	Project Category:		HHHI Directed

Evaluation Criteria and Information

1. Efficiency, Customer Value, Reliability

Main Driver:
This project is driven by conditions set forth in our asset management program section 4.7.1 "Age Profile of In-Service Power Cable Assets" which identifies primary cables having a useful life of 40 years. Such aged assets can be in poor condition and are more likely to fail posing risk to system reliability.

Priority & Reasons for Priority:
This project has a lower priority ranking than other project planned in 2016. Nonetheless replacement of aged distribution assets is a necessity to maintain reliability and lessen the amount to which our system is at risk relating to equipment failure.

Qualitative & Quantitative Analysis of Project and Project Alternatives:
The assets are significantly aged which makes them prone to failure resulting in unplanned outages and emergency replacement or reapir work. If the aged assets were not replaced fault conditions may rupture a cable causing a fault condition in which upstream cutouts may open. With no remote operable control for feeder switching in this established area customers are a t risk of extended outages until line crews can be dispatched to identify and repair the problems. Furthermore, because the cables are direct burried, repairing cables is costly because it requires mannual labour or vaccum excavation to expose the cable after which a contractor is required to install a primary splice. Following that work restoration of the site is required.

Other:
n/a.

2. Safety
Replacement of PoleTrans will improve worker safety when applying working ground to the distribution system while performing work.

3. Cyber-security, Privacy
n/a.

4. Coordination, Interoperability
Installation of new equipment shall be done in accordance with Halton Hills Hydro's construction standards and CSA C22.3 No.7 "Underground Systems" Halton Hills Hydro will advise municipality and other utilities of planned work. If other utilities want to replace their infrastructure at the same time, possibly in the same trench Halton Hills Hydro will apply our approved standards with respect to third party locations.

5. Economic Development
n/a.

6. Environmental Benefits
n/a.

7. Customer Control (Smart Grid Objective)
Access:
n/a.

Visibility:
n/a.
Control:
n/a.
Participation in Renewables:
n/a.

Customer Choice:
n/a.
Education:
n/a.

8. Power System Flexibility (Smart Grid Objective)
Distributed Renewables:
n/a.
Visibility:
n/a.

Control and Automation:
n/a.

Quality:
Supply quality will be maintained andpossibly improved by replacing aged infrastructure.

9. Adaptive Infrastructure (Smart Grid Objective)
Flexibility:
n/a.
Forward Compatibility:
n/a.

CAPITAL PLAN	ENGINEERING		2016
		System Type	SYSTEM RENEWAL
Job Request / Number:			30
Project Name:	Vintage Underground Replacements/ Refurbishments (John St. Phase 1)		
Project Category:			HHHI Directed

Encourage Innovation:
n/a.

Outcomes

1. Customer Focus

Service Quality:
n/a.

Customer Satisfaction:
n/a.

2. Operational Effectiveness

Safety:
New construction is performed to current Halton Hills Hydro standards. These standards meet or exceed minimum industry standards increasing safety for lines staff working on the system as well as improves reliability through new more efficient material and increased safety standards.

System Reliability:
System reliability is improved as new materials are used and are lessen prone to failure.

Asset Management:
This project directly ties to section 4.7.1 of our Asset Management Plan (SP14-03) with respect to replacing aged primary cables as identified in that plan.

Cost Control:
Halton Hills Hydro takes proactive measures to ensure project costs remain on budget and accounts for additional expenditures where necessary due to unforeseen circumstances. One way in which costs can be controlled is through a competative bid process for materials and contractual labour.

3. Public Policy Responsiveness

CDM
n/a.

Connection of Renewable Generation
New underground distribution assets built to current hydro standards will provide for a distribution system that is hardened and for which is less suseptible to damage or failure that would cause renewable generation to be shut off-line.

4. Financial Performance

Financial Implications
As stated in Cost Control, this project can see cost efficiencies through competitive bid processes making the project viable. Long term planning will see our old direct burried primary cable replaced with 28kV TRXLPEI primary cable in duct which will harden the distributiuon system and maintain service quality over the long term rather than expose our system to costly failures that aged assets are prone to. Viability is also established as padmounted transformers will be assessed in the design phase and if necessary may be replaced.

Third Party Planning

1. Regional (IESO Regions)
n/a.

2. Regional (geographic)
Halton Hills Hydro will seek municipal consent from the Region of Halton.

3. Municipal
Halton Hills Hydro will seek municipal consent from the Town of Halton Hills.

4. Other
Halton Hills Hydro will coordinate our relocation efforts with third party telecommunication companies.

5. Transmitter
n/a.

Other Information

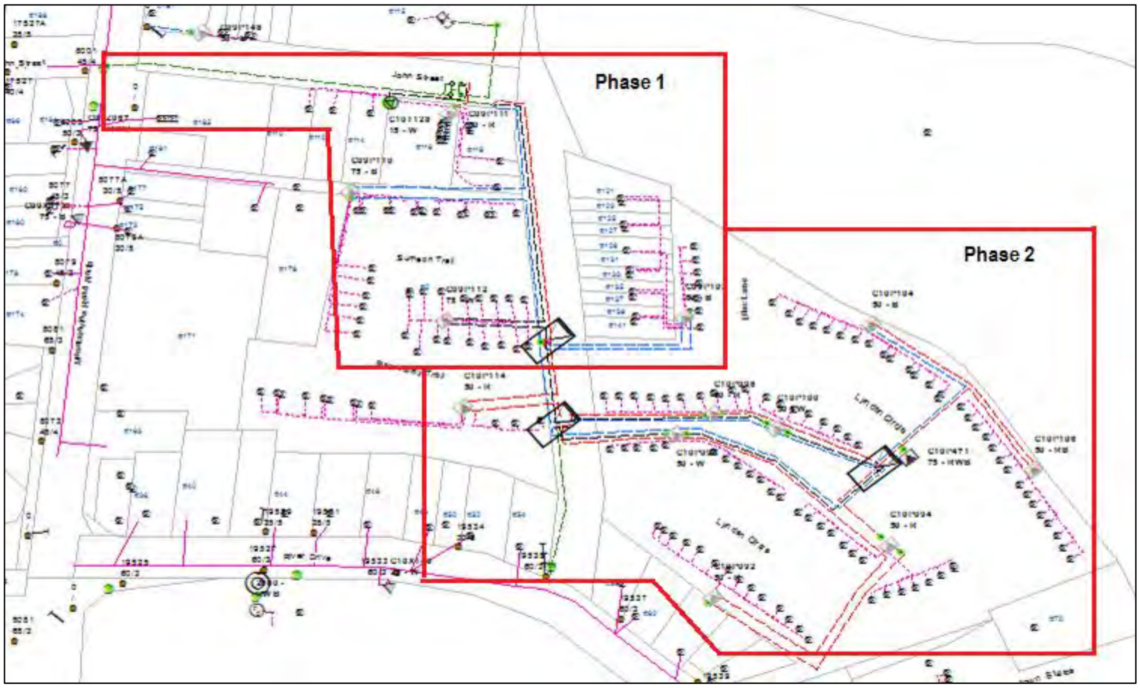
1. Factors Affecting Project Timing
Halton Hills Hydro incorporates sufficent planning and design time. Factors affecting timing may be attributed to customer concerns, contractor and material availability. Such factors can be mitigated byclosely working with our customers and tendering for construction and material purchases well in advance of the expected date they are needed.

2. Implications of NOT Implementing
By not implementing this project, Halton Hills Hydro's distribution system can be at risk of extended outages should a primary cable fault or be dug into. Furthermore, if the primary cable were to fault and being it is most likely direct burried (based on age of developments) a contractor would need to expose the primary cable and splice the primary cable together. Potential O&M increases would be expected in these cases.

3. Alternatives Considered & Reason for Not Implementing
The alternatives are do nothing or investigate the potential for cable injection. The "do nothing" options puts our distribution system at risk as the primary cables are aged and more prone to failure. Also the primary cables are direct burried which makes them more suceptible to damage during an excavation. The "do nothing" approach does not address the impact aged assets have were they to fail, the unplanned outages customers might face, and the O&M cost to repair faulty cable. The alternative of considering cable injection to extend the life of primary cable is not to be implemented in this case. Cable injection (rejuvination) can extend the life of the cable 10-15 years after which the cable would need to be replaced and while injection may be less costly the practicality in this instance is not reasonable given the aged of the assets.

CAPITAL PLAN	ENGINEERING		2016
		System Type	SYSTEM RENEWAL
Job Request / Number:			30
Project Name:	Vintage Underground Replacements/ Refurbishments (John St. Phase 1)		
Project Category:			HHHI Directed

Images



Project Authorization

Prepared by:		Authorized By:	
Date:		Assigned To:	
		Assigned Date:	
		Completion Date:	

Change History

Date	Section	Change		Reason	Change Authorized by:

CAPITAL PLAN — ENGINEERING — 2016

		System Type	SYSTEM RENEWAL
Job Request / Number:			29
Project Name:	Pole Replacements.		
Project Category:			HHHI Directed

Reference

Quadra Division:			CAP - HHHDIRECT
Job Request Number:			29
Job Number:			
Project Name:			Pole Replacements.
Project Category:			HHHI Directed
System Type:			SYSTEM RENEWAL
Priority Ranking:			5
Risk Ranking:	*Impact:* 5	*Probability:* 3	15
Customer Attachments/Load:			
Project Designer/Manager:	Meg Gonzales		
Start Date:			
In Service Date:			

Estimated Costs

Description		Estimated Cost	Notes			Estimated Expenditure Timing
Labour:	$	30,139		Q1	$	-
Materials:	$	641,761		Q2	$	359,849
Equipment:	$	5,100		Q3	$	1,411,042
Contract Labour:	$	1,323,000		Q4	$	229,110
Other:	$	-				
				Carry-over:	$	-
Non-construct capital						
Total Estimated Cost	$	2,000,000		Total:	$	2,000,000
Recoverable:	$	-				
HHHI Estimated Cost	$	2,000,000		Control	$	-
					$	-

General Information

Project Summary/Description:
This project involves the replacement of utility poles that have been tested and have been found defective. It also involves replacing poles that have reached the end of their useful life as determined in Halton Hills Hydro Asset Management Plan. Projects will include mostly individual spot replacements of defective poles but may also include larger replacement project where risk ranking identifies area's of our distribution system containing a cluster of aged poles.

Comparative Information on Equivalent Historical Projects (if any):
Halton Hills Hydro has maintained a formal pole testing and replacement program since 2004. Following a testing schedule approximately 1200 poles are tested annually and those found to be defective are replaced. Based on previous years data (2004 to 2014) 32 poles on average fail testing. In more recent years Halton Hills Hydro has begun the process of replacing significantly old poles that are well beyond their useful life. Such end of useful life replacements can appear as a cluster in our system and are replaced as part of a larger scale project rather than spot replacement. Overall asset management principles are well served when it is feasible to renew a larger part of the distribution rather than spot replacements. Having over 10 years in experience Halton Hills Hydro staff can determine rough costs to replace poles and can monitor estimates and actuals effectively.

Risks to Completion and Risk Mitigation:
This project involves the replacement of defective utility poles. Risks to completion can involve coordinating contractors and materials. To mitigate these risks Halton Hills Hydro will coordinate contractors early in the process to ensure work can begin on schedule. Staff will also ensure materials are ordered in advance of the contractor starting the job to ensure materials arrive prior to when they are needed.

Total Capital and OM&A Costs for Renewable Energy Generation portion of project (if any):
n/a.

CAPITAL PLAN	**ENGINEERING**		**2016**
		System Type	**SYSTEM RENEWAL**
Job Request / Number:			**29**
Project Name:	**Pole Replacements.**		
Project Category:			**HHHI Directed**

Evaluation Criteria and Information

1. Efficiency, Customer Value, Reliability

Main Driver:
The main driver for this project is Halton Hills Hydro's commitment to ensuring our distribution system is structurally sound. Replacing defective poles and the associated equipment will ensure Halton Hills Hydro meets the regulatory requirements O.Reg. 22/04 "electrical Distribution Safety" in specific Section 4 - Safety Standards.

Priority & Reasons for Priority:
Replacement of defective poles is a necessity to ensure the infrastructure supporting our distribution system is structurally sound and will not present hazards to the public.

Qualitative & Quantitative Analysis of Project and Project Alternatives:
Poles are one of the most significant assets in Halton Hills Hydro's distribution system. Much of our distribution system is overhead and the failure of one (1) pole can cause serious system impacts such as feeder outages and poses potential safety risks if wire supported by the pole were to come to the ground. Proactive measures to replace defective and end of useful life poles will reduce the potential of such assets affecting the distribution system and causing outages. Furthermore, a proactive approach will not impact our O&M expenditures.

Other:
n/a.

2. Safety
Replacement of defective and end of useful life poles will ensure our distribution system in structurally sound, construction will be done to Halton Hills Hydro standards, and we will meet the safety requirements of O.Reg. 22/04, Section 4.

3. Cyber-security, Privacy
n/a.

4. Coordination, Interoperability
Halton Hills Hydro will coordinate with third parties such as telecommunication companies prior to replacing poles. As well, municipalities will be advised of spot replacements and larger scale cluster replacements.

5. Economic Development
n/a.

6. Environmental Benefits
Replacement of old poles will most likely result in the removal of poles that were treated with creosote. As well, because many transformers are pole mounted, replacement of such poles benefits the environment as a new pole will be sufficient support for a transformer whereas the old pole could foreseeably fail causing a transformer to fall to the ground creating an oil spill.

7. Customer Control (Smart Grid Objective)
Access:
n/a.

Visibility:
n/a.
Control:
n/a.
Participation in Renewables:
n/a.
Customer Choice:
n/a.
Education:
n/a.

8. Power System Flexibility (Smart Grid Objective)
Distributed Renewables:
In some cases transformers may be replaced with larger units (ie: more capacity) where load dictates. Larger transformers having more capacity add to the potential for renewable generation connections.

Visibility:
n/a.

Control and Automation:
n/a.

Quality:
n/a.

9. Adaptive Infrastructure (Smart Grid Objective)
Flexibility:
n/a.
Forward Compatibility:
n/a.
Encourage Innovation:
n/a.

CAPITAL PLAN	ENGINEERING		2016
		System Type	SYSTEM RENEWAL
Job Request / Number:			29
Project Name:	Pole Replacements.		
Project Category:			HHHI Directed

Outcomes

1. Customer Focus

Service Quality:

n/a.

Customer Satisfaction:

n/a.

2. Operational Effectiveness

Safety:

New construction is performed to current Halton Hills Hydro standards. These standards meet or exceed minimum industry standards increasing safety for lines staff working on the system as well as improves reliability through new more efficient material and increased safety standards.

System Reliability:

System reliability is improved as new materials are used and are lessen prone to failure.

Asset Management:

This project directly ties to section 3.3 of our Asset Management Plan (SP14-03) and table 3-1 regarding useful lives of utility poles. The Asset Management Plan describes Halton Hills Hydro's methodical approach to renewing pole assets and the scope of our 2016 planning meets the requirements of our Asset Management Plan.

Cost Control:

Halton Hills Hydro takes proactive measures to ensure project costs remain on budget and accounts for additional expenditures where necessary due to unforeseen circumstances. One way in which costs can be controlled is through a competitive bid process for materials such as transformers. A competitive bid process will identify a manufactures transformer(s) that has a reasonable capital investment and total ownership cost when compared to alternatives. Competitive bid process for other aspects of the project may also result in cost efficiencies.

3. Public Policy Responsiveness

CDM

n/a.

Connection of Renewable Generation

Increased capacity with respect to transformation will enable greater amount of renewable nameplate capacity/ generation.

4. Financial Performance

Financial Implications

As stated in Cost Control, this project can see cost efficiencies through competitive bid processes making the project viable. Long term planning will see defective and end of useful life poles replaced to lessen the potential for failure of defective equipment. Viability is also established by replacing clusters of poles of the same or similar vintage to bring all material components up to a renewed useful life rather than having a distribution system where related components have significantly different useful lives (ex: new pole with useful life of 50 years and reuse of switch having 3 useful years remaining does not make sense. It makes more sense to replace the switch too rather than send a crew to the same location 3 years later to replace the switch.

Third Party Planning

1. Regional (IESO Regions)

n/a.

2. Regional (geographic)

Halton Hills Hydro will seek municipal consent from the Region of Halton.

3. Municipal

Halton Hills Hydro will seek municipal consent from the Town of Halton Hills.

4. Other

Halton Hills Hydro will coordinate our relocation efforts with third party telecommunication companies.

5. Transmitter

n/a.

Other Information

1. Factors Affecting Project Timing

Halton Hills Hydro incorporates sufficient planning and design time. Factors affecting timing may be attributed to contractor and material availability. Such factors can be mitigated by tendering for construction and material purchases well in advance of the expected date they are needed.

2. Implications of NOT Implementing

By not implementing this project, Halton Hills Hydro's distribution system assets are at risk of failure. Because utility poles support energized (live) equipment, if poles fail there is a potential for live equipment to come to the ground presenting hazards to the public. Also, if not replaced, defective equipment failure can lead to pole mounted transformers coming to the ground and spilling oil creating potential environmental concerns. As well, not implementing this project means Halton Hills Hydro would not meet the regulatory requirements of Section4 of O.Reg. 22/04.

3. Alternatives Considered & Reason for Not Implementing

The alternatives are do nothing or replace poles only once they have failed. Such alternatives can present hazards to the public if defective equipment is left in operation, especially considering proximity of poles to public spaces (ie: front/ rear yard, public boulevard). Reactive alternatives are not an effective way to maintain the distribution system, will not meet regulatory requirements, and will contribute to an increased number of poles having aged well past their useful lives for which significantly increased expenditures in the future might be required to replace a greater number of poles. A proactive approach on an annual basis lessens the financial impact to our customers.

CAPITAL PLAN	ENGINEERING		2016
		System Type	SYSTEM RENEWAL
Job Request / Number:			29
Project Name:	Pole Replacements.		
Project Category:			HHHI Directed

Images

Project Authorization

Prepared by:		Authorized By:	
Date:		Assigned To:	
		Assigned Date:	
		Completion Date:	

Change History

Date	Section	Change		Reason	Change Authorized by:

CAPITAL PLAN	**ENGINEERING**		**2016**
		System Type	**SYSTEM SERVICE**
Job Request / Number:			**10**
Project Name:	**46kV Automated Switches, 44kV System (2 Switches)**		
Project Category:			**HHHI Directed**

Reference

Quadra Division:			CAP - HHHDIRECT
Job Request Number:			10
Job Number:			
Project Name:			46kV Automated Switches, 44kV System (2 Switches)
Project Category:			HHHI Directed
System Type:			SYSTEM SERVICE
Priority Ranking:			3
Risk Ranking:	*Impact:* 3	*Probability:* 2	**6**
Customer Attachments/Load:			
Project Designer/Manager:			
Start Date:			
In Service Date:			

Estimated Costs

Description	Estimated Cost	Notes		Estimated Expenditure Timing
Labour:	$ 8,215		Q1	$ 2,129
Materials:	$ 134,581		Q2	$ 133,998
Equipment:	$ 12,391		Q3	$ 22,481
Contract Labour:	$ 3,420		Q4	$ -
Other:	$ -			
			Carry-over:	$ -
Non-construct capital				
Total Estimated Cost	**$ 158,607**		Total:	$ 158,607
Recoverable:	$ -			
HHHI Estimated Cost	**$ 158,607**		Control	$ -
				$ -

General Information

Project Summary/Description:
This project continues Halton Hills Hydro's development of our automated switch smart grid system. In 2016 Halton Hills Hydro will purchase and install two automated switches that will be installed at a key locations on our 44kV distribution system to enhanced the utility's ability to systematically perform switching operations during normal and emergency conditions.

Comparative Information on Equivalent Historical Projects (if any):
Halton Hills Hydro has installed automated switches on our 44kV distribution system since 2012. In the past switches were installed at normally open and normally closed switch points. Coordination with staff installing the switches and the control room are of vital importance to ensure switches are installed and commissioned to avoid impacting our 44kV distribution system.

Risks to Completion and Risk Mitigation:
By not completing this project Halton Hills Hydro will have less automated switching capabilities on our 44kV system.

Total Capital and OM&A Costs for Renewable Energy Generation portion of project (if any):
n/a.

1. Efficiency, Customer Value, Reliability

Main Driver:
This project is driven by the utilities desired to create additional functionality in the routing of supply in our distribution system. This is accomplished by installing automated switches at key locations on the distribution system to allow Halton Hills Hydro the ability to re-route the supply of power and lessen outage time for customers.

Priority & Reasons for Priority:
This projects priority is driven by the desire to install automated switches in key locations on our 44kV that will enable Halton Hills Hydro to perform automated switching on our 44kV system efficiently to re-route the supply of power and restore power.

Qualitative & Quantitative Analysis of Project and Project Alternatives:
The continued investment in automated switching will improve system reliability by creating circuit ties enabling circuit switching to reduce outage times, support projected load growth, and provide supply for new developments. Construction will be done in accordance with Halton Hills Hydro designs, standards, and will be cost effective.

Other:
n/a.

2. Safety
Halton Hills Hydro constructs projects to current standards approved as required by O.Reg. 22/04. Construction done per standards will protect the public. As well, automated switches have intelligence built into the devices. Incorporated in the switches are instrument transformers that step down high voltage and current to lesser levels that can be utilized by electronic circuitry in the switches control cabinet to send data about the state of the distribution and switch position (open/ closed) to the utility office via radio/ SCADA system. Such information can be used by the utility office and control room to operate intelligent switches during normal and emergency situations creating safer working environments for lines staff.

3. Cyber-security, Privacy
Switch controls are accessed through computer software. Users must have the specific software, user name, and passwords to access switch programming. These security features are in place to lessen the potential for intrusion.

4. Coordination, Interoperability
Many local distribution companies use automated switches. Halton Hills Hydro's automated switches when connected to our SCADA system will be controlled remotely from our shared Control Room at Oakville Hydro by the operators.

5. Economic Development
n/a.

6. Environmental Benefits
Automated switches can reduce the need to dispatch line staff in vehicles to operate switches manually. In doing so less emissions will enter the atmosphere.

rmation

Evaluation Criteria and Info	***7. Customer Control (Smart Grid Objective)*** **<u>Access:</u>** n/a.
	<u>Visibility:</u> n/a.
	<u>Control:</u> n/a. **<u>Participation in Renewables:</u>** n/a. **<u>Customer Choice:</u>** n/a. **<u>Education:</u>** n/a.
	8. Power System Flexibility (Smart Grid Objective) **<u>Distributed Renewables:</u>** Automated switches that communicate the utilities SCADA system can be operated to restore power to areas affected by power interruptions. Such switching routines could enable renewable generation on affected feeders to be reconnected and continue operations. **<u>Visibility:</u>** Automated switches have instrument transformers that step voltage and current down from a higher level (16,000V) to a lower level (120V) to be used by electronic controls contained in a utility box mounted on the side of a pole. The voltage and current readings as well as switch state (open/ closed), ambient temperature, and fault conditions can be transmitted to the utility office via the utilities SCADA system. **<u>Control and Automation:</u>** Additional switching functionality may enable early restoration of circuits on which renewable generation is connected thus enabling renewable generation to continue producing power. **<u>Quality:</u>** Automated switches are a device the utility uses to maintain its supply to customers, perform smart switching, and restore power. As well, because voltage and current readings can be transmitted from the switch to the utilities office, the utility has the ability to see supply quality at points along the distribution lines where in the past such information would not have been available.
	9. Adaptive Infrastructure (Smart Grid Objective) **<u>Flexibility:</u>** Automated switches provide flexibility by allowing utilities to restore power to areas affected by power interruptions. This can help the implementation of innovative technologies such as electric vehicle charging stations, public or private, and will help customers feel their utility power supply is supportive of innovative technologies that they already use or are considering purchasing. **<u>Forward Compatibility:</u>** The software and firmware used for automated switches is normally upgradable.` **<u>Encourage Innovation:</u>** By using automated switches to restore power in an expedient manner, customers who are exploring innovative technologies such as electric vehicles may elect to purchase EV's knowing their power supply is reliable.
Outcomes	***1. Customer Focus*** **<u>Service Quality:</u>** n/a. **<u>Customer Satisfaction:</u>** n/a.
	2. Operational Effectiveness **<u>Safety:</u>** n/a. **<u>System Reliability:</u>** Automated switches can help reduce outage times by enabling quick restoration through automated routines or remote operations. **<u>Asset Management:</u>** n/a. **<u>Cost Control:</u>** Installation of automated switches will reduce O&M expenditures by performing switching from the utility office/ control room. Remote switching will also reduce capital expenditures that normally result from time spent by field staff going to specific switch locations and manually operating switches to isolate a work zone.
	3. Public Policy Responsiveness **<u>CDM</u>** n/a. **<u>Connection of Renewable Generation</u>** n/a.
	4. Financial Performance **<u>Financial Implications</u>** Installation of automated switches will enable remote operation of switches by either control room staff or pre-programmed routine. As well, because the switch will transmit information to the utility office via SCADA, the utility will be able to see the state of the system. This will reduce the amount of time utility field staff spend in the field performing switching operations to restore power or re-configure the distribution system.
Third Party Planning	***1. Regional (IESO Regions)*** n/a.
	2. Regional (geographic) Halton Hills Hydro will seek municipal consent where required for installations.
	3. Municipal Halton Hills Hydro will seek municipal consent where required for installations.
	4. Other Halton Hills Hydro will advise telecommunication companies our project and where required coordinate relocation efforts.
	5. Transmitter n/a.
on	***1. Factors Affecting Project Timing*** The main factor affecting timing will be receiving the switch on time. This potential delay can be averted by contacting the manufacturer to determine what the delivery lead time is and build that lead time into the project scope to ensure the switch is ordered in time.

Other Informatic

2. Implications of NOT Implementing

By not implementing the project, Halton Hills Hydro will continue operating manually automated switches that are already old. Such delays can put our distribution system at risk if old equipment were to fail.

3. Alternatives Considered & Reason for Not Implementing

An alternative would be to install a manually operated switch. While manual and automated switches perform the same basic function, a manual switch requires staff to operate the switch which adds to the utilities O&M costs. As well, manual switches do not provide system information such as voltage, current, and device state to the utility. Automated switches installed at key points in the distribution system will allow the utility to leverage the equipment to benefit its customers.

Images

Project Authorizat ion

Prepared by:

Date:

Authorized By:

Assigned To:

Assigned Date:

Completion Date:

Change History					
Date	**Section**	**Change**		**Reason**	**Change Authorized by:**

Halton Hills HYDRO	**CAPITAL PLAN**	**ENGINEERING**		**2016**
			System Type	**SYSTEM SERVICE**
	Job Request / Number:			
	Project Name:	**5F3 on 32 Sdrd**		
	Project Category:			**HHHI Directed**

Reference

Quadra Division:				CAP - HHHDIRECT
Job Request Number:				
Job Number:				
Project Name:				5F3 on 32 Sdrd
Project Category:				HHHI Directed
System Type:				SYSTEM SERVICE
Priority Ranking:				3
Risk Ranking:	*Impact:* 4		*Probability:* 3	**12**
Customer Attachments/Load:				
Project Designer/Manager:				
Start Date:				
In Service Date:				

Estimated Costs

Description	Estimated Cost	Notes		Estimated Expenditure Timing
Labour:	$ 81,941		Q1	$ -
Materials:	$ 57,084		Q2	$ 234,992
Equipment:	$ 48,657		Q3	$ -
Contract Labour:	$ 47,310		Q4	$ -
Other:	$ -			
			Carry-over:	$ -
Non-construct capital				
Total Estimated Cost	**$ 234,992**		Total:	$ 234,992
Recoverable:	$ -			
HHHI Estimated Cost	**$ 234,992**		Control	$ -
				$ -

General Information

Project Summary/Description:
This project involves extending the 5F3 feeder along 32 Sdrd from 5th Ln to 4th Ln to connect up with the 5F1 feeder to better utilize the existing 5F3 feeder capacity and relieve the 5F1 from high loading.

Comparative Information on Equivalent Historical Projects (if any):
This project is similar to a previous project on the Silver Creek MS distribution system where the 5F2 was reconfigured to improve reliability. The rural areas are challenging due to existing radial feeds and limited load transfer capability between feeders and substations.

Risks to Completion and Risk Mitigation:
This project involves the installation of infrastructure close to wooded areas and across a transmission corridor. The risk to completion is mitigated through customer and transmitter consultations and coordination with all affected parties is necessary to ensure effective installation and completion of the project. By consulting with customers and other utilities, Halton Hills Hydro can set forth our project plans and set realistic expectations for all impacted parties.

Total Capital and OM&A Costs for Renewable Energy Generation portion of project (if any):
N/A

1. Efficiency, Customer Value, Reliability

Main Driver:
The main driver is reinforcement of the 8.32 kV system. Transfer of 5F1 load to the 5F3 will better balance the feeders out of Silver Creek MS, reduce line losses and provide better load transfer capability during maintenance outages and unplanned outages, contributing to better reliability.

Priority & Reasons for Priority:
The priority of this project addresses the need to reduce 5F1 feeder loading and improve reliabilty and power quality to customers

Qualitative & Quantitative Analysis of Project and Project Alternatives:
System operation efficiency would improve by balancing the 8.32 kV feeder loading, reducing line losses and enabling the transfer of load between feeders and adjacent substations. Benefits to the customers would be increased system reliability and power quality at peak load periods.

Other:
N/A

2. Safety

Halton Hills Hydro's construction will be done in accordance with approved utility standards which will protect general public and promote safe working environments for line staff. Poles will be of sufficient strength to support the load applied to them. Halton Hills Hydro lines staff will be working on a road for which they are trained to follow certain rules and set-up requirements (MTO Book 7). Such training is managed through Halton Hills Hydro's implementation of our Empower safety program with Springboard Management.

3. Cyber-security, Privacy

N/A

4. Coordination, Interoperability

New poles will allow for the placement of up to four (4) third party telecommunication company attachments and street lights. Coordination with third party attachers for attachment transfers is a normal practice and they are circulated on projects.

Evaluation Criteria and Information	
	5. Economic Development This project supports economic development in the urban Acton area by freeing up supply on adjacent feeders to accommodate greater amounts of load than can be
	6. Environmental Benefits N/A
	7. Customer Control (Smart Grid Objective) **Access:** N/A **Visibility:** N/A **Control:** N/A **Participation in Renewables:** Three phase system expansion will allow for greater amounts of renewable generation, especially in rural areas. Customers will now have the ability to install three phase generation. The utility will benefit by being able to balance out single phase generation **Customer Choice:** Reinforcing the 8.32kV distribution system will provide customers with greater ability to connect renewable generation as well as request larger services if their demand load requires. **Education:** N/A
	8. Power System Flexibility (Smart Grid Objective) **Distributed Renewables:** By reinforcing the 8.32kV system, Halton Hills Hydro will be able to continue supporting requests for generation in previously underserviced rural areas. **Visibility:** Where distribution and substation automation is installed and communicates data to the utility via a SCADA system, the utility office and control room can see the state of the distribution system at specific points. **Control and Automation:** Improved control can be achieved through distribution/substation Automation. As Halton Hills Hydro automates the 8.32 kV substations, further control is possible to inprove automation and enable generation connections. **Quality:** This project will be constructed to ensure service quality requirements (CSA C235-83) are met.
	9. Adaptive Infrastructure (Smart Grid Objective) **Flexibility:** The project will see #556kcmil ASC installed as the primary conductor. The amapacity rating of this wire is roughly 770A and is sufficient in capacity support future load growth, renewable generation, and innovative technologies such as electric vehicles and power storage. **Forward Compatibility:** This project is one phase in an annual program to develop and expand our 27.6kV distribution system to support future load growth and interoperability between our **Encourage Innovation:** N/A
Outcomes	***1. Customer Focus*** **Service Quality:** N/A **Customer Satisfaction:** N/A
	2. Operational Effectiveness **Safety:** Expansions will be constructed to Halton Hills Hydro's construction standards in accordance with O.Reg. 22/04. **System Reliability:** Expansions will be constructed to improve reliability by permitting additional routes for supplying power to customers. **Asset Management:** This project ties to section 2.2.4 (5.3.2 d) of the Distribution System Plan and enables better use of the rural 8.32 kV feeder system **Cost Control:** Cost control will be achieved by not overdesigning beyond what is truly needed to construct the expansion and using a competitive bid process for materials.
	3. Public Policy Responsiveness **CDM** There is a potential of conservation through reduction in transformation used to supply customers. Where efficiencies in supplying customers can be found through reduction of the number of transformers then to will there be a reduction in system losses. **Connection of Renewable Generation** This project will allow for renewable generation sources to be connected as previously described.
	4. Financial Performance **Financial Implications** Optimum balanced load levels on the rural distribution feeders will result in lower system losses. This will enable better cost recovery and lower system operating costs.

Third Party Planning	
	1. Regional (IESO Regions) n/a
	2. Regional (geographic) Halton Hills Hydro will seek municipal consent where required for installations.
	3. Municipal Halton Hills Hydro will seek municipal consent where required for installations.
	4. Other Third party telecommunication companies will be contacted to coordinate attachment transfers (if required). In addition this project will address provincial requirements
	5. Transmitter n/a
Other Information	***1. Factors Affecting Project Timing*** Customer awareness may be a factor if there are concerns about impacts to property or trees. Early communication with customers can help alleviate potential delays in this respect. As well, material timing could be an issue however by ordering materials in advance of when the project begins construction will reduce the potential of such
	2. Implications of NOT Implementing The risk of not implementing this project is that it will delay our overall expansion plans and may impact our ability to support future load growth. This delay may as well impact our preparedness for future growth in Halton Hills and result in being off-side with provincial regulations. Should this project not proceed, Halton Hills Hydro will
	3. Alternatives Considered & Reason for Not Implementing An alternative to expanding the 27.6kV in this area would be to renew our existing 4.8/ 8.32kV distribution system. Doing so would not provide sufficient capacity for future growth required through the province and Halton Hills Hydro would still need to extend our 27.6kV. Since renewing our 4.8/8.32kV distribution system would not support future load growth, but extending our 27.6kV distribution system would support future load growth logistically and financially it makes sense to continue extending our 27.6kV and remove the 4.8/ 8.32kV in this area. While renewing the 4.8/ 8.32kV system may be less costly in the short term, additional expenditures would

Images

Project Authorization

Prepared by:		Authorized By:	
Date:		Assigned To:	
		Assigned Date:	
		Completion Date:	

Change History					
Date	Section	Change		Reason	Change Authorized by:

Halton Hills HYDRO	CAPITAL PLAN	ENGINEERING		2016
			System Type	SYSTEM SERVICE
	Job Request / Number:			
	Project Name:	Ballinafad MS Reclosers		
	Project Category:			Substation

Reference

Quadra Division:				CAP - HHHDIRECT
Job Request Number:				
Job Number:				
Project Name:				Ballinafad MS Reclosers
Project Category:				Substation
System Type:				SYSTEM SERVICE
Priority Ranking:				5
Risk Ranking:	*Impact:* 4		*Probability:* 4	16
Customer Attachments/Load:				
Project Designer/Manager:				
Start Date:				
In Service Date:				

Estimated Costs

Description	Estimated Cost	Notes		Estimated Expenditure Timing
Labour:	$ 16,879		Q1	$ 6,720
Materials:	$ 124,000		Q2	$ 7,500
Equipment:	$ 4,750		Q3	$ 124,000
Contract Labour:	$ 10,000		Q4	$ 17,409
Other:	$ -			
			Carry-over:	$ -
Non-construct capital				
Total Estimated Cost	**$ 155,629**		Total:	$ 155,629
Recoverable:	$ -			
HHHI Estimated Cost	**$ 155,629**		Control	$ -
				$ -

General Information

Project Summary/Description:
This project involves replacing legacy oil circuit reclosers with newer vacuum reclosers. Included is the upgrade to protection relay class controllers that bring the added benefit of advanced metering and automation. Future connection to the utility SCADA system will bring the added benefit of substation automation, improved system reliability and reduction in maintenance costs.

Comparative Information on Equivalent Historical Projects (if any):
Vacuum reclosers were installed in a similar fashion at the Glen Williams MS in 2006. Operational efficiences were achieved through the reduction of life cycle operating costs associated to oil reclosers

Risks to Completion and Risk Mitigation:
N/A

Total Capital and OM&A Costs for Renewable Energy Generation portion of project (if any):
n/a

1. Efficiency, Customer Value, Reliability

Main Driver:
Reliability, efficiency and automation/smart grid are the main drivers for this project. Oil circuit reclosers require more frequent maintenance to keep them in operation and while they provide feeder protection from temporary and permanent faults, routine maintenance switching operations must be done manually on site. With the benefit of having a control room, efficiencies may be gained through the use of remotely operable reclosers with advanced control capability.

Priority & Reasons for Priority:
Priority is ranked as 5 to complete prior to next recloser maintenance cycle. This project has been previously deferred which has also necessitated the priority ranking

Qualitative & Quantitative Analysis of Project and Project Alternatives:
The continued investment in substation automation will improve system reliability by reducing outage times due to remote operator intervention, and icrease cost efficiencies by reducing on site operator visits during switching. Benefits to customers would be the ability to better monitor the feeders during peak loading conditions and ensure optimum power quality is delivered.

Other:
N/A

2. Safety
Halton Hills Hydro constructs projects to current standards approved as required by O.Reg. 22/04. Construction done per standards will protect the public. As well, automated switches have intelligence built into the devices. Incorporated in the switches are instrument transformers that step down high voltage and current to lesser levels that can be utilized by electronic circuitry in the switches control cabinet to send data about the state of the distribution and switch position (open/ closed) to the utility office via radio/ SCADA system. Such information can be used by the utility office and control room to operate intelligent switches during normal and emergency situations creating safer working environments for lines staff.

3. Cyber-security, Privacy
Recloser controls are accessed through computer software and the SCADA system. Users must have the specific software, user name, and passwords to access switch programming. These security features are in place to lessen the potential for intrusion.

4. Coordination, Interoperability
Many local distribution companies automate their substations. Halton Hills Hydro's substations, when connected to our SCADA system, will be controlled remotely from our shared Control Room at Oakville Hydro by the operators.

5. Economic Development
n/a

Evaluation Criteria and Information	***6. Environmental Benefits*** Automated substations can reduce the need to dispatch line staff in vehicles to operate equipment manually. In doing so less emissions will enter the atmosphere.
	7. Customer Control (Smart Grid Objective) **Access:** n/a **Visibility:** n/a **Control:** n/a **Participation in Renewables:** Advanced recloser control will allow for interoperation of greater amounts of renewable generation, especially in rural areas. Customers will now have the ability to install generation with the utility being assued that appropriate feeder protection is in place. The utility will benefit by being able to better monitor feeders in real time. **Customer Choice:** Automating the 8.32kV distribution system will provide customers with greater ability to connect renewable generation as well as request larger services if their demand load requires. **Education:** n/a
	8. Power System Flexibility (Smart Grid Objective) **Distributed Renewables:** Automated substations that communicate with the utility SCADA system can be operated to restore power to areas affected by power interruptions. Such switching routines could enable renewable generation on affected feeders to be reconnected and continue operations. **Visibility:** Automated substations have instrument transformers that step voltage and current down from a higher level (8,320 or 4,160V) to a lower level (120V) to be used by the electronic controls . The voltage and current readings as well as recloser state (open/ closed), ambient temperature, and fault conditions can be transmitted to the utility office via the SCADA system. **Control and Automation:** Additional switching functionality may enable early restoration of circuits on which renewable generation is connected thus enabling renewable generation to continue producing power. **Quality:** Because voltage and current readings can be transmitted from the switch to the utility office, there is the ability to see supply quality at the main substation bus where in the past such information would not have been available.
	9. Adaptive Infrastructure (Smart Grid Objective) **Flexibility:** Substation Automation provide flexibility by allowing the utility to restore power to areas affected by power interruptions. This can help the implementation of innovative technologies such as electric vehicle charging stations, public or private, and will help customers feel their utility power supply is supportive of innovative technologies that they already use or are considering purchasing. **Forward Compatibility:** The software and firmware used for substation automation is normally upgradable. **Encourage Innovation:** By using substation automation to restore power in an expedient manner, customers who are exploring innovative technologies such as electric vehicles may elect to purchase EV's knowing their power supply is reliable.
Outcomes	***1. Customer Focus*** **Service Quality:** Advanced recloser control metering provides the opportunity to monitor power quality at the source of a feeder. **Customer Satisfaction:** Improved system reliability and more timely attention to power quality issues will contribute to enhanced customer satisfaction
	2. Operational Effectiveness **Safety:** Crew safety will be enhanced by remotely monitoring the state of equipment **System Reliability:** Automated switches can help reduce outage times by enabling quick restoration through automated routines or remote operations. **Asset Management:** Equipment upgrades and smart controls enable enhanced condion monitoring that can be used to support equipment life cycle decisions **Cost Control:** Vacuum reclosers will reduce O&M expenditures by eliminating oil as an insulating and arc interrupting medium. Reduced maintenance will be required throught the useful life of the asset. Remote switching will also reduce capital expenditures that normally result from time spent by field staff going to specific switch locations and manually operating switches to isolate a work zone or to place a holdoff.
	3. Public Policy Responsiveness **CDM** n/a **Connection of Renewable Generation** n/a

4. Financial Performance

Financial Implications

Installation of automated switches will enable remote operation of switches by either control room staff or pre-programmed routine. As well, because the switch will transmit information to the utility office via SCADA, the utility will be able to see the state of the system. This will reduce the amount of time utility field staff spend in the field performing switching operations to restore power or re-configure the distribution system. An overall reduction in operating costs will result.

Third Party Planning

1. Regional (IESO Regions)

N/A

2. Regional (geographic)

There is an embedded distributor that would be coordinated with if necessary.

3. Municipal

Halton Hills Hydro will seek municipal consent where required for installations.

4. Other

N/A

5. Transmitter

n/a

Other Information

1. Factors Affecting Project Timing

The main factor affecting timing will be receiving the reclosers on time. Delays can be averted by contacting the manufacturer to determine what the delivery lead time is and build that lead time into the project scope to ensure the reclosers are ordered in time.

2. Implications of NOT Implementing

By not implementing the project, Halton Hills Hydro will continue to operate the substation manually and continue to refurbish and maintain the existing oil reclosers. Such delays can put our distribution system at risk if old equipment were to fail and maintenance costs would continue to be incurred.

3. Alternatives Considered & Reason for Not Implementing

The alternative would be to maintain the status quo and contiue to operate at a higher cost.

Images

Project Authorization

Prepared by:		**Authorized By:**	
Date:		**Assigned To:**	
		Assigned Date:	
		Completion Date:	

Change History					
Date	**Section**	**Change**		**Reason**	**Change Authorized by:**

Halton Hills Hydro	CAPITAL PLAN	ENGINEERING	2016
		System Type	SYSTEM SERVICE
	Job Request / Number:		6
	Project Name:	Feeder Upgrade and Reinforcement - Delrex Blvd. (Rexway Drive to Maple Avenue)	
	Project Category:		HHHI Directed

Reference

Quadra Division:			CAP - HHHDIRECT
Job Request Number:			6
Job Number:			
Project Name:			Feeder Upgrade and Reinforcement - Delrex Blvd. (Rexway Drive to Maple Avenue)
Project Category:			HHHI Directed
System Type:			SYSTEM SERVICE
Priority Ranking:			3
Risk Ranking:	*Impact:* 4	*Probability:* 3	**12**
Customer Attachments/Load:			
Project Designer/Manager:			
Start Date:			
In Service Date:			

Estimated Costs

Description	Estimated Cost	Notes		Estimated Expenditure Timing
Labour:	$ 127,961		Q1	$ 27,614
Materials:	$ 66,131		Q2	$ 319,198
Equipment:	$ 79,042		Q3	$ -
Contract Labour:	$ 73,678		Q4	$ -
Other:	$ -			
			Carry-over:	$ -
Non-construct capital				
Total Estimated Cost	**$ 346,812**		Total:	$ 346,812
Recoverable:	$ -			
HHHI Estimated Cost	**$ 346,812**		Control	$ -
				$ -

General Information

Project Summary/Description:
Halton Hills Hydro will upgrade and harden part of its 2.4/4.16kV distribution system along Delrex Blvd. between Rexway Drive and Maple Avenue. This project will include replacing utility poles, transformers, wire, and guying. The intent to continue feeder upgrades and system hardening projects that began in 2014 to strength our distribution system in Georgetown and support existing and future load growth.

Comparative Information on Equivalent Historical Projects (if any):
This project is comparative to past system reinforcement projects along Sargent Road and on Delrex Blvd in 2014. The project takes place in our urban Georgetown service territory where most services are residential but do include some small commercial. In past experience we have communicated with our customers to advise them of our planned work and any impacts it may have near their property. We also have coordinated tree trimming, removals, and replacements where customer trees have been impacted. We learn from past experiences and incorporate such experiences into our future designs so that we can better address customer concern and the utilities needs. These areas of the distribution system contain assets that have been in-service well beyond their useful life and replacing the infrastructure should not leave stranded assets.

Risks to Completion and Risk Mitigation:
The main two (2) risks to completion are that of customer awareness and material ordering. In respect of customer awareness, Halton Hills Hydro communicates with our customers about planned work to inform our customers of the work that will be taking place in their vicinity. Halton Hills Hydro works closely with customers to ensure their concerns are addressed as the project progresses. Secondly but of no less importance is material ordering. Halton Hills Hydro plans its projects to ensure enough lead time to receive materials before the job is scheduled to begin.

Total Capital and OM&A Costs for Renewable Energy Generation portion of project (if any):
n/a.

1. Efficiency, Customer Value, Reliability
Main Driver:
The primary driver for this project is to strengthen Halton Hills Hydro's distribution feeders along Delrex Blvd as was begun in 2014. the circuit's along Delrex Blvd allow Halton Hills Hydro to transfer load between three (3) different substations. It is essential these feeders are sufficient to support capacity/ load in this residential of Georgetown. This project is a necessity to ensure that Halton Hills Hydro will continue to provide good supply quality during peak periods and not overload our system.

Priority & Reasons for Priority:
This project has significant priority and should be completed to ensure Halton Hills Hydro's infrastructure is sufficient to support load during peak periods when distribution feeders are interconnected.
Qualitative & Quantitative Analysis of Project and Project Alternatives:
The upgrade and hardening of our distribution circuits along Delrex Blvd. will support load growth in the area, improve reliability, and provide support for field operations conducting switching operations. Construction will be done in accordance with Halton Hills Hydro designs, standards, and will be cost effective.

Other:
n/a.

2. Safety
n/a.

3. Cyber-security, Privacy
n/a.

4. Coordination, Interoperability
New poles will allow for the placement of up to four (4) third party telecommunication company attachments and street lights. Coordination with third party attachers for

Evaluation Criteria and Information	***5. Economic Development*** Feeder strengthening will ensure that supply infrastructure is sufficient to support current load and load growth. In doing so, businesses will be able to rely on their supply allowing growth, job creation, and prosperity.
	6. Environmental Benefits n/a.
	7. Customer Control (Smart Grid Objective) **Access:** n/a.
	Visibility: n/a.
	Control: n/a.
	Participation in Renewables: This project will see conductor with a higher ampacity rating and potentially larger transformers installed thus increasing local capacity for renewable generation allowing more system access by customers. **Customer Choice:** n/a. **Education:** n/a.
	8. Power System Flexibility (Smart Grid Objective) **Distributed Renewables:** This project will see an increase in local area capacity thereby potentially enabling additional renewable generation than may have previously been possible. **Visibility:** n/a. **Control and Automation:** n/a. **Quality:** n/a.
	9. Adaptive Infrastructure (Smart Grid Objective) **Flexibility:** Additional supply capacity may support innovative technologies such as battery storage and electrical vehicle charging. **Forward Compatibility:** Halton Hills Hydro has been replacing 40' and 45' poles that support one (1) circuit with 55' poles that can accommodate two (2) circuits. While only one circuit, the current circuit, will be installed as part of this project, taller poles will be framed in such a manner that permits a second circuit to be installed without significant rework or replacements. **Encourage Innovation:** n/a.
Outcomes	***1. Customer Focus*** **Service Quality:** Increased supply capacity will ensure customers are not affected by poor power quality that results from insufficient distribution supply infrastructure. **Customer Satisfaction:** n/a.
	2. Operational Effectiveness **Safety:** Construction will be done to hydro construction standards to ensure public safety. **System Reliability:** Increased supply capacity will ensure system is reliable and would not contribute to poor power quality. **Asset Management:** n/a. **Cost Control:** Halton Hills Hydro will be vigilant in designing and monitoring costs. Cost control will be achieved by not overdesigning beyond what is truly needed to construct the expansion and using a competitive bid process for materials such as transformers.
	3. Public Policy Responsiveness **CDM** n/a. **Connection of Renewable Generation** This project will allow for renewable generation sources to be connected as previously described. Increased distribution capacity will allow for greater system access for customers wanting to install renewable generation.
	4. Financial Performance **Financial Implications** This project is part of a long term plan Halton Hills Hydro has to ensure our urban feeders are sufficient to support our distribution needs. As well, these projects will allow for future development in Georgetown as there will be a location for an additional circuit to be installed on the poles without having to replace the poles again. This is an example of cost efficiency and responsible investments as customers are not impacted a second time for additional circuits related to future development.
arty Planning	***1. Regional (IESO Regions)*** n/a.
	2. Regional (geographic) Halton Hills Hydro will coordinate efforts with the Region in the event the Region has infrastructure projects in the same year. We will also contact the Region for municipal consent.
	3. Municipal Halton Hills Hydro will coordinate efforts with the Town in the event the Town has infrastructure projects in the same year. We will also contact the Town for municipal consent.

Third P

4. Other
Halton Hills Hydro will circulate all PUCC members to advise them of our project. We will also coordinate with telecommunication companies and the Town (street lighting) to ensure their transfers designs are submitted to the hydro, they are review, approved, permit issued, and installations complete so that hydro can remove the old poles.

5. Transmitter
n/a.

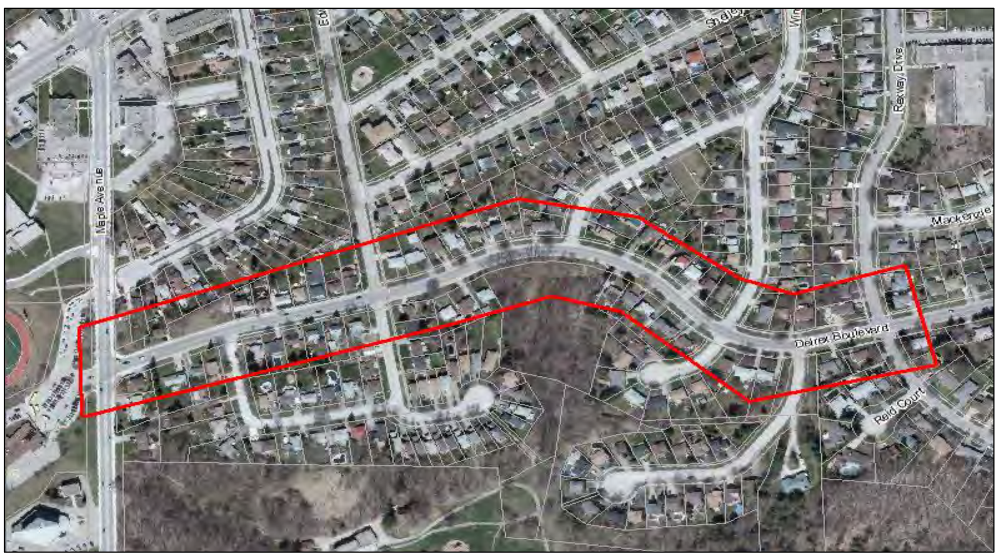
Other Information

1. Factors Affecting Project Timing
Customer awareness may be a factor if there are concerns about impacts to property or trees. Early communication with customers can help alleviate potential delays in this respect. As well, material timing could be an issue however by ordering materials in advance of when the project begins construction will reduce the potential of such delays. Furthermore, close coordination with third party telecommunications companies is necessary to get their attachments transferred to the new poles so as to not delay removing the old poles.

2. Implications of NOT Implementing
The risk of not implementing this project is that it will delay our overall feeder hardening plans and may impact our ability to support future load growth.

3. Alternatives Considered & Reason for Not Implementing
There are no alternatives. Delrex Blvd. is a major artery for Halton Hills Hydro's distribution system feeders in Georgetown and it is important to focus on ensuring our feeders are not reduced to a state that where they would not be capable of supporting existing or future load.

Images



Project Authorization

Prepared by:
Date:

Authorized By:
Assigned To:
Assigned Date:
Completion Date:

Change History					
Date	**Section**	**Change**		**Reason**	**Change Authorized by:**

Halton Hills HYDRO

CAPITAL PLAN — ENGINEERING — 2016

System Type		SYSTEM SERVICE
Job Request / Number:		
Project Name:	SCADA Remote Operated Switch Integration	
Project Category:		HHHI Directed

Reference

Quadra Division:	CAP - HHHDIRECT
Job Request Number:	
Job Number:	
Project Name:	SCADA Remote Operated Switch Integration
Project Category:	HHHI Directed
System Type:	SYSTEM SERVICE
Priority Ranking:	4
Risk Ranking: *Impact:* 3 *Probability:* 4	12
Customer Attachments/Load:	
Project Designer/Manager:	
Start Date:	
In Service Date:	

Estimated Costs

Description		Estimated Cost	Notes			Estimated Expenditure Timing
Labour:	$	16,879		Q1	$	23,145
Materials:	$	62,000		Q2	$	21,145
Equipment:	$	5,700		Q3	$	21,145
Contract Labour:	$	2,000		Q4	$	21,145
Other:	$	-				
				Carry-over:	$	-
Non-construct capital						
Total Estimated Cost	**$**	**86,579**		Total:	$	86,579
Recoverable:	$	-				
HHHI Estimated Cost	**$**	**86,579**		Control	$	-
					$	-

General Information

Project Summary/Description:
This project involves integrating existing motor operated and SCADA Mate switches with the utility SCADA system by installing radio communications technology.

Comparative Information on Equivalent Historical Projects (if any):
N/A

Risks to Completion and Risk Mitigation:
The main risk completion of the radio system backbone network that is presently undergoing construction

Total Capital and OM&A Costs for Renewable Energy Generation portion of project (if any):
n/a

1. Efficiency, Customer Value, Reliability

Main Driver:
Reliability is the main driver for this project. Interruptions on the 44kV and 27.6 kV system affect many customers and large amounts of load. Motor operated switches have been installed to provode the ability to quickly sectionalize faulted sections and restore power back to unaffected sections. Control room operators will be able to reduce outage times and assist field crews with switching, therby speeding the restoration process

Priority & Reasons for Priority:
Priority ranking is listed at 4 since many switches have already been installed and are awaiting automation

Qualitative & Quantitative Analysis of Project and Project Alternatives:
The continued investment in distribution automation will improve system reliability by reducing outage times due to remote operator intervention, and icrease cost efficiencies by reducing on site operator visits during switching. Benefits to customers would be the utility ability to better monitor the feeders during peak loading conditions and ensure optimum power quality is delivered.

Other:
N/A

2. Safety

Halton Hills Hydro constructs projects to current standards approved as required by O.Reg. 22/04. Construction done per standards will protect the public. As well, automated switches have intelligence built into the devices. Incorporated in the switches are instrument transformers that step down high voltage and current to lesser levels that can be utilized by electronic circuitry in the switches control cabinet to send data about the state of the distribution and switch position (open/ closed) to the utility office via radio/ SCADA system. Such information can be used by the utility office and control room to operate intelligent switches during normal and emergency situations creating safer working environments for lines staff.

3. Cyber-security, Privacy

Switch controls are accessed through computer software and the SCADA system. Users must have the specific software, user name, and passwords to access switch programming. These security features are in place to lessen the potential for intrusion.

4. Coordination, Interoperability

Many local distribution companies automate their distribution switches. Halton Hills Hydro's switches, when connected to our SCADA system, will be controlled remotely from our shared Control Room at Oakville Hydro by the operators.

5. Economic Development

n/a

Evaluation Criteria and Information

6. Environmental Benefits
Automated switches can reduce the need to dispatch line staff in vehicles to operate equipment manually. In doing so less emissions will enter the atmosphere.

7. Customer Control (Smart Grid Objective)
Access:
n/a
Visibility:
n/a
Control:
n/a
Participation in Renewables:
Advanced switch controls will allow for interoperation of greater amounts of renewable generation, especially in rural areas. Customers will now have the ability to install generation with the utility being assued that appropriate feeder protection is in place. The utility will benefit by being able to better monitor feeders in real time.

Customer Choice:
Automating the distribution system will provide customers with greater ability to connect renewable generation as well as request larger services if their demand load requires.

Education:
n/a

8. Power System Flexibility (Smart Grid Objective)
Distributed Renewables:
Enabling communication with the utility SCADA system will allow faster restoration of power to areas affected by interruptions. Switching routines could enable renewable generation on affected feeders to be reconnected and continue operations.
Visibility:
Automated switches have instrument transformers that step voltage and current down from a higher level (44 or 27.6kV) to a lower level (120V) to be used by the electronic controls . The voltage and current readings as well as recloser state (open/ closed), ambient temperature, and fault conditions can be transmitted to the utility office via the SCADA system.
Control and Automation:
Additional switching functionality may enable early restoration of circuits on which renewable generation is connected thus enabling renewable generation to continue producing power.
Quality:
Metering equipment within the switches may be used for monitoring power quality and logged for review and improvement initiatives.

9. Adaptive Infrastructure (Smart Grid Objective)
Flexibility:
Distribution automation provides flexibility by allowing the utility to restore power to areas affected by power interruptions. This can help the implementation of innovative technologies such as electric vehicle charging stations, public or private, and will help customers feel their utility power supply is supportive of innovative technologies that they already use or are considering purchasing.
Forward Compatibility:
The software and firmware used for substation automation is normally upgradable.
Encourage Innovation:
By using substation automation to restore power in an expedient manner, customers who are exploring innovative technologies such as electric vehicles may elect to purchase EV's knowing their power supply is reliable.

Outcomes

1. Customer Focus
Service Quality:
Advanced switch control metering provides the opportunity to monitor power quality along the length of a feeder.
Customer Satisfaction:
Improved system reliability and more timely attention to power quality issues will contribute to enhanced customer satisfaction

2. Operational Effectiveness
Safety:
Crew safety will be enhanced by remotely monitoring the state of equipment
System Reliability:
Automated switches can help reduce outage times by enabling quick restoration through automated routines or remote operations.
Asset Management:
Equipment upgrades and smart controls enable enhanced condion monitoring that can be used to support equipment life cycle decisions
Cost Control:
Remote switch monitoring will reduce O&M expenditures by tabulating operational counts and switch duty. Reduced maintenance will be required throught the useful life of the asset. Predictive analysis may be carried out to determine when maintenance is required. Remote switching will also reduce capital expenditures that normally result from time spent by field staff going to specific switch locations and manually operating switches to isolate a work zone or to place a holdoff.

3. Public Policy Responsiveness
CDM
n/a
Connection of Renewable Generation
n/a

4. Financial Performance
Financial Implications
Integration of automated switches will enable remote operation by either control room staff or pre-programmed routine. As well, because the switch will transmit information to the utility office via SCADA, the utility will be able to see the state of the system. This will reduce the amount of time utility field staff spend in the field performing switching operations to restore power or re-configure the distribution system. An overall reduction in operating costs will result.

1. Regional (IESO Regions)
n/a

Third Party Plannin	***2. Regional (geographic)*** Halton Hills Hydro will seek municipal consent where required for installations.
	3. Municipal Halton Hills Hydro will seek municipal consent where required for installations.
	4. Other Halton Hills Hydro will advise telecommunication companies of the project and if necessary coordinate any relocation work with affected parties.
	5. Transmitter n/a
Other Information	***1. Factors Affecting Project Timing*** The main factor affecting timing will be performing the integration engineering early on son that field programming and commisioning may be completed on time.
	2. Implications of NOT Implementing By not implementing the project, Halton Hills Hydro will continue to operate switches manually and continue to incure higher operating costs and experience lower reliability.
	3. Alternatives Considered & Reason for Not Implementing N/A
Images	
Project Authorizat ion	**Prepared by:** **Date:** **Authorized By:** **Assigned To:** **Assigned Date:** **Completion Date:**

Change History					
Date	**Section**	**Change**		**Reason**	**Change Authorized by:**

Halton Hills HYDRO

CAPITAL PLAN	ENGINEERING		2016
		System Type	SYSTEM SERVICE
Job Request / Number:			
Project Name:	SCADA Wireless Faulted Circuit Indicators		
Project Category:			HHHI Directed

Reference

Quadra Division:				CAP - HHHDIRECT
Job Request Number:				
Job Number:				
Project Name:				SCADA Wireless Faulted Circuit Indicators
Project Category:				HHHI Directed
System Type:				SYSTEM SERVICE
Priority Ranking:				4
Risk Ranking:	*Impact:* 4		*Probability:* 3	**12**
Customer Attachments/Load:				
Project Designer/Manager:				
Start Date:				
In Service Date:				

Estimated Costs

Description	Estimated Cost	Notes		Estimated Expenditure Timing
Labour:	$ 3,938		Q1	$ 12,246
Materials:	$ 30,380		Q2	$ 12,246
Equipment:	$ 665		Q3	$ 12,246
Contract Labour:	$ 14,000		Q4	$ 12,246
Other:	$ -			
			Carry-over:	$ -
Non-construct capital				
Total Estimated Cost	**$ 48,983**		Total:	$ 48,983
Recoverable:	$ -			
HHHI Estimated Cost	**$ 48,983**		Control	$ -
				$ -

General Information

Project Summary/Description:
This project involves the purchase of new wireless faulted circuit indicators for use on the 44 kV subtransmission system. This will give control room operators greater ability to find faulted portions of the system.

Comparative Information on Equivalent Historical Projects (if any):
N/A

Risks to Completion and Risk Mitigation:
N/A

Total Capital and OM&A Costs for Renewable Energy Generation portion of project (if any):
n/a

1. Efficiency, Customer Value, Reliability

Main Driver:
Reliability is the main driver for this project. Interruptions on the 44kV and 27.6 kV system affect many customers and large amounts of load. Motor operated switches have been installed to provode the ability to quickly sectionalize faulted sections and restore power back to unaffected sections. Control room operators will be able to reduce outage times and assist field crews with switching, therby speeding the restoration process. Customers will benefit from faster restoration times.

Priority & Reasons for Priority:
Priority ranking is listed at 4 since many automated switches have already been installed and operators now require better system visibility for finding faulted sections of line

Qualitative & Quantitative Analysis of Project and Project Alternatives:
The continued investment in distribution automation will improve system reliability by reducing outage times due to remote operator intervention, and icrease cost efficiencies by reducing on site operator visits during switching. Benefits to customers would be the utility ability to better monitor the feeders during peak loading conditions and ensure optimum power quality is delivered.

Other:
N/A

2. Safety
Halton Hills Hydro constructs projects to current standards approved as required by O.Reg. 22/04. Construction done per standards will protect the public. As well, Faulted Circuit Indicators have intelligence built into the devices. Incorporated into the FCI's are current sensors that can be utilized by electronic circuitry to send data about line loading to the utility office via radio/ SCADA system. Such information can be used by the utility office and control room to operate intelligent switches during normal and emergency situations creating safer working environments for lines staff.

3. Cyber-security, Privacy
FCIs are accessed through computer software and the SCADA system. Users must have the specific software, user name, and passwords to access switch programming. These security features are in place to lessen the potential for intrusion.

4. Coordination, Interoperability
Many local distribution companies now utilize wireless FCIs. These devices, when connected to our SCADA system, will aid operators with isolating faults and restoring power remotely in advance of field crews arriving on site to make repairs.

5. Economic Development
Faster fault finding and isolation/restoration will instill confidence in the electricty supply and attract/retain local businesses and residents

tion

Evaluation Criteria and Informa	***6. Environmental Benefits*** Wireless FCIs can reduce the need to dispatch line staff in vehicles to verify status manually. In doing so less emissions will enter the atmosphere.
	7. Customer Control (Smart Grid Objective) **Access:** n/a **Visibility:** n/a **Control:** n/a **Participation in Renewables:** n/a **Customer Choice:** n/a **Education:** n/a
	8. Power System Flexibility (Smart Grid Objective) **Distributed Renewables:** Enabling communication with the utility SCADA system will allow faster restoration of power to areas affected by interruptions. Switching routines could enable renewable generation on affected feeders to be reconnected and continue operations. **Visibility:** FCIs are able to sense and transmit line current levels in real time . The current readings, ambient temperature in some cases, and fault conditions can be transmitted to the utility office via the SCADA system. **Control and Automation:** Additional switching functionality may be realized in the future with the added benefit of automated fault restoration schemes driven by the OMS engine. **Quality:** Metering funcionality within the FCIs may be used for monitoring power quality and logged for review and improvement initiatives.
	9. Adaptive Infrastructure (Smart Grid Objective) **Flexibility:** Distribution automation provides flexibility by allowing the utility to restore power to areas affected by power interruptions. This can help the implementation of innovative technologies such as electric vehicle charging stations, public or private, and will help customers feel their utility power supply is supportive of innovative technologies that they already use or are considering purchasing. **Forward Compatibility:** The software and firmware used for FCis is normally upgradable. **Encourage Innovation:** By using FCIs to restore power in an expedient manner, customers who are exploring innovative technologies such as electric vehicles may elect to purchase EV's knowing their power supply is reliable.
Outcomes	***1. Customer Focus*** **Service Quality:** Advanced FCI metering provides the opportunity to monitor power quality along the length of a feeder. **Customer Satisfaction:** Improved system reliability and more timely attention to power quality issues will contribute to enhanced customer satisfaction
	2. Operational Effectiveness **Safety:** Crew safety will be enhanced by remotely monitoring the state of equipment **System Reliability:** FCIs can help reduce outage times by enabling quick restoration through automated routines or remote operations. **Asset Management:** Equipment upgrades and smart controls enable enhanced condion monitoring that can be used to support equipment life cycle decisions **Cost Control:** Remote line monitoring will reduce O&M expenditures by tabulating operational load data automatically. Reduced maintenance will be required throught the useful life of the asset. Predictive analysis may be carried out to determine when maintenance is required.Remote monitoring will also reduce capital expenditures that normally result from time spent by field staff going to specific FCI locations for manual verification of fault location.
	3. Public Policy Responsiveness **CDM** n/a **Connection of Renewable Generation** n/a
	4. Financial Performance **Financial Implications** Integration of FCIs will enable remote monitoring and control by either control room staff or pre-programmed routine. As well, because the FCI will transmit information to the utility office via SCADA, the utility will be able to see the state of the system. This will reduce the amount of time utility field staff spend in the field performing switching operations to restore power or re-configure the distribution system. An overall reduction in operating costs will result.
hird Party Planning	***1. Regional (IESO Regions)*** n/a
	2. Regional (geographic) Halton Hills Hydro will seek municipal consent where required for installations.
	3. Municipal Halton Hills Hydro will seek municipal consent where required for installations.
	4. Other Halton Hills Hydro will advise telecommunication companies of the project and if necessary coordinate any relocation work with affected parties.

T	***5. Transmitter*** n/a
Other Information	***1. Factors Affecting Project Timing*** The main factor affecting timing will be performing the integration engineering early on son that field programming and commisioning may be completed on time.
	2. Implications of NOT Implementing By not implementing the project, Halton Hills Hydro will continue to spend more time manually locating faults and continue to incure higher operating costs and experience lower reliability.
	3. Alternatives Considered & Reason for Not Implementing N/A
Images	
Project Authorization	**Prepared by:** **Date:** **Authorized By:** **Assigned To:** **Assigned Date:** **Completion Date:**

Change History					
Date	**Section**	**Change**		**Reason**	**Change Authorized by:**

Halton Hills HYDRO

CAPITAL PLAN — ENGINEERING — 2016

		System Type	SYSTEM SERVICE
Job Request / Number:			Job Request 9
Project Name:	Automated Switches, 27.6kV		
Project Category:			HHHI Directed

Reference

Quadra Division:			CAP - HHHDIRECT
Job Request Number:			9
Job Number:			
Project Name:			Automated Switches, 27.6kV
Project Category:			HHHI Directed
System Type:			SYSTEM SERVICE
Priority Ranking:			3
Risk Ranking:	*Impact:* 3	*Probability:* 3	9
Customer Attachments/Load:			
Project Designer/Manager:			
Start Date:			
In Service Date:			

Estimated Costs

Description	Estimated Cost	Notes		Estimated Expenditure Timing
Labour:	$ 16,350		Q1	$ 1,596
Materials:	$ 113,882		Q2	$ 141,647
Equipment:	$ 9,591		Q3	$ -
Contract Labour:	$ 3,420		Q4	$ -
Other:	$ -			
			Carry-over:	$ -
Non-construct capital				
Total Estimated Cost	**$ 143,244**		Total:	$ 143,244
Recoverable:	$ -			
HHHI Estimated Cost	**$ 143,244**		Control	$ -
				$ -

General Information

Project Summary/Description:
This project continues Halton Hills Hydro's development of our automated switch smart grid system. In 2016 Halton Hills Hydro will purchase and install an automated switch that will be installed at a key location on our 27.6kV distribution system to enhanced the utility's ability to systematically perform switching operations during normal and emergency conditions.

Comparative Information on Equivalent Historical Projects (if any):
Halton Hills Hydro has installed six (6) automated switches on our 27.6kV distribution system since 2011. In the past switches were installed at normally open and normally closed switch points.

Risks to Completion and Risk Mitigation:
By not completing this project Halton Hills Hydro will not have an automated switch in a key location until possibly a later year.

Total Capital and OM&A Costs for Renewable Energy Generation portion of project (if any):
n/a

1. Efficiency, Customer Value, Reliability

Main Driver:
This project is driven by the utilities desired to create additional functionality in the routing of supply in our distribution system. This is accomplished by installing automated switches at key locations on the distribution system to allow Halton Hills Hydro the ability to re-route the supply of power and lessen outage time for customers.

Priority & Reasons for Priority:
This projects priority is driven by the desire to install automated switches in key locations and be prepared for future growth.

Qualitative & Quantitative Analysis of Project and Project Alternatives:
The continued investment in automated switching will improve system reliability by creating circuit ties enabling circuit switching to reduce outage times, support projected load growth, and provide supply for new developments. Construction will be done in accordance with Halton Hills Hydro designs, standards, and will be cost effective.

Other:
This project will also provide additional switching functionality as Halton Hills Hydro's customer based grows as is expected by the Town of Halton Hills Vision Georgetown planning which in part is driven by provincial growth requirements.

2. Safety
Halton Hills Hydro constructs projects to current standards approved as required by O.Reg. 22/04. Construction done per standards will protect the public. As well, automated switches have intelligence built into the devices. Incorporated in the switches are instrument transformers that step down high voltage and current to lesser levels that can be utilized by electronic circuitry in the switches control cabinet to send data about the state of the distribution and switch position (open/ closed) to the utility office via radio/ SCADA system. Such information can be used by the utility office and control room to operate intelligent switches during normal and emergency situations creating safer working environments for lines staff.

3. Cyber-security, Privacy
Switch controls are accessed through computer software. Users must have the specific software, user name, and passwords to access switch programming. These security features are in place to lessen the potential for intrusion.

4. Coordination, Interoperability
Many local distribution companies use automated switches. Halton Hills Hydro's automated switches when connected to our SCADA system will be controlled remotely from our shared Control Room at Oakville Hydro by the operators.

5. Economic Development
n/a

Evaluation Criteria and Informatio	***6. Environmental Benefits*** Automated switches can reduce the need to dispatch line staff in vehicles to operate switches manually. In doing so less emissions will enter the atmosphere.
	7. Customer Control (Smart Grid Objective) **Access:** n/a **Visibility:** n/a **Control:** n/a **Participation in Renewables:** n/a **Customer Choice:** n/a **Education:** n/a
	8. Power System Flexibility (Smart Grid Objective) **Distributed Renewables:** Automated switches that communicate the utilities SCADA system can be operated to restore power to areas affected by power interruptions. Such switching routines could enable renewable generation on affected feeders to be reconnected and continue operations. **Visibility:** Automated switches have instrument transformers that step voltage and current down from a higher level (16,000V) to a lower level (120V) to be used by electronic controls contained in a utility box mounted on the side of a pole. The voltage and current readings as well as switch state (open/ closed), ambient temperature, and fault conditions can be transmitted to the utility office via the utilities SCADA system. **Control and Automation:** Additional switching functionality may enable early restoration of circuits on which renewable generation is connected thus enabling renewable generation to continue producing power. **Quality:** Automated switches are a device the utility uses to maintain its supply to customers, perform smart switching, and restore power. As well, because voltage and current readings can be transmitted from the switch to the utilities office, the utility has the ability to see supply quality at points along the distribution lines where in the past such information would not have been attainable.
	9. Adaptive Infrastructure (Smart Grid Objective) **Flexibility:** Automated switches provide flexibility by allowing utilities to restore power to areas affected by power interruptions. This can help the implementation of innovative technologies such as electric vehicle charging stations, public or private, and will help customers feel their utility power supply is supportive of innovative technologies that they already use or are considering purchasing. **Forward Compatibility:** The software and firmware used for automated switches is normally upgradable. **Encourage Innovation:** By using automated switches to restore power in an expedient manner, customers who are exploring innovative technologies such as electric vehicles may elect to purchase EV's knowing their power supply is good.
Outcomes	***1. Customer Focus*** **Service Quality:** n/a **Customer Satisfaction:** n/a
	2. Operational Effectiveness **Safety:** n/a **System Reliability:** Automated switches can help reduce outage times by enabling quick restoration through automated routines or y remote operations. **Asset Management:** n/a **Cost Control:** Installation of automated switches will reduce O&M expenditures by performing switching from the utility office/ control room. Remote switching will also reduce capital expenditures that normally result from time spent by field staff going to specific switch locations and manually operating switches to isolate a work zone.
	3. Public Policy Responsiveness **CDM** n/a **Connection of Renewable Generation** n/a
	4. Financial Performance **Financial Implications** Installation of automated switches will enable remote operation of switches by either control room staff or pre-programmed routine. As well, because the switch will transmit information to the utility office via SCADA, the utility will be able to see the state of the system. This will reduce the amount of time utility field staff spend in the field performing switching operations to restore power or re-configure the distribution system.
arty Planning	***1. Regional (IESO Regions)*** n/a
	2. Regional (geographic) Halton Hills Hydro will seek municipal consent where required for installations.
	3. Municipal Halton Hills Hydro will seek municipal consent where required for installations.

Third P	***4. Other*** Halton Hills Hydro will advise telecommunication companies of the project and if necessary coordinate any relocation work with affected parties.
	5. Transmitter n/a
Other Information	***1. Factors Affecting Project Timing*** The main factor affecting timing will be receiving the switch on time. This potential delay can be averted by contacting the manufacturer to determine what the delivery lead time is and build that lead time into the project scope to ensure the switch is ordered in time.
	2. Implications of NOT Implementing By not implementing the project, Halton Hills Hydro will be a year delayed in our program to install automated switching. Such delays can put our distribution system at risk.
	3. Alternatives Considered & Reason for Not Implementing An alternative would be to install a manually operated switch. While manual and automated switches perform the same basic function, a manual switch requires staff to operate the switch which adds to the utilities O&M costs. As well, manual switches do not provide system information such as voltage, current, and device state to the utility. Automated switches installed at key points in the distribution system will allow the utility to leverage the equipment to benefit its customers.
Images	
Project Authorizat ion	**Prepared by:** **Date:** **Authorized By:** **Assigned To:** **Assigned Date:** **Completion Date:**

Change History

Date	Section	Change		Reason	Change Authorized by:

Halton Hills HYDRO	**CAPITAL PLAN**	**ENGINEERING**		**2016**
			System Type	**SYSTEM SERVICE**
	Job Request / Number:			**CAP14-009**
	Project Name:	**Trafalgar Road, 27.6kV Extension (15 Sdrd to 17 Sdrd/ Maple Ave.).**		
	Project Category:			**HHHI Directed**

Reference

Quadra Division:				CAP - HHHDIRECT
Job Request Number:				
Job Number:				**CAP14-009**
Project Name:				Trafalgar Road, 27.6kV Extension (15 Sdrd to 17 Sdrd/ Maple Ave.).
Project Category:				HHHI Directed
System Type:				SYSTEM SERVICE
Priority Ranking:				3
Risk Ranking:	*Impact:* 2		*Probability:* 3	**6**
Customer Attachments/Load:		174+ Townhouses and additional development/ Load TBD		
Project Designer/Manager:		TBD		
Start Date:				
In Service Date:				

Estimated Costs

Description	Estimated Cost	Notes		Estimated Expenditure Timing
Labour:	$ 228,554		Q1	$ -
Materials:	$ 217,132		Q2	$ 159,236
Equipment:	$ 135,458		Q3	$ 318,472
Contract Labour:	$ 90,037		Q4	$ 193,474
Other:	$ -			
			Carry-over:	$ -
Non-construct capital				
Total Estimated Cost	**$ 671,181**		Total:	$ 671,181
Recoverable:	$ -			
HHHI Estimated Cost	**$ 671,181**		Control	$ -
				$ -

General Information

Project Summary/Description:
This project continues Halton Hills Hydro's planned expansion of our 27.6kV distribution system to support anticipated load growth, in this case north of Town of Halton Hills office on Halton Hills Drive. This project will see our 27.6kV distribution system brought north along Trafalgar Road between 15 Side Road and 17 Side Road/ Maple Avenue and will require poles and supporting apparatus to be replaced and new infrastructure installed that will support the existing 44kV and 8.32kV circuits and additionally permit a place for a 27.6kV circuit. This project will also ensure that Halton Hills Hydro remains compliant with the OEB Distribution System Code and can provide an Offer to Connect.

Comparative Information on Equivalent Historical Projects (if any):
This project is comparative to past 27.6kV expansion projects along Trafalgar Road between 10 Side Road and 15 Side Road. That project took place in our rural service territory where much of the land is farmed . In past experience we have communicated with our customers to advise them of our planned work and any impacts it may have near their property. We also have coordinated tree trimming, removals, and replacements where customer trees have been impacted. We learn from past experiences and incorporate such experiences into our future designs so that we can better address customer concern and the utilities needs. The primary differences with the project described herein is that our work will be within the urban limits where our work will be close to residential properties.

Risks to Completion and Risk Mitigation:
The main two (2) risks to completion are that of customer awareness and material ordering. In respect of customer awareness, Halton Hills Hydro communicates with our customers about planned work to inform our customers of the work that will be taking place in their vicinity. Halton Hills Hydro works closely with customers to ensure their concerns are addressed as the project progresses. Working closely with our customers will help to mitigate the risk of public resistance to changes. Secondly but of no less importance is material ordering. Halton Hills Hydro plans its projects to ensure enough lead time to receive materials before the job is scheduled to begin.

Total Capital and OM&A Costs for Renewable Energy Generation portion of project (if any):
N/A.

1. Efficiency, Customer Value, Reliability

Main Driver:
Plan and prepare to support future load growth in the Halton Hills Drive area.

Halton Hills HYDRO	**CAPITAL PLAN**	**ENGINEERING**	**2016**
		System Type	**SYSTEM SERVICE**
	Job Request / Number:		**CAP14-009**
	Project Name:	**Trafalgar Road, 27.6kV Extension (15 Sdrd to 17 Sdrd/ Maple Ave.).**	
	Project Category:		**HHHI Directed**

Evaluation Criteria and Information

Priority & Reasons for Priority:

The priority level of this expansion project is reflective of the need to be prepared for load growth in 2016/ 2017. In discussion with Town of Halton Hills planning staff the development if approved would likely proceed in 2 to 3 years. Halton Hills Hydro needs to ensure it's distribution system will support the anticipated load growth in this area and in doing so would need to begin construction at least 1 year prior to a developer needing site power. As well, the Town of Halton Hills has surplus lands for which they have undertaken studies to determine the best use of. Additional development along Halton Hills Drive (shown below) is anticipated and could be in the form of multi-unit buildings, townhouses, or a combination thereof.

Qualitative & Quantitative Analysis of Project and Project Alternatives:

The expansion of our 27.6kV circuits will support the additional load and improve system reliability by becoming part of feeder ties on our 27.6kV discussed for 2019 and 2020 in our DS Plan. Construction will be done in accordance with Halton Hills Hydro designs, standards, and will be cost effective. An alternative would be to connect the developments to our 8.32kV distribution system however doing so many impact Halton Hills Hydro's ability to remove stations from service during heavily loaded periods and/ or make feeder switching more difficult where load on the feeder being transferred is higher than what the feeder accepting the load can accept.

Other:

N/A.

2. Safety

Halton Hills Hydro's construction will be done in accordance with approved utility standards which will protect general public and promote safe working environments for line staff. Poles will be of sufficient strength to support the load applied to them. Halton Hills Hydro lines staff will be working on a very busy road for which they are trained to follow certain rules and set-up requirements (MTO Book 7). Such training is managed through Halton Hills Hydro's implementation of our Empower safety program with Springboard Management.

3. Cyber-security, Privacy

N/A.

4. Coordination, Interoperability

New poles will allow for the placement of up to four (4) third party telecommunication company attachments and street lights. Coordination with third party attachers for attachment transfers is a normal practice and they are circulated on projects.

5. Economic Development

This project supports economic development by providing supply facilities that can accommodate greater amounts of load than our 8.32kV distribution system. This will help support growth in the Maple Avenue, Trafalgar Road, Halton Hills Drive area of Georgetown.

6. Environmental Benefits

N/A.

7. Customer Control (Smart Grid Objective)

Access:

N/A.

Visibility:

N/A.

Control:

N/A.

Participation in Renewables:

Three phase 27.6kV system expansion will allow for renewable generation greater amounts of renewable generation, especially in areas where 4.8kV single phase only existed. Customers will now have the ability to install three phase generation.

Customer Choice:

Growing our 16/ 27.6kV distribution system will provide customers with greater ability to connect renewable generation as well as request larger services if their demand load requires.

Education:

N/A.

8. Power System Flexibility (Smart Grid Objective)

Distributed Renewables:

By expanding and interconnecting different 27.6kV feeders, Halton Hills Hydro will be able to continue supporting requests for generation through feeder switching if necessary.

Visibility:

Where intelligent switches are installed and communicate data to the utility via a SCADA system, the utility office and control room can see the state of the distribution system at specific points.

Control and Automation:

Improved control can be achieved through installing switches at key locations. As Halton Hills Hydro develops the use of automated switches on our 27.6kV distribution system, further automation control is possible to support and maintain generation connections along Trafalgar Road.

Quality:

This project will be constructed to ensure service quality requirements (CSA C235-83) are met.

Halton Hills HYDRO	CAPITAL PLAN	ENGINEERING	2016
		System Type	SYSTEM SERVICE
	Job Request / Number:		CAP14-009
	Project Name:	Trafalgar Road, 27.6kV Extension (15 Sdrd to 17 Sdrd/ Maple Ave.).	
	Project Category:		HHHI Directed

Outcomes

9. Adaptive Infrastructure (Smart Grid Objective)

Flexibility:

The project will see #556kcmil ASC installed as the primary conductor. The ampacity rating of this wire is roughly 770A and is sufficient in capacity support future load growth, renewable generation, and innovative technologies such as electric vehicles and power storage.

Forward Compatibility:

This project will is one phase in an annual program to develop and expand our 27.6kV distribution system to support future load growth and interoperability between our current feeders and allow for the addition of future 27.6kV circuits as the project will allow for a future circuit to be installed. Future 27.6kV plans discussed in this DS Plan include finishing a much needed 27.6kV distribution loop along Maple Avenue to 8th Line to improve reliability for customers connected to our 27.6kV along 8th Line (ie: subdivision development).

Encourage Innovation:

N/A.

1. Customer Focus

Service Quality:

N/A.

Customer Satisfaction:

N/A.

2. Operational Effectiveness

Safety:

Expansions will be constructed to Halton Hills Hydro's construction standards in accordance with O.Reg. 22/04.

System Reliability:

Expansions will be constructed to improve reliability by permitting additional routes for supplying power to customers.

Asset Management:

N/A.

Cost Control:

Cost control will be achieved by not overdesigning beyond what is truly needed to construct the expansion and using a competitive bid process for materials such as transformers.

3. Public Policy Responsiveness

CDM

There is a potential of conservation through reduction in transformation used to supply customers. Where efficiencies in supplying customers can be found through reduction of the number of transformers then to will there be a reduction in system losses.

Connection of Renewable Generation

This project will allow for renewable generation sources to be connected as previously described. Currently there is one (1) microFIT connected along this section of pole line. Our construction will ensure that the renewable generation can be connected to the new infrastructure once built.

4. Financial Performance

Financial Implications

N/A.

Third Party Planning

1. Regional (IESO Regions)

N/A.

2. Regional (geographic)

Region of Halton will be contacted for municipal consent.

3. Municipal

Town of Halton Hills will be contacted for municipal consent.

4. Other

Third party telecommunication companies will be contacted to coordinate attachment transfers (if required). In addition this project will address provincial requirements with respect to growth in Halton Hills by ensuring supply infrastructure is readily available to new development. Halton Hills Hydro will also coordinate with our customer in the project area who has a microFIT renewable generator connected to our distribution system to ensure they are aware that we will need to disconnect their generation (and load service) at some point during the course of our work to enable services to be transferred to the new line.

5. Transmitter

N/A.

Information

1. Factors Affecting Project Timing

Customer awareness may be a factor if there are concerns about impacts to property or trees. Early communication with customers can help mitigate potential delays in this respect. As well, material timing could be an issue however by ordering materials in advance of when the project begins construction will reduce the potential of such delays.

2. Implications of NOT Implementing

The risk of not implementing this project in 2016 is not so significant that a high priority is warranted. Construction of the development may not commence until 2017 or 2018. However, Halton Hills Hydro believes it is in the best interest of the utility. to be prepared for anticipated load growth and as such believes the need to extend the 27.6kV as discussed is warranted and given the extent of the work involves significant time will be required to construct the project.

CAPITAL PLAN	ENGINEERING		2016
		System Type	SYSTEM SERVICE
Job Request / Number:			CAP14-009
Project Name:	Trafalgar Road, 27.6kV Extension (15 Sdrd to 17 Sdrd/ Maple Ave.).		
Project Category:			HHHI Directed

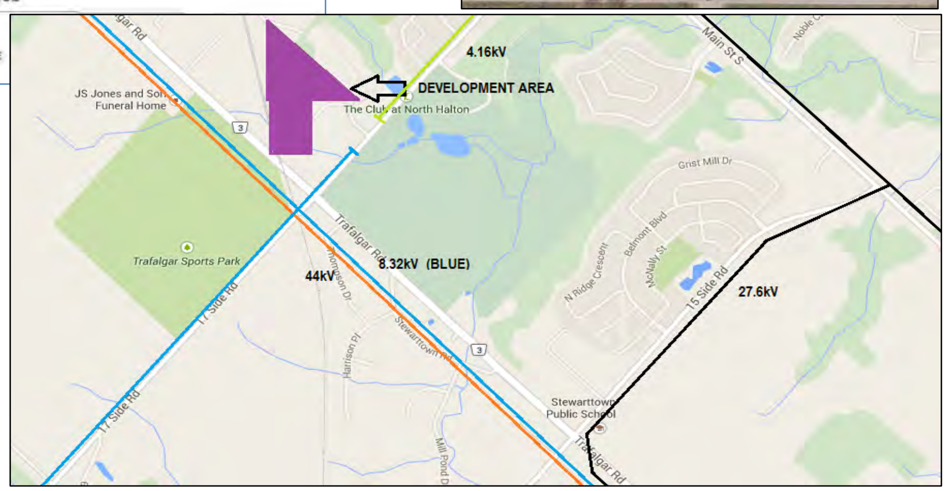
Other

3. Alternatives Considered & Reason for Not Implementing

There are two alternative. (1) Wait until development is proceeding at which point begin construction. This option may result in Halton Hills Hydro not being able to support the development in time and it may impact projects planned for later years in our DS Plan. By that we mean projects that had been planned may have to be deferred to accommodate this project. (2) An alternative supply source is from our 8.32kV distribution system. While the 8.32kV distribution system is currently along Trafalgar Road, connecting this development and others we are aware may potentially occur will constrain our 8.32kV distribution system in this area and may make it harder to transfer load between substations.

Images

174 Townhouse units.



Project Authorization

Prepared by:		Authorized By:	
Date:		Assigned To:	
		Assigned Date:	
		Completion Date:	

Change History

Date	Section	Change		Reason	Change Authorized by:

CAPITAL PLAN	**ENGINEERING**		**2016**
		System Type	**SYSTEM SERVICE**
Job Request / Number:			**14**
Project Name:	**Voltage Conversion, 5 Side Road (Trafalgar Road to 8th Line)**		
Project Category:			**HHHI Directed**

Reference

Quadra Division:			CAP - HHHDIRECT
Job Request Number:			14
Job Number:			
Project Name:			Voltage Conversion, 5 Side Road (Trafalgar Road to 8th Line)
Project Category:			HHHI Directed
System Type:			SYSTEM SERVICE
Priority Ranking:			4
Risk Ranking:	*Impact:* 4	*Probability:* 3	**12**
Customer Attachments/Load:			
Project Designer/Manager:	TBD		
Start Date:			
In Service Date:			

Estimated Costs

Description	Estimated Cost	Notes		Estimated Expenditure Timing
Labour:	$ 148,681		Q1	$ -
Materials:	$ 133,547		Q2	$ 193,760
Equipment:	$ 84,454		Q3	$ 214,934
Contract Labour:	$ 42,011		Q4	$ -
Other:	$ -			
			Carry-over:	$ -
Non-construct capital				
Total Estimated Cost	**$ 408,694**		Total:	$ 408,694
Recoverable:	$ -			
HHHI Estimated Cost	**$ 408,694**		Control	$ -
				$ -

General Information

Project Summary/Description:
This project continues Halton Hills Hydro's planned expansion of our 27.6kV distribution system into areas of our service territory where 8.32kV is the current distribution voltage. By expanding our 27.6kV distribution system we will also be phasing out portions of our 8.32kV distribution system in the southern regions of our service territory that often single phase radial supplies. This project will enable Halton Hills Hydro to build a feeder loop between our 41M21 and 41M29 feeders along 5 Side Road between Trafalgar Road and 8th Line. It will also serve to support additional load growth anticipated by the Town of Halton Hills Vision Georgetown plan (20,000 people and 1700 jobs by 2031) where development is expected to start in the early 2020's. This project will also provide options for directing power flow to current load and subdivisions under development in Georgetown by providing additional switching capabilities which will enable Halton Hills Hydro to switch load and maintain good service quality and reduce restoration time.

Comparative Information on Equivalent Historical Projects (if any):
This project is comparative to past 27.6kV expansion projects along 5 Side Road between 5th Line and Trafalgar Road. The project takes place in our rural service territory where much of the land is farmed and there exists significant tree populations. In past experience we have communicated with our customers to advise them of our planned work and any impacts it may have near their property. We also have coordinated tree trimming, removals, and replacements where customer trees have been impacted. We learn from past experiences and incorporate such experiences into our future designs so that we can better address customer concern and the utilities needs.

Risks to Completion and Risk Mitigation:
The main two (2) risks to completion are that of customer awareness and material ordering. In respect of customer awareness, Halton Hills Hydro communicates with our customers about planned work to inform our customers of the work that will be taking place in their vicinity. Halton Hills Hydro works closely with customers to ensure their concerns are addressed as the project progresses. Secondly but of no less importance is material ordering. Halton Hills Hydro plans its projects to ensure enough lead time to receive materials before the job is scheduled to begin.

Total Capital and OM&A Costs for Renewable Energy Generation portion of project (if any):
N/A.

1. Efficiency, Customer Value, Reliability

Main Driver:
Increase system reliability and support future load growth.

Priority & Reasons for Priority:
The priority level of this expansion project is reflective of the need to be prepared for load growth in the southern area's of Georgetown (Town of Halton Hills Vision Georgetown Plan) as well as supporting new load growth along Steeles Avenue along the 401 corridor (Halton Hills Premier Gateway).

	CAPITAL PLAN	**ENGINEERING**	**2016**
		System Type	**SYSTEM SERVICE**
	Job Request / Number:		**14**
	Project Name:	**Voltage Conversion, 5 Side Road (Trafalgar Road to 8th Line)**	
	Project Category:		**HHHI Directed**

Evaluation Criteria and Information

Qualitative & Quantitative Analysis of Project and Project Alternatives:

The expansion of our 27.6kV circuits will improve system reliability by adding feeder ties enabling circuit switching to reduce outage times, support projected load growth, and provide supply for new developments. Construction will be done in accordance with Halton Hills Hydro designs, standards, and will be cost effective. An alternative would be to renew the existing 4.8/ 8.32kV radial distribution system however in doing so such renewal would not be able to support future load growth in Georgetown or the 401 corridor. It makes financial sense to replace the 4.8/ 8.32kV infrastructure with 16/ 27.6kV to supply current load, accommodate future load, and increase system reliability. As well, a higher distribution voltage can accommodate higher levels of renewable generation.

Other:

N/A.

2. Safety

Halton Hills Hydro's construction will be done in accordance with approved utility standards which will protect general public and promote safe working environments for line staff. Poles will be of sufficient strength to support the load applied to them. Halton Hills Hydro lines staff will be working on a very busy road for which they are trained to follow certain rules and set-up requirements (MTO Book 7). Such training is managed through Halton Hills Hydro's implementation of our Empower safety program with Springboard Management.

3. Cyber-security, Privacy

N/A.

4. Coordination, Interoperability

New poles will allow for the placement of up to four (4) third party telecommunication company attachments and street lights. Coordination with third party attachers for attachment transfers is a normal practice and they are circulated on projects.

5. Economic Development

This project supports economic development by providing supply facilities that can accommodate greater amounts of load than our 8.32kV distribution system. Such development that will be supported in the Vision Georgetown plan and 401 Premier Gateway development area.

6. Environmental Benefits

Asset records show some of the poles in the scope of this project were treated with creosote. Replacement of old poles will result in the removal of poles that were treated with creosote.

7. Customer Control (Smart Grid Objective)

Access:

N/A.

Visibility:

N/A.

Control:

N/A.

Participation in Renewables:

Three phase 27.6kV system expansion will allow for renewable generation greater amounts of renewable generation, especially in areas where 4.8kV single phase only existed. Customers will now have the ability to install three phase generation.

Customer Choice:

Growing our 16/ 27.6kV distribution system will provide customers with greater ability to connect renewable generation as well as request larger services if their demand load requires.

Education:

N/A.

8. Power System Flexibility (Smart Grid Objective)

Distributed Renewables:

By expanding and interconnecting different 27.6kV feeders, Halton Hills Hydro will be able to continue supporting requests for generation through feeder switching if necessary.

Visibility:

Where intelligent switches are installed and communicate data to the utility via a SCADA system, the utility office and control room can see the state of the distribution system at specific points.

Control and Automation:

Improved control can be achieved through installing switches at key locations. As Halton Hills Hydro develops the use of automated switches on our 27.6kV distribution system, further automation control is possible to support and maintain generation connections.

Quality:

This project will be constructed to ensure service quality requirements (CSA C235-83) are met.

9. Adaptive Infrastructure (Smart Grid Objective)

Flexibility:

The project will see #556kcmil ASC installed as the primary conductor. The amapacity rating of this wire is roughly 770A and is sufficient in capacity support future load growth, renewable generation, and innovative technologies such as electric vehicles and power storage.

Forward Compatibility:

This project is one phase in an annual program to develop and expand our 27.6kV distribution system to support future load growth and interoperability between our current feeders and allow for the addition of future 27.6kV circuits as the project will allow for a future circuit to be installed.

CAPITAL PLAN	ENGINEERING		2016
		System Type	SYSTEM SERVICE
Job Request / Number:			14
Project Name:	Voltage Conversion, 5 Side Road (Trafalgar Road to 8th Line)		
Project Category:			HHHI Directed

Encourage Innovation:
N/A.

Outcomes

1. Customer Focus
Service Quality:
N/A.
Customer Satisfaction:
N/A.

2. Operational Effectiveness
Safety:
Expansions will be constructed to Halton Hills Hydro's construction standards in accordance with O.Reg. 22/04.
System Reliability:
Expansions will be constructed to improve reliability by permitting additional routes for supplying power to customers.
Asset Management:
N/A.
Cost Control:
Cost control will be achieved by not overdesigning beyond what is truly needed to construct the expansion and using a competitive bid process for materials such as transformers.

3. Public Policy Responsiveness
CDM
There is a potential of conservation through reduction in transformation used to supply customers. Where efficiencies in supplying customers can be found through reduction of the number of transformers then to will there be a reduction in system losses.
Connection of Renewable Generation
This project will allow for renewable generation sources to be connected as previously described.

4. Financial Performance
Financial Implications
N/A.

Third Party Planning

1. Regional (IESO Regions)
N/A.

2. Regional (geographic)
Region of Halton will be contacted for municipal consent.

3. Municipal
Town of Halton Hills will be contacted for municipal consent.

4. Other
Third party telecommunication companies will be contacted to coordinate attachment transfers (if required). In addition this project will address provincial requirements with respect to growth in Halton Hills by ensuring supply infrastructure is readily available to new development.

5. Transmitter
N/A.

Other Information

1. Factors Affecting Project Timing
Customer awareness may be a factor if there are concerns about impacts to property or trees. Early communication with customers can help alleviate potential delays in this respect. As well, material timing could be an issue however by ordering materials in advance of when the project begins construction will reduce the potential of such delays.

2. Implications of NOT Implementing
The risk of not implementing this project is that it will delay our overall expansion plans and may impact our ability to support future load growth. This delay may as well impact our preparedness for future growth in Halton Hills and result in being off-side with provincial regulations. Should this project not proceed, Halton Hills Hydro will not have an important piece of our 16/ 27.6kV distribution system in place for reliability and redundancy purposes.

3. Alternatives Considered & Reason for Not Implementing
An alternative to expanding the 27.6kV in this area would be to renew our existing 4.8/ 8.32kV distribution system. Doing so would not provide sufficient capacity for future growth required through the province and Halton Hills Hydro would still need to extend our 27.6kV. Since renewing our 4.8/8.32kV distribution system would not support future load growth, but extending our 27.6kV distribution system would support future load growth logistically and financially it makes sense to continue extending our 27.6kV and remove the 4.8/ 8.32kV in this area. While renewing the 4.8/ 8.32kV system may be less costly in the short term, additional expenditures would need to be made in the future to support load growth and reliability in the next 10 to 15 years according to current projected growth plans. Additionally, if we renewed the 4.8/ 8.32kV distribution system and then 10 to 15 years later replaced it with 16/ 27.6kV, we would be stranding the assets installed for system renewal as those assets would not have reached their end of useful lives.

Halton Hills HYDRO	CAPITAL PLAN	ENGINEERING	2016
		System Type	SYSTEM SERVICE
	Job Request / Number:		14
	Project Name:	Voltage Conversion, 5 Side Road (Trafalgar Road to 8th Line)	
	Project Category:		HHHI Directed

Images

Project Authorization

Prepared by:		Authorized By:	
Date:		Assigned To:	
		Assigned Date:	
		Completion Date:	

Change History					
Date	Section	Change		Reason	Change Authorized by:

Halton Hills HYDRO

CAPITAL PLAN	IT		2016
		System Type	GENERAL PLANT
Job Request / Number:			
Project Name:	IBM System i POWER8 Install		
Project Category:			HHHI Directed

Reference

Quadra Division:				
Job Request Number:				
Job Number:				
Project Name:				IBM System i POWER8 Install
Project Category:				HHHI Directed
System Type:				GENERAL PLANT
Priority Ranking:				3
Risk Ranking:	*Impact:* 4		*Probability:* 3	**12**
Customer Attachments/Load:				
Project Designer/Manager:				
Start Date:				
In Service Date:				

Estimated Costs

Description	Estimated Cost	Notes		Estimated Expenditure Timing
Labour:	$ 9,000		Q1	
Materials:	$ 56,000		Q2	
Equipment:	$ -		Q3	$ -
Contract Labour:	$ 10,000		Q4	$ 75,000
Other:	$ -			
			Carry-over:	$ -
Non-construct capital				
Total Estimated Cost	**$ 75,000**		Total:	$ 75,000
Recoverable:	$ -			
HHHI Estimated Cost	**$ 75,000**		Control	$ -
				$ 75,000

General Information

Project Summary/Description:
This project is to replace our existing IBM System i 520 (Power5+) Server which was installed in 2008. In 2016 Halton Hills Hydro will purchase and install an IBM Power System S814 (Power8). The new Enterprise POWER8 Server will provide increased system performance, dynamic resource sharing, reduced footprint, and improved energy efficiency.

Comparative Information on Equivalent Historical Projects (if any):
Halton Hills Hydro installed our current System i5 520 in June 2008 for roughly $75,000.

Risks to Completion and Risk Mitigation:
By not completing this project Halton Hills Hydro may run the risk of increased hardware failures, slower system performance, and an increase of downtime (current objective of 99.0%) by maintaining the existing 8 year old server. The existing IBM System I was withdrawn from the market late in 2008.

Total Capital and OM&A Costs for Renewable Energy Generation portion of project (if any):
n/a

nformation

1. Efficiency, Customer Value, Reliability

Main Driver:
This project is driven by Halton Hills Hydro's IT Departments desired to maintain an exemplary level of system reliability and performance. This is accomplished by regularly scheduled maintenance and replacement of IT infrastructure. The project will be contingent on a CIS System review to be completed in Q1/Q2 of 2016.

Priority & Reasons for Priority:
This projects priority is driven by the existing age of our IBM System i5 520 (installed in 2008).

Qualitative & Quantitative Analysis of Project and Project Alternatives:
The continued investment in Halton Hills Hydro IT infrastructure will improve internal system reliability which directly relates to the customer service we provide the residents and businesses of Halton Hills. Hardware procurement, planning, and installation will be completed with a project team consisting of IBM, Mid-Range Systems and Halton Hills Hydro IT department.

Other:

2. Safety
n/a

3. Cyber-security, Privacy
During the planning phase of the project, system and network segregation will be reviewed. Operational network/system segragation involves partitioning the network into smaller networks. Network segregation involves developing and enforcing a ruleset controlling which computing devices are permitted to communicate with which other computing devices. This can be achieved using a variety of technologies and methods: demilitarised zones (DMZ), Virtual Local Area Networks (VLANs), application firewalls, network and host-based firewalls, etc. Existing user operating system and application security will be ported over from existing server to new server.

4. Coordination, Interoperability
n/a

5. Economic Development
n/a

Evaluation Criteria and I	
	6. Environmental Benefits
	7. Customer Control (Smart Grid Objective) **<u>Access:</u>** n/a **<u>Visibility:</u>** n/a **<u>Control:</u>** n/a **<u>Participation in Renewables:</u>** n/a **<u>Customer Choice:</u>** n/a **<u>Education:</u>** n/a
	8. Power System Flexibility (Smart Grid Objective) **<u>Distributed Renewables:</u>** n/a **<u>Visibility:</u>** n/a **<u>Control and Automation:</u>** n/a **<u>Quality:</u>** n/a
	9. Adaptive Infrastructure (Smart Grid Objective) **<u>Flexibility:</u>** n/a **<u>Forward Compatibility:</u>** n/a **<u>Encourage Innovation:</u>** n/a
Outcomes	***1. Customer Focus*** **<u>Service Quality:</u>** n/a **<u>Customer Satisfaction:</u>** n/a
	2. Operational Effectiveness **<u>Safety:</u>** n/a **<u>System Reliability:</u>** n/a **<u>Asset Management:</u>** n/a **<u>Cost Control:</u>** n/a
	3. Public Policy Responsiveness **<u>CDM</u>** n/a **<u>Connection of Renewable Generation</u>** n/a
	4. Financial Performance **<u>Financial Implications</u>** Installation of a new IBM System i Server will reduce hardware failure and any potential Customer Information System downtime which may directly impact our ability to bill customers in a timely basis. The first three years support and maintenance costs are included in the purchase of a new server. This will reduce the amount of maintenance we are currently paying on an 8 year old server.
Third Party Planning	***1. Regional (IESO Regions)*** n/a
	2. Regional (geographic) n/a
	3. Municipal n/a
	4. Other n/a
	5. Transmitter n/a
nformation	***1. Factors Affecting Project Timing*** The main factor affecting timing will be receiving the hardware and all the necessary components and scheduling all vendors to begin the project when all resources are available.
	2. Implications of NOT Implementing By not implementing the project, Halton Hills Hydro will continue to pay higher maintenance costs on older hardware and be more vulnerable to the possibillity of hardware failures and unscheduled downtime.

Other I	***3. Alternatives Considered & Reason for Not Implementing*** An alternative would be to have our IBM System i hosted with an external managed services and hosting organization. This would significantly increase our operating costs with hosting services and an increase in communication costs, reduce our flexibility if we were to share the physical server with another organization being hosted on the same server, and reduction in performance due to the remote communications between our site and hosted location.
Images	
Project Authorization	**Prepared by:** ____ **Date:** ____ **Authorized By:** ____ **Assigned To:** ____ **Assigned Date:** ____ **Completion Date:** ____

Change History					
Date	**Section**	**Change**		**Reason**	**Change Authorized by:**

CAPITAL PLAN	CUSTOMER CARE		2016
		System Type	GENERAL PLANT
Job Request / Number:			
Project Name:	Installation - Interactive Voice Response System (IVR)		
Project Category:			Non-Construction - General

Reference

Quadra Division:				
Job Request Number:				
Job Number:				
Project Name:				Installation - Interactive Voice Response System (IVR)
Project Category:				Non-Construction - General
System Type:				GENERAL PLANT
Priority Ranking:				3
Risk Ranking:	*Impact:* 3		*Probability:* 3	9
Customer Attachments/Load:				
Project Designer/Manager:		Kate Sweetman		
Start Date:				
In Service Date:				

Estimated Costs

Description	Estimated Cost	Notes		Estimated Expenditure Timing
Labour:	$ -		Q1	$ -
Materials:	$ -		Q2	$ -
Equipment:	$ -		Q3	$ -
Contract Labour:	$ -		Q4	$ -
Other:	$ -			
			Carry-over:	$ -
Non-construct capital	$ 100,000			
Total Estimated Cost	**$ 100,000**		Total:	$ -
Recoverable:	$ -			
HHHI Estimated Cost	**$ 100,000**		Control	$ 100,000
				$ 100,000

General Information

Project Summary/Description:

Currently, HHHI has live Customer Care Representatives to answer inquiries during normal business hours (Monday to Friday 8:30am to 4:30pm, excluding holidays). If customers are unable to call our CCRs during office hours, then there are few options available to the customer. Customers can contact the after-hours service and leave a message, use the "Contact Us - General Inquiries" page on the HHHI website or use the Account On-Line feature at http://haltonhillshydro.com/index.php/accountonline/. During power outages, customers are able to see updates on the HHHI website, Twitter and Facebook, however, for customer without access, there is no method to relay the information. The IVR is available 24 hours a day, 7 days a week, including holidays. The IVR will be directly connected to the Customer Information System (CIS) and will allow customers to access information about their accounts and power outages in real-time. The IVR will allow better accessibility to customers without internet or those who prefer to use the phone.

Comparative Information on Equivalent Historical Projects (if any):

N/A

Risks to Completion and Risk Mitigation:

The risks to completion include delays in IVR RFP and installation. To mitigate the risk, a project timeline will be created.

Total Capital and OM&A Costs for Renewable Energy Generation portion of project (if any):

N/A

CAPITAL PLAN	CUSTOMER CARE		2016
		System Type	GENERAL PLANT
Job Request / Number:			
Project Name:	Installation - Interactive Voice Response System (IVR)		
Project Category:			Non-Construction - General

Evaluation Criteria and Information

1. Efficiency, Customer Value, Reliability

Main Driver:

The main drivers to the IVR installation is Business Operations Efficiency and Customer Value. The IVR will provide customers with a method to access generic account information (such as current balances, due dates, consumptions, read dates) without having to wait in the queue for a CCR. The IVR will reduce the number of calls

Priority & Reasons for Priority:

Qualitative & Quantitative Analysis of Project and Project Alternatives:

HHHI tracks customer calls through a Contact Management system. When a call comes into Customer Care, the CCR logs the call using a specific call type that indicates the reason for the call. It is expected that by performing trend analysis on all call types before the IVR and after the IVR, an accurate analysis of the IVR effectiveness can be accomplished.

Other:

2. Safety

N/A

3. Cyber-security, Privacy

The IVR chosen will conform to all HHHI cyber-security and privacy protocols.

4. Coordination, Interoperability

N/A

5. Economic Development

N/A

6. Environmental Benefits

The IVR will provide a more efficient use of existing technologies by interfacing with the CIS for real-time information.

7. Customer Control (Smart Grid Objective)

Access:

The IVR will provide greater access of information to all customers.

Visibility:

Customers will have another method of receiving information using the IVR.

Control:

Real time information may aid customers in determining ways to control costs and consumptions.

Participation in Renewables:

N/A

Customer Choice:

The IVR provides another channel for customers to interact with HHHI.

Education:

N/A

8. Power System Flexibility (Smart Grid Objective)

Distributed Renewables:

N/A

Visibility:

N/A

Control and Automation:

N/A

Quality:

N/A

9. Adaptive Infrastructure (Smart Grid Objective)

Flexibility:

N/A

Forward Compatibility:

The IVR RFP will include the interface to HHHI's CIS system and consideration will be given to additional interface capabilities.

Encourage Innovation:

Halton Hills HYDRO	**CAPITAL PLAN**	**CUSTOMER CARE**	**2016**
		System Type	**GENERAL PLANT**
	Job Request / Number:		
	Project Name:	**Installation - Interactive Voice Response System (IVR)**	
	Project Category:		**Non-Construction - General**

Outcomes

1. Customer Focus

Service Quality:

The IVR will improve calls answered on time and call abandon measures.

Customer Satisfaction:

The IVR can improve first contact resolution and accessibility.

2. Operational Effectiveness

Safety:

N/A

System Reliability:

N/A

Asset Management:

N/A

Cost Control:

Potential to limit the need for additional CCRs.

3. Public Policy Responsiveness

CDM

N/A

Connection of Renewable Generation

N/A

4. Financial Performance

Financial Implications

Potential to limit the need for additional CCRs thus limiting increases to OM&A.

Third Party Planning

1. Regional (IESO Regions)

N/A

2. Regional (geographic)

N/A

3. Municipal

N/A

4. Other

N/A

5. Transmitter

N/A

Other Information

1. Factors Affecting Project Timing

2. Implications of NOT Implementing

3. Alternatives Considered & Reason for Not Implementing

An alternative is on-line account information. HHHI has already implemented Account On-Line with full accessibility, however, the on-line option does not address the retrieval of information during a power outage or customers who do not have on-line availability. Another alternative is the status quo. The status quo will merely continue providing the same level of customer service as customers have been receiving, with no improvement. Customers want many different options to access information, including an IVR.

Halton Hills HYDRO	CAPITAL PLAN	CUSTOMER CARE	2016
		System Type	GENERAL PLANT
	Job Request / Number:		
	Project Name:	Installation - Interactive Voice Response System (IVR)	
	Project Category:		Non-Construction - General

Images

Project Authorization

Prepared by:		Authorized By:	
Date:		Assigned To:	
		Assigned Date:	
		Completion Date:	

Change History

Date	Section	Change		Reason	Change Authorized by:

Halton Hills HYDRO	**CAPITAL PLAN**	**OPERATIONS**		**2016**
			System Type	**GENERAL PLANT**
	Job Request / Number:			
	Project Name:	**Trucking - non construction capital**		
	Project Category:			**Non-Construction - Vehicles**

Reference

Quadra Division:				
Job Request Number:				
Job Number:				
Project Name:				Trucking - non construction capital
Project Category:				Non-Construction - Vehicles
System Type:				GENERAL PLANT
Priority Ranking:				4
Risk Ranking:	*Impact:* 4		*Probability:* 2	**8**
Customer Attachments/Load:				
Project Designer/Manager:		Don Matthews		
Start Date:		May, 2016		
In Service Date:		June 2016 & July, 2017		

Estimated Costs

Description		**Estimated Cost**	**Notes**			**Estimated Expenditure Timing**
Labour:	$	-		Q1	$	-
Materials:	$	-		Q2	$	35,000
Equipment:	$	145,000		Q3	$	110,000
Contract Labour:	$	-		Q4	$	-
Other:	$	-				
				Carry-over:	$	-
Non-construct capital						
Total Estimated Cost	**$**	**145,000**		Total:	$	145,000
Recoverable:						
HHHI Estimated Cost	**$**	**145,000**		Control	$	-
					$	145,000

General Information

Project Summary/Description:

$110,000 to purchase chassis in Q3 for new digger derrick in 2016, boom and body to be purchased in 2017. Costs spread over 2 years to balance spending over a ten year period for fleet purchasing. Also $35,000 is budgeted in Q2 for a new Engineering/Metering vehicle as we currently have 7 employees sharing 3 vehicles in our Engineering & Metering departments.

Comparative Information on Equivalent Historical Projects (if any):

Historically chassis prices can range between $85,000 to $110,000 depending on the size of vehicle to be manufactured. We will be replacing our dual axle (large) digger derrick in 2017 so our chassis will need to be able to accommodate this heavy vehicle. We must also take into consideration the exchange rate on the US dollar as the chassis's are manufactured in the United States. Small vehicle fleet purchases range between $25,000 and $50,000. We will be considering electric & hybrid vehicles for our Engineering/Metering department. We also purchase AWD or 4x4 vehicles for safety reasons due to the environment and road conditions that these vehicles are subjected to. ie subdivisions under construction, unassumed roads, winter driving conditions etc.

Risks to Completion and Risk Mitigation:

Provided we follow our 20 year fleet replacement plan we have a relatively balanced dollar value budgeted for each year to avoid hills and valleys in spending while maintaining a 10 year replacement for small fleet vehicles and a 12 year replacement for large fleet vehicle formula. If a budgeted purchase is deferred for any reason the costs associated to the deferred purchase are added to the following years non construction capital budget as these costs do not go away. Maintaining post end of life fleet vehicles directly affects our OM&A budget as well as creating downtime for the employees that rely on our fleet vehicles to perform their duties safely and efficiently.

Total Capital and OM&A Costs for Renewable Energy Generation portion of project (if any):

Halton Hills HYDRO	CAPITAL PLAN	OPERATIONS	2016
		System Type	GENERAL PLANT
	Job Request / Number:		
	Project Name:	Trucking - non construction capital	
	Project Category:		Non-Construction - Vehicles

Evaluation Criteria and Information

1. Efficiency, Customer Value, Reliability

Main Driver:
To maintain a reliable fleet in order to provide a robust distribution system while managing OM&A costs at an acceptable level

Priority & Reasons for Priority:
A properly equipped, reliable and maintained fleet is essential for safely and efficiently completing daily tasks of the Operations, Engineering & Metering departments

Qualitative & Quantitative Analysis of Project and Project Alternatives:
In accordance with Halton Hills Hydro's standard practise, we replace our small fleet vehicles after 10 years of service and our large fleet vehicles after 12 years service.

Other:

2. Safety
To provide our employees with the appropriate tools and equipment to safely and efficiently perform their duties

3. Cyber-security, Privacy

4. Coordination, Interoperability

5. Economic Development

6. Environmental Benefits
We will consider hybrid or electric vehicles when replacing our Engineering/Metering vehicles. If it makes good business sense to pursue this option we will.

7. Customer Control (Smart Grid Objective)
Access:

Visibility:

Control:

Participation in Renewables:

Customer Choice:

Education:

8. Power System Flexibility (Smart Grid Objective)
Distributed Renewables:

Visibility:

Control and Automation:

Quality:

9. Adaptive Infrastructure (Smart Grid Objective)
Flexibility:

Forward Compatibility:

Encourage Innovation:

CAPITAL PLAN	OPERATIONS		2016
		System Type	GENERAL PLANT
Job Request / Number:			
Project Name:	Trucking - non construction capital		
Project Category:			Non-Construction - Vehicles

Outcomes

1. Customer Focus

Service Quality:

To have the fleet vehicles required to safely maintain our system and react to power interruptions in a timely manner

Customer Satisfaction:

To construct and maintain our distribution system in order to reduce the number of power outages as well as reducing the duration of outages when they occur

2. Operational Effectiveness

Safety:

To have the appropriate equipment to work on energized conductors in a safe and efficient manner

System Reliability:

To react to disturbances in our system in a timely manner

Asset Management:

Cost Control:

Maintaining an 10/12 year plan for small/large fleet vehicles while monitoring OM&A costs and balancing spending over 20 years for our entire fleet.

3. Public Policy Responsiveness

CDM

Connection of Renewable Generation

4. Financial Performance

Financial Implications

Third Party Planning

1. Regional (IESO Regions)

2. Regional (geographic)

3. Municipal

4. Other

5. Transmitter

Other Information

1. Factors Affecting Project Timing

Timelines to build a new unit once budget approval and order is placed approx 10 to 12 months for large fleet vehicles

2. Implications of NOT Implementing

Maintaining current fleet licensing, di-electric testing and OM&A costs on unit to be replaced

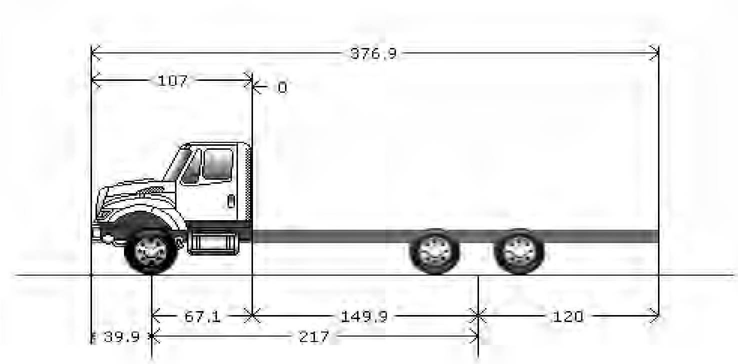
3. Alternatives Considered & Reason for Not Implementing

Extending our 10/12 year life cycle for vehicles - not implemented due to reliability issues/down time, increased OM&A costs associated to maintenance issues, corrosion control for vehicle bodies, trade in value/depreciation etc.

CAPITAL PLAN	**OPERATIONS**		**2016**
		System Type	GENERAL PLANT
Job Request / Number:			
Project Name:	Trucking - non construction capital		
Project Category:			Non-Construction - Vehicles

Images

Digger Derrick to be replaced in 2017



Chassis only in 2016

Engineering/Metering vehicle

Project Authorization

Prepared by:	Don Matthews	**Authorized By:**	
Date:	February 23, 2015	**Assigned To:**	
		Assigned Date:	
		Completion Date:	

Change History

Date	Section	Change		Reason	Change Authorized by:

CAPITAL PLAN	**ENGINEERING**		**2016**
		System Type	GENERAL PLANT
Job Request / Number:			
Project Name:	SCADA Outage Management System Interfaces		
Project Category:			HHHI Directed

Reference

Quadra Division:				CAP - HHHDIRECT
Job Request Number:				
Job Number:				
Project Name:				SCADA Outage Management System Interfaces
Project Category:				HHHI Directed
System Type:				GENERAL PLANT
Priority Ranking:				4
Risk Ranking:	*Impact:* 4		*Probability:* 3	12
Customer Attachments/Load:				
Project Designer/Manager:				
Start Date:				
In Service Date:				

Estimated Costs

Description	Estimated Cost	Notes		Estimated Expenditure Timing
Labour:	$ 2,813		Q1	$ 16,953
Materials:	$ -		Q2	$ 50,860
Equipment:	$ -		Q3	$ -
Contract Labour:	$ 65,000		Q4	$ -
Other:	$ -			
			Carry-over:	$ -
Non-construct capital				
Total Estimated Cost	**$ 67,813**		Total:	$ 67,813
Recoverable:	$ -			
HHHI Estimated Cost	**$ 67,813**		Control	$ -
				$ -

General Information

Project Summary/Description:
This project involves the purchase of new software interface licenses for the SCADA system and contract services for implementation of a SCADA based outage management system. In order to give the control room operators greater ability to find faulted portions of the system, greater imformation needs to be brought into the real time SCADA database from customer information systems, Advanced Metering Infrastructure, among others.

Comparative Information on Equivalent Historical Projects (if any):
N/A

Risks to Completion and Risk Mitigation:
Alignment with upgrades to other corporate information systems
Total Capital and OM&A Costs for Renewable Energy Generation portion of project (if any):
n/a

1. Efficiency, Customer Value, Reliability
Main Driver:
Efficiency and future automation are the main drivers for this project. Quicker response time to power interruptions and better guidance to field crews will increase efficiency. Better outage reporting will improve reliability metrics over the long term. Customers will benefit from faster restoration times.

Priority & Reasons for Priority:
Priority ranking is listed at 4 since many automated switches have already been installed and operators now require better system visibility for finding faulted sections of line

Qualitative & Quantitative Analysis of Project and Project Alternatives:
The continued investment in distribution automation will improve system reliability by reducing outage times due to remote operator intervention, and icrease cost efficiencies by reducing on site operator visits during switching. Benefits to customers would be the utility ability to better monitor the feeders during peak loading conditions and ensure optimum power quality is delivered.
Other:
N/A

2. Safety
Halton Hills Hydro constructs projects to current standards approved as required by O.Reg. 22/04. Construction done per standards will protect the public. Outage Management systems collect outage related data from many information systes. Such information can be used by the utility office and control room identify potential fault locations and allow the operation of itellegent switches during outage situations. Levels of control and safeguards are designed into the system to create safer working environments for lines staff.

3. Cyber-security, Privacy
OMS is accessed through computer software and the SCADA system. Users must have the specific software, user name, and passwords to access switch programming. These security features are in place to lessen the potential for intrusion.

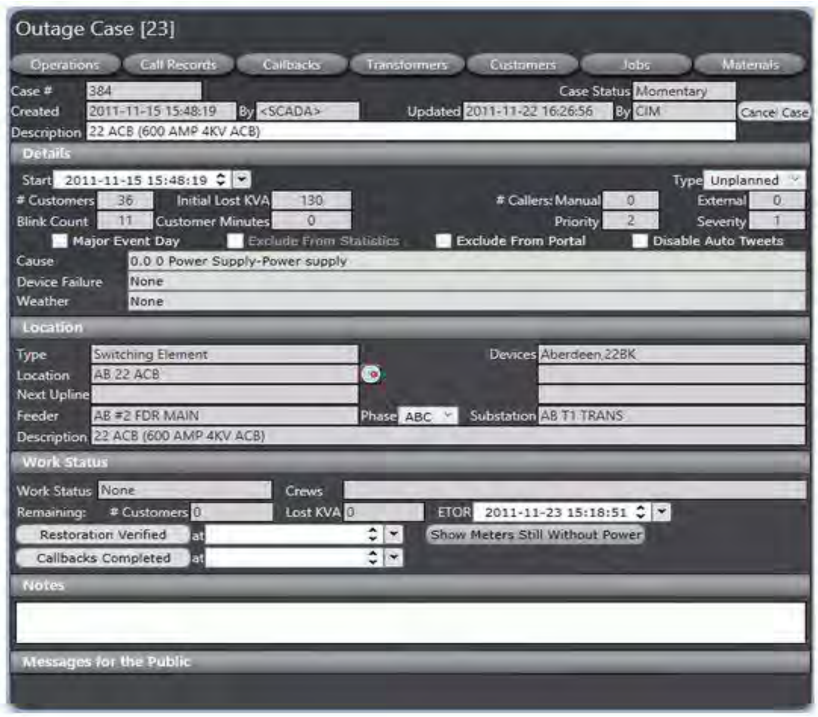
4. Coordination, Interoperability
Many local distribution companies now utilize OMS. When connected to our SCADA system, OMS will aid operators with isolating faults and restoring power remotely in advance of field crews arriving on site to make repairs.

5. Economic Development
Faster fault finding and isolation/restoration will instill confidence in the electricty supply and attract/retain local businesses and residents

Evaluation Criteria and Information	***6. Environmental Benefits*** OMS can reduce the need to dispatch line staff in vehicles to verify status manually. In doing so less emissions will enter the atmosphere.
	7. Customer Control (Smart Grid Objective) **Access:** n/a **Visibility:** n/a **Control:** n/a **Participation in Renewables:** n/a **Customer Choice:** n/a **Education:** n/a
	8. Power System Flexibility (Smart Grid Objective) **Distributed Renewables:** Enabling communication with the utility SCADA system will allow faster restoration of power to areas affected by interruptions. Switching routines could enable renewable generation on affected feeders to be reconnected and continue operations. **Visibility:** OMS enables greater visibility into the status of the distribution system for operators in real time . This enables better decicion making and faster response to outages along with faster restoration. **Control and Automation:** Additional switching functionality may be realized in the future with the added benefit of automated fault restoration schemes driven by the OMS engine. **Quality:** OMS systems allow real time access to power flows and voltage levels, enabling operators to monitor and maintain effective power quality
	9. Adaptive Infrastructure (Smart Grid Objective) **Flexibility:** Distribution automation provides flexibility by allowing the utility to restore power to areas affected by power interruptions. This can help the implementation of innovative technologies such as electric vehicle charging stations, public or private, and will help customers feel their utility power supply is supportive of innovative technologies that they already use or are considering purchasing. **Forward Compatibility:** The software and firmware used for FCis is normally upgradable. **Encourage Innovation:** OMS is used to identify faulted portions of the distribution system and restore power in an expedient manner, customers who are exploring innovative technologies such as electric vehicles, stoage or who are interested in generations may elect to invest in new technology knowing their power supply is reliable. OMS would assist the utility in keeping customers informed and up to date on the status of the distribution system during outages and restoration efforts
Outcomes	***1. Customer Focus*** **Service Quality:** OMS provides the opportunity to monitor power quality, improve customer communications and verify status of distribution equipment **Customer Satisfaction:** Improved system reliability and more timely attention to power quality issues will contribute to enhanced customer satisfaction
	2. Operational Effectiveness **Safety:** Crew safety will be enhanced by remotely monitoring the state of equipment and coordinating outage response **System Reliability:** OMS can help reduce outage times by enabling quick identification of faulted sections, and restoration through automated routines or remote operations. **Asset Management:** OMS can enable automatic reporting of outage causes for later analysis. This data may be used to support equipment upgrades and lifeand smart controls enable **Cost Control:** OMS will enable a reduction in O&M expenditures by tabulating operational outage data automatically. Post outage analysis may be carried out to support maintenance and capital expenditure reduction.Remote monitoring will also reduce costs that normally result from time spent by field staff patrolling lines in seach of faults.
	3. Public Policy Responsiveness **CDM** n/a **Connection of Renewable Generation** n/a
	4. Financial Performance **Financial Implications** Integration of OMS will enable remote monitoring and control by either control room staff or pre-programmed routine. Predictive fault location will reduce the amount of time utility field staff spend in the field patrolling lines and performing switching operations to restore power or re-configure the distribution system. An overall reduction in operating costs will result.
lanning	***1. Regional (IESO Regions)*** N/A
	2. Regional (geographic) N/A

Third Party P	***3. Municipal*** N/A
	4. Other Halton Hills Hydro will advise telecommunication companies of the project and if necessary coordinate any relocation work with affected parties.
	5. Transmitter N/A
Other Information	***1. Factors Affecting Project Timing*** The main factor affecting timing will be the verification of the system model and state of readiness for insformation sytesms that the OMS would need to connect to.
	2. Implications of NOT Implementing By not implementing the project, Halton Hills Hydro will continue to spend more time manually locating faults and continue to incure higher operating costs and experience lower reliability.
	3. Alternatives Considered & Reason for Not Implementing N/A

Images



Project Authorization

Prepared by:		**Authorized By:**	
Date:		**Assigned To:**	
		Assigned Date:	
		Completion Date:	

Change History					
Date	**Section**	**Change**		**Reason**	**Change Authorized by:**

AESI

www.aesi-inc.com
aesi@aesi-inc.com

August 18, 2015

Jennifer Gordon
Halton Hills Hydro Inc.
43 Alice Street
Acton, ON L7J 2A9

Dear Reader:

Re: Consolidated Distribution System Plan

As part of the filing requirements set out by the Ontario Energy Board (OEB) for Distributor's, Halton Hills Hydro Inc. has prepared the attached Consolidated Distribution System Plan. The Plan was prepared in accordance with Good Asset Management Practice, Good Utility Practice and the current Chapter 5 Filing Requirements. Halton Hills Hydro Inc. prepared the data and furnished the information contained in the plan.

AESI critiqued this plan and confirms that it addresses the goals and achieves the purpose of the OEB ***Chapter 5 Consolidated Distribution System Plan Filing Requirements*** dated March 28, 2013.

Sincerely,

Acumen Engineered Solutions International Inc.

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