December 3, 2018

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
27th Floor/ P.O. Box 2319
2300 Yonge St.
Toronto, ON M4P 1E4

Dear Ms. Walli:

Re: Incremental Capital Module Rate Application,
Halton Hills Hydro Inc.,
Board File no. TBD

Halton Hills Hydro Inc. ("HHHI") is filing its Incremental Capital Module ("ICM") Rate Application with the Ontario Energy Board ("the Board"). HHHI is submitting its ICM Rate Application in accordance with all directives and guidelines issued by the Board. HHHI is requesting an effective date of May 1, 2019 for the implementation of the Proposed Incremental Revenue Requirement Rate Riders.

The ICM Rate Application includes:

- Manager's Summary (pdf)
- 2018_Capital_Module_ACM_Model Version 4_20 (Excel)
- Off-line Rate Rider Calculations (Excel)
- Off-line Bill Impact Calculations (Excel)

Please find attached to this cover letter:

- 2 paper copies of the ICM Rate Application; and
- 1 electronic copy of the ICM Rate Application.

A copy of the Application has also been filed through the Web Portal.

In the event of any additional information, questions or concerns, please contact David Smelsky, Chief Financial Officer, at dsmelsky@haltonhillshydro.com or (519) 853-3700 extension 208, or Tracy Rehberg-Rawlingson, Regulatory Affairs Officer, at tracyr@haltonhillshydro.com or (519) 853-3700 extension 257.

Sincerely,

(Original signed)

David J. Smelsky, CPA, CMA, C. Dir.
Chief Financial Officer, HHHI

Cc: Arthur A. Skidmore, President & CEO, HHHI

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IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O.1998, c. 15, (Schedule B);

AND IN THE MATTER OF an application by Halton Hills Hydro Inc. to the Ontario Energy Board for an Order or Orders approving or fixing just and reasonable rates and other charges for electricity distribution to be effective May 1, 2019.

HALTON HILLS HYDRO INC. ("HHHI") APPLICATION FOR APPROVAL OF INCREMENTAL REVENUE REQUIREMENT RECOVERY THROUGH RATES

MANAGER'S SUMMARY

Filed: December 3, 2018

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APPLICATION FOR APPROVAL OF INCREMENTAL REVENUE REQUIREMENT RECOVERY THROUGH RATES

MANAGER'S SUMMARY

Introduction

a) The Applicant is Halton Hills Hydro Inc. ("HHHI"). HHHI is a corporation incorporated pursuant to the *Ontario Business Corporations Act* and located in the Town of Halton Hills (Acton). HHHI carries on the business of distributing electricity pursuant to HHHI's Electricity Distribution Licence ED-2002-0552.

b) HHHI hereby applies to the Ontario Energy Board ("the Board") pursuant to section 78 of the *Ontario Energy Board Act, 1998* as amended (the "OEB Act") for approval of proposed incremental revenue requirement recovery, as it relates to the building of a Municipal Transformer Station, through rate riders effective May 1, 2019.

c) HHHI is applying for a rate adjustment under the Incremental Capital Module ("ICM").

d) HHHI has followed the Instructions provided in the *Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors (*the "July 2008 Report of the Board"*)*, the *Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors - EB-2007-0673* (the "Supplemental Report"), the *Report of the Board – New Policy Options for the Funding of Capital Investments: The Advanced Capital Module – EB-2014-0219* and the *Supplemental Report dated January 22, 2016* (together the "September 2014 Report") in relation to the incremental capital recovery request in addition to Chapter 3 of the Filing Requirements For Electricity Distribution Rate Applications - 2017 Edition for 2018 Rate Applications ("Filing Guidelines").

e) HHHI has completed the Capital Module Applicable for ACM and ICM - Version 4.0 as revised by Board Staff for HHHI's filing. HHHI confirms the accuracy of the billing determinants entered in the models.

f) HHHI is applying for Revenue Requirement Recovery related to the ICM application for a new transformer station (the "TS") that will be commissioned in 2019.

g) HHHI is applying for and requesting that the Board deem the TS to be a distribution asset pursuant to section 84(a) of the OEB Act in order that HHHI may recover the revenue requirement related to the TS through distribution rates.

h) HHHI is applying for an exemption to the general ICM policy in order to recover incremental Operating, Maintenance and Administration ("OM&A") costs in relation to the TS.

i) HHHI is applying for recovery of annual incremental OM&A costs related to the TS.

j) 2019 will be HHHI's third (3rd) year of its five (5) year IRM period.

k) HHHI is applying for a Deferral and Variance Account to track the costs and recovery of the TS for purposes of truing up the variance at the next Cost of Service.

l) HHHI has provided additional information in this Application (the "Application") where HHHI has determined that such information may be useful to the Board.

Notice of Application

HHHI will publish the Notice of Application as per directions issued by the Board Registrar, if required.

Current Tariff of Rates and Charges

HHHI has provided in **Appendix A**, a copy of its approved Tariff of Rates and Charges, effective May 1, 2018 and issued by the Board on April 26, 2018.

Background

In 2007, HHHI's load forecasts first identified the need for a new source of transmission supply. At that time, HHHI, together with the Town of Halton Hills, worked with the planned TransCanada Energy Halton Hills Generating Station ("HHGS") to identify a parcel of land adjacent to the new HHGS for possible construction of a new HHHI TS.

The agreement with the HHGS was to build a transformer station on the land adjacent to the generating station and connect to the transmission system via HHGS's 230kV switchyard. Initial discussions with the IESO also began in 2007 to determine if the option of a unique connection arrangement with HHGS could be accommodated. Supply options, feasibility studies and alternative site studies were also completed. A Class Environmental Assessment was commenced, and corresponding Public Information Centres took place in 2008.

Due to the economic decline in late 2008, HHHI took the prudent approach and deferred work on a transformer station until such time as a revised load forecast, adjusted for the economic downturn, predicted the need.

In 2011, work recommenced on the transformer station. By that time, it became apparent to HHHI that avoiding the cost of tunneling under the King's Highway 401 (the "401") (by connecting to HHGS) represented a potentially significant capital cost saving. However, because of the unique nature of connecting to HHGS, HHHI met with the OEB and the provincial Ministry of Energy to determine the regulatory barriers to the connection.

In July 2013, Ontario Regulation 219/13 was made, exempting the HHGS from requiring an Electricity Transmission Licence. Part of this Regulation stipulated that a connection agreement was to be entered into by TransCanada (HHGS) and the distributor (HHHI). The HHGS and HHHI filed the Form of Connection Agreement with the Board in November 2013. The Board's authority under the Regulation was to reject (or not) the TransCanada – HHHI connection agreement. This arrangement, the first of its kind in Ontario, provided significant cost savings to rate payers over the other options that required the need to bring new transmission supply north, under the 401.

In February 2015, the Board issued a letter indicating that they would not reject the connection agreement. This assurance allowed HHHI to begin moving forward with the purchase of land, the design and construction of the TS. The land purchase (at the agreed upon 2007 price) was finalized in November of 2015.

In August 2015, HHHI filed its 2016 to 2020 Distribution System Plan ("DSP") as part of HHHI's 2016 Cost of Service rate application (EB-2015-0074). The DSP provided a comprehensive strategy for asset maintenance and capital expenditure over a five (5) year period covering 2016 to 2020.

HHHI's mission statement, "*To Provide Halton Hills with Electricity Distribution Excellence in a Safe and Reliable Manner*" provided the overall vision that guided the creation of the DSP. Safety and reliability are top priorities for the utility and are two key ways HHHI strives to provide distribution excellence to customers. The DSP was built on the principles of excellence, safety and reliability and takes a prudent, cost effective approach to infrastructure investment and renewal to try to serve current and future customer preferences and requirements.

The DSP provided a comprehensive strategy for asset management as well as prudent, cost effective guidance for planned capital project expenditure over the five (5) years between Cost of Service applications. HHHI developed a detailed Asset Management Strategy which informed the Asset Management Process section of the DSP and also provided a detailed capital expenditure plan which supports asset management, accommodates third party requirements and plans for significant growth and technological improvements.

The Capital Expenditure portion of the DSP provided an analysis of the historical five (5) year period as well as forecasted costs for the life of the DSP. Projects were categorized as System Access, System Renewal, System Service and General Plant. Within each category and across categories, projects were assigned a risk ranking and a priority to help HHHI with resource planning and budgeting.

The DSP did not include the request for an Advanced Capital Module for the construction of the new TS as budgetary numbers were still very preliminary and not sufficiently robust for inclusion in the DSP at that time. The DSP did provide details identifying the need for the TS in addition to the prudent investment strategy that included a number of projects that would enable supply from the new station. The DSP also clearly indicated that the capital requirement for the station would be filed as a separate ICM module.

As stated in section 1.1.6 of the DSP:

> "*As the capital requirement for this project is significant, HHH intends to file a separate Incremental Capital Module (ICM) for associated expenditures rather than including in this Distribution System Plan. Many of the projects outlined in this Distribution System Plan are required to enable the supply from this new Transformer Station. Where possible, projects will include the addition of circuits to existing poles that have already been replaced or installed as part of voltage conversion projects or regional road activities. Some voltage conversion projects may be accelerated or placed in a high priority to ensure that new circuits are available to make use of the MTS capacity as it becomes available.*"

On March 4, 2016, Board Staff submitted their comments on the Settlement Proposal in HHHI's Cost of Service application (EB-2015-0074). In their comments, Board Staff stated "OEB staff does note that the OEB retained the ICM for the IR years for projects not included in a DSP filed with the most recent cost of service application, and for projects that were included in the DSP but which did not contain sufficient information at the time of the cost of service application to address need and prudence" in response to HHHI not submitting estimated numbers for TS as part of an Advanced Capital Module in the Cost of Service application.

In June 2017, HHHI updated its load forecast to verify the required in service date for the TS and to ensure prudent and timely spending. The updated load forecast confirmed a required in-service date of 2019.
Town of Halton Hills Site Plan Approval and Building Permits were received in 2017 and site construction started in the fall of that year. Major equipment, consulting, engineering and construction services were all purchased

through a Request for Proposal process. Criteria for selecting vendor's bids were based on consultant and design engineer recommendations, prior LDC experience and industry reputation.

The completed TS will receive final commissioning and energization in the spring of 2019. The timing of energization needs to coincide with TransCanada Energy's spring maintenance outage window.

Engineering and Construction

On February 9, 2015, HHHI received a letter from the Board indicating that the Board will not make an order rejecting the Connection Agreement between HHHI and TransCanada Energy HHGS. This was the key milestone required to commence work on the station. In 2015, a project consultant was brought on board to assist HHHI in retaining appropriate engineering services and to assist with procurements of major equipment and construction services. An RFP for professional engineering services to complete station design was issued later that same year. Detailed design began in 2016 and applications for IESO System Impact Assessment (SIA) and Hydro One Customer Impact Assessments (CIA) were completed by the end of 2016.

Construction of the TS required work both on the HHHI owned property and within the switchyard of the adjacent HHGS to facilitate the connection. Work within the HHGS switchyard had to be coordinated with scheduled plant maintenance shutdown windows. As such, the first construction within the switchyard was completed in April 2017. It was critical to commence work at this time to ensure that all of the required construction within HHGS's site could be completed within the available shut down windows to ensure the in service date of spring of 2019 could be met. The work completed in April of 2017 was the installation of concrete foundations for switches and breakers to be installed during the next maintenance window.

The Site Plan Approval process with the Town of Halton Hills began with the pre-consultation process in 2016. Agencies involved in the approval process included the Town of Halton Hills, Halton Region and Conservation Halton. Final Site Plan Approval was received in August 2017 and the Building Permit for the Switchgear Building was received in November 2017.

Major equipment with long lead times was ordered in 2017. The purchase order for the two power transformers was issued in June 2017 for delivery in September 2018. The purchase order for medium voltage switchgear was issued in December 2017 for delivery in October 2018.

Eptcon Ltd. was awarded the contract for general construction at the end of August 2017. Initial site clearing and grading began that fall as permitted by the approvals received. Steel structures, switches and breakers were installed during the fall HHGS maintenance window. Construction on the TS site began in earnest in 2018. Construction on the switchgear building began in the spring of 2018.

Major equipment, consulting, engineering and construction services were all purchased through a Request for Proposal process. Criteria for selecting vendor's bids were based on consultant and design engineer recommendations, prior LDC experience and industry reputation.

During the fall maintenance window at HHGS, protection and control work was completed including the commissioning of newly installed breakers and switches, registration with the IESO and Hydro One COVER.

Construction will be completed in early 2019 with final commissioning and energization planned to coincide with HHGS's 2019 spring maintenance outage window.

Criteria

In the July 2008 Report of the Board, the Supplemental Report, and the September 2014 Report, the OEB established three tests for eligibility for an ICM application: Materiality, Need and Prudence.

Materiality

There are two materiality tests related to ICM applications.

Materiality Threshold

The first test is the ICM materiality threshold formula, which serves to demonstrate the level of capital expenditures that a distributor should be able to manage within current rates. The test states that: "Any incremental capital amounts approved for recovery must fit within the total eligible incremental capital amount" and "must clearly have a significant influence on the operation of the distributor". The materiality threshold is determined by the following formula:

$$Threshold\ Value\ (\%) = \left(1 + \left[\left(\frac{RB}{d}\right) \times \left(g + PCI \times (1+g)\right)\right]\right) \times \left((1+g) \times (1+PCI)\right)^{n-1} + X\%$$

where n is the number of years since the cost of service rebasing. Many of the parameters remain unchanged from the original formula except for the following:

- the growth factor g is annualized
- the dead band X has been reduced to 10%
- the stretch factor used in the PCI will be the factor assigned to the middle cohort (currently 0.3%) for all distributors

HHHI states that it has appropriately calculated a materiality threshold of $1,859,883 using the Capital Module Applicable for ACM and ICM - Version 4.0 as revised by Board Staff for HHHI's filing. The threshold calculation can be found on Tab "9. Threshold Test" on the ICM attached as **Appendix B**.

Eligible Incremental Capital

The Board adopted a second, project-specific materiality test in the Funding of Capital Report. The project-specific materiality test is as follows: "Minor expenditures in comparison to the overall capital budget should be considered ineligible for ACM or ICM treatment. A certain degree of project expenditure over and above the Board-defined threshold calculation is expected to be absorbed within the total capital budget". HHHI has provided **Table 1** to show a comparison between the summary of capital expenditures as approved in HHHI's 2016 Cost of Service Settlement Proposal (Appendix B) and actual capital expenditures as audited for 2016 and 2017 in addition to the revised budgeted capital expenditures for 2018, 2019 and 2020.

Table 1 - Capital Expenditure Comparison 2016-2020

Year	2016	2017	2018 (forecast)	2019 (budget)	2020 (DSP)	Total	Average
	($)	($)	($)	($)	($)	($)	($)
Estimated Capital Expenditure from DSP	7,708,601	7,408,324	7,788,106	7,893,817	8,149,827	38,948,675	7,789,735
Capital Expenditures	9,539,998	11,095,939	6,902,214	7,159,383	7,000,000	41,697,534	8,339,507
Sub-total - Variance	**1,831,397**	**3,687,615**	**(885,892)**	**(734,434)**	**(1,149,827)**	**2,748,859**	**549,772**

HHHI calculated the Eligible Incremental Capital using the ICM and as shown on Tab "10. Proposed ACM ICM Projects" (**Appendix B**). The eligible incremental capital calculated amount for HHHI is $28,775,942 based on total 2019 total DSP capital expenditures in the amount of $30,635,824 less a materiality threshold of $1,859,883 as shown in **Table 2**.

Table 2 - Eligible Incremental Capital

Eligible Incremenal Capital	Capital Expenditures
Forecasted 2019 Capex	7,159,383
Incremental Capital - TS	23,476,441
Total 2019 Capex	**30,635,824**
Less: Materiality Threshold	1,859,883
Maximum Eligible Incremental Capital	**28,775,942**

The incremental revenue requirement corresponding to the incremental capital amount of $23,476,441 is $1,698,085 as calculated on Tab "11. Incremental Capital Adj." and shown in **Appendix B**. The revenue requirement approved in HHHI's 2016 Cost of Service application and adjusted for depreciation in HHHI's 2018 IRM (EB-2017-0045) is $10,458,405. The OEB is guided by the words "significant influence on the operation of the distributor" and "minor expenditure in comparison to the overall capital budget" in assessing project specific materiality. The incremental revenue requirement is equivalent to an increase of 16.2% over the 2016 revised Cost of Service revenue requirement, thus, materiality is evident.

Need

As stated in the Filing Guidelines, distributors "must pass the Means Test (as defined in the September 2014 Report). Amounts must be based on discrete projects, and should be directly related to the claimed driver. The amounts must be clearly outside of the base upon which the rates were derived".

Means Test

Page 15 of the September 2014 Report states "If the regulated return exceeds 300 basis points above the deemed return on equity embedded in the distributor's rates, the funding for any incremental capital project will not be allowed" and on page 16 of the September 2014 Report it states "a threshold of 300 basis points retains some flexibility for distributors to maximize their earnings while also recognizing that funding in advance of the next rebasing is likely not required from a cash flow perspective". **Table 3,** below, shows HHHI's Historical Regulated Return for the year prior to the 2016 Cost of Service to the most recently reported. HHHI's deemed Regulated Return is 9.19%. It is highly unlikely that HHHI will exceed the 300 basis points above the deemed return on equity embedded in rates.

Table 3 - Historical Regulated Return

Year	Deemed Rate of Return	Regulated Rate of Return	Variance
2015	8.82%	6.70%	-2.12%
2016	9.19%	6.76%	-2.43%
2017	9.19%	6.98%	-2.21%

Discrete Project

On page 13 of the September 2014 Report, the Board states that ICM requests "must be discrete projects, and not part of typical annual capital programs". The building of a transformer station is not part of a typical annual capital program for HHHI. In fact, the TS is the first transformer station that HHHI has built.

As stated on page 14 of the September 2014 Report, "The use of an ACM is most appropriate for a distributor that:

- does not have multiple discrete projects for each of the four IR years for which it requires incremental capital funding;
- is not seeking funding for a series of projects that are more related to recurring capital programs for replacements or refurbishments (i.e. "business as usual" type projects); or
- is not proposing to use the entire eligible incremental capital envelope available for a particular year."

HHHI does not have other discrete projects that will require incremental capital funding. HHHI is not seeking additional funding for a series of projects that are business as usual type projects. HHHI is not proposing to use the entire eligible incremental capital envelope available for 2019. Therefore, the ICM meets the discrete project requirement.

Outside of Rate Base

In HHHI's 2016 Cost of Service Application, the only expense that had been incurred was the purchase of land for the TS. As shown on the Summary of Proposed Changes tab in Appendix E of the Settlement Proposal in EB-2015-0074, the land purchase was excluded from rate base and not included in the 2016 approved rates. Therefore, all costs associated with the ICM request are clearly outside of the base upon which the rates were derived.

Prudence

Support of the Need for the TS

The need for HHHI to build a transformer station was identified in the IESO's Northwest Greater Toronto Area Integrated Regional Resource Plan (NWGTA Region IRRP Report) (**Appendix C**) published in April 28, 2015. As shown in Section 7.1.3.1:

> *"Option 3: 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."*

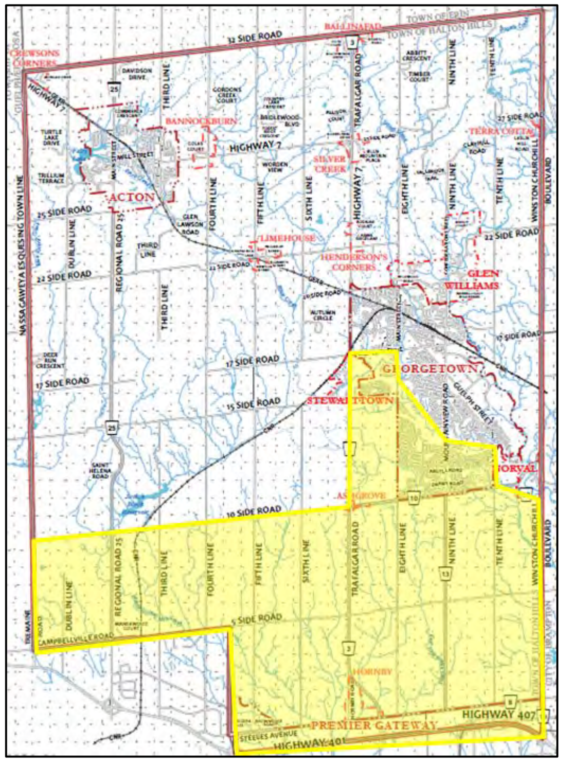
As identified through this regional planning process, the Hydro One Halton TS is nearing full capacity and there is not enough space to add new feeders.

While load forecasts as early as 2007 identified the need for a new transformer station, HHHI took the prudent step of conducting another load forecast prior to construction of the TS, to ensure the timing of station energization would coincide with load requirements. The load forecast considered historical growth, known planned growth and forecasted inclusion of the "Vision Georgetown" development. This load forecast, dated January 2017 and shown in **Appendix D**, focused on the 27.6kV distribution system and load forecast in the area of the proposed TS and supported the findings of the IESO's IRRP Report. The load forecast report identified the need for a new transformer station by the end of 2019.

The TS is required to meet near term load requirements and prepare for significant growth planned within the Town of Halton Hills. The TS will serve some existing but primarily new load in Georgetown South and the Steeles Avenue - Premier Gateway corridor to the north of Highway 401. In particular, and as a result of the "Ontario Places to Grow" legislation, the Vision Georgetown development will bring 20,000 people and 1,700 jobs to a 1,000 acre parcel in Georgetown with construction phased in between 2021 and 2031. This exceptional growth necessitates the need for new supply.

HHHI currently receives 27.6kV supply from three feeder positions at the Hydro One Halton TS. These feeders supply the Southern portion of HHHI's service territory including the Steeles Avenue Prestige Industrial Corridor, the Toronto Premium Outlets Premier Gateway corridor, Georgetown South and the surrounding rural area. Within the boundaries of this area are the lands slated for development of Vision Georgetown.

Figure 1 – Town of Halton Hills Map



As identified in the IESO's Northwest Greater Toronto Area Integrated Regional Resource Plan and supported by HHHI's load forecast, the Hydro One Halton TS and the three (3) HHHI feeders supplying HHHI in particular, are nearing capacity thus necessitating the new TS.

<u>Options</u>

HHHI determined there were three (3) possible options to increase the supply capacity to the region. The options and results are shown in **Table 4** below.

Table 4 - Study Options to Increase Supply

Option Description	Result	Reasoning
HONI expands HONI owned Halton TS	Unacceptable	Infrastructure limitation in the area does not allow additional feeders out of the HONI Halton TS into the HHHI service territory
Build a new TS	Accepted	Most prudent option to provide safe and reliable supply
Do nothing	Unacceptable	The existing supply will not meet the future increased electricity demand in the HHHI service territory

Once the decision was made to build a new transfer station, the evaluation of site options was conducted using the following criteria:

- *Technical*–Related to proximity to demand and transmission connection, available land size, availability of distribution circuits.
- *Environmental (Physical and Social)*–Related to terrestrial and aquatic ecology, existing/planned land uses, and cultural heritage.
- *Economic*–Related to total cost for completion (design and build) of TS with consideration for equipment required.

The following **Table 5** indicates the results of the site evaluations and the overall rankings.

Table 5 - Site Option Evaluation Results

Alternative Site Identification and Location	Technical	Environmental	Economic	Overall Ranking
1A North side of Steeles Avenue, near James Snow Parkway	Unacceptable	Low	Unacceptable	Unacceptable
1B South side of Steeles Avenue, near James Snow Parkway	Unacceptable	Unacceptable	Low	Unacceptable
1C South side of Steeles Avenue, near 5th Line North	Low	Low	Low	Low
2A South side of Steeles Avenue, near 5th Line South	Medium	Low	Low	Low-Medium
2B South side of Steeles Avenue, near 5th Line South (east of site 2A)	Unacceptable	Low	Low	Unacceptable
2C South side of Steeles, near 6th Line South (HHGS site)	**High**	**Medium**	**High**	**High-Medium**
2D South side of Steeles Avenue, forested area near 6th Line South (west of HHGS site)	Medium	Low	Low	Low-Medium
3A South side of Steeles Avenue, just west of Trafalgar Road	Medium	Unacceptable	Low	Unacceptable
3B South side of Steeles Avenue, just west of Trafalgar Road	Medium	Unacceptable	Low	Unacceptable
3C Trafalgar Road, south side of Highway 401	Unacceptable	Low	Low	Unacceptable
3D Trafalgar Road, Hornby Junction (ORC Lands) – South of Highway 401	Unacceptable	Medium	High	Unacceptable

High Acceptability – No effects are associated or anticipated for this site based on identified criteria.
Medium Acceptability – Few effects have been identified although the potential exists to prevent or mitigate these effects through implementation of measures and/or methodologies.
Low Acceptability - A number of effects have been identified although the potential for avoidance or mitigation is low.
Unacceptable – Effects or limitations identified are considerable (numerous) and mitigation or avoidance is not possible, therefore precluding the site consideration.

HHHI chose option 2C – HHGS Site to provide ongoing, reliable supply to serve existing customers and new growth within the Town of Halton Hills as it was the most cost effective solution that met the technical, environmental and economic criteria.

Customer Engagement

HHHI began customer engagement activities around the proposed TS in conjunction with the Class Environmental Assessment and review of alternative locations beginning in March 2008.

Customers and agencies were notified of the study commencement and invited to attend a Public Information Centre in May 2008. This Public Information Centre meeting was advertised in the local papers and customers and agencies were directly notified through letters. Customers and agencies were again notified at the completion of the study in August 2008.

The Public Information Centre provided the following information to customers, agencies and stakeholders:

i. Introduction of the MTS and the Class Environmental Assessment process
ii. Evaluation of alternative sites & reason for site selection
iii. Provide opportunity for public to become informed and to comment

A page dedicated to the TS is situated on HHHI's website. This page was launched in 2008 and includes information about where and why the TS is being constructed and includes copies of the Environmental Assessment report and the Public Information Centre materials.

In the 2016 Cost of Service (EB-2015-0074) Interrogatory Responses, Appendix B, HHHI included a letter from the Chief Administrative Officer, Town of Halton Hills, indicating that the Town of Halton Hills expected that HHHI would "be able to provide the necessary energy needs to Vision Georgetown prior to 2021". The letter is included in this Application as **Appendix E**.

Benefits

HHHI chose Option 2C as the least cost option that ensures reliability of supply for its customers. This option takes advantage of an innovative partnership with TransCanada Energy, the first of its kind in Ontario – enabled via a regulation passed by the provincial government. By utilizing an existing connection to Hydro One rather than building a new connection, several benefits are realized:

- Cost savings compared to building a new transmission connection crossing the 401.
- Cost savings related to land purchase and egress

- Reduced transformation costs for customers
- Reliable supply for new growth along Steeles Avenue and for the new Vision Georgetown subdivision which will add 20,000 customers to Georgetown South over a ten (10) year period.

By connecting to the transmission system through a new supply point rather than taking additional feeders from an existing point of supply, HHHI can provide improved reliability of service through additional switching options.

Planning and Cost Savings / Efficiencies / Avoidance

In planning for the new TS coming on line, HHHI ensured its distribution system would be ready to take advantage of the new supply through a number of projects that were identified in the 2016 DSP. Where possible, projects involving the addition of circuits to existing poles that were already replaced or installed as part of voltage conversion projects or regional road activities/projects were augmented rather than building new pole lines. Some voltage conversion projects were accelerated or given a higher priority to ensure that new circuits will be available to make use of the TS capacity as it becomes available.

HHHI has taken steps throughout the design and construction of the TS to create cost efficiencies. The site selection and unique connection to the transmission system through HHGS's switchyard provided significant cost savings over the option of connecting directly to Hydro One and requiring new transmission connections underneath the 401. The land purchase price for the site location was locked in at 2007 prices and resulted in considerable cost savings compared to the cost of land in the Steeles Avenue Prestige Industrial Corridor today.

Major equipment, consulting, engineering and construction services were all purchased through a Request for Proposal process. Vendors were invited to bid based on consultant and design engineer recommendations, prior LDC experience and industry reputation. Proposals were evaluated based on a scoring matrix that included relevant experience, ability to meet the technical requirements, reputation and price. Major equipment bids were evaluated by HHHI staff, design engineer and project consultant, with final approval by HHHI Executives and the HHHI Board of Directors. Each successful proponent was asked to find cost efficiencies wherever possible.

In an effort to maximize cost savings, the two largest pieces of equipment (power transformers and gas insulated switchgear) were purchased through a joint purchase agreement with another LDC also constructing a transformer station. Savings on the switchgear was 3% of the total cost and savings achieved on the cost of the power transformers was 1%. The combined cost savings was $74,504.32. Another cost saving opportunity was realized in the purchase of the 230kV primary cable required for the transmission connection. Typically, this specialized cable has a minimum purchase requirement. Through working directly with cable manufacturers, HHHI was able to save $22,000 through sourcing a cable length to meet our requirements.

Through diligent procurement and project management, overall costs have remained under budget.

Conclusion of Prudence

HHHI's mission statement is "*To Provide Halton Hills with Electricity Distribution Excellence in a Safe and Reliable Manner*". Safety and reliability are top priorities for HHHI and are two key ways HHHI strives to provide distribution excellence to customers. Capital expenditure decisions are built on the principles of excellence, safety and reliability and take a prudent, cost effective approach to infrastructure investment and renewal to try to serve current and future customer preferences and requirements. As evidenced above, HHHI needed to fill the need for the TS to ensure capacity and reliability to customers. In building the TS, HHHI used every means available to make cost effective decisions in order to limit the impacts to customers and rates. Thus, HHHI has proven its prudence in the incurring of the ICM costs.

Incremental Operating, Maintenance and Administration Costs

The July 2008 Report of the Board, the Supplemental Report and the September 2014 Report address only incremental capital expenditures. In many cases, incremental capital projects consist of only capitalized assets and the associated burdens and labour. However, in some cases, additional incremental operating, maintenance and administrative ("OM&A") costs are also incurred in the current year of the project and every year going forward.

The TS is an example of a capital expenditure that requires incremental OM&A costs each year going forward. Operating costs for the TS have been projected as an incremental cost driver for the period April 2019 to December 31, 2019 in the amount of $120,250 and then $131,515 annually in 2020. The costs considered include 24/7 monitoring by a third party control room, weekly and monthly inspections and preventable maintenance, property taxes and increase insurance costs. The incremental OM&A costs are shown in **Table 6** below.

Table 6 - Incremental OM&A Costs related to the TS

Description	April 2019 to December 31, 2019	January 1, 2020 to December 31, 2020
Training Costs[1]	$ 35,000	$ 5,000
TS Monitoring Costs TS Communication Costs[2]	18,750	25,000
Property taxes	27,750	38,110
Insurance & property protection	15,000	18,405
SCADA maintenance	3,750	5,000
Station maintenance[3]	20,000	40,000
Total	**$ 120,250**	**$ 131,515**

Notes:
[1] Training Costs - include initial training on Equipment operation, Protection and Control
[2] TS Monitoring Costs TS Communication Costs - Third Party Control Room, Fibre communications
[3] Station maintenance -$20,000 prior to expiry of warranty period

While the operating costs relating to the TS are direct increases to OM&A spending, it should be noted that customers will realize savings in monthly transformation connection costs as HHHI will be able to transfer some of the existing load to the new TS. In addition, customers will avoid additional transformation connection costs going forward as a result of HHHI supplying all new loads from the new TS. Both of these will mitigate the impact of the increased OM&A expenditure relating to the TS.

In its 2018 IRM application, HHHI requested additional rate riders to help off-set the cost of increased labour costs related to a pay-equity adjustment to wages. This request was denied, thus putting a strain on HHHI's OM&A envelope spending. For HHHI to further absorb $131,515 in additional and incremental OM&A costs, other programs may need to be reduced with a risk of decreased reliability.

ICM Model

HHHI has completed the 2018 Capital Module Applicable to ACM and ICM - Version 4.0, as revised by Board Staff and sent to HHHI on September 10, 2018 and has provided both a hard copy (see **Appendix B**) and a live Excel file of the model.

HHHI confirms the consumption and demands entered in the model are consistent with the Reporting and Record Keeping Requirements filed with the Board. The data entered into Tab "6. Rev_Req_Check" is consistent with the revenue requirement workform submitted as part of the depreciation adjustment in EB-2018-0045 – 2018 IRM application.

The TS capital costs are separated into five (5) categories and are shown below in **Table 7** with the amortization expense and CCA calculations. The projected TS capital costs are $23,476,441.

Table 7 - TS Capital Cost Categories

Cost Category	Capital Cost	Amortization Expense	Capital Cost Allowance (CCA)		
			Class	Rate	Amount
TS Switchgear - Gas, Transformer	6,789,816	196,505	47	8%	543,185
Substation Equipment, U/G Cables, Meters, Capital Contribution	9,060,154	243,061	47	8%	724,812
Duct & Civil, Building	6,408,952	153,855	47	8%	512,716
SCADA & DC System	230,519	15,368	45	45%	103,734
Land	987,000	-	n/a	n/a	-
Total Costs	**23,476,441**	**608,789**			**1,884,447**

Where applicable, HHHI has used the HHHI specific Kinetrics report (Kinetrics Inc. Report No: K-418022-RA-0001-R003 dated December 10, 2009) to determine useful lives and calculate amortization expense. Where a specific asset is not included in this report, HHHI has used the Board Kinetrics Report, dated July 2010, for recommended useful lives. The HHHI specific and Board Kinetrics reports are include in **Appendices F and G** respectively.

HHHI has no outstanding Connection Cost Recovery Agreements with Hydro One and therefore, there are no true-ups required to be included with the ICM.

Revenue Requirement

The revenue requirement calculation for the incremental capital costs can be found on Tab "11. Incremental Capital Adj." in **Appendix B**. The incremental capital revenue requirement calculated by the model is $1,698,085 and shown in **Table 8** below.

Table 8 - Incremental Capital Revenue Requirement

Current Revenue Requirement			
Current Revenue Requirement - Total		$ 10,458,405	A
Eligible Incremental Capital for ACM/ICM Recovery	**Total Claim**	**Eligible for ACM / ICM**	
Incremental Capital	23,476,441	$ 23,476,441	B
Depreciation Expense	608,789	$ 608,789	C
CCA	1,884,447	$ 1,884,447	V
Return on Rate Base			
Incremental Capital		$ 23,476,441	B
Depreciation Expense		$ 608,789	C
Incremental Capital to be included in Rate Base		$ 23,172,047	D = B - C/2
Deemed ShortTerm Debt %	4% E	$ 926,882	G = D * E
Deemed Long Term Debt %	56% F	$ 12,976,346	H = D * F
Short Term Interest	1.65% I	$ 15,294	K = G * I
Long Term Interest	2.89% J	$ 375,016	L = H * J
Return on Rate Base - Interest		$ 390,310	M = K + L
Deemed Equity %	40.00% N	$ 9,268,819	P = D * N
Return on Rate Base -Equity	9.19% O	$ 851,804	Q = P * O
Return on Rate Base - Total		$ 1,242,114	R = M + Q
Amortization Expense			
Amortization Expense - Incremental	C	$ 608,789	S
Grossed up PIL's			
Regulatory Taxable Income	O	$ 851,804	T
Add Back Amortization Expense	S	$ 608,789	U
Deduct CCA		$ 1,884,447	V
Incremental Taxable Income		$ (423,854)	W = T + U - V
Current Tax Rate	26.5% X		
PIL's Before Gross Up		$ (112,321)	Y = W * X
Incremental Grossed Up PIL's		$ (152,818)	Z = Y / (1 - X)
Incremental Revenue Requirement			
Return on Rate Base - Total	Q	$ 1,242,114	AA
Amortization Expense - Total	S	$ 608,789	AB
Incremental Grossed Up PIL's	Z	$ (152,818)	AC
Incremental Revenue Requirement		**$ 1,698,085**	**AD = AA + AB + AC**

The Working Capital Allowance used in the ICM is 7.5%, and the Cost of Capital used is 1.65% for Short Term Debt, 2.89% for Long Term Debt, a 9.19% Deemed Return on Rate Base and calculated Incremental Grossed up PILs is a credit of $152,818. As per the September 2014 Report and Filing Guidelines, the Board decided that the half-year rule would apply only in the final year (4th) of the Price Cap IR plan term. HHHI is in the 3rd year of the IRM and notes that the half-year rule was not applied in the calculation of incremental depreciation.

While HHHI has built the TS on the basis of planned significant future growth, the greatest growth period will begin in 2021, the same year as HHHI expects to file the next Cost of Service. Prior to 2021, customer revenues from new customer growth facilitated by the TS will be modest. As typical trending growth is expected to occur between this Application and the next Cost of Service application, HHHI has not included any revenue off-sets to the incremental capital revenue requirement.

In addition to the incremental capital revenue requirement, HHHI is also requesting $131,515 in incremental OM&A costs as detailed above.

HHHI is requesting $1,829,600 in total incremental cost recovery, as shown in **Table 9** immediately below.

Table 9 - Total Incremental Cost Recovery Request

Incremental Costs	Amount
Revenue Requirement - Capital	1,698,085
Revenue Requirement - OM&A	131,515
Total	**1,829,600**

Rate Riders

Due to the incremental OM&A request and the fixed to variable ratio adjustment for Residential customers, HHHI has calculated the Rate Riders outside the ICM Excel file. The calculations will be submitted with the Application in Excel format and are shown in **Appendix H** (pdf). **Table 10** below provides a summary of the calculations. As per Board policy, Residential rate riders are fully fixed.

Table 10 - Proposed Incremental Revenue Requirement Rate Riders

Rate Class	Total Revenue by Rate Class	Billed Customers or Connections	Billed kWh	Billed kW	Service Charge Rate Rider	Distribution Volumetric Rate kWh Rate Rider	Distribution Volumetric Rate kW Rate Rider
		From Sheet 4	From Sheet 4	From Sheet 4	Col F / Col K / 12	Col G / Col L	Col H / Col M
RESIDENTIAL	$ 1,124,339	20,188	193,694,443	-	$ 4.64	$ -	$ -
GENERAL SERVICE LESS THAN 50 KW	$ 200,461	1,810	50,527,239	-	$ 5.03	$ 0.0018	$ -
GENERAL SERVICE 50 TO 999 KW	$ 304,149	186	135,373,696	394,783	$ 15.38	$ -	$ 0.6835
GENERAL SERVICE 1,000 TO 4,999 KW	$ 165,500	11	99,309,703	262,132	$ 32.87	$ -	$ 0.6148
UNMETERED SCATTERED LOAD	$ 3,469	152	934,714	-	$ 1.41	$ 0.0010	$ -
SENTINEL LIGHTING	$ 7,961	173	260,238	704	$ 1.68	$ -	$ 6.3607
STREET LIGHTING	$ 23,721	4,674	1,128,400	3,155	$ 0.41	$ -	$ 0.2750
Total	$ 1,829,600	27,194	481,228,433	660,774			

Deferral and Variance Account

HHHI requests Board approval to create a deferral and variance account to track the costs and recovery of costs related to the TS with the intention of truing up the balance at HHHI's next Cost of Service. HHHI will follow the accounting treatment for deferral and variance accounts as described in the Accounting Procedures Handbook and the ACM Report.

Bill Impacts

The proposed rate impacts reflect HHHI's 2018 distribution rates, adjusted for a Price Cap Index of 1.20%; this includes a Productivity Factor of 0.00% based on the assignment of HHHI to Stretch Factor Group I (PEG Report dated August 2018, Table 5) and the calculated Incremental Revenue Requirement Rate Rider related to the recovery of revenue requirement as it pertains to the new TS for all impacts that include the IRM. Additional bill impacts are shown in **Appendix I.**

Table 11 –Proposed Total Bill Impacts by Rate Class for Incremental Revenue Requirement

Rate Class	Volumes		% Change (IRM Only)	% Change (ICM Only)	% Change (IRM & ICM)
	kWhs	kWs			
Residential - Time of Use	750	-	-2.50%	4.40%	1.90%
General Service Less Than 50 kW	2,000	-	-3.24%	3.37%	0.12%
General Service 50 to 999 kW	328,500	500	9.59%	0.82%	10.41%
General Service 1,000 to 4,999 kW - Interval Meters	1,600,000	2,500	9.64%	0.74%	10.38%
Unmetered Scattered Load	150	-	-2.36%	6.33%	3.97%
Sentinel Lighting	650	1	-1.00%	7.42%	6.42%
Street Lighting	94,033	251	9.04%	0.56%	9.60%

In **Table 11**, HHHI has included the proposed percentage change resulting from HHHI's 2019 IRM application (EB-2018-0037) alone, the bill impact of the ICM application alone and the combined bill impact. As shown in the table, the IRM mitigates the ICM bill impacts in all classes that normally bill Regulated Price Plan ("RPP"). It should be noted that the General Service 50-999 kW, General Service 1,000 to 4,999 kW and Street Lighting classes, all classes that normally bill hourly prices and the Global Adjustment Rate Rider, see a substantial increase to their bills as a result of the IRM application and, in particular, the Global Adjustment rate rider changing from a credit in 2018 rates to a debit in the proposed 2019 rates. If the effects of the Global Adjustment Rate Rider were removed, the proposed bill impacts would be those shown in **Table 12**. This equates to an approximately 11% bill impact solely related to the Global Adjustment Rate Rider.

Table 12 –Proposed Total Bill Impacts by Rate Class (excluding Global Adjustment Rate Rider Impact)

Rate Class	Volumes		% Change (IRM excluding GA Rate Rider)	% Change (ICM Only)	% Change (IRM- excluding GA Rate Riders & ICM)	% Change - GA Rate Rider Only	% Change (IRM & ICM)
	kWhs	kWs					
Residential - Time of Use	750	-	-2.50%	4.40%	1.90%	0.00%	1.90%
General Service Less Than 50 kW	2,000	-	-3.24%	3.37%	0.12%	0.00%	0.12%
General Service 50 to 999 kW	328,500	500	-1.42%	0.82%	-0.61%	11.02%	10.41%
General Service 1,000 to 4,999 kW - Interval Meters	1,600,000	2,500	-1.44%	0.74%	-0.70%	11.09%	10.38%
Unmetered Scattered Load	150	-	-2.36%	6.33%	3.97%	0.00%	3.97%
Sentinel Lighting	650	1	-1.00%	7.42%	6.42%	0.00%	6.42%
Street Lighting	94,033	251	-2.08%	0.56%	-1.52%	11.14%	9.60%

Setting aside the impact of the Global Adjustment Rate Rider which is mechanistic and outside the control of HHHI, HHHI is not suggesting any rate mitigation as the overall bill impact is mitigated by the proposed IRM application.

Conclusion

HHHI respectfully submits that it has complied with the Board's Chapter 3 of the Filing Requirements for Transmission and Distribution Applications issued July 12, 2018 and all ACM/ICM Reports and Supplemental Reports.

The ICM is intended to address the treatment of a distributor's capital investment needs that arise during the rate-setting plan that are incremental to a materiality threshold. The ICM is a funding mechanism for significant, incremental and discrete capital projects for which a utility is granted rate recovery in advance of its next rebasing application. In the application above, HHHI submits that it has shown the materiality, need and prudence for the incremental capital expenditure as required.

The proposed rate impacts reflect HHHI's 2018 distribution rates, adjusted for a Price Cap Index of 1.20%; this includes a Productivity Factor of 0.00% based on the assignment of HHHI to Stretch Factor Group I and the calculated Incremental Revenue Requirement Rate Rider as it pertains to costs associated with the new TS.

Consequences of Non-Approval of ICM

If the approval for incremental revenue requirement is not granted, HHHI will be faced with a significant negative cash flow in the short term and financial hardship during the incentive regulation term. HHHI will be forced to consider early rebasing if it fails to secure incremental revenues through this Application.

Relief Sought

HHHI is making an Application for an Order or Orders approving the following:

- The proposed Rate Riders for recovery of Incremental Revenue Requirement as it relates to the new TS and set out in **Appendix H** to the Application as just and reasonable rates and charges pursuant to Section 78 of the OEB Act, to be effective May 1, 2019.
- HHHI is requesting that the Board deem the TS to be a distribution asset pursuant to section 84(a) of the OEB Act in order that it may recover the revenue requirement related to the TS through distribution rates.
- HHHI is requesting an exemption to the general ICM policy in order to recover incremental Operating, Maintenance and Administration ("OM&A") costs in relation to the TS.

- HHHI is requesting recovery of annual incremental OM&A costs related to the TS commencing May 1, 2019.
- An accounting order for the creation of a USofA 1508 Deferral and Variance sub-account to record costs and recoveries related to the Incremental Revenue Requirement application.

Form of Hearing Requested

HHHI requests that this Application be disposed of by way of a written hearing.

Respectfully submitted this 3rd day of December, 2018.

(Original signed)

David J. Smelsky, CPA, CMA, C.Dir.
Chief Financial Officer
Halton Hills Hydro Inc.

Attachments

Appendix A	2018 Tariff of Rates and Charges
Appendix B	2019_Capital_Module_ACM_Model Version 4_20_20181203
Appendix C	2015-Northwest-GTA-IRRP-Report-1
Appendix D	Stantec HHH Load Forecast - January 2017
Appendix E	2015 Town CAO Letter
Appendix F	HHHI Specific Kinetrics Report
Appendix G	Kinetrics-OEB Asset Amortization
Appendix H	2019 Proposed Incremental Revenue Requirement Rate Rider Calculation to be effective May 1, 2019 – Offline Calculation
Appendix I	Proposed Bill Impacts – Offline Calculation

Appendix A

2018 Tariff of Rates and Charges

(Intentionally Blank)

Halton Hills Hydro Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2018
This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2017-0045

RESIDENTIAL SERVICE CLASSIFICATION

This classification applies to an account taking electricity at 750 volts or less where the electricity is used exclusively in a separate metered living accommodation. Customers shall be residing in single-dwelling units that consist of a detached house or one unit of a semi-detached, duplex, triplex or quadruplex house, with a residential zoning. Separately metered dwellings within a town house complex or apartment building also qualify as residential customers. The customer will be supplied at one service entrance only. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	23.48
Smart Metering Entity Charge - effective until December 31, 2022	$	0.57
Distribution Volumetric Rate	$/kWh	0.0034
Low Voltage Service Rate	$/kWh	0.0026
Rate Rider for Disposition of Global Adjustment Account (2018) - effective until April 30, 2019 Applicable only for Non-RPP Customers	$/kWh	(0.0010)
Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective until April 30, 2019	$/kWh	(0.0014)
Rate Rider for Disposition of Capacity Based Recovery Account (2018) - effective until April 30, 2019 Applicable only for Class B Customers	$/kWh	(0.0001)
Retail Transmission Rate - Network Service Rate	$/kWh	0.0068
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0056

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0032
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0003
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Halton Hills Hydro Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2018
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EB-2017-0045

GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION

This classification applies to a non-residential account taking electricity at 750 volts or less whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	28.37
Smart Metering Entity Charge - effective until December 31, 2022	$	0.57
Distribution Volumetric Rate	$/kWh	0.0102
Low Voltage Service Rate	$/kWh	0.0024
Rate Rider for Disposition of Global Adjustment Account (2018) - effective until April 30, 2019 Applicable only for Non-RPP Customers	$/kWh	(0.0010)
Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective until April 30, 2019	$/kWh	(0.0014)
Rate Rider for Disposition of Capacity Based Recovery Account (2018) - effective until April 30, 2019 Applicable only for Class B Customers	$/kWh	(0.0001)
Retail Transmission Rate - Network Service Rate	$/kWh	0.0060
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0053

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0032
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0003
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Halton Hills Hydro Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2018
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EB-2017-0045

GENERAL SERVICE 50 TO 999 KW SERVICE CLASSIFICATION

This classification applies to a non-residential customer with an average peak demand equal to or greater than 50 kW over the past twelve months, or is forecast to be equal to or greater than 50 kW, but less than 1,000 kW. For a new customer without prior billing history, the peak demand will be based on 90% of the proposed capacity or installed transformer. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

Billing demands are established at the greater of 100% of the kW, or 90% of the kVA amounts with the exception of the Retail Transmission Rate-Network Service Rate, which is billed on a $/kW basis only.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	86.83
Distribution Volumetric Rate	$/kW	3.8580
Low Voltage Service Rate	$/kW	1.0483
Rate Rider for Disposition of Global Adjustment Account (2018) - effective until April 30, 2019 Applicable only for Non-RPP Customers	$/kWh	(0.0010)
Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective until April 30, 2019 Applicable only for Non-Wholesale Market Participants	$/kW	(1.2172)
Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective until April 30, 2019	$/kW	0.5107
Rate Rider for Disposition of Capacity Based Recovery Account (2018) - effective until April 30, 2019 Applicable only for Class B Customers	$/kW	(0.0276)
Retail Transmission Rate - Network Service Rate	$/kW	2.6217
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	2.2146

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0032
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0003
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Halton Hills Hydro Inc.
TARIFF OF RATES AND CHARGES
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EB-2017-0045

GENERAL SERVICE 1,000 TO 4,999 KW SERVICE CLASSIFICATION

This classification applies to a non-residential customer with an average peak demand equal to or greater than 1,000 kW over the past twelve months, or is forecast to be equal to or greater than 1,000 kW, but less than 5,000 kW. For a new customer without prior billing history, the peak demand will be based on 90% of the installed transformer. Class A and Class B consumers are defined in accordance with O.Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

The rate rider for the disposition of WMS - Sub-account CBR Class B is not applicable to wholesale market participants (WMP), customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new Class B customers.

The rate rider for the disposition of Global Adjustment is only applicable to non-RPP Class B customers. It is not applicable to WMP, customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new non-RPP Class B customers.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

Billing demands are established at the greater of 100% of the kW, or 90% of the kVA amounts with the exception of the Retail Transmission Rate-Network Service Rate, which is billed on a $/kW basis only.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	185.55
Distribution Volumetric Rate	$/kW	3.4705
Low Voltage Service Rate	$/kW	1.0483
Rate Rider for Disposition of Global Adjustment Account (2018) - effective until April 30, 2019 Applicable only for Non-RPP Customers	$/kWh	(0.0010)
Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective until April 30, 2019	$/kW	(0.9398)
Rate Rider for Disposition of Capacity Based Recovery Account (2018) - effective until April 30, 2019 Applicable only for Class B Customers	$/kW	(0.0341)
Retail Transmission Rate - Network Service Rate	$/kW	2.6217
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	2.2146

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MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0032
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0003
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Halton Hills Hydro Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2018
This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2017-0045

UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification applies to an account taking electricity at 750 volts or less whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, pedestrian X-Walk signals/beacons, railway crossings, etc. The level of the consumption will be agreed to by the distributor and the customer, based on detailed manufacturer information/documentation with regard to electrical consumption of the unmetered load or periodic monitoring of actual consumption. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	7.97
Distribution Volumetric Rate	$/kWh	0.0054
Low Voltage Service Rate	$/kWh	0.0024
Rate Rider for Disposition of Global Adjustment Account (2018) - effective until April 30, 2019 Applicable only for Non-RPP Customers	$/kWh	(0.0010)
Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective until April 30, 2019	$/kWh	(0.0012)
Rate Rider for Disposition of Capacity Based Recovery Account (2018) - effective until April 30, 2019 Applicable only for Class B Customers	$/kWh	(0.0001)
Retail Transmission Rate - Network Service Rate	$/kWh	0.0060
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0053

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0032
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0003
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Halton Hills Hydro Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2018
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EB-2017-0045

SENTINEL LIGHTING SERVICE CLASSIFICATION

This classification refers to accounts that are an unmetered lighting load supplied to a sentinel light. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	9.47
Distribution Volumetric Rate	$/kW	35.9050
Low Voltage Service Rate	$/kW	0.7547
Rate Rider for Disposition of Global Adjustment Account (2018) - effective until April 30, 2019 Applicable only for Non-RPP Customers	$/kWh	(0.0010)
Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective until April 30, 2019	$/kW	(0.4711)
Rate Rider for Disposition of Capacity Based Recovery Account (2018) - effective until April 30, 2019 Applicable only for Class B Customers	$/kW	(0.0298)
Retail Transmission Rate - Network Service Rate	$/kW	1.8704
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.5942

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0032
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0003
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Halton Hills Hydro Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2018
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EB-2017-0045

STREET LIGHTING SERVICE CLASSIFICATION

All services supplied to street lighting equipment owned by or operated for the Municipality, the Region or the Province of Ontario shall be classified as Street Lighting Service. Street Lighting plant, facilities, or equipment owned by the customer are subject to the Electrical Safety Authority (ESA) requirements and Halton Hills Hydro specifications. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	2.30
Distribution Volumetric Rate	$/kW	1.5523
Low Voltage Service Rate	$/kW	0.7393
Rate Rider for Disposition of Global Adjustment Account (2018) - effective until April 30, 2019 Applicable only for Non-RPP Customers	$/kWh	(0.0010)
Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective until April 30, 2019	$/kW	(0.9785)
Rate Rider for Disposition of Capacity Based Recovery Account (2018) - effective until April 30, 2019 Applicable only for Class B Customers	$/kW	(0.0285)
Retail Transmission Rate - Network Service Rate	$/kW	1.8617
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.5617

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0032
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0003
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Halton Hills Hydro Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2018
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EB-2017-0045

microFIT SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Independent Electricity System Operator's microFIT program and connected to the distributor's distribution system. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

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MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	5.40

ALLOWANCES

Transformer Allowance for Ownership - per kW of billing demand/month	$/kW	(0.60)
Primary Metering Allowance for Transformer Losses - applied to measured demand & energy	%	(1.00)

Halton Hills Hydro Inc.
TARIFF OF RATES AND CHARGES
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EB-2017-0045

SPECIFIC SERVICE CHARGES

APPLICATION

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No charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

Customer Administration

Arrears certificate	$	15.00
Statement of account	$	15.00
Pulling post dated cheques	$	15.00
Duplicate invoices for previous billing	$	15.00
Request for other billing information	$	15.00
Easement Letter	$	15.00
Income tax letter	$	15.00
Notification charge	$	15.00
Account history	$	15.00
Credit reference/credit check (plus credit agency costs)	$	15.00
Returned Cheque (plus bank charges)	$	15.00
Charge to certify cheque	$	15.00
Legal letter charge	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Special meter reads	$	30.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00

Non-Payment of Account

Late Payment - per month	%	1.50
Late Payment - per annum	%	19.56
Collection of account charge - no disconnection	$	30.00
Collection of account charge - no disconnection - after regular hours	$	165.00
Disconnect/Reconnect at Meter - during regular hours	$	65.00
Disconnect/Reconnect at Meter - after regular hours	$	185.00
Disconnect/Reconnect at Pole - during regular hours	$	185.00
Disconnect/Reconnect at Pole - after regular hours	$	415.00
Install/Remove Load Control Device - during regular hours	$	65.00
Install/Remove Load Control Device - after regular hours	$	185.00

Other

Service call - customer owned equipment	$	30.00
Service call - after regular hours	$	165.00
Temporary service install & remove - overhead - no transformer	$	500.00
Temporary service install & remove - underground - no transformer	$	300.00
Temporary service install & remove - overhead - with transformer	$	1,000.00
Specific charge for access to the power poles - $/pole/year (with the exception of wireless attachments)	$	22.35
Interval meter charge	$	20.00

Halton Hills Hydro Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2018
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EB-2017-0045

RETAIL SERVICE CHARGES (if applicable)

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

Retail Service Charges refer to services provided by a distributor to retailers or customers related to the supply of competitive electricity.

One-time charge, per retailer, to establish the service agreement between the distributor and the retailer	$	100.00
Monthly Fixed Charge, per retailer	$	20.00
Monthly Variable Charge, per customer, per retailer	$/cust.	0.50
Distributor-consolidated billing monthly charge, per customer, per retailer	$/cust.	0.30
Retailer-consolidated billing monthly credit, per customer, per retailer	$/cust.	(0.30)
Service Transaction Requests (STR)		
Request fee, per request, applied to the requesting party	$	0.25
Processing fee, per request, applied to the requesting party	$	0.50
Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party		
Up to twice a year		no charge
More than twice a year, per request (plus incremental delivery costs)	$	2.00

LOSS FACTORS

If the distributor is not capable of prorating changed loss factors jointly with distribution rates, the revised loss factors will be implemented upon the first subsequent billing for each billing cycle.

Total Loss Factor - Secondary Metered Customer < 5,000 kW	1.0560
Total Loss Factor - Primary Metered Customer < 5,000 kW	1.0455

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Appendix B

2018_Capital_Module_ACM_Model Version 4_20_20181203

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Note: Depending on the selections made below, certain worksheets in this workbook will be hidden. **Version** **4.20**

Utility Name	Halton Hills Hydro Inc.
Assigned EB Number	
Name of Contact and Title	David Smelsky, Chief Financial Officer
Phone Number	519-853-3700 x 208
Email Address	dsmelsky@haltonhillshydro.com
Is this Capital Module being filed in a CoS or Price-Cap IR Application?	**Price-Cap IR**
Rate Year	**2019**
Indicate the Price-Cap IR Year (1, 2, 3, 4, etc) in which Halton Hills Hydro Inc. is applying:	**3**
Halton Hills Hydro Inc. is applying for:	**ICM Approval**
Last Rebasing Year:	**2016**
The most recent complete year for which actual billing and load data exists	**2017**
Current IPI	**1.20%**
Strech Factor Assigned to Middle Cohort	**III**
Stretch Factor Value	**0.30%**
Price Cap Index	**0.90%**

Based on the inputs above, the growth factor utilized in the Materiality Threshold Calculation will be determined by:

$$\frac{\text{Revenues Based on 2017 Actual Distribution Demand}}{\text{Revenues Based on 2016 Board-Approved Distribution Demand}}$$

Notes

Pale green cells represent input cells.

Pale blue cells represent drop-down lists. The applicant should select the appropriate item from the drop-down list.

White cells contain fixed values, automatically generated values or formulae.

While this model has been provided in Excel format and is required to be filed with the applications, the onus remains on the applicant to ensure the accuracy of the data and the results.

OEB policies regarding rate-setting and rebasing following distributor consolidations could allow a distributor to not rebase rates for up to ten years. A distributor could also apply for and receive OEB approval to defer rebasing. If a distributor is under Price Cap IR for more than four years after rebasing and applies for an ICM, this spreadsheet will need to be adapted to accommodate those circumstances. The distributor should contact OEB staff to discuss the circumstances so that a customized model can be provided.

Ontario Energy Board

Capital Module
Applicable to ACM and ICM
Halton Hills Hydro Inc.

Select the appropriate rate classes as they appear on your most recent Board-Approved Tariff of Rates and Charges, excluding the MicroFit Class.

How many classes are on your most recent Board-Approved Tariff of Rates and Charges? **7**

Select Your Rate Classes from the **Blue Cells** below. Please ensure that a rate class is assigned to **each shaded cell.**

	Rate Class Classification
1	RESIDENTIAL
2	GENERAL SERVICE LESS THAN 50 kW
3	GENERAL SERVICE 50 TO 999 kW
4	GENERAL SERVICE 1,000 TO 4,999 kW
5	UNMETERED SCATTERED LOAD
6	SENTINEL LIGHTING
7	STREET LIGHTING

Ontario Energy Board

Capital Module
Applicable to ACM and ICM
Halton Hills Hydro Inc.

Input the billing determinants associated with Halton Hills Hydro Inc.'s Revenues Based on 2017 Actual Distribution Demand. Input the current approved distribution rates. Sheets 4 & 5 calculate the NUMERATOR portion of the growth factor calculation.

		2017 Actual Distribution Demand			Current Approved Distribution Rates		
Rate Class	**Units**	**Billed Customers or Connections**	**Billed kWh**	**Billed kW (if applicable)**	**Monthly Service Charge**	**Distribution Volumetric Rate kWh**	**Distribution Volumetric Rate kW**
RESIDENTIAL	$/kWh	20,188	193,694,443		23.48	0.0034	0.0000
GENERAL SERVICE LESS THAN 50 kW	$/kWh	1,810	50,527,239		28.37	0.0102	0.0000
GENERAL SERVICE 50 TO 999 kW	$/kW	186	135,373,696	394,783	86.83	0.0000	3.8580
GENERAL SERVICE 1,000 TO 4,999 kW	$/kW	11	99,309,703	262,132	185.55	0.0000	3.4705
UNMETERED SCATTERED LOAD	$/kWh	152	934,714		7.97	0.0054	0.0000
SENTINEL LIGHTING	$/kW	173	260,238	704	9.47	0.0000	35.9050
STREET LIGHTING	$/kW	4,674	1,128,400	3,155	2.30	0.0000	1.5523

Ontario Energy Board

Capital Module

Applicable to ACM and ICM

Halton Hills Hydro Inc.

Calculation of pro forma 2016 Revenues. No input required.

Rate Class	2017 Actual Distribution Demand			Current Approved Distribution Rates										
	Billed Customers or Connections	Billed kWh	Billed kW (if applicable)	Monthly Service Charge	Distribution Volumetric Rate kWh	Distribution Volumetric Rate kW	Service Charge Revenue	Distribution Volumetric Rate Revenue kWh	Distribution Volumetric Rate Revenue kW	Revenues from Rates	Service Charge % Revenue	Distribution Volumetric Rate % Revenue kWh	Distribution Volumetric Rate % Revenue kW	Total % Revenue
Total	0	0	0	D	E	F	0	0	0	0	K = G / J	L = H / J	M = I / J	0.0%
RESIDENTIAL	20,188	193,694,443		23.48	0.0034	0.0000	5,688,171	658,561	0	6,346,732	89.6%	10.4%	0.0%	61.5%
GENERAL SERVICE LESS THAN 50 kW	1,810	50,527,239		28.37	0.0102	0.0000	616,196	515,378	0	1,131,574	54.5%	45.5%	0.0%	11.0%
GENERAL SERVICE 50 TO 999 kW	186	135,373,696	394,783	86.83	0.0000	3.8580	193,805	0	1,523,077	1,716,881	11.3%	0.0%	88.7%	16.6%
GENERAL SERVICE 1,000 TO 4,999 kW	11	99,309,703	262,132	185.55	0.0000	3.4705	24,493	0	909,729	934,222	2.6%	0.0%	97.4%	9.0%
UNMETERED SCATTERED LOAD	152	934,714		7.97	0.0054	0.0000	14,537	5,047	0	19,585	74.2%	25.8%	0.0%	0.2%
SENTINEL LIGHTING	173	260,238	704	9.47	0.0000	35.9050	19,660	0	25,277	44,937	43.7%	0.0%	56.3%	0.4%
STREET LIGHTING	4,674	1,128,400	3,155	2.30	0.0000	1.5523	129,002	0	4,898	133,900	96.3%	0.0%	3.7%	1.3%
Total	**27,194**	**481,228,433**	**660,774**				**6,685,864**	**1,178,986**	**2,462,980**	**10,327,831**				**100.0%**

Ontario Energy Board

Capital Module
Applicable to ACM and ICM

Applicants Rate Base

Last COS Rebasing: 2016

Average Net Fixed Assets						
Gross Fixed Assets - Re-based Opening	$	81,716,296	A			
Add: CWIP Re-based Opening	$	4,516,245	B			
Re-based Capital Additions	$	7,708,601	C			
Re-based Capital Disposals	$	-	D			
Re-based Capital Retirements	$	-	E			
Deduct: CWIP Re-based Closing	-$	4,516,245	F			
Gross Fixed Assets - Re-based Closing	$	89,424,897	G			
Average Gross Fixed Assets				$	85,570,597	H = (A + G) / 2
Accumulated Depreciation - Re-based Opening	$	28,972,192	I			
Re-based Depreciation Expense	$	2,022,154	J			
Re-based Disposals	$	-	K			
Re-based Retirements	$	-	L			
Accumulated Depreciation - Re-based Closing	$	30,994,346	M			
Average Accumulated Depreciation				$	29,983,269	N = (I + M) / 2
Average Net Fixed Assets				**$**	**55,587,328**	O = H - N
Working Capital Allowance						
Working Capital Allowance Base	$	75,531,774	P			
Working Capital Allowance Rate		7.5%	Q			
Working Capital Allowance				**$**	**5,664,883**	R = P * Q
Rate Base				**$**	**61,252,211**	S = O + R
Return on Rate Base						
Deemed ShortTerm Debt %		4.00%	T	$	2,450,088	W = S * T
Deemed Long Term Debt %		56.00%	U	$	34,301,238	X = S * U
Deemed Equity %		40.00%	V	$	24,500,884	Y = S * V
Short Term Interest		1.65%	Z	$	40,426	AC = W * Z
Long Term Interest		2.89%	AA	$	991,306	AD = X * AA
Return on Equity		9.19%	AB	$	2,251,631	AE = Y * AB
Return on Rate Base				**$**	**3,283,363**	AF = AC + AD + AE
Distribution Expenses						
OM&A Expenses	$	6,007,592	AG			
Amortization	$	2,022,154	AH			
Ontario Capital Tax	$	-	AI			
Grossed Up Taxes/PILs	$	-	AJ			
Low Voltage			AK			
Transformer Allowance			AL			
Property Tax	$	104,440	AM			
			AN			
			AO			
				$	**8,134,186**	AP = SUM (AG : AO)
Revenue Offsets						
Specific Service Charges	-$	375,470	AQ			
Late Payment Charges	-$	120,000	AR			
Other Distribution Income	-$	252,074	AS			
Other Income and Deductions	-$	211,600	AT	**-$**	**959,144**	AU = SUM (AQ : AT)
Revenue Requirement from Distribution Rates				**$**	**10,458,405**	AV = AF + AP + AU
Rate Classes Revenue						
Rate Classes Revenue - Total (Sheet 5)				$	10,327,831	AW
Difference				$	130,575	AZ = AV - AW
Difference (Percentage - should be less than ±1%)					1.26%	BA = AZ / AW

Ontario Energy Board

Capital Module

Applicable to ACM and ICM

Halton Hills Hydro Inc.

Input the billing determinants associated with Halton Hills Hydro Inc.'s Revenues Based on 2016 Board-Approved Distribution Demand. This sheet calculates the DENOMINATOR portion of the growth factor calculation.
Pro forma Revenue Calculation.

Rate Class	2016 Board-Approved Distribution Demand: Billed Customers or Connections	Billed kWh	Billed kW	Current Approved Distribution Rates: Monthly Service Charge	Distribution Volumetric Rate kWh	Distribution Volumetric Rate kW	Service Charge Revenue	Distribution Volumetric Rate Revenue kWh	Distribution Volumetric Rate Revenue kW	Total Revenue By Rate Class	Service Charge % Revenue	Distribution Volumetric Rate % Revenue kWh	Distribution Volumetric Rate % Revenue kW	Total % Revenue
Total	0	0	0	D	E	F	0	0	0	0	$K = G / J_{total}$	$L = H / J_{total}$	$M = I / J_{total}$	0.0%
RESIDENTIAL	19,971	205,578,737		23.48	0.0034	0.0000	5,627,029	698,968	0	6,325,997	53.7%	6.7%	0.0%	60.3%
GENERAL SERVICE LESS THAN 50 kW	1,967	58,991,538		28.37	0.0102	0.0000	669,645	601,714	0	1,271,359	6.4%	5.7%	0.0%	12.1%
GENERAL SERVICE 50 TO 999 kW	206	136,566,740	362,031	86.83	0.0000	3.8580	214,644	0	1,396,719	1,611,363	2.0%	0.0%	13.3%	15.4%
GENERAL SERVICE 1,000 TO 4,999 kW	13	112,173,675	302,644	185.55	0.0000	3.4705	28,946	0	1,050,326	1,079,272	0.3%	0.0%	10.0%	10.3%
UNMETERED SCATTERED LOAD	144	895,971		7.97	0.0054	0.0000	13,772	4,838	0	18,610	0.1%	0.0%	0.0%	0.2%
SENTINEL LIGHTING	175	461,109	628	9.47	0.0000	35.9050	19,830	0	22,548	42,379	0.2%	0.0%	0.2%	0.4%
STREET LIGHTING	4,649	1,535,681	4,282	2.30	0.0000	1.5523	128,299	0	6,647	134,946	1.2%	0.0%	0.1%	1.3%
Total	**27,124**	**516,203,452**	**669,585**				**6,702,165**	**1,305,520**	**2,476,241**	**10,483,925**				**100.0%**

Ontario Energy Board

Capital Module

Applicable to ACM and ICM

Halton Hills Hydro Inc.

Current Revenue from Rates

This sheet is used to determine the applicant's most current allocation of revenues (after the most recent revenue to cost ratio adjustment, if applicable) to appropriately allocate the incremental revenue requirement to the classes.

	Current OEB-Approved Base Rates			2017 Actual Distribution Demand										
Rate Class	**Monthly Service Charge**	**Distribution Volumetric Rate kWh**	**Distribution Volumetric Rate kW**	**Re-based Billed Customers or Connections**	**Re-based Billed kWh**	**Re-based Billed kW**	**Current Base Service Charge Revenue**	**Current Base Distribution Volumetric Rate kWh Revenue**	**Current Base Distribution Volumetric Rate kW Revenue**	**Total Current Base Revenue**	**Service Charge % Total Revenue**	**Distribution Volumetric Rate % Total Revenue**	**Distribution Volumetric Rate % Total Revenue**	**Total % Revenue**
Total	**A**	**B**	**C**	**D**	**E**	**F**	**0**	**0**	**0**	**0**	**$L = G / J_{total}$**	**$M = H / J_{total}$**	**$N = I / J_{total}$**	**0.0%**
RESIDENTIAL	23.48	0.0034	0.0000	20,188	193,694,443		5,688,171	658,561	0	6,346,732	55.08%	6.38%	0.00%	61.5%
GENERAL SERVICE LESS THAN 50 kW	28.37	0.0102	0.0000	1,810	50,527,239		616,196	515,378	0	1,131,574	5.97%	4.99%	0.00%	11.0%
GENERAL SERVICE 50 TO 999 kW	86.83	0.0000	3.8580	186	135,373,696	394,783	193,805	0	1,523,073	1,716,877	1.88%	0.00%	14.75%	16.6%
GENERAL SERVICE 1,000 TO 4,999 kW	185.55	0.0000	3.4705	11	99,309,703	262,132	24,493	0	909,729	934,222	0.24%	0.00%	8.81%	9.0%
UNMETERED SCATTERED LOAD	7.97	0.0054	0.0000	152	934,714		14,537	5,047	0	19,585	0.14%	0.05%	0.00%	0.2%
SENTINEL LIGHTING	9.47	0.0000	35.9050	173	260,238	704	19,660	0	25,277	44,937	0.19%	0.00%	0.24%	0.4%
STREET LIGHTING	2.30	0.0000	1.5523	4,674	1,128,400	3,155	129,002	0	4,898	133,900	1.25%	0.00%	0.05%	1.3%
Total							**6,685,864**	**1,178,986**	**2,462,977**	**10,327,827**				**100.0%**

Ontario Energy Board

Capital Module
Applicable to ACM and ICM
Halton Hills Hydro Inc.

No Input Required.

Final Materiality Threshold Calculation

$$Threshold\ Value\ (\%) = 1 + \left[\left(\frac{RB}{d}\right) \times (g + PCI \times (1+g))\right] \times ((1+g) \times (1+PCI))^{n-1} + 10\%$$

Cost of Service Rebasing Year	**2016**		
Price Cap IR Year in which Application is made	**3**		n
Price Cap Index	**0.90%**		PCI
Growth Factor Calculation			
Revenues Based on 2017 Actual Distribution Demand	**$10,327,831**		
Revenues Based on 2016 Board-Approved Distribution Demand	**$10,483,925**		
Growth Factor	**-1.49%**		$g\ (Note\ 1)$
Dead Band	**10%**		

Average Net Fixed Assets			
Gross Fixed Assets Opening	$	81,716,296	
Add: CWIP Opening	$	4,516,245	
Capital Additions	$	7,708,601	
Capital Disposals	$	-	
Capital Retirements	$	-	
Deduct: CWIP Closing	-$	4,516,245	
Gross Fixed Assets - Closing	$	89,424,897	
Average Gross Fixed Assets	$	85,570,597	
Accumulated Depreciation - Opening	$	28,972,192	
Depreciation Expense	$	2,022,154	
Disposals	$	-	
Retirements	$	-	
Accumulated Depreciation - Closing	$	30,994,346	
Average Accumulated Depreciation	$	29,983,269	
Average Net Fixed Assets	$	55,587,328	
Working Capital Allowance			
Working Capital Allowance Base	$	75,531,774	
Working Capital Allowance Rate		8%	
Working Capital Allowance	$	5,664,883	
Rate Base	**$**	**61,252,211**	RB
Depreciation	**$**	**2,022,154**	d

Threshold Value (varies by Price Cap IR Year subsequent to CoS rebasing)	
Price Cap IR Year 2017	**92%**
Price Cap IR Year 2018	**92%**
Price Cap IR Year 2019	**92%**
Price Cap IR Year 2020	**92%**
Price Cap IR Year 2021	**92%**
Price Cap IR Year 2022	**92%**
Price Cap IR Year 2023	**92%**
Price Cap IR Year 2024	**93%**
Price Cap IR Year 2025	**93%**
Price Cap IR Year 2026	**93%**

Threshold CAPEX			$Threshold\ Value\ \times d$
Price Cap IR Year 2017	**$**	**1,855,452**	
Price Cap IR Year 2018	**$**	**1,857,674**	
Price Cap IR Year 2019	**$**	**1,859,883**	
Price Cap IR Year 2020	**$**	**1,862,078**	
Price Cap IR Year 2021	**$**	**1,864,260**	
Price Cap IR Year 2022	**$**	**1,866,429**	
Price Cap IR Year 2023	**$**	**1,868,585**	
Price Cap IR Year 2024	**$**	**1,870,728**	
Price Cap IR Year 2025	**$**	**1,872,857**	
Price Cap IR Year 2026	**$**	**1,874,975**	

Note 1: The growth factor g is annualized, depending on the number of years between the numerator and denominator for the calculation. Typically, for ACM review in a cost of service and in the fourth year of Price Cap IR, the ratio is divided by 2 to annualize it. No division is normally required for the first three years under Price Cap IR.

Ontario Energy Board

Capital Module
Applicable to ACM and ICM

Halton Hills Hydro Inc.

Identify ALL Proposed ACM projects and related CAPEX costs in the relevant years

		Cost of Service	*Price Cap IR*				*Price Cap IR (Deferred Rebasing)*						
		Test Year **2016**	**Year 1** **2017**	**Year 2** **2018**	**Year 3** **2019**	**Year 4** **2020**	**Year 5** **2021**	**Year 6** **2022**	**Year 7** **2023**	**Year 8** **2024**	**Year 9** **2025**	**Year 10** **2026**	
Distribution System Plan CAPEX		$ 9,539,998	$ 11,095,939	$ 6,902,214	$ 30,635,824	$ 8,149,827							
Materiality Threshold			$ 1,855,452	$ 1,857,674	$ 1,859,883	$ 1,862,078	$ 1,864,260	$ 1,866,429	$ 1,868,585	$ 1,870,728	$ 1,870,728	$ 1,870,728	
Maximum Eligible Incremental Capital (Forecasted Capex less Threshold)		$ -	$ 9,240,487	$ 5,044,540	$ 28,775,942	$ 6,287,749	$ -	$ -	$ -	$ -	$ -	$ -	
Project Descriptions:	**Type**	**Test Year 2016**	**Year 1 2017**	**Year 2 2018**	**Year 3 2019**	**Year 4 2020**	**Year 5 2021**	**Year 6 2022**	**Year 7 2023**	**Year 8 2024**	**Year 9 2025**	**Year 10 2026**	**Total**
TS Switchgear - Gas, Transformer	**New ICM**				$ 6,789,816								**$ 6,789,816**
Substation Equipment, U/G Cables, Meters, Capital Contribution	**New ICM**				$ 9,060,154								**$ 9,060,154**
Duct & Civil, Building	**New ICM**				$ 6,408,952								**$ 6,408,952**
SCADA & DC System	**New ICM**				$ 230,519								**$ 230,519**
Land	**New ICM**				$ 987,000								**$ 987,000**
													$ -
													$ -
													$ -
													$ -
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													$ -
													$ -
Total Cost of ACM/ICM Projects		$ -	$ -	$ -	$ 23,476,441	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ 23,476,441**
Maximum Allowed Incremental Capital			$ -	$ -	$ 23,476,441	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 23,476,441

		Price Cap IR			
	Test Year 2016	**Year 1 2017**	**Year 2 2018**	**Year 3 2019**	**Year 4 2020**
Distribution System Plan CAPEX	$ 9,539,998	$ 11,095,939	$ 6,902,214	$ 30,635,824	$ 8,149,827
Materiality Threshold		$ 1,855,452	$ 1,857,674	$ 1,859,883	$ 1,862,078
Maximum Eligible Incremental Capital (Forecasted Capex less Threshold)	$ -	$ 9,240,487	$ 5,044,540	$ 28,775,942	$ 6,287,749

		Test Year 2016	**Year 1 2017**			**Year 2 2018**			**Year 3 2019**			**Year 4 2020**		
Project Descriptions:	**Type**		**Proposed ACM/ICM**	**Amortization Expense**	**CCA**	**Proposed ACM/ICM**	**Amortization Expense**	**CCA**	**Proposed ACM/ICM**	**Amortization Expense**	**CCA**	**Proposed ACM/ICM**	**Amortization Expense**	**CCA**
TS Switchgear - Gas, Transformer	**New ICM**		$ -	$ -	$ -	$ -			**$ 6,789,816**	$ 196,505	$ 543,185	$ -		
Substation Equipment, U/G Cables, Meters, Capital Contribution	**New ICM**		$ -	$ -		$ -			**$ 9,060,154**	$ 243,061	$ 724,812	$ -		
Duct & Civil, Building	**New ICM**		$ -			$ -			**$ 6,408,952**	$ 153,855	$ 512,716	$ -		
SCADA & DC System	**New ICM**		$ -			$ -			**$ 230,519**	$ 15,368	$ 103,734	$ -		
Land	**New ICM**		$ -			$ -			**$ 987,000**	$ -	$ -	$ -		
			$ -			$ -			$ -			$ -		
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			$ -			$ -			$ -			$ -		
Total Cost of ACM/ICM Projects			$ -	$ -	$ -	$ -	$ -	$ -	$ 23,476,441	$ 608,789	$ 1,884,447	$ -	$ -	$ -

Price Cap IR (Deferred Rebasing) (if necessary)

		Price Cap IR			
		Year 5 2021	Year 6 2022	Year 7 2023	Year 8 2024
Distribution System Plan CAPEX		$ -	$ -	$ -	$ -
Materiality Threshold		$ 1,864,260	$ 1,866,429	$ 1,868,585	$ 1,870,728
Maximum Eligible Incremental Capital (Forecasted Capex less Threshold)	$ -	$ -	$ -	$ -	$ -

		Year 5 2021			Year 6 2022			Year 7 2023			Year 8 2024		
Project Descriptions:	Type	Proposed ACM/ICM	Amortization Expense	CCA	Proposed ACM/ICM	Amortization Expense	CCA	Proposed ACM/ICM	Amortization Expense	CCA	Proposed ACM/ICM	Amortization Expense	CCA
TS Switchgear - Gas, Transformer	New ICM	$ -			$ -	$ -		$ -			$ -		
Substation Equipment, U/G Cables, Meters, Capital Contribution	New ICM	$ -			$ -	$ -		$ -			$ -		
Duct & Civil, Building	New ICM	$ -			$ -			$ -			$ -		
SCADA & DC System	New ICM	$ -			$ -			$ -			$ -		
Land	New ICM	$ -			$ -			$ -			$ -		
		$ -			$ -			$ -			$ -		
		$ -			$ -			$ -			$ -		
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		$ -			$ -			$ -			$ -		
		$ -			$ -			$ -			$ -		
Total Cost of ACM/ICM Projects		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Price Cap IR (Deferred Rebasing) (if necessary)

		Price Cap IR	
		Year 9 2025	Year 10 2026
Distribution System Plan CAPEX		$ -	$ -
Materiality Threshold		$ 1,870,728	$ 1,870,728
Maximum Eligible Incremental Capital (Forecasted Capex less Threshold)	$ -	$ -	$ -

		Year 9 2025			Year 10 2026		
Project Descriptions:	Type	Proposed ACM/ICM	Amortization Expense	CCA	Proposed ACM/ICM	Amortization Expense	CCA
TS Switchgear - Gas, Transformer	New ICM	$ -			$ -		
Substation Equipment, U/G Cables, Meters, Capital Contribution	New ICM	$ -			$ -		
Duct & Civil, Building	New ICM	$ -			$ -		
SCADA & DC System	New ICM	$ -			$ -		
Land	New ICM	$ -			$ -		
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		$ -			$ -		
Total Cost ofACM/ICM Projects		$ -	$ -	$ -	$ -	$ -	$ -

Ontario Energy Board

Capital Module
Applicable to ACM and ICM

Halton Hills Hydro Inc.

Incremental Capital Adjustment **Rate Year:** **2019**

Current Revenue Requirement

Current Revenue Requirement - Total		$	10,458,405	**A**

Eligible Incremental Capital for ACM/ICM Recovery

	Total Claim		Eligible for ACM/ICM (Prorated Amount) *(from Sheet 10b)*	
Amount of Capital Projects Claimed	$23,476,441	$	23,476,441	**B**
Depreciation Expense	$ 608,789	$	608,789	**C**
CCA	$ 1,884,447	$	1,884,447	**V**

ACM/ICM Incremental Revenue Requirement Based on Eligible Amount in Rate Year

Return on Rate Base

Incremental Capital			$	23,476,441	**B**
Depreciation Expense (prorated to Eligible Incremental Capital)			$	608,789	**C**
Incremental Capital to be included in Rate Base (average NBV in year)			$	23,172,047	**D = B - C/2**
	% of capital structure				
Deemed Short-Term Debt	4.0%	**E**	$	926,882	**G = D * E**
Deemed Long-Term Debt	56.0%	**F**	$	12,976,346	**H = D * F**
	Rate (%)				
Short-Term Interest	1.65%	**I**	$	15,294	**K = G * I**
Long-Term Interest	2.89%	**J**	$	375,016	**L = H * J**
Return on Rate Base - Interest			$	390,310	**M = K + L**
	% of capital structure				
Deemed Equity %	40.00%	**N**	$	9,268,819	**P = D * N**
	Rate (%)				
Return on Rate Base -Equity	9.19%	**O**	$	851,804	**Q = P * O**
Return on Rate Base - Total			$	1,242,114	**R = M + Q**

Amortization Expense

Amortization Expense - Incremental	**C**	$	608,789	**S**

Grossed up Taxes/PILs

Regulatory Taxable Income		**O**	$	851,804	**T**
Add Back Amortization Expense (Prorated to Eligible Incremental Capital)		**S**	$	608,789	**U**
Deduct CCA (Prorated to Eligible Incremental Capital)			$	1,884,447	**V**
Incremental Taxable Income			-$	423,854	**W = T + U - V**
Current Tax Rate	26.5%	**X**			
Taxes/PILs Before Gross Up			-$	112,321	**Y = W * X**
Grossed-Up Taxes/PILs			-$	152,818	**Z = Y / (1 - X)**

Incremental Revenue Requirement

Return on Rate Base - Total	**Q**	$	1,242,114	**AA**
Amortization Expense - Total	**S**	$	608,789	**AB**
Grossed-Up Taxes/PILs	**Z**	-$	152,818	**AC**
Incremental Revenue Requirement		$	1,698,085	**AD = AA + AB + AC**

Ontario Energy Board

Capital Module
Applicable to ACM and ICM

Halton Hills Hydro Inc.

Calculation of incremental rate rider. Choose one of the 3 options:

Rate Class	Service Charge % Revenue	Distribution Volumetric Rate % Revenue kWh	Distribution Volumetric Rate % Revenue kW	Service Charge Revenue	Distribution Volumetric Rate Revenue kWh	Distribution Volumetric Rate Revenue kW	Total Revenue by Rate Class	Billed Customers or Connections	Billed kWh	Billed kW	Service Charge Rate Rider	Distribution Volumetric Rate kWh Rate Rider	Distribution Volumetric Rate kW Rate Rider
	From Sheet 8	*From Sheet 8*	*From Sheet 8*	Col C * Col I_{total}	Col D* Col I_{total}	Col E* Col I_{total}	*Col I_{total}*	*From Sheet 4*	*From Sheet 4*	*From Sheet 4*	Col F / Col K / 12	Col G / Col L	Col H / Col M
RESIDENTIAL	55.08%	6.38%	0.00%	935,240	108,280	0	1,043,520	20,188	193,694,443		4.31	0.0000	0.0000
GENERAL SERVICE LESS THAN 50 kW	5.97%	4.99%	0.00%	101,314	84,738	0	186,052	1,810	50,527,239		4.66	0.0017	0.0000
GENERAL SERVICE 50 TO 999 kW	1.88%	0.00%	14.75%	31,865	0	250,421	282,286	186	135,373,696	394,783	14.28	0.0000	0.6343
GENERAL SERVICE 1,000 TO 4,999 kW	0.24%	0.00%	8.81%	4,027	0	149,576	153,603	11	99,309,703	262,132	30.51	0.0000	0.5706
UNMETERED SCATTERED LOAD	0.14%	0.05%	0.00%	2,390	830	0	3,220	152	934,714		1.31	0.0009	0.0000
SENTINEL LIGHTING	0.19%	0.00%	0.24%	3,232	0	4,156	7,388	173	260,238	704	1.56	0.0000	5.9034
STREET LIGHTING	1.25%	0.00%	0.05%	21,210	0	805	22,016	4,674	1,128,400	3,155	0.38	0.0000	0.2552
Total	**64.74%**	**11.42%**	**23.85%**	**1,099,279**	**193,847**	**404,959**	**1,698,085**	**27,194**	**481,228,433**	**660,774**			
							1,698,085						
							From Sheet 11, E93						

Appendix C

2015-Northwest-GTA-IRRP-Report-1

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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.

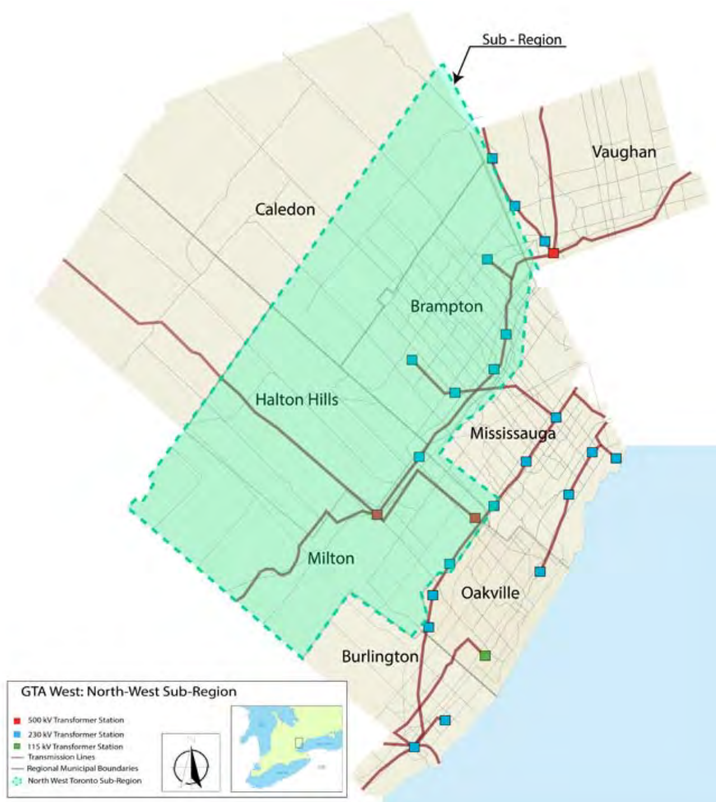
This report is organized as follows:

- 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)

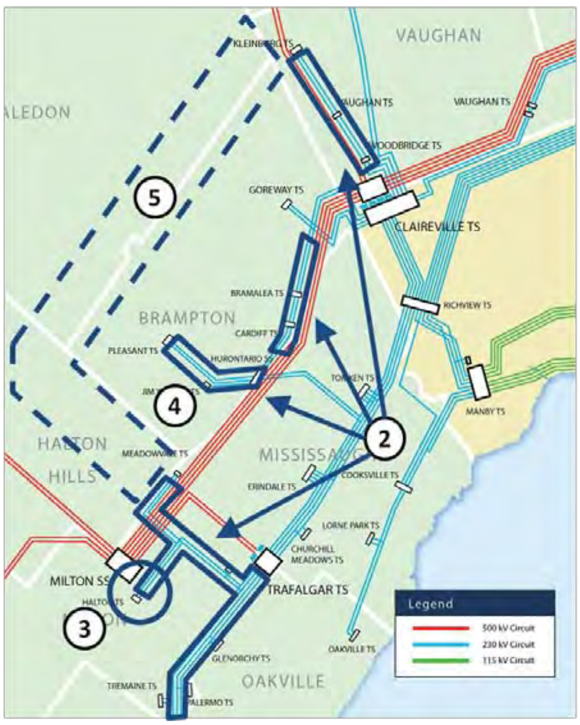


For the near and medium term, the IRRP identifies specific investments to be implemented. This is necessary to ensure that they are in service in time to address the region's more urgent needs, respecting the lead time for their development.

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

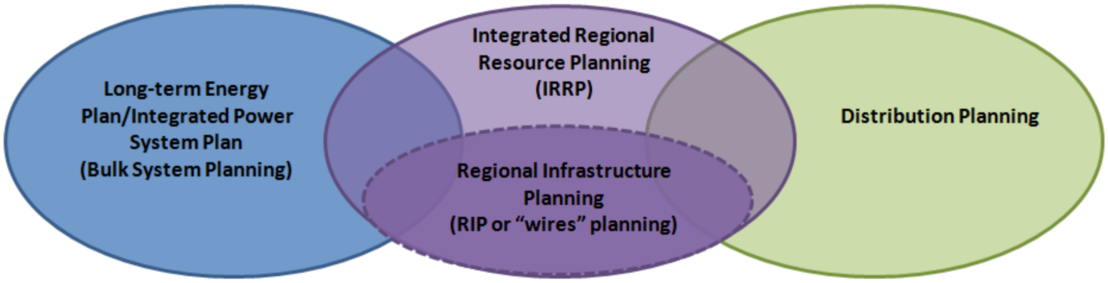
Infrastructure Plan ("RIP") is developed. The scoping assessment process also identifies any sub-regions that require assessment. There may also be regions where infrastructure investments do not require regional coordination and can be planned directly by the distributor and transmitter, outside of 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

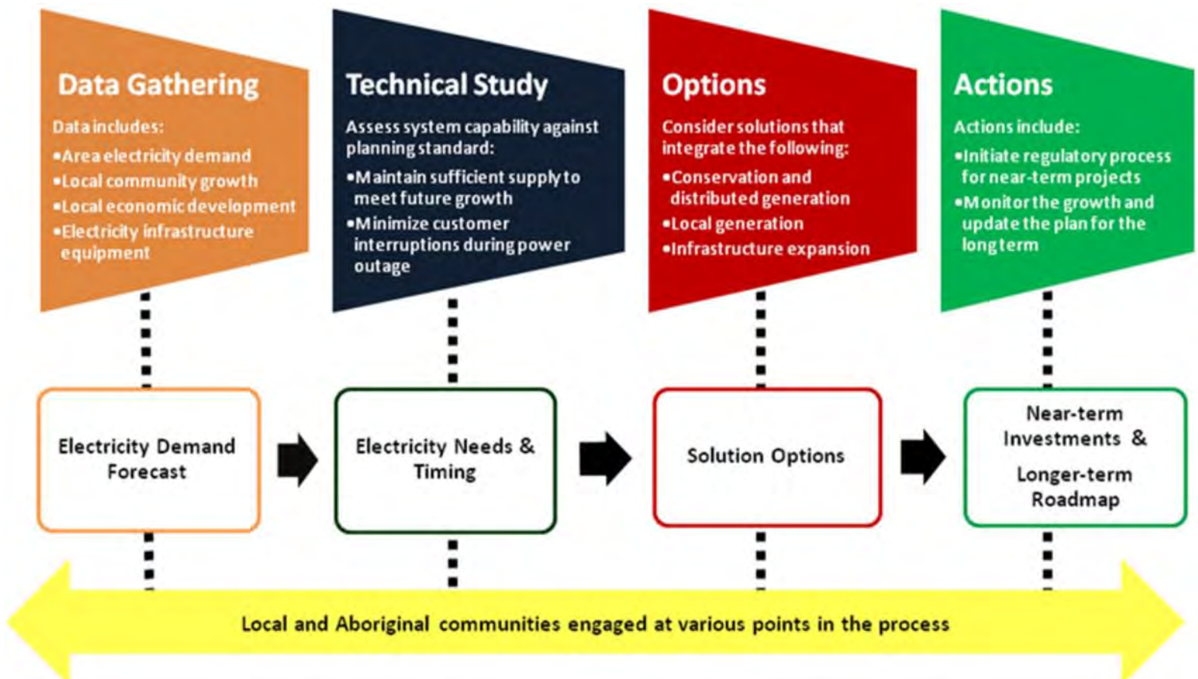
IRRPs assess electricity system needs for a region over a 20-year period. The 20-year outlook anticipates long-term trends so that near-term actions are developed within the context of a longer-term view. This enables coordination and consistency with the long-term plan, rather than simply reacting to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

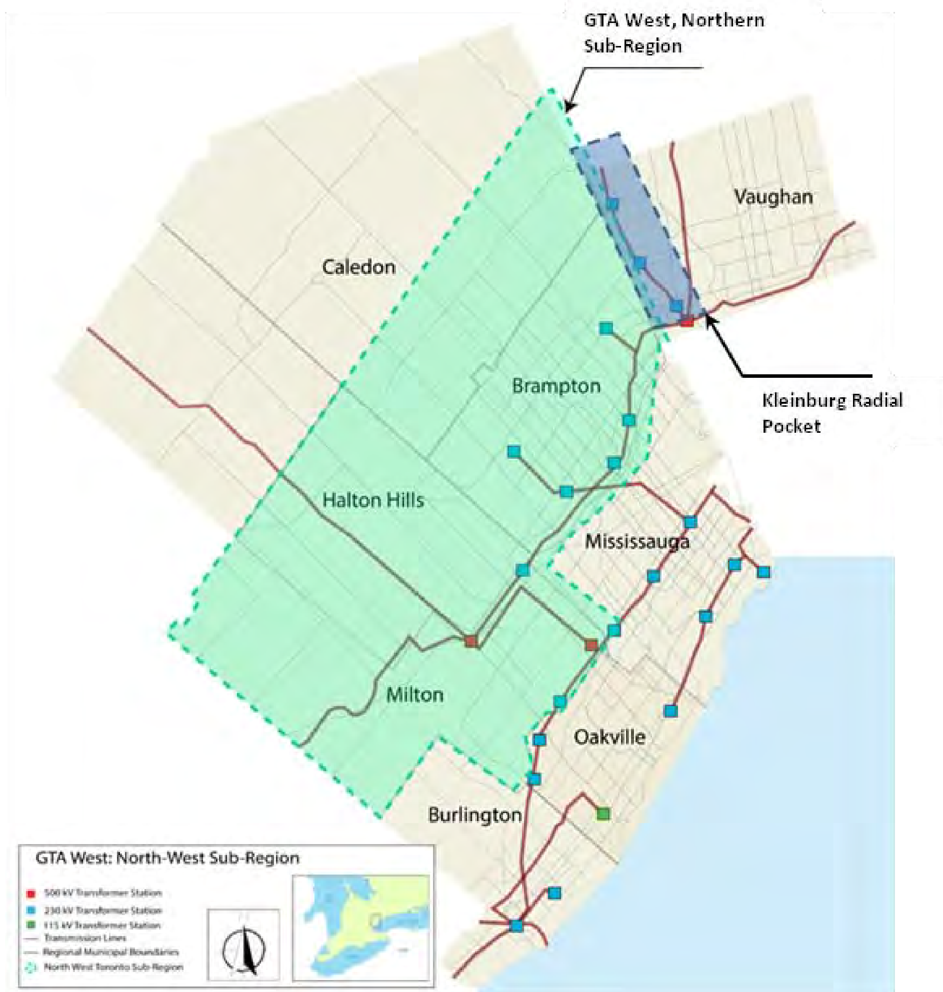
This report presents an integrated regional electricity plan for NW GTA for the 20-year period from 2014 to 2033. The planning process leading to this IRRP began in 2013, in recognition of the high electrical demand growth observed over the previous 10 years, expanding urban boundaries, limited existing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

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[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

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

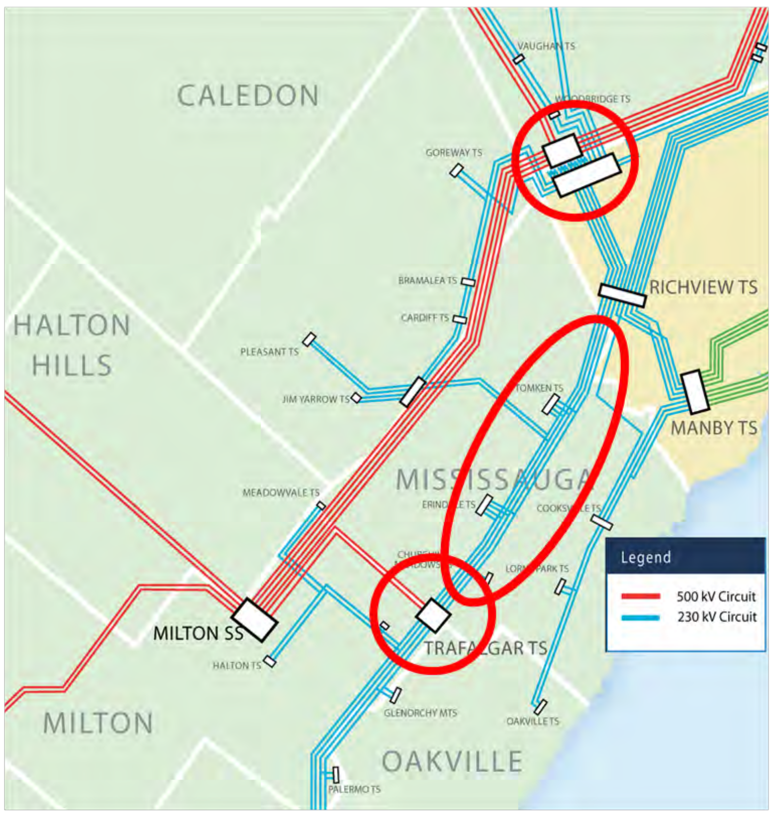
the area, provides switching for 500 kV circuits. Currently there are no 500-230 kV transformation facilities at this station.

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]

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

5. Load Forecast

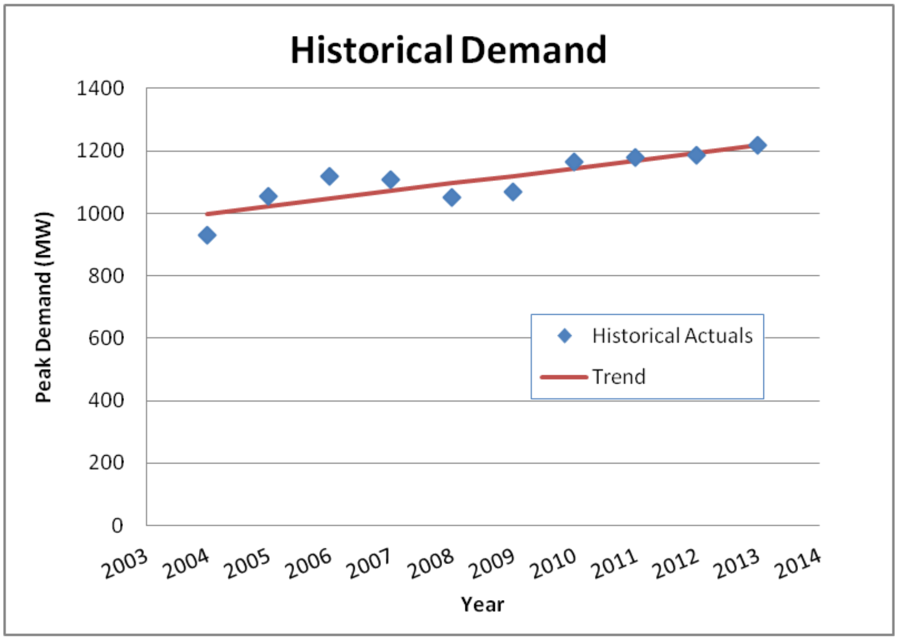
This section outlines the forecast of electricity demand within the Northwest GTA sub-region. It highlights the assumptions made for peak-demand load forecasts, the contribution of conservation to reducing peak demand and the role of distributed generation resources in supplying demand in this area. 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)

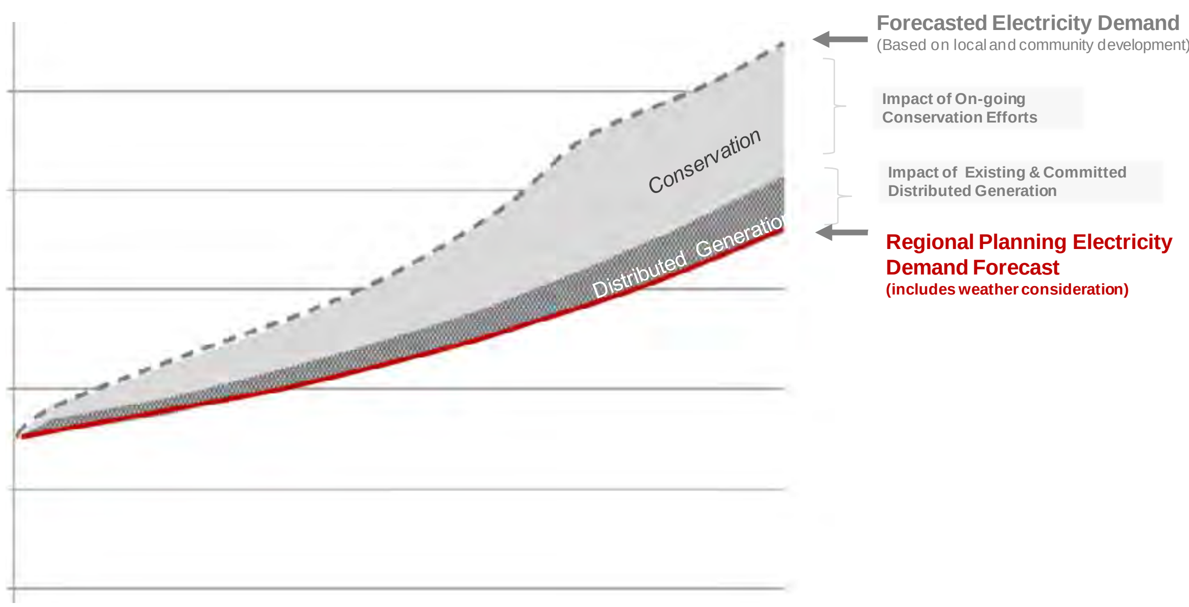
LDC	2009	2010	2011	2012	2013	Avg % Growth
Hydro One Brampton	739.35	800.67	807.70	810.65	825.55	2.32 %
Milton Hydro	130.82	143.42	156.18	156.93	168.28	6.05 %
Halton Hills Hydro	85.67	93.67	92.69	92.83	97.09	2.41 %
Hydro One Distribution (Caledon)	114.39	128.42	123.28	125.45	126.44	1.73 %
TOTAL	1070.24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

[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

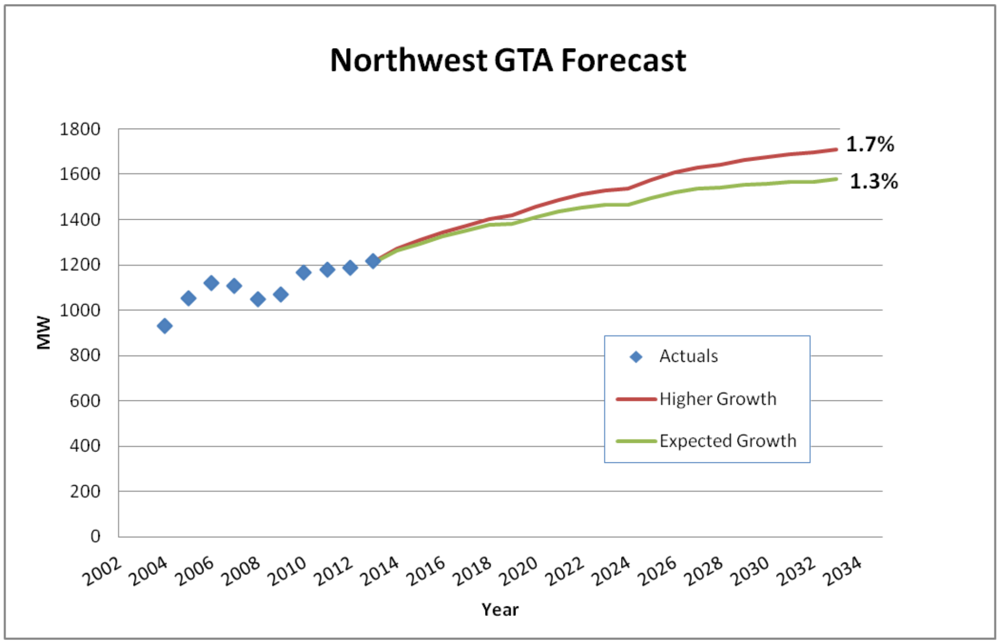
As described above, the IESO developed two planning forecasts:

- 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.

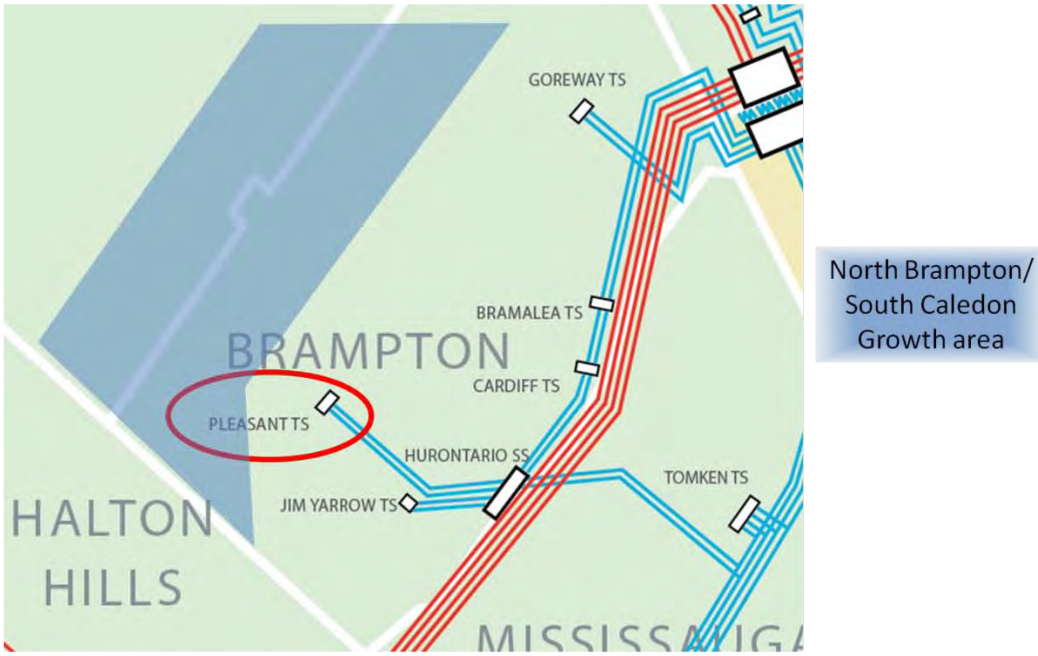
The following constraints must be accounted for when developing options for providing relief to Halton TS:

- **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.

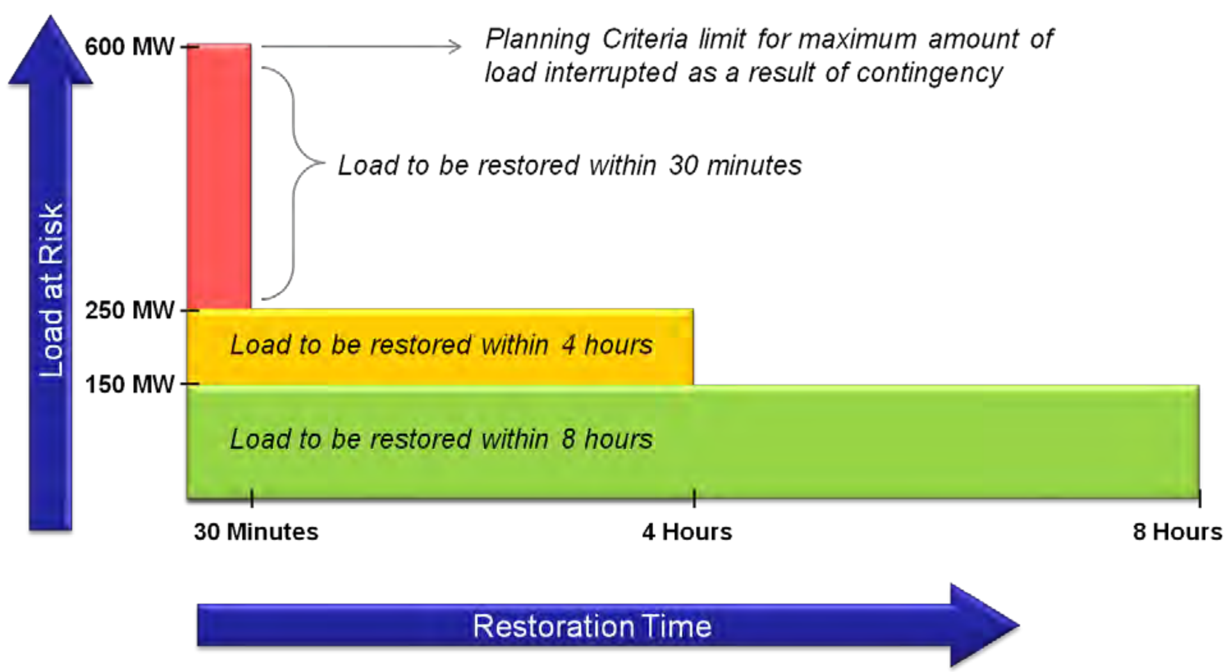
Actual loading on the 44 kV Pleasant TS will need to be reviewed during the next regional planning cycle given that the actual need date may vary from 2033. If new loads cannot be fully offset through conservation and DG initiatives, a new transmission line will be required to enable incremental capacity 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.

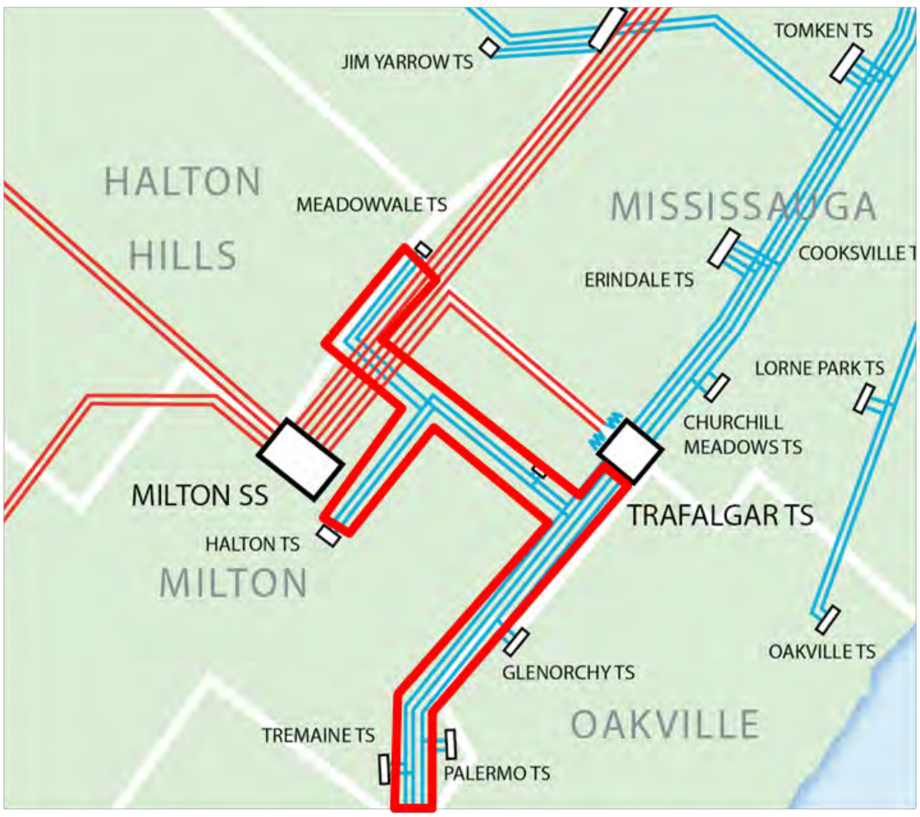
Because NW GTA is a densely populated area, it is assumed that sufficient maintenance and operations workforce are nearby to perform necessary repairs and restore loads within eight hours for expected failure modes. As a result, this analysis will only focus on 30-minute and four-hour restoration capability.

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

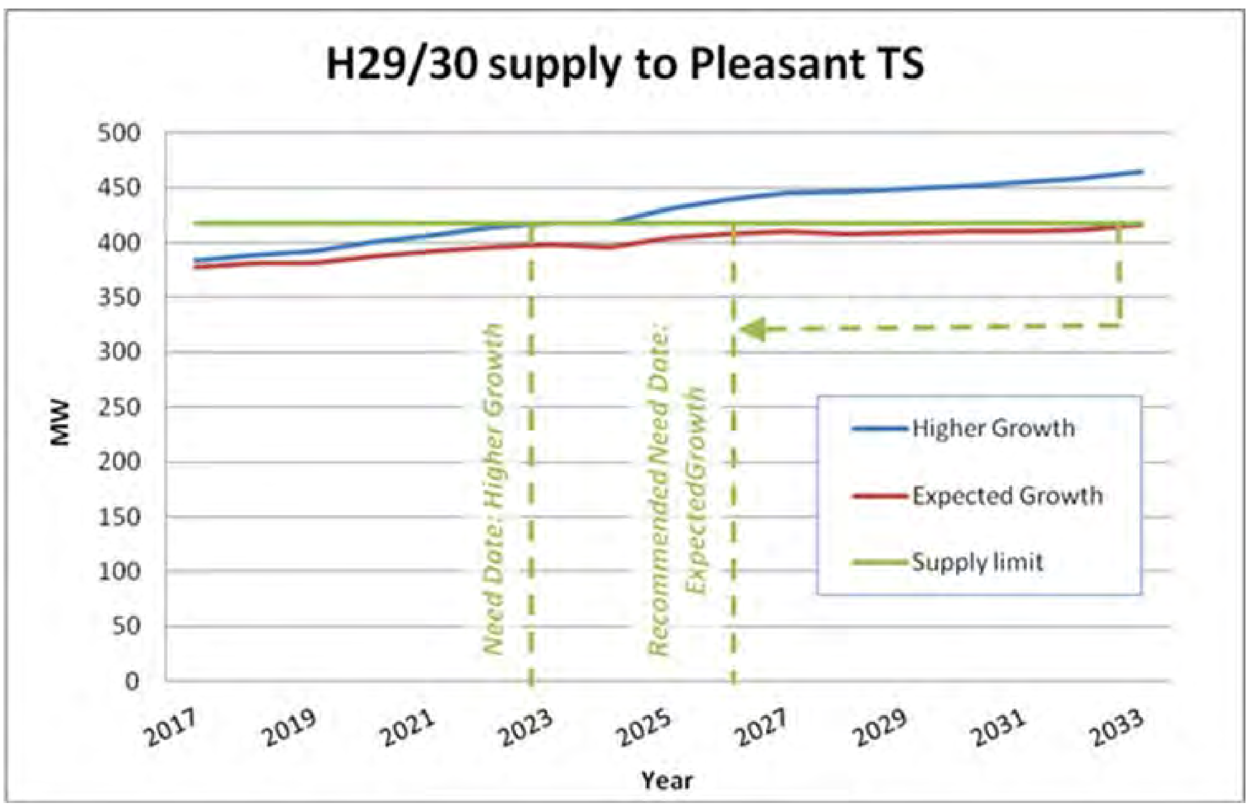


Figure 6-7 also shows that the need date under the Higher Growth forecast is less sensitive to small variations in demand, due to a stronger annual growth rate. As a result, it is not recommended that the need date be advanced under the Higher Growth forecast.

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.

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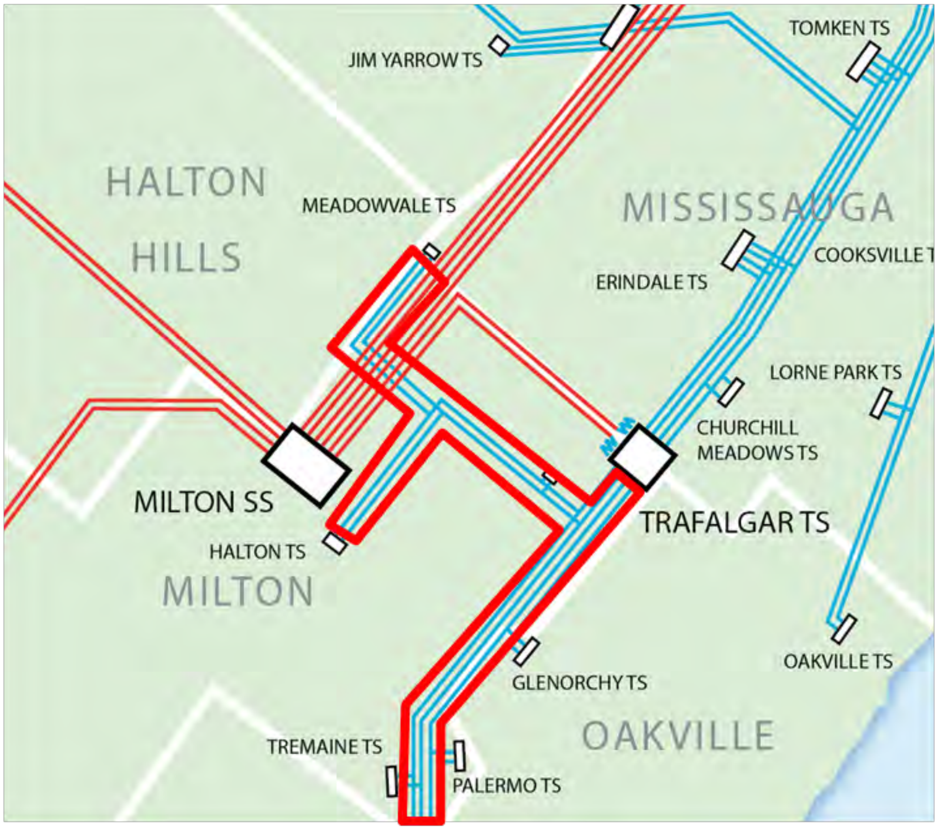
[11] http://www.ieso.ca/Documents/caa/caa_SIAReportFinalDraft_2006-231_R2.pdf.
[12] http://www.ieso.ca/Documents/caa/caa_SIAReportFinalDraft_2006-248_R2.pdf

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.

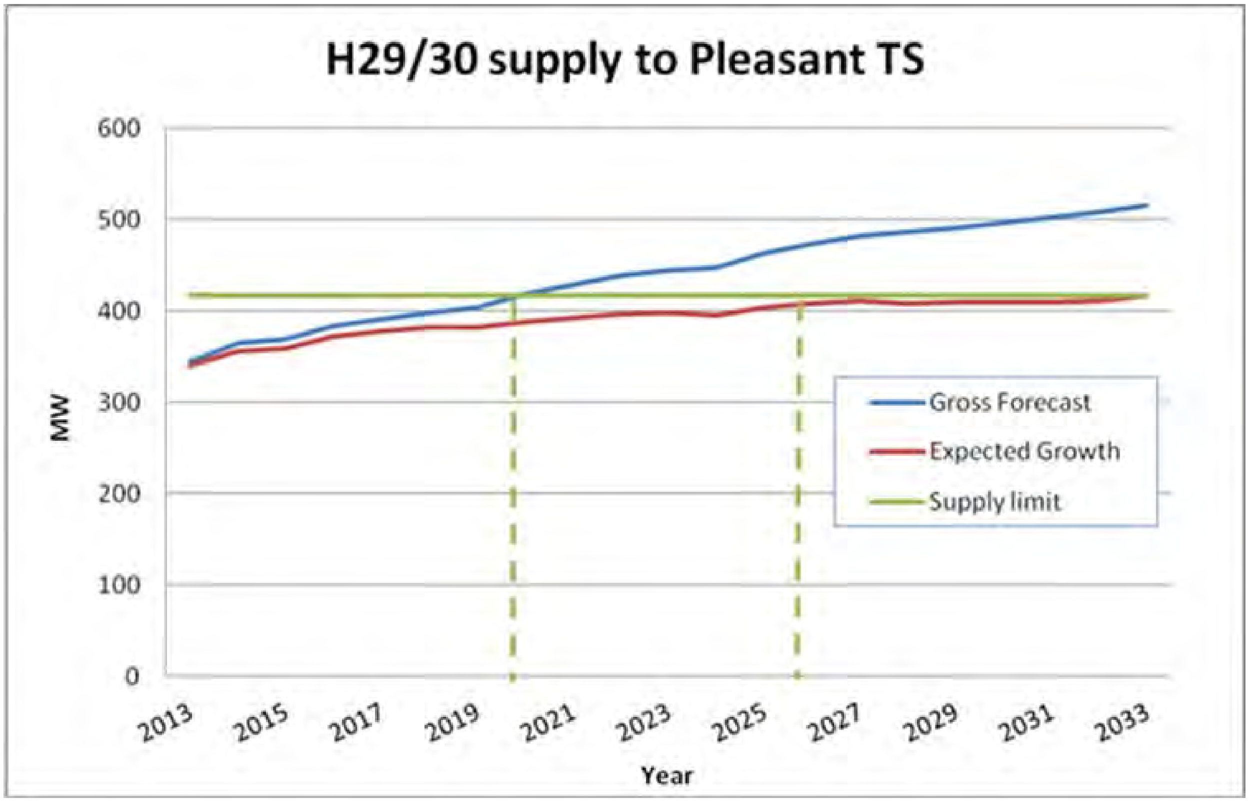
The examples below demonstrate the expected economic benefit from the achievement of the expected peak-demand savings from the LTEP energy reduction targets in two key areas in Northwest GTA: the Pleasant TS and Kleinburg TS service territories. While Pleasant TS and Kleinburg TS have been highlighted, 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.

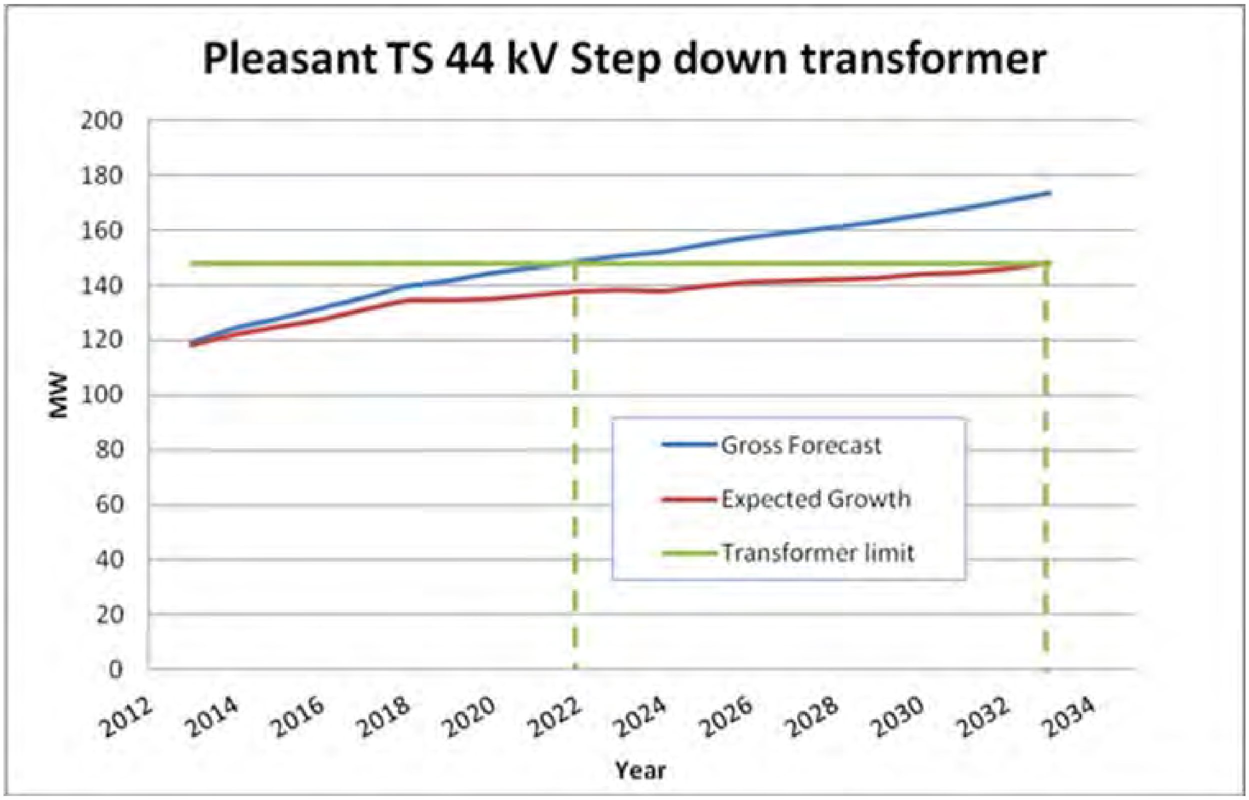
Figure 7-1: Effect of Conservation on H29/30 Needs



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

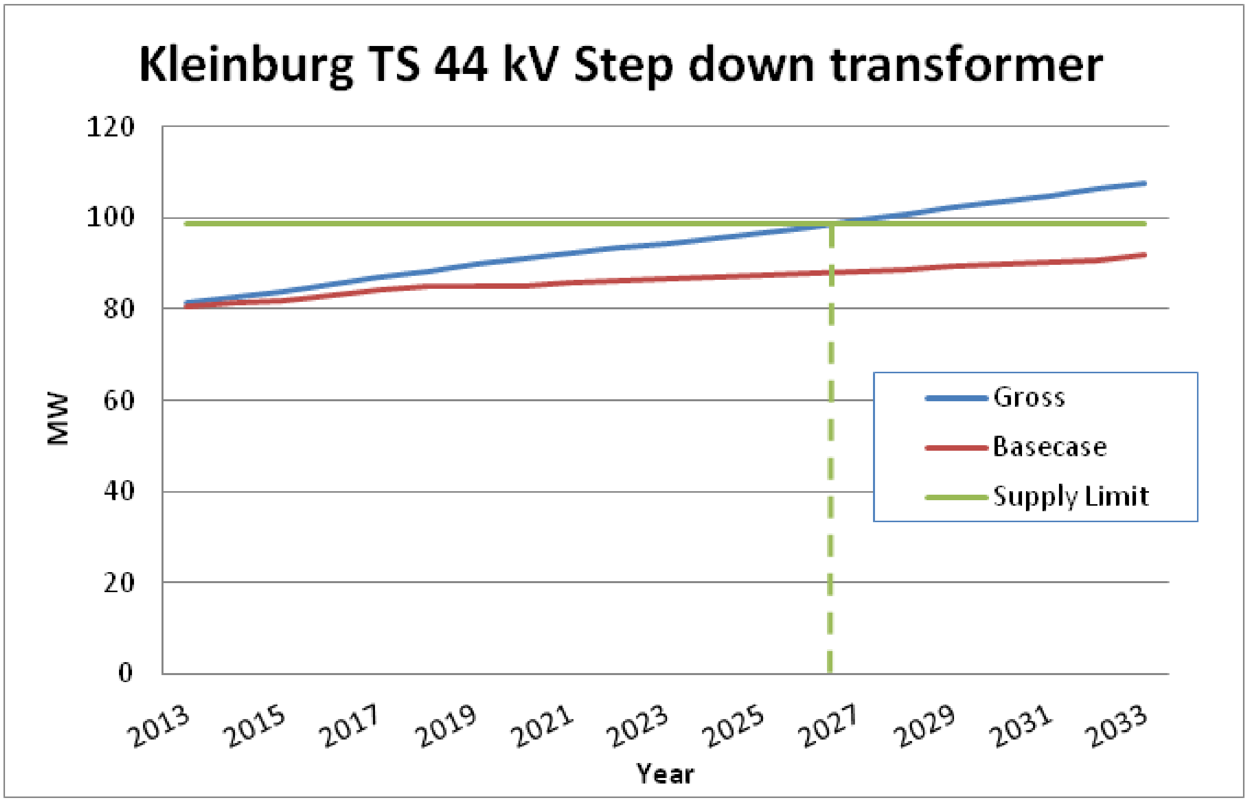


Kleinburg TS – Step-down transformer needs

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.

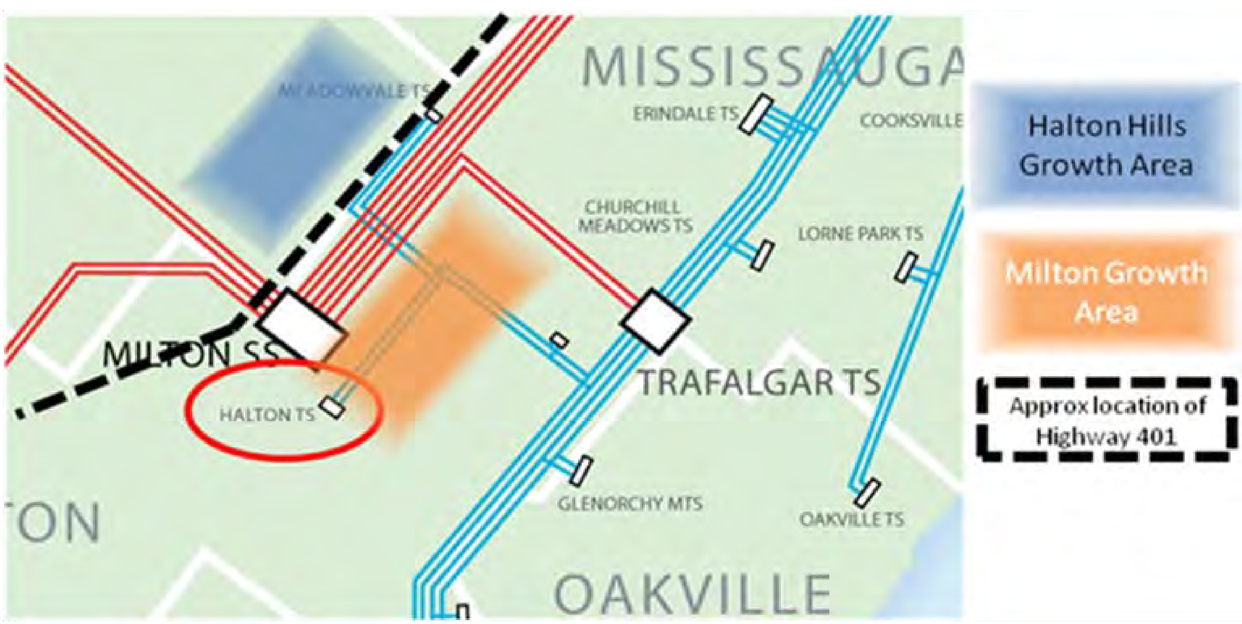
- **Meadowvale TS**: This station outputs at the 44 kV distribution level and so is not suitable for meeting growth currently supplied at the 27.6 kV level from Halton TS.

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,

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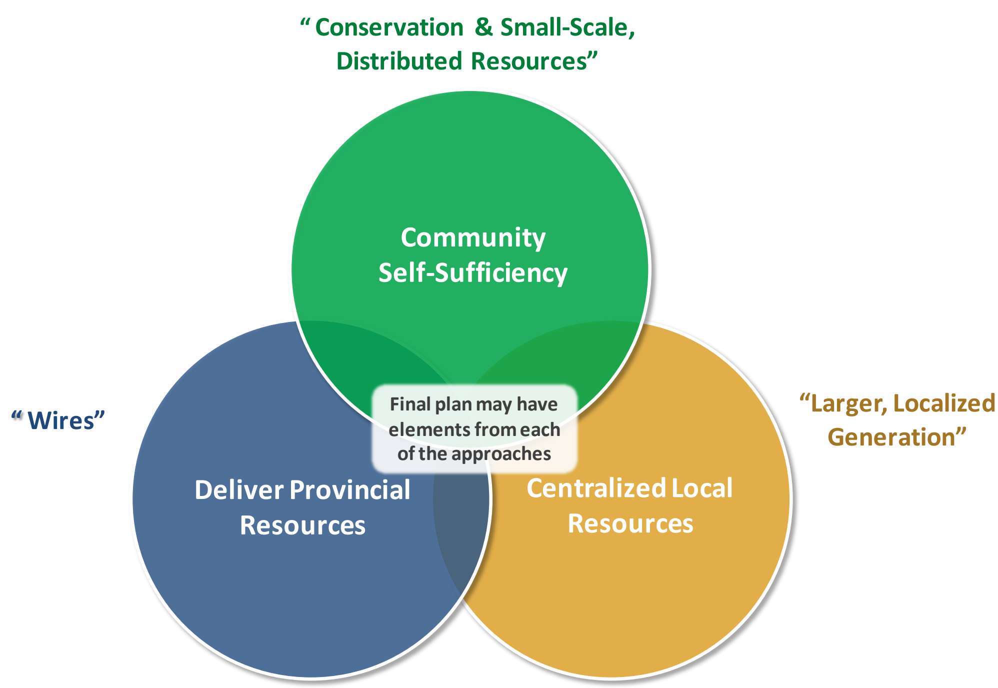
[14] http://www.mah.gov.on.ca/AssetFactory.aspx?did=10463

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.

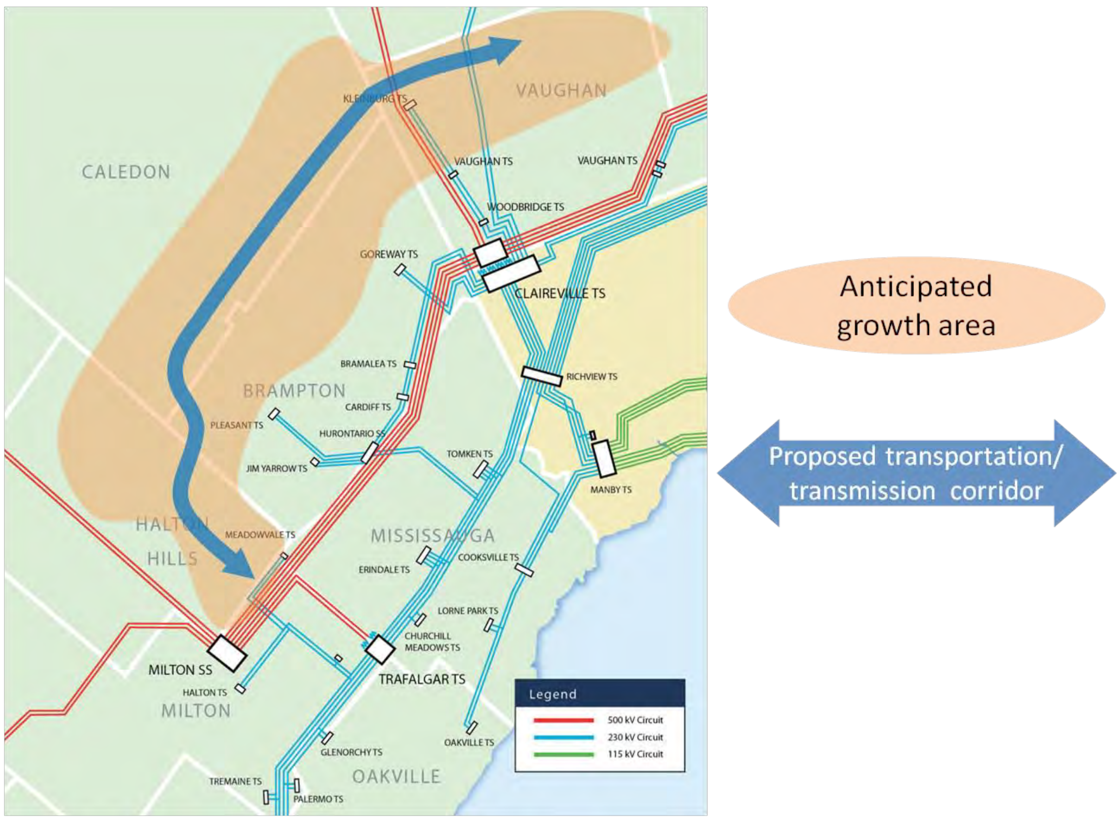
If peak reduction efforts, including conservation and distributed generation, are unable to defer these capacity needs (both circuit and transformer) and distribution solutions such as load transfers prove technically or economically infeasible, a new step-down transformer station will be required in 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.

Appendix D

Stantec HHH Load Forecast - January 2017

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Load Forecast Report for Halton Hills Hydro 27.6 kV Distribution System

Load Forecast of 27.6kV Distribution System of Halton Hills Hydro Inc.

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Revision 1.0

Sign-off Sheet

This document entitled Load Forecast Report for Halton Hills Hydro 27.6 kV Distribution System was prepared by Stantec Consulting Ltd. ("Stantec") for the account of Halton Hills Hydro Inc. (the "Client"). Any reliance on this document by any third party is strictly prohibited. The material in it reflects Stantec's professional judgment in light of the scope, schedule and other limitations stated in the document and in the contract between Stantec and the Client. The opinions in the document are based on conditions and information existing at the time the document was published and do not take into account any subsequent changes. In preparing the document, Stantec did not verify information supplied to it by others. Any use which a third party makes of this document is the responsibility of such third party. Such third party agrees that Stantec shall not be responsible for costs or damages of any kind, if any, suffered by it or any other third party as a result of decisions made or actions taken based on this document.

Prepared by AMIR ______________________________
(signature)

Amir Tashakori, P.Eng.

Reviewed by ______________________________
(signature)

Mike Voll

Revision Record

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C	Final Report Issue	A. Tashakori	AT	M.Boloorchi	MB	M.Voll	12/20/16
D	Revised Final Report including Client Comments	M.Voll	MV	A.Tashakori	AT	M.Voll	01/11/17

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Executive Summary

This load forecast has been performed for three 27.6 kV feeders, Nos. 41M21, 41M29 and 41M30, out of the Halton 230kV-27.6kV transformer station (TS), which are supplying Halton Hills Hydro's (HHH) southern territory.

Forecasting the load growth on each of the above feeders, has been performed for a 10-year period, starting from 2016, based on the methodology, assumptions, load records and information as described herein.

Because of the effect of the provincially mandated conservation target, a stable load growth rate has been considered for load growth projection during the 10-year study period. Two growth rates have been used to develop the expected growth forecast and higher growth forecast scenarios. The combined expected impact of conservation and distributed generation by station across the study area, has been considered to develop the expected growth forecast. However, for the higher growth forecast, half of the peak-demand reduction due to the conservation target was accounted for in the forecast. In addition, other expected loads, as specified by HHH are added to the calculated load of each year. Planned load growth in Georgetown South (the Vision Georgetown document) is added to the closest feeder (41M30).

Studies show that by 2020, assuming a high load growth forecast, the feeders will be overloaded, as each 27.6 kV feeder can only supply about 15.5 MW to nearby loads, and new feeders will be needed to avoid equipment overloading or load shedding and unwanted service interruption at peak time. This conclusion is valid if load transfer between feeders (e.g. from 41M21 to 41M29 or vice versa or between other feeders) is possible. Otherwise, new feeders are needed earlier when any of the feeders has reached its maximum allowed load, with no (further) possibility of load transfer to other feeders.

Abbreviations

CCAP	Climate Change Action Plan
GHG	Greenhouse Gases
HHH	Halton Hills Hydro (Client)
HONI	Hydro One Networks Inc.
LF	Loss Factor
OPO	Ontario Planning Outlook
PF	Power factor
TS	Transformer/Transmission Station

Glossary

Diversity Factor	The ratio of the sum of the individual non-coincident maximum demands of various subdivisions of the system to the maximum demand of the complete system. The diversity factor is always 1 or greater.
Maximum Demand	The greatest of all the demands that have occurred during a specified period of time; determined by measurement over a prescribed time interval.

1.0 INTRODUCTION

Halton Hills Hydro Inc. (HHH) wishes to develop a load forecast for their distribution system. This report addresses the first section of their system associated with the 27.6kV system.

The goal of this report is to prepare a load forecast for each small area which is supplied by each of the three 27.6 kV feeders, Nos. 41M21, 41M29 and 41M30, out of the Halton 230 kV-27.6kV transformer station (TS), thereby increasing the accuracy of the analysis. The intent is to structure this report in such a way as to facilitate the streamlined integration of other feeder systems in the future.

Total Halton Hills load is around 87MW and almost 35% of it is on the 27.6 kV feeders. Halton TS has 12 feeders and three of them (41M21, 41M29, and 41M 30) belong to HHH. The Halton TS is already expanded to its full capacity and there is not enough space for adding new feeders. The IESO IRRP [6] concludes that by 2018, two new transmission substations are required for serving the future loads in Milton and Halton Hills. Based on the technical and economic considerations, one of stations should be on the north side of the 401 highway (serving Halton Hills), and the other one on the south side of the 401 highway (for serving Milton). In this way, a minimum or no crossing of the highway for distribution lines is expected.

2.0 METHODOLOGY

For the current studies, available historical records on HHH 27.6 kV loads and other load forecasting reports as addressed in the references are analyzed to provide a basis for each feeder's load, load growth rate and annual load increase. Then, with a calculated basis of each feeder load and growth rate, the load for the perspective years, (period of 2017 to 2026) for each feeder is calculated.

The Climate Change Action Plan (CCAP) is very high level and although some of the referenced tables within this report detail a high rate of substitution of gas and oil with electricity, the total load growth rate is still below the calculated growth rate in this report (see Section 4.0). In addition, any significant, referenced loads within the CCAP, such as new transportation electrification facilities, have already been accounted for in this load forecast. For this reason, input from the CCAP does not impact this load forecast.

In this study the following formula is used for load forecasting:

$$Y_n = Y_{n-1} * (1+r_n) + Y_{ne}$$

In which;

Y_n: Load at year n;

Y_{n-1}: Load at year n-1;

r_n: Load growth rate at year n; and

Y_{ne}: Expected load at year n;

Note: The expected load at year n (Y_{ne}), is the load that is not forecasted in the load growth rate calculation. This load (except for the Vision Georgetown anticipated loads), is only considered in the load forecasting with higher growth rate.

3.0 ANALYZING LOAD RECORDS

Table 1 below summarizes the load history received from HHH. Table 1 outlines a maximum demand for each feeder at each year in the period of 2005 to 2016. As shown, for the first five years, the total 27.6 kV distribution system maximum demand is not provided, therefore, diversity factors and load growth rates have only been calculated based on information given for the period of 2010 to 2016. The 2016 maximum demand is calculated from current records since the maximum demand occurs in the summer. Monthly data has been provided under Appendix A.

Table 1 – Maximum Demand for Each Feeder and for 27.6 kV Distribution System within the Period of 2005 to 2016 Based on HHH Historical Data

Year	41M21 (MW)	41M29+ 41M30 (MW)	Total (MW)	Diversity factor
2005	19.9	-	NA	
2006	17.0	18.8	NA	
2007	17.7	8.3	NA	
2008	16.8	17.1	NA	
2009	17.5	25.2	NA	
2010	20.2	18.4	28.5	1.353
2011	19.2	19.0	30.1	1.272
2012	19.6	18.9	30.0	1.282
2013	14.3	20.3	30.9	1.120
2014	17.3	20.8	29.2	1.306
2015	17.7	20.4	29.5	1.293
2016	15.3	26.9	31.4	1.343
Annual Load Growth Rate			**1.65%**	

3.1 NORTHWEST GTA FORECAST

The IESO IRRP [6] states that "Under the Expected 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."

Figure 1 below shows both planning forecasts, along with historic demand in the Northwest greater Toronto Area including the Halton Hills Hydro distribution system.

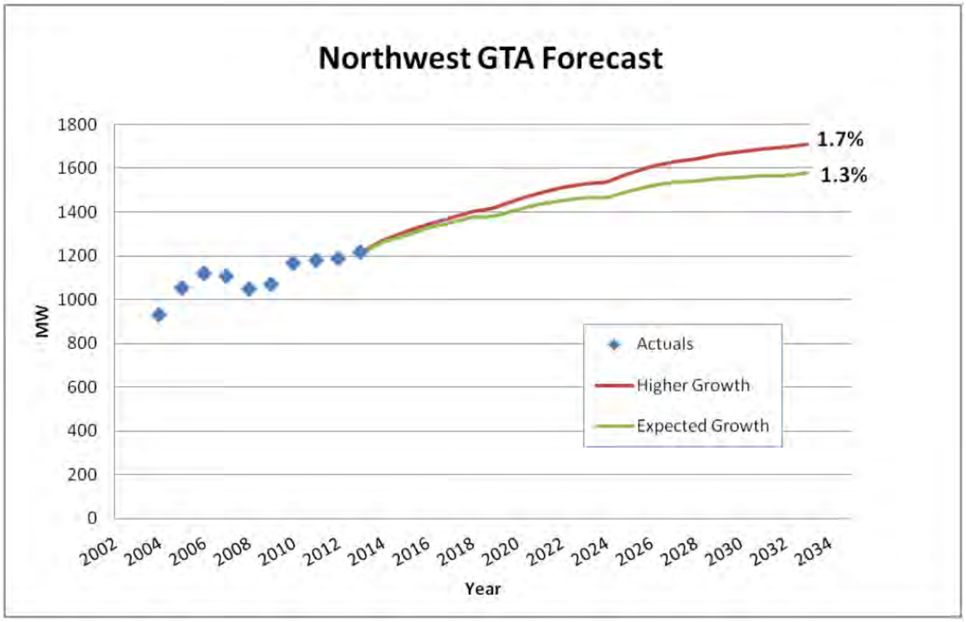

Figure 1 – Historical Demand and Expected and Higher Growth Forecasts from IESO Report [6]

Review and analysis of the information, given in Table 1 above, indicates that:

1. The maximum annual peak demand occurs between July and September.
2. The growth rate of maximum demand during the period of 2010 to 2016 is around 1.65%, based on the maximum demand of 28.5MW at 2010.

The calculated actual load growth rate (1.65%) is comparable to the IESO forecasted expected rate (1.68%). As stated above, as per the IESO IRRP [6], the expected load growth rate and high load growth rate for the mid-term planning period are 1.65% and 2.06%. The mid-term planning period is a ten-year period starting from 2015 [6]. After the mid-term, as per the IESO IRRP [6], there will be a decrease in load growth rate for the years beyond 2025. The maximum demand growth rate, for the mid-term and long-term planning periods, are summarized in Table 2 below and is compared with the calculated maximum demand growth rate for the period of 2010-2016 only.

Table 2 – Load Growth Rate for Different Periods and Scenarios (Mid-Term and Long Term)

Period	2015-2025 Mid-Term(1)	2026-2035 Next Medium-Term(1)	2015-2035 Long-Term(1)	Calculated Growth Rate for 2010-2016
Expected	1.68%	0.82%	1.3%	1.65%
Highest	2.06%	1.18%	1.7%	Not calculated

(1) Reference: Integrated Regional Resource Plan, Northwest Greater Toronto Area Sub-Region, IESO 2015

4.0 ONTARIO CLIMATE CHANGE ACTION PLAN (CCAP)

The purpose of Ontario Climate Change Action Plan is to reduce pollution and Greenhouse Gases (GHG) by reduction of oil and gas usage. Based on this plan, the IESO has conducted studies which are combined with load forecast studies for Ontario to investigate if the IESO-controlled grid has sufficient capacity to supply the new loads. This IESO Ontario Planning Outlook (OPO) [7] report details the target energy consumption (in TWh) which will be required to meet the objectives of the CCAP.

There are four outlooks presented in the IESO report, A through D. Outlook A is related to the minimum increase of electrical load and outlook D is related to the maximum load increase, (maximum energy consumption that will be transferred from oil and gas to electricity). As per Outlook D, which represents the highest increase in electrical load, the maximum energy consumption is forecasted to be 198 TWh by 2035, while it has been 144.5 TWh in 2015. It is expected most of this additional load will be related to heating devices and will be added to the winter load. However, based on the preliminary calculation as given in Table 3 below, the summer maximum demand is still higher than the winter maximum demand, and shall therefore be considered as the annual maximum demand.

Table 3 – 27.6 kV Feeders Load Considering Climate Change Action Plan

Ontario 2015 Load (TWh)	Ontario 2035 Outlook D Load (TWh)	HHH 2035 Load (0.43% of Ontario Load) (TWh)	HHH 2035 Maximum Load, Load Factor =0.7 (MW)	27.6kV Feeders load-35% of Total HHH Load (MW)
144.5	198	0.843	137.4	48.1

5.0 LOAD FORECASTING FOR PERIOD OF 2016 TO 2025

The maximum annual demand of each feeder, for the period of 2010 to 2026, based on the expected growth rate of 1.65% is shown in Table 4 below and based on the higher growth rate of 2.06% is given in Table 5. Please note that both Table 4 and Table 5 include anticipated additional loads in addition to load forecasts associated with Vision Georgetown [3], which is based on an average, linear annual growth rate over the forecasting period.

For the purposes of this assessment, a 27.6 kV feeder is assumed to be at full capacity when it reaches 15.5 MW.

Table 4 – Expected Load Forecast with 1.65% Load Growth Rate and Planned New Loads are in Service

	From	Load statistic-MW							10 years Load Forecast-MW										
		2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Feeder																			
41M21 load including expected load	**Halton TS**	**12.8**	**13.0**	**13.2**	**13.4**	**13.6**	**13.9**	**14.1**	**14.3**	**14.7**	**14.9**	**15.2**	**15.4**	**15.7**	**15.9**	**16.2**	**16.4**	**16.7**
41M21 Base Load Calculation[1]		12.8	13.0	13.2	13.4	13.6	13.9	14.1	14.3	14.6	14.8	15.0	15.3	15.5	15.8	16.1	16.3	16.6
Expected Annual load growth[1]			0.21	0.21	0.22	0.22	0.23	0.23	0.23	0.24	0.24	0.24	0.25	0.25	0.26	0.26	0.27	0.27
Expected new loads										0.108	0.108	0.108	0.108	0.108	0.108	0.108	0.108	0.108
41M29 load including expected load	**Halton TS**	**8.8**	**9.0**	**9.1**	**9.3**	**9.4**	**9.6**	**9.8**	**11.4**	**11.5**	**11.7**	**11.9**	**12.0**	**12.2**	**12.4**	**12.6**	**12.8**	**12.9**
41M29 Base Load Calculation[1]		8.8	9.0	9.1	9.3	9.4	9.6	9.8	9.9	10.1	10.2	10.4	10.6	10.8	10.9	11.1	11.3	11.5
Expected Annual load growth[1]			0.15	0.15	0.15	0.15	0.16	0.16	0.16	0.16	0.17	0.17	0.17	0.17	0.18	0.18	0.18	0.19
Expected new loads			0.15	0.15	0.15	0.15	0.16	0.16	0.16	0.16	0.17	0.17	0.17	0.17	0.18	0.18	0.18	0.19
41M30 load including expected load	**Halton TS**	**6.9**	**7.0**	**7.1**	**7.2**	**7.3**	**7.5**	**8.6**	**13.4**	**15.7**	**16.4**	**18.8**	**23.6**	**26.4**	**29.3**	**32.1**	**34.9**	**37.7**
41M30 Base Load Calculation[1]		6.9	7.0	7.1	7.2	7.3	7.5	7.6	7.7	7.8	8.0	8.1	8.2	8.4	8.5	8.7	8.8	8.9
Expected Annual load growth[1]			0.11	0.12	0.12	0.12	0.12	0.12	0.13	0.13	0.13	0.13	0.13	0.14	0.14	0.14	0.14	0.15
Expected new loads without Vision Georgetown								1.00	5.68	7.89	8.44	10.69	12.71	12.71	12.71	12.71	12.71	12.71
Vision Georgetown													2.68	5.36	8.04	10.71	13.39	16.07
Total		28.5	29.0	29.4	29.9	30.4	30.9	32.4	39.1	41.9	43.0	45.8	51.1	54.3	57.6	60.8	64.1	67.4

1- Load growth rate 1.65%

Table 5 – High Load Forecast with 2.06% Load Growth Rate and Planned New Loads are in Service

	From	Load statistic-MW							10 years Load Forecast-MW										
		2010	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
Feeder																		
41M21 load including expected load	**Halton TS**	**12.8**	**13.0**	**13.3**	**13.6**	**13.9**	**14.1**	**14.4**	**14.7**	**15.1**	**15.5**	**15.8**	**16.1**	**16.4**	**16.8**	**17.1**	**17.5**	**17.8**
41M21 Base Load Calculation[1]		12.8	13.0	13.3	13.6	13.9	14.1	14.4	14.7	15.0	15.3	15.7	16.0	16.3	16.7	17.0	17.3	17.7
Expected Annual load growth[1]			0.26	0.27	0.27	0.28	0.29	0.29	0.30	0.30	0.31	0.32	0.32	0.33	0.34	0.34	0.35	0.36
Expected new loads										0.108	0.108	0.108	0.108	0.108	0.108	0.108	0.108	0.108
41M29 load including expected load	**Halton TS**	**8.8**	**9.0**	**9.2**	**9.4**	**9.6**	**9.8**	**10.0**	**11.7**	**11.9**	**12.1**	**12.3**	**12.5**	**12.7**	**13.0**	**13.2**	**13.5**	**13.7**
41M29 Base Load Calculation[1]		8.8	9.0	9.2	9.4	9.6	9.8	10.0	10.2	10.4	10.6	10.8	11.1	11.3	11.5	11.8	12.0	12.3
Expected Annual load growth[1]			0.18	0.19	0.19	0.19	0.20	0.20	0.21	0.21	0.21	0.22	0.22	0.23	0.23	0.24	0.24	0.25
Expected new loads									1.45	1.45	1.45	1.45	1.45	1.45	1.45	1.45	1.45	1.45
41M30 load including expected load	**Halton TS**	**6.9**	**7.0**	**7.2**	**7.3**	**7.5**	**7.6**	**8.8**	**13.6**	**16.0**	**16.7**	**19.1**	**24.0**	**26.9**	**29.7**	**32.6**	**35.4**	**38.3**
41M30 Base Load Calculation[1]		6.9	7.0	7.2	7.3	7.5	7.6	7.8	7.9	8.1	8.3	8.4	8.6	8.8	9.0	9.2	9.3	9.5
Expected Annual load growth[1]			0.14	0.14	0.15	0.15	0.15	0.16	0.16	0.16	0.17	0.17	0.17	0.18	0.18	0.18	0.19	0.19
Expected new loads without Vision Georgetown								1.000	5.683	7.893	8.442	10.69	12.71	12.71	12.71	12.71	12.71	12.71
Vision Georgetown													2.679	5.357	8.036	10.71	13.39	16.07
Total		28.5	29.1	29.7	30.3	30.9	31.6	33.2	40.0	43.0	44.2	47.2	52.6	56.0	59.5	62.9	66.4	69.8

1- Load growth rate 2.06%

6.0 CONCLUSIONS AND RECOMMENDATIONS

Preliminary load analysis and load forecast results are presented within Table 1 to Table 5 of this report. The load forecast is done for a 10-year period from 2017 to 2026. Ten years' forecast is considered as a mid-term load forecast.

As shown in Table 5 above, feeder overloading will begin in 2017; however, the addition of new feeders may not be required considering the load transfer capability between the feeders. Nevertheless, this load transfer capability will end by the end of 2019 and the addition of a new feeder will then be needed. This new feeder cannot be provided through expansion of the existing Halton TS #1; as there is no space for further expansion. Therefore, it is essential to have the new Halton TS by the end of 2019 at the latest. This assessment is consistent with Table 6-1 in the IESO IRRP where, for meeting both the Expected and Higher Growth scenarios, a new 27.6 kV step-down station serving Halton Hills Hydro is required, approximately by 2018.

7.0 REFERENCES

[1] HHH_Map_Operators_276k_Oct28_2016_R2.

[2] HHH Historical Loading for Halton TS spreadsheet. (Appendix A)

[3] Vision Georgetown Second Status Update – Phase 2 File D08 VI (Vision Georgetown)

[4] Load Forecast - Engineering Dec 2016 spreadsheet (Appendix B)

[5] Halton_Appl_Exhibit- 2_Rate_Base_Part_2_Distribution_System_Plan_ 20151 (HHH DSP).

[6] NORTHWEST GREATER TORONTO AREA INTEGRATED REGIONAL RESOURCE PLAN, Part of the GTA West Planning Region | April 28, 2015 (IESO IRRP)

[7] Ontario Planning Outlook, a technical report on the electricity system prepared by IESO September 1,2016 (IESO OPO)

[8] Ontario Energy Board HHH 2015 Yearbook

[9] Ontario's Five Year Climate change action plan 2016-2020

APPENDIX A

Halton TS Non-Coincident Peak Data

APPENDIX A
HALTON TS NON-COINCIDENT PEAK DATA

Year	Month	M21 (kW)	M29 & M30 (kW)	M21 (MW)	M29 & M30 (MW)	Total (MW)	Diversity Factor
2005	1	12569		19.9	N/A	N/A	
	2	10505					
	3	10547					
	4	9961					
	5	11754					
	6	19470					
	7	19876					
	8	18531					
	9	16766					
	10	13336					
	11	11938					
	12	13547					
2006	1	12039		17.0	18.8	N/A	
	2	12220					
	3	12220					
	4	13416	7196				
	5	15272	7614				
	6	14747	18759				
	7	16974	7796				
	8	13268	7997				
	9	9333	7714				
	10	9920	6967				
	11	10427	3436.59				
	12	11834	3628				
2007	1	11150	3647	17.7	8.3	N/A	
	2	11911	3894				
	3	10607	7036				
	4	9399	7179				
	5	12709	8072				
	6	17736	8338				
	7	17269	8305				
	8	16613	8162				
	9	15740	7859				
	10	13777	7670				
	11	12655	4406				
	12	14139	7705				

APPENDIX A
HALTON TS NON-COINCIDENT PEAK DATA

Year	Month	M21 (kW)	M29 & M30 (kW)	M21 (MW)	M29 & M30 (MW)	Total (MW)	Diversity Factor
2008	1	12277	4227	16.8	17.1	N/A	
	2	12369	5331				
	3	10889	6991				
	4	9479	15214				
	5	9628	8074				
	6	16597	8498				
	7	16821	8546				
	8	15356	8857				
	9	14992	8666				
	10	11030	8658				
	11	14011	5080				
	12	12990	17082				
2009	1	13273	5370	17.5	25.2	N/A	
	2	11801	5351				
	3	10742	25163.97				
	4	9961	8848				
	5	10566	9037				
	6	17181	8942				
	7	12783	9506				
	8	17499	9455				
	9	12525	9262				
	10	10781	9206				
	11	12492	5511				
	12	13832	8830				
2010	1	13070	5783	20.2	18.4	28.5	1.353
	2	12265	6051.07				
	3	11019	9364.61				
	4	10167	9369.99				
	5	17181	9577.28				
	6	19115	9632.73				
	7	20177	9843.35				
	8	17889	10092.41				
	9	12574	11311.95				
	10	10090	9326.1				
	11	11643	5747.26				
	12	5321	18401.33				

APPENDIX A
HALTON TS NON-COINCIDENT PEAK DATA

Year	Month	M21 (kW)	M29 & M30 (kW)	M21 (MW)	M29 & M30 (MW)	Total (MW)	Diversity Factor
2011	1	0	17390.52	19.2	19.0	30.1	1.272
	2	9832	17982.13				
	3	11061	19039.72				
	4	9757	9938.61				
	5	15275	10488.84				
	6	16807	10792				
	7	19229	11428.18				
	8	15868	11212.11				
	9	12207	18939.35				
	10	10605	9831.06				
	11	12322	12430.49				
	12	12754	10123.93				
2012	1	12098	15960.39	19.6	18.9	30.0	1.282
	2	12630	16376.61				
	3	10712	8971.07				
	4	10166	9548.55				
	5	15939.48	16456.39				
	6	18747.7	15533.37				
	7	19560.37	13947.49				
	8	13033.31	14548.21				
	9	12830.36	18862.84				
	10	8457.87	16588.05				
	11	9575.57	11576.78				
	12	10251.92	11046.94				
2013	1	9717.87	8954.72	14.3	20.3	30.9	1.120
	2	9333.01	8342.63				
	3	8849.7	11290.85				
	4	7814.83	17082.68				
	5	11022.26	20319.96				
	6	13392.46	15731.27				
	7	14310.85	17503.37				
	8	12302.06	17081.87				
	9	13240.45	17333.31				
	10	11244.17	13753.65				
	11	9703.96	13497.86				
	12	9950.76	13793.46				

Stantec

APPENDIX A
HALTON TS NON-COINCIDENT PEAK DATA

Year	Month	M21 (kW)	M29 & M30 (kW)	M21 (MW)	M29 & M30 (MW)	Total (MW)	Diversity Factor
2014	1	9659.04	18128.47	17.3	20.8	29.2	1.306
	2	9028.08	10463.17				
	3	8880.1	13682.56				
	4	7110.23	13339.36				
	5	9785.89	14587.96				
	6	17310.46	15518.23				
	7	17157.82	16483.61				
	8	12064.32	17297.18				
	9	12414.99	17459.62				
	10	7675.92	14249.08				
	11	12702.03	20777.79				
	12	13745.19	11213.94				
2015	1	9116.33	18578.88	17.7	20.4	29.5	1.293
	2	182.83	19572.69				
	3	1008.02	19399.21				
	4	11141.01	19618.02				
	5	17670.6	13082.79				
	6	10805.76	14492.41				
	7	13576.47	16403.37				
	8	13546.53	16322.33				
	9	14583.26	20421.72				
	10	7744.21	18695.73				
	11	8963.28	19064.56				
	12	9240.78	18536.17				
2016	1	9619.74	9685.66	15.3	26.9	31.4	1.343
	2	8802.41	9468.35				
	3	8397.16	12551.15				
	4	8240.88	19181.35				
	5	12319.27	14539.07				
	6	14538.61	26920.07				
	7	14832.44	25791.96				
	8	14539.58	16426.29				
	9	15305.4	17024.98				
	10	7892.03	13665.48				
	11	N/A	N/A				
	12	N/A	N/A				
Annual Load Growth Rate						1.651%	

APPENDIX B

Halton Load Forecast Data

APPENDIX B
HALTON LOAD FORECAST DATA

Load Forecast - Engineering (Dec. 2016)

Development Name	# of Lots	Proposed Feeder	Number of Transformers	Size of Transformation (kW)	Number of Connections	Customer Specified Demand Load (kW)	Estimate Load kW (Low)	Estimate Load kW (Medium)	Estimate Load kW (High)	Connection Date (Estimated)
First Gulf @ Cleve Court	1	41M29	1	2500	1-2	1540	924	1232	1540	2017
Building A - West Bridge Drive			1	1000	1	n/a	750	775	800	2017
Building B - West Bridge Drive			1	2000	1	n/a	1500	1550	1600	2017
Building C - West Bridge Drive	3	41M30	1	3000	1	1900	1425	1472.5	1520	2017
Toronto Premium Outlets	1		3-4	2500-3500	6	n/a	1300	1450	1600	2018
Toronto Premium Outlets	1	41M30	1	750	1	667	500.25	516.925	533.6	2017
Halton Hills Village Phase 5 & 6 (Residential)					50	n/a	125	175	225	2017
Halton Hills Village Phase 5 & 6 (Residential)					91	n/a	227.5	318.5	409.5	2018
Halton Hills Village Phase 5 & 6 (Residential)					122	n/a	305	427	549	2019
Halton Hills Village Phase 5 & 6 (Residential)					141	n/a	352.5	493.5	634.5	2020
Halton Hills Village Phase 5 & 6 (Residential)	649		74	50	169	n/a	422.5	591.5	760.5	2021
Halton Hills Village Phase 5 & 6 (School)	1	41M30	1	300	1	n/a	150	195	240	? (see Note1)
Region of Halton Water Pump Station (Trafalgar Road)	1	41M21	1	150	1	90	72	90	108	2018
Norval Development Area (F4 in HHHI DSP)	300-400	41M30	45-50	50	?	n/a	1200	1560	1920	? (see Note1)
Broccolini, 11400 Steeles Avenue	1	41M30	1	1000	1	1250	750	1000	1250	2016
9 Brigden Gate	1	41M29	1	750	1	274	164.4	219.2	274	2017
29 Brownridge Drive	1	41M30	1	500	1	n/a	375	387.5	400	2017/2018
Premier Gateway Phase 1B	Study phase only. No siginficant land use concepts yet. Potential of commerical development to replace developable lands frozen by MTO for 400 series highway.									
Town Surplus Land (Halton Hills Drive).	?	41M21	?	DSP identifies connection to 27.6kV, Support Trafalgar Road MS Better.						
Vision Georgetown (Residential Lots)	7000	New TS	784	50	7000	n/a	19600	25480	31360	2021-2031
Vision Georgetown (Elementary School)	6	New TS	6	500	6	n/a	1800	2100	2400	2021-2031
Vision Georgetown (High School)	1	New TS	1	1000	1	n/a	600	700	800	2021-2031
Vision Georgetown (Municipal Public Building)	1	New TS	1	500	1	n/a	250	325	400	2021-2031
Vision Georgetown (Grocery Stores)	1	New TS	1	1000	1-2	n/a	500	650	800	2021-2031
Vision Georgetown (Gas Stations)	2	New TS	2	150	1-2	n/a	150	180	210	2021-2031

Revised November 16, 2016 - First Gulf (Cleve Court) and TPO Parking Garage. TPO demand load increased from original estimate, see comments in "Customer specified Demand Load" for both sites.

Revised December 14, 2016 - Modified anticipated connection horizon for highlighted cells. Expanded Halton Hills Village Phase 5 & 6 to 5 years connection horizon and included approximate connection per year based on current information. Estimated load for HHVH Ph 5 & 6 is based on

Note 1: Connection date for load forecasting in current report is considered 2020.

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Appendix E

2015 Town CAO Letter

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TOWN OF
HALTON HILLS
Working Together Working for You!

December 15, 2015

Mr. Arthur Skidmore
President & CEO
Halton Hills Hydro Inc.
43 Alice Street
Acton, Ontario.
L7J 2A9

Re: Vision Georgetown

Dear Mr. Skidmore,

Further to our discussion of Halton Hills Hydro Inc.'s rate application process wherein your Regulator has inquired about the likelihood of Vision Georgetown proceeding, I can confirm that Vision Georgetown is definitely going ahead as per Regional Official Plan Amendment No. 38/ Sustainable Halton. There is an active Vision Georgetown Committee consisting of developers, councillors and Town staff.

It is the Town's expectation that Halton Hills Hydro Inc. will be able to provide the necessary energy needs to Vision Georgetown prior to 2021.

Thank you for your continued efforts and dedication to the community of Halton Hills.

Sincerely,

Brent Marshall
Chief Administrative Officer
Town of Halton Hills

1 Halton Hills Drive, Halton Hills, Ontario L7G 5G2

Tel: 905-873-2601 Toll Free: 1-877-712-2205 Fax: 905-873-2347 Web: www.haltonhills.ca

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Appendix F

HHHI Specific Kinetrics Report

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James Macumber
Enersource Corporation
3240 Mavis Road
Misissauga, ON
L5C 3K1

Enersource Corporation, Burlington Hydro, Oakville Hydro, Halton Hills Hydro & Milton Hydro Useful Life of Assets

Kinectrics Inc. Report No: K-418022-RA-0001-R003

December 10, 2009

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

DISCLAIMER

Kinectrics Inc. has prepared this report in accordance with, and subject to, the terms and conditions of the agreement between Kinectrics Inc. and Enersource Corporation, Burlington Hydro, Oakville Hydro, Halton Hills Hydro & Milton Hydro.

Enersource Corporation, Burlington Hydro, Oakville Hydro, Halton Hills Hydro, & Milton Hydro Useful Life of Assets

Kinectrics Inc. Report No: K-418022-RA-0001-R002

November 23, 2009

Prepared by:

Fan Wang
Engineer
Distribution and Asset Management Department

Leslie Greey
Engineer
Distribution and Asset Management Department

Reviewed by:

Katrina Lotho
Engineer
Distribution and Asset Management Department

Approved by:

Yury Tsimberg
Director – Asset Management
Transmission and Distribution Technologies

Dated: December 10, 2009

Enersource Corporation, Burlington Hydro, Oakville Hydro, Halton Hills Hydro & Milton Hydro Useful Life of Assets

To: **James Macumber**
Enersource Corporation
3240 Mavis Road
Mississauga, Ontario L5C 3K1

Burlington Hydro
1340 Brant Street,
Burlington, Ontario L7R 3Z7

Oakville Hydro
P.O. Box 1900
861 Redwood Square
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Halton Hills Hydro
43 Alice Street
Acton, Ontario L7J 2A9

Milton Hydro Distribution Inc.
55 Thompson Road South
Milton, Ontario L9T 6P7

Revision History

Revision Number	Date	Comments	Approved
R000	October 8, 2009	Initial Draft	n/a
R001	October 28, 2009	Finalized Draft	
R002	November 23, 2009	Finalized Report	

Table of Contents

1 Executive Summary

1.1 Introduction

One of the aspects of switching to International Financial Reporting Standards (IFRS) methodology that Ontario's Local Distribution Companies (LDCs) are embarking upon is trying to align the time period assets are amortized over with their actual useful life.

This is a rather onerous task because LDCs own and operate a large number of assets that are divided into different asset categories, each with its own degradation mechanism and useful life range. Moreover, some assets are comprised of several components that may have differing useful life than the assets themselves. It is therefore important for LDCs to properly account for the useful lives of assets and their components to facilitate conversion to IFRS.

This report reviews the useful lives of the assets, and their components that are applicable to Enersource Corporation, Burlington Hydro, Oakville Hydro, Halton Hills Hydro and Milton Hydro (the Consortium). The useful life values are compiled from several different sources, namely, industrial statistics, research studies and reports (either by individuals or working groups such as CIGRE), and Kinectrics experience, all listed in Section 35 of this Report. Useful lives of assets are dependent on a number of utilization factors (mechanical stress, electrical loading, environmental factors and operating practices) that are described in more detail in Section 1.4 of this report and it is worth noting that the useful lives of assets do not generally follow standard distribution curves as they are derived from empirical statistics.

1.2 Project Scope

This report provides an in-depth evaluation of the useful lives of the assets that are owned and operated by the Consortium members. The typical parent system(s) to which the asset belongs is provided and these "parent" systems are: *Overhead Lines* (OH), *Transmission Stations* (TS), *Municipal Stations* (MS), *Underground Systems* (UG) and *Monitoring and Control System* (S). The long term degradation mechanism of each asset category is described for each asset category and when applicable assets are sub-categorized into components: components are included when their cost is material enough and, at the same time, component could be replaced without a need to replace the whole asset. For each asset or component, the following information is presented:

- Useful Life Range
- Typical Life
- Typical time-based maintenance intervals, if applicable
- Impact of Utilization Factors

Section 1.4 provides definitions for the above terms, as well as descriptions of typical distribution system assets and asset components.

1.3 Project Execution Process

The project execution process entailed a number of steps to ensure that the industry-based information compiled by Kinectrics not only includes all the relevant assets and components used by Consortium, but also that it addresses the specific needs related to the IFRS review. The procedure is as follows:

- The initial list of assets and components was produced by the Consortium members to Kinectrics for review.
- Upon review of the initial list, Kinectrics generated an intermediate asset list that had a somewhat different background, granularity, and componentization, based on industry practices and Kinectrics experience.
- The intermediate list was reviewed jointly by the Consortium members and Kinectrics to derive a "final" list.
- For each asset and component in the "final" list, Kinectrics then gathered the information described in Section 1.2 from the sources described in Section 1.1 of this report. A Draft Report that summarized the findings and provided detail descriptions, including degradation mechanisms and applicable assumptions for each asset, was then produced.
- This Draft Report was reviewed by the Consortium members and their feedback was incorporated in the Final Report.

1.4 Definition of Terms

1.4.1 *Typical Distribution System Asset*

Typical distribution system assets include transformers, breakers, switches, underground cables, poles, vaults, cable chambers, etc. Some of the assets, such as power transformers, are rather complex systems and include a number of components.

1.4.2 *Component*

For the purposes of this study, component refers to the sub-category of an asset that meets both of the following criteria:

- Its value is significant enough, relative to the asset value.
- A need to replace the component does not necessarily warrant replacing the entire asset.

An *asset* may be comprised of more than one component, each with an independent failure mode and degradation mechanism that may result in a substantially different useful life than the overall asset. A component may also have an independent maintenance and replacement schedule.

1.4.6 *Impact of Utilization Factors*

For the purpose of this report, stress that impacts the assets refers to *Mechanical Stress* (MC), *Electrical Loading* (EL), *Environmental Conditions* (EN) and/or *Operating Practices* (OP):

- Mechanical stress includes factors such as wind and ice that leads to degradation over time
- Electrical loading refers to either constant loading that creates long term degradation or temporary overloading that may causes a severe degradation
- Environmental conditions include pollution, salt, acid rain, extreme temperature and detrimental animals (i.e. woodpeckers) that may cause degradation over time
- Operating practices refers to how frequently an asset is subject to operating procedure (automatic or manual) that impacts its useful life, e.g. reclosers operations.

Each asset could be impacted by one or more of these factors resulting in a different degradation rates for the same assets and/or components in different jurisdictions. Therefore, it is expected that some of the utility specific typical life values would be different than the ones provided in this report based on the qualitative assessment of the above factors.

1.5 Summary of Findings

Table 1-1 summarizes useful and typical lives, time based maintenance schedules, and impact of stress for Consortium assets.

Table 1-1 Summary of Componentized Assets

Report Section #	Parent*	Asset Category	Componentization *(sub category)*		Useful Life *(years)*			Maint. Type**	Time Based Maint. Schedule *(years)*	Impact of Stress***	Reference #
					Minimum	Typical	Maximum				
2	OH	Wood Poles	Pole		40	44	50	RI	15	MC, EN	[1], [2], [3], [4], [38],[39], [40]
			Cross Arm	Wood	20	40	50				
				Composite	40	60	80				
				Steel	20	70	100				
			Bracket	Galvanized Steel	20	40	50				
			Insulator	Composite	10	20	45				
				Porcelain	40	40	50				
			Anchors & Guying		20	40	50				
3	OH	Concrete Poles	*Refer to Wood Poles (1)*		50	60	60	RI	15	MC, EN	[5], [6]
4	OH	Steel Poles	*Refer to Wood Poles (1)*		60	60	80	RI	15	MC, EN	[7], [8], [41]
5	OH	Composite Poles	*Refer to Wood Poles (1)*		50	70	100	N/A	N/A	MC	[9]

* OH = Overhead Lines TS=Transmission Stations MS=Municipal Stations UG=Underground Systems S=Monitoring & Control System
** RI=Routine Inspection RTM=Routine Testing/Maintenance
*** MC=Mechanical Stress EL=Electrical Loading EN=Environmental Factors OP=Operating Practices

Report Section #	Parent*	Asset Category	Componentization (sub category)		Useful Life (years) Minimum	Typical	Maximum	Maint. Type**	Time Based Maint. Schedule (years)	Impact of Stress***	Reference #
6	OH	Wires	Conductor	ACSR	50	60	77	N/A	N/A	MC, EL, EN	[5], [10]
				AAC	50	60	77				
				Cu	50	60	77				
				Insulated wire	50	60	77				
			Arrester								
7	OH	Pole Mounted Transformers	Transformer		30	40	60	N/A	N/A	EL, EN	[5]
			Arrester								
8	OH	Manual Overhead Line Switches			30	50	60	RTM	2	EL, EN	[6]
9	OH	Local Motorized Overhead Switches	Switch		30	50	60	RTM	2	EL, EN	[6]
			Motor		15	20	20				
10	OH	Remote Automated Overhead Switches	Switch		30	50	60	RTM	2	EL, EN	[11], [12]
			Motor		15	20	20				
			RTU		15	20	30				
11	OH	Fuse Cutouts			30	40	60	N/A	N/A	EL, EN	[6]
12	OH	Voltage Regulator			15	20	40	N/A	N/A	EL, EN, OP	[5], [42]

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Section #	Parent*	Asset Category	Componentization (sub category)		Useful Life Minimum	Useful Life Typical	Useful Life Maximum	Maint. Type**	Maint. Schedule	Impact of Stress***	Reference #
13	OH	Reclosers	Breaker	Vacuum	30	40	40	RTM	10	EL, OP	[5], [6], [11], [12]
				Oil	30	42	60				
			RTU		15	20	30				
14	TS	Station Service Transformers	Dry Type		20	30	40	RTM	3	EL, EN	[1],[13], [45],[46]
			Other		32	45	55				
15	TS	TS Power Transformers	Winding		32	45	55	RTM	2	EL, EN, OP	[1], [13], [14],[15], [16],[43] [44],[48]
			Manual/Automatic On Load Tap Changer		20	20	60				
16	MS	MS Power Transformers	Winding		32	45	55	RTM	2	EL, EN, OP	[1], [13], [14],[15], [16],[43] [44],[48]
			Manual/Automatic On Load Tap Changer		20	20	60				
17	MS	DC Station Service	Battery bank		10	20	30	RTM	1	EL, EN, OP	[6],[17], [18],[19]
			Charger		20	20	30				
18	MS	Air Insulated Switchgear	Breaker	SF6	30	42	60	RTM	6	EL, EN, OP	[1],[6], [20],[21],
				Vacuum	30	40	60				
				Air Magnetic	25	40	60				
			Switchgear assembly		40	50	60				

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Section #	Parent*	Asset Category	Componentization *(sub category)*		Useful Life Minimum	Useful Life Typical	Useful Life Maximum	Maint. Type**	Maint. Schedule	Impact of Stress***	Reference #
19	MS	Gas Insulated Switchgear	Breaker	SF6	30	42	60	RTM	6	EL, EN, OP	[1],[6], [20],[21],
				Vacuum	30	40	60				
				Air Magnetic	25	40	60				
			Switchgear assembly		40	50	60				
20	MS	Building	Building		30	50	80	RI	1	MC, EN	[13]
			Roof		15	20	20				
			Fence		30	35	45				
21	MS	Station Grounding System			25	40	50	N/A	N/A	EN	[13],[22], [23]
22	UG	UG Primary Cables	TR-XLPE	In Duct	40	40	60	N/A	N/A	EL, EN	[6],[24], [25]
				In Concrete Encased Duct	40	40	60				
				Direct Buried	20	25	40				
			Termination		25	40	60				
			Arrester								
23	UG	UG Secondary Cables	PI (polyethylene insulated)		40	40	60	N/A	N/A	EL, EN	[6],[24], [25]
			PIJ (PVC jacket)		40	40	60				

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Section #	Parent*	Asset Category	Componentization (sub category)		Useful Life			Maint. Type**	Maint. Schedule	Impact of Stress***	Reference #
					Minimum	Typical	Maximum				
24	UG	Distribution Transformer	Transformer	Pad Mounted	30	40	40	N/A	N/A	EL, EN, OP	[5],[4], [6]
				Vault	30	40	40				
				Submersible	25	35	40				
			Elbows and Inserts		20	40	60				
25	UG	Pad Mounted Switchgear	Air Insulated		20	30	40	RI	3	EL, EN, OP	[26],[27], [28]
			Gas Insulated		30	30	50				
			Solid Dielectric		30	30	50				
26	UG	Vault Switch	Metal Enclosed Switch		20	30	40	RI	3	EL, EN, OP	[6],[26], [27]
			Metal Enclosed Cutout		30	40	60				
27	UG	Utility Chamber			50	60	80	RTM	3	EN	[5],[6], [29]
28	UG	Duct	Duct Bank		30	50	80	N/A	N/A	EN	[5],[6], [30]
			Direct Buried Pipe (PVC)		30	50	75				
			HDPE		50	50	100				
29	UG	Transformer and Switchgear Foundations			30	60	80	RTM	3	EN	[5],[6]
30	UG	Junction Cubicle			25	40	50	N/A	N/A	EN	[5]
31	S	"Classic" SCADA	RTU		15	20	30	N/A	N/A	OP	[1],[11], [12],[32]
			Relay		20	30	50				
			Battery		5	10	10				

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Section #	Parent*	Asset Category	Componentization *(sub category)*		Useful Life Minimum	Useful Life Typical	Useful Life Maximum	Maint. Type**	Maint. Schedule	Impact of Stress***	Reference #
32	S	IED Based SCADA	IED		10	15	15	N/A	N/A	OP	[13],[32], [33]
			Battery		5	10	20				
33	S	Fault Indicators	Overhead		5	10	20	N/A	N/A	EN	[34], [47]
			Underground		10	20	30				
34	S	Metering	Meter	Residential	20	30	45	N/A	N/A	EN	[5],[35], [36]
				Industrial	20	30	60				
				Wholesale	20	30	60				
			CT		30	45	50				
			PT		30	45	50				
35	S	Smart Metering	Smart Meter		15	15	20	N/A	N/A	EN	[5],[37]
			Repeaters		5	10	15				
			Antennas								
			Data Concentrator	Sockets & Poles	10	20	20				
			Powerline Repeaters		5	10	15				
			Sky Pilot Devices								
			WAN Equipment								

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2 Wood Poles

The asset referred to in this category is the fully dressed wood pole ranging in size from 30 to 75 feet. This includes the wood pole, cross arm, bracket, insulator, and anchor & guys. Wood poles are typically the most common form of support for overhead distribution feeders and low voltage secondary lines.

The most significant component of this asset is the wood pole itself. The wood species predominately used for distribution systems are Red Pine, Jack Pine, and Western Red Cedar (WRC), either butt treated or full length treated. Smaller numbers of Larch, Fir, White Pine and Southern Yellow Pine have also been used. Preservative treatments applied prior to 1980, range from none on some WRC poles, to butt treated and full length Creosote or Pentachlorophenol (PCP) in oil. The present day treatment, regardless of species, is CCA-Peg (Chromated Copper Arsenate, in a Polyethylene Glycol solution). Other treatments such as Copper Naphthenate and Ammoniacal Copper Arsenate have also been used, but these are relatively uncommon.

2.1 Degradation Mechanism

The end of life criteria for wood poles includes loss of strength, functionality, or safety (typically due to rot, decay, or physical damage). As wood is a natural material the degradation processes are somewhat different from those which affect other physical assets on the electricity distribution systems. The critical processes are biological, involving naturally occurring fungi that attack and degrade wood, resulting in decay. The nature and severity of the degradation depends both on the type of wood and the environment. Some fungi attack the external surfaces of the pole and some the internal heartwood. Therefore, the mode of degradation can be split into either external rot or internal rot. As a structural item the sole concern when assessing the condition for a wood pole is the reduction in mechanical strength due to degradation or damage.

2.2 System Hierarchy

Wood poles are considered to be a part of the Overhead Lines asset grouping.

2.3 Useful Life and Typical Life

The overall useful life of a wood pole is in the range of 40 to 50 years; the typical life is 44 years.

This asset also has several major components, each with a different useful life:

- Cross Arm (Wood, Composite, Steel)
- Bracket (Galvanized Steel)
- Insulator (Composite, Porcelain)
- Anchor and Guying

2.3.1 *Cross Arm*

The useful life of a <u>wood</u> cross arm is in the range of 20 to 50 years; the typical life is 40 years.

3 Concrete Poles

This asset category includes the concrete pole with the same components as for the wood poles, namely cross arm, bracket, insulator, and anchor. These poles range in size from 35 to 80 feet, with the typical pole being 60 feet.

3.1 Degradation Mechanism

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

3.2 System Hierarchy

Concrete poles are considered to be a part of the Overhead Lines assets grouping.

3.3 Useful Life and Typical Life

The useful life range of the concrete pole component is 50 to 60 years; the typical life is 60 years. For other components, (cross arm, bracket, insulator, and anchor), please refer to Section 2.3.

3.4 Time Based Maintenance Intervals

A typical routine inspection interval for this asset is every 15 years.

3.5 Impact of Utilization Factors

The useful life of this asset is impacted by Mechanical Stress and Environmental Conditions.

The useful life of a composite cross arm is in the range of 40 to 80 years; the typical life is 60 years.

The useful life of a steel cross arm is in the range of 20 to 100 years; the typical life is 70 years.

2.3.2 *Bracket (Galvanized Steel)*

The useful life of an aluminum bracket component ranges from 20 to 50 years, with a typical value of approximately 40 years.

2.3.3 *Insulator*

The useful life of a composite insulator is in the range of 10 to 45 years; the typical life is 20 years.

The useful life of a porcelain insulator is in the range of 40 to 50 years, with a typical life of 40 years.

2.3.4 *Anchors and Guying*

The useful life of anchors and guying is in the range of 20 to 50 years; the typical life is 40 years.

2.4 Time Based Maintenance Intervals

A typical routine inspection interval for this asset is every 15 years.

2.5 Impact of Utilization Factors

The useful life of this asset is impacted by Mechanical Stress and Environmental Conditions.

4 Steel Poles

This asset category includes the directly buried steel pole, cross arm, bracket, insulator, and anchor.

4.1 Degradation Mechanism

The degradation of directly buried steel poles is mainly due to steel corrosion in-ground. In-ground situations are vastly different because of the wide local variations in soil chemistry, moisture content and conductivity that will affect the way coated or uncoated steel will perform in the ground.

There are two issues that determine the life of buried steel. The first is the life of the protective coating and the second is the corrosion rate of the steel. The item can be deemed to have failed when the steel loss is sufficient to prevent the steel performing its structural function. Where polymer coatings are applied to buried steel items, the failures are rarely caused by general deterioration of the coating. Localized failures due to defects in the coating, pin holing or large-scale corrosion related to electrolysis are common causes of failure in these installations.

Metallic coatings, specifically galvanizing, and to a lesser extent aluminum, fail through progressive consumption of the coating by oxidation or chemical degradation. The rate of degradation is approximately linear, and with galvanized coatings of known thickness, the life of the galvanized coating then becomes a function of the coating thickness and the corrosion rate.

4.2 System Hierarchy

Steel poles are considered a part of the Overhead Lines asset grouping.

4.3 Useful Life and Typical Life

The useful life of steel poles is in the range of 60 to 80 years; the typical life is 60 years. For other components, (cross arm, bracket, insulator, and anchor), please refer to Section 2.3.

4.4 Time Based Maintenance Intervals

A typical routine inspection interval for this asset is every 15 years.

4.5 Impact of Utilization Factors

This asset is impacted by Mechanical Stress and Environmental Conditions.

5 Composite Poles

This asset category includes the composite pole, cross arm, bracket, insulator, and anchor. At Consortium the composite poles are fiberglass.

5.1 Degradation Mechanism

The most significant component in this class is the composite pole itself. The major degradation of composite poles is ultra violet (UV) degradation. It represents an attack from ultra-violet radiation, which might result in crack or disintegration in composite poles. It is a common problem in products exposed to sunlight. Continuous exposure is a more serious problem than intermittent exposure, since attack is dependent on the extent and degree of exposure. In fiber products like composite poles, useful life will be shortened because the outer fibers will be attacked first, and will easily be damaged by abrasion. This will end up with fiber blooming and fading.

5.2 System Hierarchy

Composite poles are considered to be a part of the Overhead Lines assets grouping.

5.3 Useful Life and Typical Life

The useful life range of the composite pole component is 50 to 100 years; the typical life is 70 years. For other components, (cross arm, bracket, insulator, and anchor), please refer to Section 2.3.

5.4 Time Based Maintenance Intervals

. Composite poles are not subject to planned maintenance.

5.5 Impact of Utilization Factors

This asset is impacted by Mechanical Stress.

6 Wires

Overhead conductors along with structures that support them constitute overhead lines or feeders that distribute electrical energy either directly to large customers or from Municipal Stations via distribution transformers to the end users. These conductors are sized to carry a specified maximum current and to meet other design criteria, i.e. mechanical loading.

The overhead conductors typically used by the Consortium are aluminum conductor steel reinforced (ACSR), all aluminum conductor (AAC), copper, and insulated wire.

6.1 Degradation Mechanism

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

Generally, corrosion represents the most critical life-limiting factor for aluminum-based conductors. Visual inspection cannot detect corrosion readily in conductors. Environmental conditions affect degradation rates from corrosion. Both aluminum and zinc-coated steel core conductors are particularly susceptible to corrosion from chlorine-based pollutants, even in low concentrations.

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

In designing transmission lines, engineers ensure that conductors receive no more than 60% of their rated tensile strength (RTS) during heaviest anticipated weather loads. The tensile strength of conductors gradually decreases over time. When conductors experience unexpectedly large mechanical loads and tensions beyond 50% of their RTS, they begin to undergo permanent stretching with noticeable increases in sagging.

Overloading lines beyond their thermal capacity causes elevated operating temperatures. When operating at elevated temperatures, aluminum conductors begin to anneal and lose tensile strength. Each elevated temperature event adds further damage to the conductor. After a loss of 10% of a conductor's RTS, significant sag occurs, requiring either resagging or replacement of the conductor.

Phase to phase power arcs can result from conductor galloping during severe storm events. This can cause localized burning and melting of a conductor's aluminum strands, reducing strength at those sites and potentially leading to conductor failures. Visual inspection readily detects arcing damage.

Other forms of conductor damage include:

- Broken strands (i.e., outer and inners)
- Strand abrasion
- Elongation (i.e., change in sags and tensions)
- Burn damage (i.e., power arc/clashing)
- Birdcaging

The degradation of copper wire is mostly due to corrosion. Oxidization gives copper a high resistance to corrosion. Derivatives of chlorine and sulfur contained in coastal atmospheres start the oxidation by forming a blackish or greenish film. The film is very dense, has low solubility, high electric resistance and high resistance to the chemical attack and to corrosion. Despite this, mechanical vibrations, abrasion, erosion and thermal variations may cause fissures and faults in this layer. When this happens, the metal is uncovered and corrosion may occur. Also electrolytes with low Cl contents could enter, causing a dislocation of the passivity. This may also be the result of a deficit of oxygen which would make the area anodic.

6.2 System Hierarchy

The Wire asset category belongs to the Overhead Lines assets grouping.

6.3 Useful Life and Typical Life

The useful life of conductors is in the range of 50 to 77 years; the typical life is 60 years.

6.4 Time Based Maintenance Intervals

Overhead conductors are not subject to planned maintenance.

6.5 Impact of Utilization Factors

This asset is impacted by Mechanical Stress, Electrical Loading and Environmental Conditions.

7 Pole Mounted Transformers

Distribution pole top mounted transformers change sub-transmission or primary distribution voltages to 120/240 V or other common voltages for use in residential and commercial applications.

7.1 Degradation Mechanism

It has been demonstrated that the life of the transformer's internal insulation is related to temperature-rise and duration. Therefore, transformer life is affected by electrical loading profiles and length of time in service. Other factors such as mechanical damage, exposure to corrosive salts, and voltage and current surges also have a strong effect. Therefore, a combination of condition, age and load based criteria is commonly used to determine the useful remaining life of distribution transformers.

The impacts of loading profiles, load growth, and ambient temperature on asset condition, loss-of-life, and life expectancy can be assessed using methods outlined in ANSI/IEEE Loading Guides. This also provides an initial baseline for the size of transformer that should be selected for a given number and type of customers to obtain optimal life.

7.2 System Hierarchy

The Pole Mounted Transformer asset category belongs to the Overhead Lines assets grouping.

7.3 Useful Life and Typical Life

The useful life of the pole mounted transformer is in the range of 30 to 60 years, with a typical value close to 40 years.

7.4 Time Based Maintenance Intervals

Pole mounted distribution transformers are not subject to planned maintenance.

7.5 Impact of Utilization Factors

This asset is impacted by Electrical Loading and Environmental Conditions.

8 Manual Overhead Line Switches

This asset class consists of overhead line switches. The primary function of switches is to allow for isolation of line sections or equipment for maintenance, safety or other operating requirements. The operating control mechanism can be either a simple hook stick or manual gang.

8.1 Degradation Mechanism

The main degradation processes associated with manually operated line switches include the following, with rate and severity depending on operating duties and environment:

- Corrosion of steel hardware or operating rod
- Mechanical deterioration of linkages
- Switch blades falling out of alignment
- Loose connections
- Non functioning padlocks
- Insulators damage
- Missing ground connections
- Missing nameplates for proper identification

8.2 System Hierarchy

Overhead Switches asset category belongs to the Overhead Lines assets grouping.

8.3 Useful Life and Typical Life

The useful life of manually operated switches is in the range of 30 to 60 years; the typical life is 50 years.

8.4 Time Based Maintenance Intervals

The typical routine testing/maintenance schedule for manually operated overhead switches is two years.

8.5 Impact of Utilization Factors

This asset is impacted by Electrical Loading and Environmental Conditions.

9 Local Motorized Overhead Line Switches

This asset class consists of overhead line three-phase, gang operated switches and a motor. The primary function of switches is to allow for isolation of line sections or equipment for maintenance, safety or other operating requirements. The operating control mechanism is controlled by a motor.

9.1 Degradation Mechanism

Like the remotely operated switch, the main degradation processes associated with local motorized overhead switches include the following:

- Corrosion of steel hardware or operating rod
- Mechanical deterioration of linkages
- Switch blades falling out of alignment
- Loose connections
- Non functioning padlocks
- Insulators damage
- Missing ground connections
- Missing nameplates for proper identification

The rate and severity of degradation are a function on operating duties and environment.

9.2 System Hierarchy

Local Motorized Overhead Switches category belongs to the Overhead Lines assets grouping.

9.3 Useful Life and Typical Life

The local motorized overhead switch can be componentized into two components:

- Switch
- Motor

9.3.1 *Switch*

The useful life of the switch is in the range of 30 to 60 years; the typical life is 50 years (the same as for Manually Operated Overhead switch in section 8.3 of this report).

9.3.2 *Motor*

The useful life of the motor of local motorized switches is in the range of 15 to 20 years; the typical life is about 20 years.

9.4 Time Based Maintenance Intervals

The typical routine testing/maintenance schedule for local motorized switches is every two years.

9.5 Impact of Utilization Factors

This asset is impacted by Electrical Loading and Environmental Conditions.

10 Remote Automated Overhead Line Switches

This asset class consists of overhead line three-phase, gang operated switches. The primary function of switches is to allow for isolation of line sections or equipment for maintenance, safety or other operating requirements. While some categories of the switches are rated for load interruption, others are designed to operate under no load conditions and operate only when the current through the switch is zero. Most distribution line switches are rated 600 to 900 A continuous rating. Switches when used in conjunction with cutout fuses provide short circuit interruption rating. Disconnect switches are sometimes provided with padlocks to allow staff to obtain work permit clearance with the switch handle locked in open position. This component also consists of a remote terminal unit (RTU) component.

10.1 Degradation Mechanism

The main degradation processes associated with line switches include:

- Corrosion of steel hardware or operating rod
- Mechanical deterioration of linkages
- Switch blades falling out of alignment
- Loose connections
- Non functioning padlocks
- Insulators damage
- Missing ground connections
- Missing nameplates for proper identification

The rate and severity of these degradation processes depends on a number of inter-related factors including the operating duties and environment in which the equipment is installed. In most cases, corrosion or rust represents a critical degradation process. The rate of deterioration depends heavily on environmental conditions in which the equipment operates. Corrosion typically occurs around the mechanical linkages of these switches. Corrosion can cause seizing. When lubrication dries out, the switch operating mechanism may seize making the disconnect switch inoperable. In addition, when blades fall out of alignment, excessive arcing may result. While a lesser mode of degradation, air pollution also can affect support insulators. Typically, this occurs in heavy industrial areas or where road salt is used.

10.2 System Hierarchy

Remote Automated Overhead switches asset category belongs to the Overhead Lines assets grouping.

10.3 Useful Life and Typical Life

The remote automated overhead switch can be componentized into three components:

- Switch
- Motor
- Remote Terminal Unit (RTU)

10.3.1 *Switch*

The useful life of the switch is in the range of 30 to 60 years; the typical life is 50 years (the same as for Manually Operated Overhead Switch in section 8.3 of this report).

10.3.2 *Motor*

The useful life of a motor is in the range of 15 to 20 years; the typical life is 20 years (the same as for Local Motorized Overhead Switch in section 9.3.2 of this report).

10.3.3 *Remote Terminal Unit (RTU)*

The useful life of an RTU is in the range of 15 to 30 years; the typical life is 20 years.

10.4 Time Based Maintenance Intervals

The typical routine testing/maintenance schedule for remote automated overhead switches is every two years.

10.5 Impact of Utilization Factors

This asset is impacted by Electrical Loading and Environmental Conditions.

11 Fuse Cutouts

This asset is applied on overhead transformers, capacitors, cables or lines. Fuse Cutouts will interrupt all faults including low current that will melt the fuse link and high rated interrupting current so long as the system is under realistic transient-recovery-voltage conditions.

11.1 Degradation Mechanism

The major degradation of fuse cutouts is on fuse body. There are several degradation modes in practice including the production of carbon from organic materials in the fuse, generation of water vapor to assist current interruption and electrical breakdown in high stress areas of the core.

The production of carbon from organic materials in the fuse body is one degradation mode in practice. This carbon is not produced until a particular body temperature is reached, and the time for this to occur depends on the fuse design. The most critical factors would appear to include the heat generated in the fulgurite, the distance between the fulgurite and the fuse body, the thermal conductivity of the filler material, and the breakdown temperature of the organic material.

For some fuses that generate water vapor to assist current interruption, the water is deposited on the inside surface of the body. Treeing is observed on the surface, ultimately leading to a steady increase in leakage current until failure.

For the fuse cores that contain organic material, hollow core is developed at high temperature due to release of water molecules, resulting in electrical breakdown in high stress areas of the core in certain designs.

11.2 System Hierarchy

Fuse Cutouts asset category belongs to the Overhead Lines assets grouping.

11.3 Useful Life and Typical Life

The useful life of fuse cutouts is in the range of 30 to 60 years; the typical life is 40 years.

11.4 Time Based Maintenance Intervals

Fuse Cutouts are not subject to planned maintenance

11.5 Impact of Utilization Factors

This asset is impacted by Electrical Loading and Environmental Conditions.

12 Voltage Regulators

Voltage regulators are static devices that perform step-up and step-down voltage change operations. Distribution line transformers change the medium or low distribution voltage to 120/240 V or other common voltages for use in residential and commercial applications.

12.1 Degradation Mechanism

It has been demonstrated that the life of the voltage regulator's internal insulation is related to temperature-rise and duration. Therefore, voltage regulator life is affected by electrical loading profiles and length of time in service. Other factors such as mechanical damage, exposure to corrosive salts, and voltage and current surges also have a strong effect. Therefore, a combination of condition, age and load based criteria is commonly used to determine the useful remaining life of voltage regulators.

The impacts of loading profiles, load growth, and ambient temperature on asset condition, loss-of-life, and life expectancy can be assessed using methods outlined in ANSI/IEEE Loading Guides. This also provides an initial baseline for the size of voltage regulator that should be selected for a given number and type of customers to obtain optimal life. There is also the operating practices affect on voltage regulators. If it is a strong system, the voltage regulator may not need to step-up or step-down the voltage, in which case there would be less stress on the device itself.

12.2 System Hierarchy

Voltage Regulators asset category belongs to the Overhead Lines assets grouping.

12.3 Useful Life and Typical Life

The useful life of voltage regulators is in the range of 15 to 40 years; the typical life is 20 years.

12.4 Time Based Maintenance Intervals

Voltage Regulators are not subject to planned maintenance.

12.5 Impact of Utilization Factors

This asset is impacted by Electrical Loading, Environmental Conditions and Operating Practices.

13 Reclosers

This asset class consists of light duty circuit breakers equipped with interrupters that use controllers. This is where the breaking and making of fault current takes place. The interrupters use oil of vacuum as the insulating agent. The controllers are either hydraulic or electric. It is designed for single phase or three phase use, depending on the model.

13.1 Degradation Mechanism

The degradation processes associated with reclosers involves the effects of making and breaking fault current, the mechanism itself and deterioration of components. The effects of making and breaking fault current affect suppression devices as well as the contacts, the oil, and the arc control. The degradation of these devices depends on the prevailing fault, if it is well below the rated capability of the recloser, the deteriorating effects will be small. For the mechanism itself, deterioration or mal-operation of the mechanism causes deterioration during operation. Typically lack of use, corrosion and poor lubrication are the main causes of mechanism mal-function. For deterioration, exposure to weather is a potentially significant degradation process – primarily corrosion of the tank and other metallic components and deterioration of bushings.

13.2 System Hierarchy

Recloser asset category belongs to the Overhead Lines assets grouping.

13.3 Useful Life and Typical Life

Reclosers can be categorized into two components:

- Breaker (Vacuum, Oil)
- RTU

13.3.1 *Breaker*

The useful life of Vacuum breakers is in the range of 30 to 40 years; the typical life is 40 years.

The useful life of Oil breakers is in the range of 30 to 60 years; the typical life is 42 years.

13.3.2 *RTU*

The useful life of recloser RTUs is in the range of 15 to 30 years; the typical life is 20 years.

13.4 Time Based Maintenance Intervals

The typical routine testing/maintenance schedule for the breaker component of reclosers is every ten years.

13.5 Impact of Utilization Factors

This asset is impacted by Electrical Loading and Operating Practices.

14 Station Service Transformers

The station service transformers are the small transformers are configured to provide power to the auxiliary equipment, such as fans, pumps, heating, or lighting, in the distribution station. The most reliable source of such power is directly from the transmission or distribution lines. This report refers to both to both dry type and other types of transformers.

14.1 Degradation Mechanism

As with most transformers, end of life is typically a result of insulation failure, particularly paper insulation. The oil and paper insulation degrade as oxidation takes place in the presence of oxygen, high temperature, and moisture. Acids, particles, and static electricity also have degrading effects to the insulation.

For dry type transformers, the major degradation factors are dirt and moisture. Dirt will contaminate insulation surfaces allowing the formation of conductive paths along the surfaces and eventually to ground. In the case of ventilated dry type transformers, the windings are in direct contact with the air. External air-carrying contaminants or excessive moisture could reduce winding insulation. Dust and dirt accumulation can also reduce air circulation through windings, which eventually shorten the life expectancy of a dry type transformer.

14.2 System Hierarchy

Station service transformers are considered part of the Transmission Stations assets grouping.

14.3 Useful Life and Typical Life

The useful life of a station service transformer is based on the transformer type:

- Dry Type
- Other

14.3.1 *Dry Type*

The useful life of dry type station service transformers is in the range of 20 to 40 years; the typical life is 30 years.

14.3.2 *Other*

The useful life of other station service transformers is in the range of 32 to 55 years; the typical life is 45 years.

14.4 Time Based Maintenance Intervals

The typical routine testing/maintenance interval for these transformers is three years.

14.5 Impact of Utilization Factors

This asset is impacted by Electrical Loading and Environmental Conditions. If this device is running within an electrically stable system there will be less stress imposed on it.

15 TS Power Transformers

While power transformers can be employed in either step-up or step-down mode, a majority of the applications in transmission and distribution stations involve step down of the transmission or sub-transmission voltage to distribution voltage levels. Power transformers vary in capacity and ratings over a broad range. There are two general classifications of power transformers: transmission station transformers and distribution station transformers. For transformer stations, when step down from 230kV or 115kV to distribution voltage is required, ratings may range from 30MVA to 125 MVA. The Consortium typically uses TS Power Transformers rated 75/125 MVA.

15.1 Degradation Mechanism

Transformers operate under many extreme conditions, and both normal and abnormal conditions affect their aging and breakdown. They are subject to thermal, electrical, and mechanical aging. Overloads cause above-normal temperatures, through-faults can cause displacement of coils and insulation, and lightning and switching surges can cause internal localized over-voltages.

For a majority of transformers, end of life is a result of the failure of insulation, more specifically, the failure of pressboard and paper insulation. While the insulating oil can be treated or changed, it is not practical to change the paper and pressboard insulation. The condition and degradation of the insulating oil, however, plays a significant role in aging and deterioration of the transformer, as it directly influences the speed of degradation of the paper insulation. The degradation of oil and paper in transformers is essentially an oxidation process. The three important factors that impact the rate of oxidation of oil and paper insulation are the presence of oxygen, high temperature, and moisture. Particles and acids, as well as static electricity in oil cooled units, also affect the insulation.

Tap changers and bushing are major components of the power transformer. Tap changers are complex mechanical devices and are therefore prone to failure resulting from either mechanical or electrical degradation. Bushings are subject to aging from both electrical and thermal stresses.

15.2 System Hierarchy

Power Transformers belong to the Transformer Stations assets grouping.

15.3 Useful Life and Typical Life

This asset could be componentized into the following components:

- Winding
- Manual/Automatic On Load Tap Changer

15.3.1 *Winding*

The useful life of the winding can be in the range of 32-55 years, depending on the loading condition and ambient operating temperature, and routine maintenance practices. A typical life of 45 years can be expected for the winding system.

15.3.2 *Manual/Automatic On Load Tap Changer*

The useful life range of the manual or automatic on load tap changer, assuming it is vacuum type, is 20-60 years; the typical life is 20 years.

15.4 Time Based Maintenance Intervals

For TS power transformers, the typical routine testing/maintenance interval is two years.

15.5 Impact of Utilization Factors

This asset is impacted by Electrical Loading, Environmental Conditions and Operating Practices. It is specifically the on load tap changer component that is affected by operating practices. If this device is running within an electrically stable system there will be less stress imposed on it.

16 MS Power Transformers

Power transformers at distribution stations typically step down voltage to distribution levels. Ratings typically range from 5 MVA to 30 MVA. The Consortium typically uses MS Power Transformers rated 20/33.3 MVA.

16.1 Degradation Mechanism

The degradation of the power transformers at municipal stations or at customer sites is similar to that of the transformers at transmission stations. These transformers are subject to electrical, thermal, and mechanical aging. Degradation of the insulating oil, and more significantly, paper insulation, typically results in end of life. Insulation degradation is a result of oxidation, a process that occurs in the presence of oxygen, high temperature, and moisture. For oil cooled transformers, particles, acids, and static electricity will also deteriorate the insulation.

Tap changers and bushing are major components of the power transformer. Tap changers are prone to failure resulting from either mechanical or electrical degradation. Bushings are subject to aging from both electrical and thermal stresses.

16.2 System Hierarchy

MS Power Transformer asset category belongs to the Municipal Stations assets grouping.

16.3 Useful Life and Typical Life

The power transformer also has major components that have different useful lives. Componentization is as follows:

- Winding
- Manual/Automatic On Load Tap Changer

16.3.1 *Winding*

The useful life of windings is 32 to 55 years; the typical life is 45 years.

16.3.2 *Manual/Automatic On Load Tap Changer*

The useful life range of the manual or automatic tap changer, assuming it is vacuum type, is 20 to 60 years; the typical life is 20 years.

16.4 Time Based Maintenance Intervals

The typical routine testing/maintenance interval for these transformers is two years.

16.5 Impact of Utilization Factors

This asset is impacted by Electrical Loading, Environmental Conditions and Operating Practices. It is specifically the on load tap changer component that is affected by operating practices. If this device is running within an electrically sound system there will be less stress imposed on it.

17 DC Station Service

The DC station service asset class includes battery banks and chargers. Equipment within transmission and municipal stations must be provided with a guaranteed source of power to ensure they can be operated under all system conditions, particularly during fault conditions. There is no known way to store AC power so the only guaranteed instantaneous power source must be DC, based on batteries.

17.1 Degradation Mechanism

Effective battery life tends to be much shorter than many of the major components in a station. The deterioration of a battery from an apparently healthy condition to a functional failure can be rapid. This makes condition assessment very difficult. However, careful inspection and testing of individual cells often enables the identification of high risk units in the short term.

It is well understood in the utility industry that regular inspection and maintenance of batteries and battery chargers is necessary. In most cases the explicit reason for carrying out regular maintenance inspection is to detect minor defects and rectify them. However, critical examination of trends in maintenance records can give an early warning of potential failures.

Despite the regular and frequent maintenance and inspection of battery systems, failures in service are still relatively frequent. For this reason, many utilities employ battery monitors and alarm systems. The earlier versions of these are still widely used and are relatively unsophisticated devices that measure basic battery parameters with pre-set alarm levels. More modern monitoring devices have the ability to identify a potential failure as it develops and to provide a warning.

Although battery deterioration is difficult to detect, any changes in the electrical characteristics or observation of significant internal damage can be used as sensitive measures of impending failure. Batteries consist of multiple individual cells. While the significant deterioration/failure of an individual cell may be an isolated incident, detection of deterioration in a number of cells in a battery is usually the precursor to widespread failure and functional failure of the total battery.

Battery chargers are also critical to the satisfactory performance of the whole battery system. Battery chargers are relatively simple electronic devices that have a high degree of reliability and a significantly longer lifetime than the batteries themselves. Nevertheless, problems do occur. As with other electronic devices, it is difficult to detect deterioration prior to failure. It is normal practice during the regular maintenance and inspection process to check the functionality of the battery chargers, in particular the charging rates. Where any functional failures are detected it would be normal to replace the battery charger.

17.2 System Hierarchy

DC station services belong to Municipal Stations assets grouping.

17.3 Useful Life and Typical Life

This asset also has two major components that have differing useful lives:

- Battery Banks
- Charger

17.3.1 *Battery Bank*

The battery bank has a useful life range of 10 to 30 years; typical life is 20 years.

17.3.2 *Charger*

The charger has a useful life range of 20 to 30 years; typical life is 20 years.

17.4 Time Based Maintenance Intervals

Typically, routine testing/maintenance for batteries are conducted annually. The maintenance of schedule battery chargers is typically coordinated with that of the battery.

17.5 Impact of Utilization Factors

This asset is impacted by Electrical Loading, Environmental Conditions and Operating Practices. This device cannot be overloaded, last longer when there is not extreme cold weather conditions and only the battery bank component is affected by operating practices (i.e., it only runs if the AC fails).

18 Air Insulated Switchgear

Air Insulated Switchgear consists of an assembly of retractable/racked switchgear devices that are totally enclosed in a metal envelope (metal-enclosed). These devices operate in the medium voltage range, from 4.16 to 44 kV. The switchgear includes breakers; disconnect switches, or fusegear, current transformers (CTs), voltage transformers (VTs) and occasionally some or all of the following: metering, protective relays, internal DC and AC power, battery charger(s), and AC station service transformation. The gear is modular in that each breaker is enclosed in its own metal envelope (cell). The gear also is compartmentalized with separate compartments for breakers, control, incoming/outgoing cables or bus duct, and bus-bars associated with each cell.

18.1 Degradation Mechanism

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

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

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

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

18.2 System Hierarchy

Switchgear asset category belongs to the Municipal Stations assets grouping.

18.3 Useful Life and Typical Life

This asset also has several major components, each with a different useful life:

- Breaker (SF6, Vacuum, Air Magnetic)
- Switchgear Assembly

18.3.1 *Breaker*

The useful life range of SF6 type breaker in air insulated switchgear is 30 to 60 years; typical life is 42 years.

The useful life range of vacuum type breaker in air insulated switchgear is 30 to 60 years; typical life is 40 years.

The useful life range of air magnetic type breaker in air insulated switchgear is 25 to 60 years; typical life is 40 years.

18.3.2 *Switchgear Assembly*

The useful life range of switchgear assembly is 40 to 60 years; typical life is 50 years.

18.4 Time Based Maintenance Intervals

The typical routine testing/maintenance interval for this asset is six years.

18.5 Impact of Utilization Factors

This asset is impacted by Electrical Loading, Environmental Conditions and Operating Practices. It is specifically the breaker component that is affected by operating practices. If this device is running within an electrically system there will be less stress imposed on it. It is specifically the switchgear assembly component that is affected by environmental factors, specifically temperature.

19 Gas Insulated Switchgear

The latest design of metalclad gear is the Gas Insulated Switchgear (GIS), which uses low-pressure SF6 gas as a general insulation medium, as a replacement for the air. The insulation within the metal enclosure is not necessarily the same as the working fluid in the breakers themselves, which presently is either SF6 or vacuum.

19.1 Degradation Mechanism

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

Generally, mechanism malfunction causes most operational problems in GIS. Corrosion and lubrication failure may compromise mechanism performance by preventing or slowing its operation.

Solid insulation such as that in entrance bushings, internal support insulators, plus breaker and switch operating rods have caused many GIS failures. Manufacturing, shipping, installing, maintaining and operating the GIS can cause defects in the insulation. Defects include voids in epoxy insulators, delamination of epoxy and metallic hardware, and protrusions on conductors. In floating components, fixed and moving particles can lead to failures. Partial discharge (PD) activity usually leads to flashovers.

Corrosion and general deterioration increase risks of moisture ingress and SF6 leaks, particularly in outdoor GIS. If not treated, these factors may cause the end-of-life for GIS.

GIS is designed and manufactured for outdoor use, but it generally has better long-term performance when installed indoors. Outdoor GIS, particularly older ITE designs, have higher than acceptable SF6 gas leaks because of the poor quality of fittings, connectors, valves, by-pass piping, general enclosure porosity and flange corrosion. Indoor installations reduce problems from corrosion, moisture ingress, low ambient temperatures and SF6 leaks.

GIS have more costly, difficult and time-consuming post fault maintenance requirements than air insulated switchgear. Older GIS have even more post-fault maintenance problems. Accessibility, fault location, fault level and duration, degree of compartmentalization, isolation requirements, pressure relief, burn-through protection, parts and service capabilities all help determine post-fault maintenance needs.

19.2 System Hierarchy

Switchgear asset category belongs to the Municipal Stations assets grouping.

19.3 Useful Life and Typical Life

This asset also has several major components, each with a different useful life:

- Breaker (SF6, Vacuum, Air Magnetic)
- Switchgear Assembly

19.3.1 *Breaker*

The useful life range of SF6 type breaker in air insulated switchgear is 30 to 60 years; typical life is 42 years.

The useful life range of vacuum type breaker in air insulated switchgear is 30 to 60 years; typical life is 40 years.

The useful life range of air magnetic type breaker in air insulated switchgear is 25 to 60 years; typical life is 40 years.

19.3.2 *Switchgear Assembly*

The useful life range of switchgear assembly is 40 to 60 years; typical life is 50 years.

19.4 Time Based Maintenance Intervals

The typical routine testing/maintenance interval for this asset is six years.

19.5 Impact of Utilization Factors

This asset is impacted by Electrical Loading, Environmental Conditions and Operating Practices. It is specifically the breaker component that is affected by operating practices. If this device is running within an electrically system there will be less stress imposed on it. It is specifically the switchgear assembly component that is affected by environmental factors, specifically temperature.

20 Building

Buildings at major transformer and municipal stations house the switchgear, relays and controls and serve as a base for administrative and service work. This asset includes the building itself (foundations, walls), roof, and fence.

20.1 Degradation Mechanism

The following contribute to the degradation of this asset:

- Building age
- Structural condition of loading members
- Condition of floors, walls and ceilings
- Protection against weather elements
- Environmental concerns
- Functional requirements

Buildings are a very maintainable asset. The capital cost of replacement is high enough that the lowest long term cost is achieved even with quite high levels of annual maintenance. Age alone is a very poor indicator of end of life. Rather impacts such as environmental rain, wind and snow storms contribute highly to the degradation of buildings. It is the potential water ingress with poses the most danger to the asset due to the presence of electrical equipment. In order to prevent this, the buildings must be weatherproof.

Also, since the foundation materials typically consist of reinforced concrete designed to consider environmental elements including soil conditions and climate. Landscaping is used to control soil erosion, maintain site cleanliness and facilitate an efficient and safe work environment.

Preventative maintenance helps ensure long-term integrity of buildings. This type of maintenance should be done on a regular basis. As well the occasional refurbishment of doors, windows and roofs helps with the viability of the building.

The building roof is the most susceptible to degradation due to environmental factors. The roof is typically level and composed of tar and an aggregate that is designed to keep the wind from wearing at the tar. Nevertheless, the roof is still susceptible to environmental degradation and if not sealed properly can become a source of flooding. The maintenance of the roof is generally the largest undertaking for buildings.

20.2 System Hierarchy

Building asset category belongs to the Municipal Stations assets grouping.

20.3 Useful Life and Typical Life

The overall useful life range of the building itself is 30 to 80 years; the typical life is 50 years.

This asset also has two other major components, each of which has a different useful life. From a maintenance practice perspective, the building can be componentized into the following:

- Roof
- Fence

20.3.1 *Roof*

The useful life of the roof can be in the range of 15 to 20 years, with a typical life of 20 years.

20.3.2 *Fence*

The useful life range of the fence is 30 to 45 years, with a typical life of 35 years.

20.4 Time Based Maintenance Intervals

The typical routine inspection interval for this asset is every year.

20.5 Impact of Utilization Factors

This asset is impacted by Mechanical Stress and Environmental Conditions.

21 Station Grounding System

The station grounding system asset refers to grounding rods and connectors. Grounding systems in stations dissipate maximum ground fault currents without interfering with power system operation or causing voltages dangerous to people or equipment. Safety hazards from inadequate grounding include excessive ground potential rises and excessive step and touch potentials. Generally, grounding system assets provide suitable paths for ground currents to follow from power equipment and conductors into the earth. Consequently, complete grounding systems include buried conductors, ground rods and connections, plus soil and vegetation in the area. Soil and vegetative conditions affect water retention and drainage, which impact overall performance of the grounding system.

21.1 Degradation Mechanism

Station grounding systems keep ground potential rise, step and touch potentials below specified limits when maximum (i.e. worst case) ground faults occur. Under fault conditions, the following factors determine step and touch potentials:

- Magnitude of the fault current
- Resistance of ground combined with the ground grid consisting of station electrodes, transmission line sky wires and distribution neutrals
- Ground resistivity of upper and lower layers of earth.

Increases in system capacity and fault currents at a station may lead to unacceptable performance of the ground grid. Corrosion of buried conductors and connectors, mechanical damage to buried electrodes, plus burning-off of grounding conductors and connectors during heavy fault currents also may lead to unsatisfactory performance. Further, changes in resistivity of upper or lower layers of earth may adversely affect ground grid characteristics.

21.2 System Hierarchy

Station Grounding Systems asset category belongs to the Municipal Stations assets groupings.

21.3 Useful Life and Typical Life

Station grounding systems have a useful life range of 25 to 50 years; the typical life is 40 years.

21.4 Time Based Maintenance Intervals

Station Grounding Systems are not subject to planned maintenance.

21.5 Impact of Utilization Factors

This asset is impacted by Environmental Conditions.

22 Underground Primary Cables

Distribution underground cables are mainly used in urban areas where it is either impossible or extremely difficult to build overhead lines due to aesthetic, legal, environmental and safety reasons. The initial capital cost of a distribution underground cable circuit is three or more times the cost of an overhead line of equivalent capacity and voltage. The cross linked polyethylene (XLPE) cable is the type of underground distribution cables used by Consortium. While XLPE underground cable can be installed in ducts (and concrete enclosed ducts), it can also be directly buried.

Cable terminations are designed to separate the cable ground from the conductor in a safe and controlled manner. Inside the cable, ground and high voltage are separated by only a few millimeters. This distance is much too small to support any voltage. Therefore the termination must increase this separation while being able to withstand the surrounding environment.

22.1 Degradation Mechanism

Over the past 30 years XLPE insulated cables have all but replaced paper-insulated cables. These cables can be manufactured by a simple extrusion of the insulation over the conductor and therefore are much more economic to produce. In normal cable lifetime terms XLPE cables are still relatively young. Therefore, failures that have occurred can be classified as early life failures. Certainly in the early days of polymeric insulated cables their reliability was questionable. Many of the problems were associated with joints and accessories or defects introduced in the manufacturing process. Over the past 30 years many of these problems have been addressed and modern XLPE cables and accessories are generally very reliable.

Polymeric insulation is very sensitive to discharge activity. It is therefore very important that the cable, joints and accessories are discharge free when installed. Discharge testing is, therefore, an important factor for these cables. This type of testing is conducted during commissioning and is not typically used for detection of deterioration of the insulation. These commissioning tests are an area of some concern for polymeric cables because the tests themselves are suspected of causing permanent damage and reducing the life of polymeric cables.

Water treeing is the most significant degradation process for polymeric cables. The original design of cables with polymeric sheaths allowed water to penetrate and come into contact with the insulation. In the presence of electric fields water migration can result in treeing and ultimately breakdown. The rate of growth of water trees is dependent on the quality of the polymeric insulation and the manufacturing process. Any contamination voids or discontinuities will accelerate degradation. This is assumed to be the reason for poor reliability and relatively short lifetimes of early polymeric cables. As manufacturing processes have improved the performance and ultimate life of this type of cable has also improved.

The major degradation problems with the cable terminations concern mostly flashover and tracking associated with the outside and interior surfaces of the accessory. However, there are also problems of overheating at connections and voltage control at the end of the cable shield.

22.2 System Hierarchy

Underground Primary Cables asset category belongs to the Underground Systems assets grouping.

22.3 Useful Life and Typical Life

The overall useful life range of the cable itself is dependent on the cable type and component:

- TR-XLPE (In Duct, In Concrete Encased Duct, Direct Buried)
- Termination

22.3.1 *TR-XLPE*

The useful life range of in duct cable is 40 to 60 years; the typical life is 40 years.

The useful life range of in concrete encased duct cable is 40 to 60 years; the typical life is 40 years.

The useful life range of direct buried cable is 20 to 40 years; the typical life is 25 years.

22.3.2 *Termination*

The useful life range of termination component of underground cable is 25 to 60 years; the typical life is 40 years.

22.4 Time Based Maintenance Intervals

Underground Primary Cables are not subject to planned maintenance.

22.5 Impact of Utilization Factors

This asset is impacted by Electrical Loading and Environmental Conditions.

23 Underground Secondary Cables

Secondary underground cables are used to supply customer premises. The Polyethylene Insulated (PI) and PVC Jacket (PIJ) are similar to the XLPE cables described above, and are assumed to be in duct.

23.1 Degradation Mechanism

Underground secondary conductors are typically insulated with polyethylene. Polyethylene insulation is very sensitive to discharge activity. It is therefore very important that the cable, joints and accessories are discharge free when installed. These commissioning tests are an area of some concern for polyethylene cables because the tests themselves are suspected of causing permanent damage and reducing the life of polymeric cables. However those with the PVC jacket have further insulation to prevent some deterioration of the insulation.

23.2 System Hierarchy

Underground Secondary Cables are used in the Underground system.

23.3 Useful Life and Typical Life

The underground secondary cable can be categorized into two types:

- Polyethylene Insulated
- PVC Jacket

23.3.1 *Polyethylene Insulated*

The useful life range of in polyethylene insulated cable is 40 to 60 years; the average life is 40 years.

23.3.2 *PVC Jacket*

The useful life range of in PVC jacket cable is 40 to 60 years; the average life is 40 years.

23.4 Time Based Maintenance Intervals

Underground Secondary Cables are not subject to planned maintenance

23.5 Impact of Utilization Factors

This asset is impacted by Electrical Loading and Environmental Conditions.

24 Distribution Transformer

This asset class consists of the transformer and elbows and inserts associated with the system. There are three types of transformers that Consortium uses: Pad Mounted, Vault and Submersible.

Pad mounted transformers typically employ sealed tank construction and are liquid filled, with mineral insulating oil being the predominant liquid. Vault transformers typically employ sealed tank construction and are liquid filled with mineral insulating oil. Submersible transformers typically employ sealed tank construction and are liquid filled with mineral insulating oil.

24.1 Degradation Mechanism

The pad-mounted transformer has a similar degradation mechanism to other distribution transformers. It has been demonstrated that the life of the transformer's internal insulation is related to temperature rise and duration. Therefore, the transformer life is affected by electrical loading profiles and length of service life. Other factors such as mechanical damage, exposure to corrosive salts, and voltage current surges also have strong effects. Therefore, a combination of condition, age, and load based criteria is commonly used to determine the useful remaining life.

In general, the following are considered when determining the health of the pad-mounted transformer:

- Tank corrosion, condition of paint
- Extent of oil leaks
- Condition of bushings
- Condition of padlocks, warning signs, etc.
- Transfer operating age and winding temperature profile

The vault transformer and submersible transformer have a similar degradation mechanism to other distribution transformers. The life of the transformer's internal insulation is related to temperature rise and duration, so transformer life is affected by electrical loading profiles and length of service life. Mechanical damage, exposure to corrosive salts, and voltage current surges has strong effects. In general, a combination of condition, age, and load based criteria is commonly used to determine the useful remaining life.

24.2 System Hierarchy

Distribution Transformers asset category belongs to the Underground Systems asset grouping.

24.3 Useful Life and Typical Life

The overall useful life range of the transformer itself is dependent on the component:

- Transformer (Pad Mounted, Vault, Submersible)
- Elbows and Inserts

24.3.1 *Transformer*

The useful life range of pad mounted distribution transformers are 30 to 40 years; the typical life is 40 years.

The useful life range of vault distribution transformers is 30 to 40 years; the typical life is 40 years.

The useful life range of submersible distribution transformers is 25 to 40 years; the typical life is 35 years.

24.3.2 *Elbows and Inserts*

The useful life range of the elbows and inserts component of distribution transformers is 20 to 60 years; the typical life is 40 years.

24.4 Time Based Maintenance Intervals

Distribution Transformers are not subject to planned maintenance.

24.5 Impact of Utilization Factors

This asset is impacted by Electrical Loading, Environmental Conditions and Operating Practices. The operating practices impact only the elbows and inserts component of the asset.

25 Pad Mounted Switchgear

Pad-mounted switchgear is used for protection and switching in the underground distribution system. The switching assemblies can be classified into air insulated, SF6 load break switches and vacuum fault interrupters. A majority of the pad mounted switchgear currently employs air-insulated gang operated load-break switches.

25.1 Degradation Mechanism

The pad-mounted switchgear is very infrequently used for switching and often used to drop loads way below its rating. Therefore, switchgear aging and eventual end of life is often established by mechanical failures, e.g. rusting of the enclosures or ingress of moisture and dirt into the switchgear causing corrosion of operating mechanism and degradation of insulated barriers.

The first generation of pad mounted switchgear was first introduced in early 1970's and many of these units are still in good operating condition. The life expectancy of pad-mounted switchgear is impacted by a number of factors that include frequency of switching operations, load dropped, presence or absence of corrosive environmental and absence of existence of dampness at the installation site.

In the absence of specifically identified problems, the common industry practice for distribution switchgear is running it to end of life, just short of failure. To extend the life of these assets and to minimize in-service failures, a number of intervention strategies are employed on a regular basis: e.g. inspection with thermographic analysis and cleaning with CO2 for air insulated pad-mounted switchgear. If problems or defects are identified during inspection, often the affected component can be replaced or repaired without a total replacement of the switchgear.

Failures of switchgear are most often not directly related to the age of the equipment, but are associated instead with outside influences. For example, pad-mounted switchgear is most likely to fail due to rodents, dirt/contamination, vehicle accidents, rusting of the case, and broken insulators caused by misalignment during switching. All of these causes are largely preventable with good design and maintenance practices. Failures caused by fuse malfunctions can result in a catastrophic switchgear failure.

Aging and end of life is established by mechanical failures, such as corrosion of operating mechanism from rusting of enclosure or moisture and dirt ingress. Switchgear failure is associated more with outside influences rather than age. For example, switchgear failure is more likely to be caused by rodents, dirt or contamination, vehicle accidents, rusting of the case, and broken insulators caused by misalignment during switching.

25.2 System Hierarchy

Pad-Mounted Switchgear belongs to the Underground Systems assets grouping.

25.3 Useful Life and Typical Life

The overall useful life range of the switchgear itself is dependent on the pad mount switchgear type:

- Air Insulated
- Gas Insulated
- Solid Dielectric

25.3.1 *Air Insulated*

The useful life range of this air insulated pad mount switchgear is 20 to 40 years; the typical life is 30 years.

25.3.2 *Gas Insulated*

The useful life range of this gas insulated pad mount switchgear is 30 to 50 years; the typical life is 30 years.

25.3.3 *Solid Dielectric*

The useful life range of this solid dielectric pad mount switchgear is 30 to 50 years; the typical life is 30 years.

25.4 Time Based Maintenance Intervals

The typical routine inspection interval for this asset is three years.

25.5 Impact of Utilization Factors

This asset is impacted by Electrical Loading, Environmental Conditions and Operating Practices.

26 Vault Switch

The vault switches used by Consortium are metal enclosed switch and metal enclosed cutout. These units are essentially pad mounted switchgear, enclosed in stainless steel containers, with the ability to be wall or ceiling mounted.

26.1 Degradation Mechanism

The degradation mechanism of this asset is similar to that of other types of pad mounted switchgear. Aging and end of life is established by mechanical failures, such as corrosion of operating mechanism from rusting of enclosure or moisture and dirt ingress. Switchgear failure is associated more with outside influences rather than age. For example, switchgear failure is more likely to be caused by rodents, dirt or contamination, vehicle accidents, rusting of the case, and broken insulators caused by misalignment during switching.

26.2 System Hierarchy

Vault Switches asset category belongs to the Underground Systems assets grouping.

26.3 Useful Life and Typical Life

The overall useful life range of the vault switch is dependent on the pad mount switchgear type:

- Metal Enclosed Switch
- Metal Enclosed Cutout

26.3.1 *Metal Enclosed Switch*

The useful life range of metal enclosed switch is 20 to 40 years; the typical life is 30 years.

26.3.2 *Metal Enclosed Cutout*

The useful life range of metal enclosed cutout is 30 to 60 years; the typical life is 40 years.

26.4 Time Based Maintenance Intervals

The typical routine inspection interval for this asset is 3 years.

26.5 Impact of Utilization Factors

This asset is impacted by Electrical Loading, Environmental Conditions and Operating Practices.

27 Utility Chamber

Utility Chambers facilitate cable pulling into underground ducts and provide access to splices and facilities that require periodic inspections or maintenance. They come in different styles, shapes and sizes according to the location and application. Pre-cast cable chambers are normally installed only outside the traveled portion of the road although some end up under the road surface after road widening. Cast-in-place cable chambers are used under the traveled portion of the road because of their strength and also because they are less expensive to rebuild if they should fail. Customer cable chambers are on customer property and are usually in a more benign environment. Although they supply a specific customer, system cables loop through these chambers so other customers could also be affected by any problems.

27.1 Degradation Mechanism

These assets must withstand the heaviest structural loadings that they might be subjected to. For example, when located in streets, utility chambers must withstand heavy loads associated with traffic in the street. When located in driving lanes, utility chamber chimney and collar rings must match street grading. Since utility chambers and vaults often experience flooding, they sometimes include drainage sumps and sump pumps. Nevertheless, environmental regulations in some jurisdictions may prohibit the pumping of utility chambers into sewer systems, without testing of the water for environmentally hazardous contaminants.

Although age is loosely related to the condition of underground civil structures, it is not a linear relationship. Other factors such as mechanical loading, exposure to corrosive salts, etc. have stronger effects. Utility chamber degradation commonly includes corrosion of reinforcing steel, spalling of concrete, and rusting of covers or rings. Acidic salts (i.e. sulfates or chlorides) affect corrosion rates. Utility chamber systems also may experience a number of deficiencies or defects. In roadways, defects exist when covers are not level with street surfaces. Conditions that lead to flooding, clogged sumps, and non-functioning sump-pumps also represent major deficiencies in a utility chamber system. Similarly, utility chamber systems with lights that do not function properly constitute defective systems. Deteriorating ductwork associated with utility chambers also requires evaluation in assessing the overall condition of a utility chamber system.

27.2 System Hierarchy

Utility Chambers asset category belongs to the Underground Systems assets grouping.

27.3 Useful Life and Typical Life

Utility chambers have a useful life range of 50 to 80 years; the typical life range is 60 years.

27.4 Time Based Maintenance Intervals

The typical routine testing/maintenance interval for this asset class is three years.

27.5 Impact of Utilization Factors

This asset is impacted by Environmental Conditions.

28 Duct

In areas such as road crossings, ducts provide a conduit for underground cables to travel. They are comprised of a number of ducts, in trench, and typically encased in concrete. Ducts are sized as required and are usually two to six inches in diameter.

28.1 Degradation Mechanism

The ducts connecting one utility chamber to another cannot easily be assessed for condition without excavating areas suspected of suffering failures. However, water ingress to a utility chamber that is otherwise in sound condition is a good indicator of a failure of a portion of the ductwork. Since there are no specific tests that can be conducted to determine duct integrity at reasonable cost, the duct system is typically treated on an ad hoc basis and repaired or replaced as is determined at the time of cable replacement or failure.

28.2 System Hierarchy

Ducts asset category belongs to the Underground Systems assets grouping.

28.3 Useful Life and Typical Life

The overall useful life range of the duct is dependent on the type:

- Duct Bank
- Direct Buried Pipe (PVC)
- High Density Polyethylene (HDPE)

28.3.1 *Duct Bank*

The useful life range of the duct bank type is 30 to 80 years; the typical life is 50 years.

28.3.2 *Direct Buried Pipe (PVC)*

The useful life range of the direct buried pipe type is 30 to 75 years; the typical life is 50 years.

28.3.3 *High Density Polyethylene (HDPE)*

The useful life range of the HDPE type is 50 to 100 years; the typical life is 50 years.

28.4 Time Based Maintenance Intervals

Ducts are not subject to planned maintenance.

28.5 Impact of Utilization Factors

This asset is impacted by Environmental Conditions.

29 Transformer and Switchgear Foundations

This asset class is similar to the utility chamber asset. It is a buried pre cast concrete vault on which pad-mounted transformers or switchgear are mounted. The foundation itself is buried; however the top portion is above ground.

29.1 Degradation Mechanism

These assets must withstand the heaviest structural loadings that they might be subjected to. For example, when located in streets, transformer and switchgear foundation must withstand heavy loads associated with traffic in the boulevard. When located in driving lanes, concrete vault must match street grading. Since vaults often experience flooding, they sometimes include drainage sumps and sump pumps. Nevertheless, environmental regulations in some jurisdictions may prohibit the pumping into sewer systems, without testing of the water for environmentally hazardous contaminants.

Although age is loosely related to the condition of underground civil structures, it is not a linear relationship. Other factors such as mechanical loading, exposure to corrosive salts, etc. have stronger effects. Transformer and switchgear foundation degradation commonly includes corrosion of reinforcing steel, spalling of concrete, and rusting of covers or rings. Acidic salts (i.e. sulfates or chlorides) affect corrosion rates. Transformer and switchgear foundation also may experience a number of deficiencies or defects. In roadways, defects exist when covers are not level with street surfaces. Conditions that lead to flooding, clogged sumps, and non-functioning sump-pumps also represent major deficiencies in a transformer and switchgear foundation. Similarly, transformer and switchgear foundation with lights that do not function properly constitute defective systems.

29.2 System Hierarchy

Transformer and Switchgear foundations asset category belongs to the Underground Systems assets grouping.

29.3 Useful Life and Typical Life

The overall useful life range of Transformer and switchgear foundation is 30 to 80 years; the typical life is 60 years.

29.4 Time Based Maintenance Intervals

The typical routine testing/maintenance interval for this asset class is three years.

29.5 Impact of Utilization Factors

This asset is impacted by Environmental Conditions.

30 Junction Cubicle

This asset class consists of a wiring box similar to pad mount switchgear. For the purposes of this study there is only reference to junction casing.

30.1 Degradation Mechanism

The main degradation associated with the junction cubicle casing is caused by outside sources. These include corrosion, vehicle damage, case rusting, and dirt or contamination.

30.2 System Hierarchy

Junction cubicle is used in the Underground Systems assets grouping.

30.3 Useful Life and Typical Life

The overall useful life range of junction cubicle casing is 25 to 50 years; the typical life is 40 years.

30.4 Time Based Maintenance Intervals

Junction Cubicles are not subject to planned maintenance

30.5 Impact of Utilization Factors

This asset is impacted by Environmental Conditions.

31 "Classic" SCADA

Supervisory Control and Data Acquisition (SCADA) refers to the centralized monitoring and control system of a facility. SCADA remote terminal units (RTUs) allow the master SCADA system to communication, often wirelessly, with field equipment. In general, RTUs collect digital and analog data from equipment, exchange information to the master system, and perform control functions on field devices. They are typically comprised of the following: power supply, CPU, I/O Modules, housing and chassis, communications interface, and software.

31.1 Degradation Mechanism

There are many factors that contribute to the end-of-life of RTUs. Utilities may choose to upgrade or replace older units that are no longer supported by vendors or where spare parts are no longer available. Because RTUs are essentially computer devices, they are prone to obsolescence. For example, older units may lack the ability to interface with Intelligent Electronic Devices (IEDs), be unable to support newer or modern communications media and/or protocols, or not allow for the quantity, resolution, and accuracy of modern data acquisition. Legacy units may have limited ability of multiple master communication ports and protocols, or have an inability to segregate data into multiple RTU addresses based on priority.

31.2 System Hierarchy

Classic SCADA asset category belongs to the Monitoring and Control Systems assets grouping.

31.3 Useful Life and Typical Life

This asset has several major components, each of which has a different useful life. From a maintenance practice perspective, classic SCADA can be componentized into the following:

- RTU
- Relay
- Battery

31.3.1 *RTU*

The useful life of the RTU in "classic" SCADA is in the range of 15 to 30 years; the typical life is 20 years.

31.3.2 *Relay*

The useful life of the relay in "classic" SCADA is in the range of 20 to 50 years; the typical life is 30 years.

31.3.3 *Battery*

The useful life of the battery in "classic" SCADA is in the range of 5 to 10 years; the typical life is 10 years.

31.4 Time Based Maintenance Intervals

“Classic” SCADA is not subject to planned maintenance.

31.5 Impact of Utilization Factors

This asset is impacted by Operating Practices. It is specifically the battery and relay components that are affected by operating practices. If this device is running within an electrically stable system there will be less stress imposed on it.

32 IED Based SCADA

Intelligent Electronic Devices (IED) based Supervisory Control and Data Acquisition (SCADA) refers to the centralized monitoring and control system of a facility.

32.1 Degradation Mechanism

Physical degradation of IED Based SCADA happens on hardware part of an IED. Compared to solid state relays, IEDs are not sensitive to ambient environment. The major contributing factor of degradation is the electrical environment, i.e. inrush transient. Since IEDs have built-in self-supervision system, the settings with perfect long time stability is guaranteed.

The failure mode of an IED can be:

- Fail to trip because communication port is held by defective external equipment
- Mal-function due to hardware/firmware/software version mismatch
- Mal-function due to software design flaw causing software latched by external EMI interference
- Will not operate due to power supply failure

To assess the health status of an IED, the following condition parameters are studied:

- Operating mechanism, including power supply, insulation, connection
- Recalibration, including recalibration record and relay functionality (e.g., overcurrent, distance etc.)
- Reliability, including mal-operation count, loading and age

32.2 System Hierarchy

IED Based SCADA asset category belongs to the Monitoring and Control Systems assets grouping.

32.3 Useful Life and Typical Life

This asset has two major components, each of which has a different useful life. From a maintenance practice perspective, classic SCADA can be componentized into the following:

- IED
- Battery

32.3.1 *IED*

The useful life of the IED in IED based SCADA is in the range of 10 to 15 years; the typical life is 15 years.

32.3.2 *Battery*

The useful life of the battery in IED based SCADA is in the range of 5 to 20 years; the typical life is 10 years.

32.4 Time Based Maintenance Intervals

IED based SCADA is not subject to planned maintenance.

32.5 Impact of Utilization Factors

This asset is impacted by Operating Practices. It is specifically the battery component that is affected by operating practices. If this device is running within an electrically stable system there will be less stress imposed on it.

33 Fault Indicators

Fault indicators are used for loaded underground distribution circuits where secondary voltage is available - pad mounted transformers, switchgear and underground vault applications. A sensor monitors the line current. When the trip rating is exceeded, the indicator trips to the fault position. To reset the display the fault indicator uses a secondary voltage source, such as the low-voltage terminals of distribution transformers.

33.1 Degradation Mechanism

Fault indicators have durable Lexan housings, and utilize coated nickel iron sensor laminations encapsulated in a polyurethane potting compound for environmental protection. Overhead fault indicators use batteries, hence their useful life is based primarily on the end of life of the battery itself. The useful life of overhead fault indicators is significantly less than underground fault indicators due to this battery component.

33.2 System Hierarchy

Fault Indicators asset category belongs to the Monitoring and Control Systems assets grouping.

33.3 Useful Life and Typical Life

The overall useful life range of the fault indicator itself is dependent on the type:

- Overhead
- Underground

33.3.1 *Overhead*

The useful life of the overhead fault indicator is based on the useful life of its battery which is in the range of 5 to 20years; the typical life is 10 years.

33.3.2 *Underground*

The useful life of the underground fault indicator is in the range of 10 to 30 years; the typical life is 20 years.

33.4 Time Based Maintenance Intervals

Fault Indicators are not subject to planned maintenance.

33.5 Impact of Utilization Factors

This asset is impacted by Environmental Conditions.

34 Metering

The metering is how electricity providers measure billable services by measuring various aspects of power usage. When used in electricity retailing, the utilities record the values measured by these meters to generate an invoice for the electricity. This report focuses on those meters used for residential meters, industrial/commercial meters and wholesale meters. This asset consists of three components: the meter itself, the current transformer (CT) and the potential transformer (PT).

34.1 Degradation Mechanism

The major degradation mechanism of traditional meters is listed as follows:

- Electronic component aging due to long-term power quality impact, for solid-state meters
- Meter creep due to high temperature for induction type meters. This occurs when the meter disc rotates continuously with potential applied and the load terminals open circuited
- Magnetization alteration due to overload or short-circuited conditions
- Mechanical damage due to vibration of meter mounting
- Other adverse operating environment that might expedite the aging of components, such as humidity or dirt

34.2 System Hierarchy

Metering asset category belongs to the Monitoring and Control Systems assets grouping.

34.3 Useful Life and Typical Life

There are two components of the meter which have their own useful and typical life:

- Meter (Residential, Industrial/Commercial, Wholesale)
- Transformer (Current, Potential)

34.3.1 *Meter*

The useful life range of residential type meter is 20 to 45 years; typical life is 30 years.

The useful life range of industrial/commercial type meter is 20 to 60 years; typical life is 30 years.

The useful life range of wholesale type meter is 20 to 60 years; typical life is 30 years.

34.3.2 *Transformer (Current, Potential)*

The useful life range of the CT component is 30 to 50 years; typical life is 45 years.

The useful life range of the PT component is 30 to 50 years; typical life is 45 years.

34.4 Time Based Maintenance Intervals

Meters are not subject to planned maintenance

34.5 Impact of Utilization Factors

This asset is impacted by Environmental Conditions.

35 Smart Metering

A smart meter is an advanced meter is an electrical meter that identifies consumption in more detail than a conventional meter; and communicates that information via some network back to the local utility for monitoring and billing purposes.

35.1 Degradation Mechanism

The major degradation mechanism of smart metering system is listed as follows:

- Wiring insulation deterioration due to corrosion, moisture or overheating
- Poor electrical connections due to corrosion, vibration or other physical problems
- Cabinetry or rack damage or wear
- Faulty electronic components

The rate and severity of degradation in the equipment depend on its operational duties and environmental factors. Corrosion and moisture ingress, or combinations of these, represent the most critical degradation processes in microwave equipment of smart metering system.

Environmental conditions in relay and switch-rooms can affect microwave equipment's condition and reliability. Humidity, temperature, dust and pollution can cause component degradation. When plant temperatures fall below the dew point condensation can occur. When water enters equipment rooms through roof or other leaks, it can affect performance and aggravate corrosion.

Typically, terminations and connectors experience mechanical degradation. In damp locations it is common for verdigris, which is the green coating or patina formed when copper, brass or bronze is weathered and exposed to air or seawater over a period of time, to form. Typical problems for these components include:

- Failed crimped terminations due to movement
- Cracked terminal blocks
- Stripped threads
- Mechanical damage from over tightening

Typical degradation processes for the cabinets or racks include:

- Corrosion
- Loss of mechanical strength through use (e.g. swing front panels)

Microwave electronics in smart metering system range from capacitors and resistors to solid-state printed circuit boards. All electronic components have finite lifetimes. Modern highly integrated electronic equipment consists of application specific integrated circuits, surface mounted components, and multi-layer boards.

35.2 System Hierarchy

Smart Metering asset category belongs to the Monitoring and Control Systems assets grouping.

35.3 Useful Life and Typical Life

There are several components of the smart meter which have their own useful and typical life:

- Smart Meter
- Repeater
- Data Concentrator
- Powerline Repeaters

35.3.1 *Smart Meter*

The useful life range of the smart meter is 15 to 20 years; typical life is 15 years.

35.3.2 *Repeater*

The useful life range of the repeater is 5 to 15 years; typical life is 10 years.

35.3.3 *Data Concentrator*

The useful life range of the data concentrator is 10 to 20 years; typical life is 20 years.

35.3.4 *Powerline Repeaters*

The useful life range of the powerline repeater is 5 to 15 years; typical life is 10 years.

35.4 Time Based Maintenance Intervals

Smart Meters are not subject to planned maintenance

35.5 Impact of Utilization Factors

This asset is impacted by Environmental Conditions.

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Appendix G

Kinetrics - OEB Asset Amortization

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Asset Depreciation Study for the Ontario Energy Board

Kinectrics Inc. Report No: K-418033-RA-001-R000

July 8, 2010

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DISCLAIMER

EXECUTIVE SUMMARY

Generally accepted accounting principles (GAAP) requires entities with property, plant and equipment (PP&E) to amortize the cost of assets over the period of time that they provide useful service. Prior to adoption of International Financial Reporting Standards (IFRS), GAAP in Canada permitted the use of asset service lives specified by the regulator. IFRS (without approval of a standard for Rate-regulated Activities) does not allow for the use of externally mandated depreciation rates. The Ontario Energy Board (OEB) stipulated that all Ontario's utilities are expected to adopt IFRS effective January 1, 2011[1]. At the same time, OEB is requiring all distributors to adopt useful life estimates that do not depend on the regulator and are determined by independent asset service life studies. In addition, IFRS is requiring componentization of assets placed in service by distributors at a sufficient level of detail to recognize that portions of an overall asset may be replaced or refurbished during the life of the asset of which they are a component, while the overall life of the asset may be somewhat longer.

The purpose of this Report is to assist utilities in making the transition from GAAP to IFRS and to assist them with determining appropriate initial service lives for assets most commonly used in the distribution of electricity in Ontario. This approach is considered an effective way to minimize the need and cost to Ontario consumers of a myriad of like studies by individual distributors. This report may also serve as a reference guide for the OEB in reviewing rate applications while keeping the responsibility for selecting and substantiating asset service lives with the utilities.

This Report identifies and describes common groups of assets and their most common "components". Total service lives are ascribed to each component, and assets are assigned to one of the following "parent" systems:

- Overhead Lines (OH)
- Transformer and Municipal Stations (TS&MS)
- Underground Systems (UG)
- Monitoring and Control Systems (S)

For each of the assets and their respective components, a useful life range and a typical useful life value within the range are given. This information is a composite of industry values known to Kinectrics Inc. (see Section E - 6) and information from six Ontario Local Distribution Companies (LDCs) of varying sizes and geographical locations selected as a sample, and with whom Kinectrics Inc. met on an individual basis.

It is also recognized that the useful lives of assets are dependent on a number of Utilization Factors (UFs) that are present within each jurisdiction. The degrees of impact of these influencing factors were qualitatively determined using information gathered from the LDCs. The UFs are identified as:

- Mechanical Stress
- Electrical Loading
- Operating Practices
- Environmental Conditions
- Maintenance Practices
- Non-Physical Factors

By considering the useful life ranges and the extent to which the utilization factors impact their assets, utilities will be able to select appropriate depreciation periods for their asset groups as

[1] *Report of the Board – Transition to International Financial Reporting Standards*, July 28, 2009

shown in the example for Power Transformers in Section E - 5 of this Report. The example demonstrates how UFs can be used in conjunction with local circumstances to estimate an appropriate depreciation period within the prescribed useful life range.

Table F-1 summarizes useful lives and the factors impacting those lives as developed by this report.

For completeness, Kinectrics has included a table that summarizes typical useful lives for Ontario's Local Distribution Companies' non-distribution assets, sometimes referred to as Minor Assets (Table F-2). The useful life values for Minor Assets were based on utility practices without further analysis.

In addition to the useful life information presented in this Report, Kinectrics has identified several areas for improvement that, once addressed, can enhance the Local Distributors' ability to improve the accuracy of their determination of asset service lives.

CREDENTIALS OF THE CONSULTANT

Kinectrics Inc is a recognized expert in determining useful lives of asset as a leader in developing "state of the art" Asset Condition Assessment methodology that estimates condition of assets based on their End-of-Life criteria and successfully completed a number of large scale Asset Management projects. These projects involved condition assessments of both station and lines distribution assets and included performing risk assessments based on the findings and recommending future life cycle sustaining investments, both capital and maintenance in nature.

Over the last year Kinectrics Inc completed a number of projects aimed at assisting Ontario's LDCs with the IFRS conversion. The projects involved developing LDC-specific assets groupings and componentization and for each asset grouping/component providing industry based useful life ranges. Kinectrics Inc has also provided information on typical industry time-based maintenance intervals and qualitative assessment of factors that may influence typical life within the range, such as operational practices, utilization, functional requirements, environmental impact etc. In addition, Kinectrics has acted as the Technical Due Diligence Consultant in many of the Ontario LDC mergers, in which depreciation assessments and valuation of assets were major tasks.

Kinectrics Inc observations on the useful life of assets as they relate to IFRS have recently been published in the November 2009 Special Edition of "The Distributor", an Electricity Distributors Association (EDA) publication.

Kinectrics staff understands power systems, having conducted comprehensive work on line design, standards, protection, losses and virtually every other aspect of planning and design for the last 30 years. Kinectrics has high voltage and high current lab testing expertise and has conducted many distribution asset failure investigations. Our theoretical knowledge is backed up by practical experience with power system components. This equipment expertise is of great practical value in working with utility staff whose mandate is to achieve the optimal physical and economic life cycle for these assets. Kinectrics asset management experience goes far deeper than logging equipment populations and demographics in computer databases.

Kinectrics has a unique and cost-effective capability covering a wide spectrum of areas including:

- Intimate knowledge of transmission and distribution systems equipment and their needs, and additional lifecycle-management or test result analysis services that we offer beyond testing and that are based on this extensive experience and understanding

- Kinectrics' testing facility that is world industry leader in capability and expertise in this domain and includes access to over 25 world-class Ontario-based laboratory and testing facilities, and to a range of proprietary technologies and processes

- In-depth experience in the management and execution of utility projects for numerous clients in Ontario and Canada, as well as North America and the rest of the world

- Access to staff from Kinectrics and other utility experts in key focus areas

- Operation under the ISO 9001 quality management system, with additional ISO 17025 qualification for key laboratories

- Project execution at the Project Management Professional (PMP) level

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A INTRODUCTION

Generally accepted accounting principles (GAAP) require entities with property, plant, and equipment (PP&E) to amortize the cost of such assets over the period of time that they provide useful service. Determination of such periods of time (total service lives) is generally based on engineering studies, asset retirement statistics and the experience of other utilities with like assets. Total service lives are reviewed from time to time to ensure they are current.

The majority of electricity distributors in Ontario continue to use asset service lives originally prescribed by Ontario Hydro at least 20 years ago.

Prior to adoption of International Financial Reporting Standards (IFRS), GAAP in Canada permitted the use of asset service lives specified by the regulator. IFRS (without approval of a standard for Rate-regulated Activities) does not allow for the use of externally mandated depreciation rates. Ontario Energy Board (OEB) has stipulated that all Ontario's distributors are expected to adopt IFRS beginning in 2011. In order to be IFRS compliant, distributors must adopt useful life estimates that do not depend on the regulator and are supported by independent asset service life studies.

In addition IFRS requires the componentization of assets placed in service by distributors at a sufficient level of detail to recognize that portions of an overall asset may be replaced or refurbished during the life of the asset of which they are a component, while the overall life of the asset may be somewhat longer. For many distributors, the level of detail maintained in their fixed asset and depreciation records is already sufficient to meet the IFRS componentization requirements. Such distributors have typically broken their PP&E into parts and have established formal "plant retirement units" (scaled in anticipation that they could be retired from service part way through the life of the asset of which they are a part). For other distributors, additional breakout may be necessary in adopting IFRS.

Because of the myriad of possible asset and system configurations, there are no industry standard components or plant retirement units. Nonetheless, industry practice in Ontario has been common enough that there are expected to be normative collections of asset components and system design configurations that can enable a study of service lives to be performed on the most commonly found components and configurations.

The purpose of this Report is to assist utilities in making the transition to IFRS and to assist them with determining appropriate initial service lives for assets most commonly used in the distribution of electricity in Ontario, particularly in situations where they have not conducted their own study. This approach is considered an effective way to minimize the need and cost to Ontario consumers of a myriad of like studies by individual distributors.

The method of depreciation of PP&E used by Ontario distributors is the straight-line remaining service life method, and Kinectrics understands this will continue to be the method used under IFRS.

This study will assist distributors with the determination of suitable asset total service lives. Distributors must still evaluate whether the total service lives set out in this Report are completely applicable to their own utility. This evaluation includes assessing the applicability of utilization factors (UF) that affect the most likely values provided in the Report, determining whether adjustments need to be made to reflect their individual componentization circumstances, determining how much service life remains for each component as well as the amount, if any, of residual or scrap value that is expected on disposition/removal from service of the component. Such utility-specific work is not part of the work for which Kinectrics Inc was engaged.

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B OBJECTIVE AND SCOPE

B - 1 OBJECTIVE

The objective of this Report is to assist electricity distributors in Ontario in determining total service lives for typical electricity distribution system assets that they own.

The information contained in the Report is expected to further facilitate transfer of responsibility for determining asset total service lives to distributors as they transition to IFRS.

B - 2 SCOPE OF WORK

This Report identifies and describes commonly configured groups of assets forming most commonly found “components” and ascribes total service lives to such components. In addition, assets are assigned to one of the following “parent” systems:

- Overhead Lines (OH)
- Transformer and Municipal Stations (TS&MS)
- Underground Systems (UG)
- Monitoring and Control Systems (S)

For each of the assets and their components, this Report provides a useful life range and a typical useful life value within the range. To further assist distributors with selecting the depreciation periods most appropriate for their utility, the Report also assesses the importance of various factors that affect the typical useful life value.

Useful life is expressed as a specific number of years rounded off to the nearest multiple of 5, being the Typical Useful Life (TUL). As well, a lower and upper limit of number of years is provided, within which most situations could be expected to occur. These upper and lower limits are referred to as the Minimum Useful Life (MIN UL) and Maximum Useful Life (MAX UL) and are also rounded off to the nearest multiple of 5. The definition of these terms is provided in Subsection E - 1 of this Report.

The Report also indicates the typical Utilization Factors (UF) affecting the degree to which shorter or longer total services lives could be judged by a distributor in a particular circumstance to be more appropriate. These factors include Maintenance Practices, Environmental Conditions, Mechanical Loading, Electrical Loading, Operating Practices, and Non-Physical Factors such as obsolescence. A description of these factors is provided in Subsection E - 1of this Report.

The Report includes a summary of the statistical analysis that establishes a percentage of assets that will reach their end-of-life (EOL) between MIN UL and MAX UL in Subsection E - 6.

In addition, the Report provides a guideline regarding the typical depreciation periods used in Ontario for other utility assets that do not fall under any of the above “parent” systems, such as office equipment, computers, buildings, vehicles, and communication equipment. These assets are often referred to as Minor Assets or General Plant.

Kinectrics selected six Ontario distributors in collaboration with the Ontario Energy Board staff and met with these distributors to ascertain what they consider to be appropriate values for TUL, MIN UL and MAX UL, as well as factors that they felt impacted the TUL for each class of depreciable property. A class of depreciable property is that grouping of components that is appropriate to consider together for purposes of this study. Some such distributors had recently completed depreciation studies of their own, and all were prepared to assist with this work.

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C EXECUTION PROCESS

The project execution process entailed seven steps to ensure that the industry-based information compiled by Kinectrics includes all the relevant assets and components used by Ontario's Local Distribution Companies (LDCs). The procedure was as follows:

Step 1
Kinectrics established a list of asset groupings representative of the typical breakdown of assets for Ontario's LDCs. This list was based on Kinectrics familiarity with LDCs business practices, particularly as a result of having performed a number of studies in support of the IFRS transition initiative for a number of large LDCs. The asset breakdown presented in this Report should be regarded as a guideline as it is likely that LDCs will have a somewhat different asset breakdown based on their specific asset mix and existing accounting practices.

Step 2
Kinectrics provided further breakdown or componentization for some of the asset categories. This was also based on Kinectrics familiarity with LDCs business practices and, at the same time was assessed against the following two criteria:

1. A value of component is significant or material enough relative to the value of the asset of which it is a component.

2. A need to replace the component does not necessarily warrant replacement of the entire asset.

Step 3
Kinectrics compiled industry based useful life values for the assets and their components using different sources, including industry statistics, research studies and reports (either by individuals or working groups, such as CIGRE), and Kinectrics Inc past experience (see Section E-2).

The listing for each asset/component includes a minimum and maximum useful life range (MIN UL and MAX UL) as well as TUL and utilization factors, such as maintenance practices, environmental conditions, mechanical and electrical loading, etc. that have an impact on whether the actual life for a particular utility is longer or shorter than the typical life.

Step 4
Six LDCs of different sizes were engaged to provide input to the study. The selection was made considering variables such as asset mix and geographical location. The utilities had varying experience regarding assets grouping, breakdown and componentization. Kinectrics Inc met with these utilities directly and obtained and discussed their assessments of each of the useful life values and the influencing utilization factors for each asset.

Step 5
The typical lives for some assets/components were combined with the corresponding lives obtained from utility interviews as described in Section E - 4 of this Report for each of the asset categories/components to come up with the recommended TUL, as well as recommended MIN UL and MAX UL. The study work also summarized and displayed the qualitative assessment of the degree to which each Utilization Factor underwrites the choice of TUL and affects TUL and the range between MIN UL, and MAX UL.

Step 6
A Draft Report was prepared by Kinectrics and circulated for comment from the LDC community.

Step 7
This Final Report was prepared and submitted to the OEB incorporating adjustments in response to comments on the Draft Report.

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D DELIVERABLES

This Report is the primary deliverable to the Ontario Energy Board from this engagement for use by electricity distributors in Ontario. In particular, this Report includes:

1. An Executive Summary and Table of Contents.

2. A summary of the credentials of the consultant.

3. A description of the methods used to determine estimated total life and estimated ranges of the respective categories of the depreciable assets, as well as a description of the data sources relied upon.

4. A description of each asset category and component for which Kinectrics has determined a service life.

5. A reference table listing the asset categories and components for which a service life has been determined:

   i. a most likely service life for the component expressed in years (referred to as the typical useful life or TUL), and

   ii. a reasonable upper and lower limit stated in years for the service life of the component under various operating or environmental conditions (referred to as the minimum and maximum useful live or MIN UL and MAX UL, respectively)

   iii. a description of the factors that impact the useful life of each asset.

6. Implementation suggestions that Kinectrics considers useful for distributors to consider when implementing the service lives (these suggestions include utilization and maintenance factors and practices).

7. Other matters Kinectrics considers relevant including the definition of Useful Life, Factors Impacting Typical Useful Life and statistical evaluation of percentage of the asset population that is expected to fall between MIN UL and MAX UL.

Kinectrics also provided in Section G some conclusions about areas of need where distributors could improve the overall process of managing depreciation cost.

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E METHODOLOGY

This Section defines some of the terms used throughout this report and describes the methodology used to estimate typical useful life, its range between minimum and maximum values for the defined distribution assets categories and the utilization factors influencing useful life.

E - 1 DEFINITIONS

The definitions of Asset Categories and Components, Useful Life Ranges, Typical Useful Life and the Factors that impact Useful Life (both physical and non-physical in nature) are listed below.

Asset Categories
Asset categories refer to typical distribution system assets such as as station transformers, distribution transformers (overhead and underground), breakers, switches, underground cables, poles, vaults, cable chambers, etc. Some of the assets, such as power transformers, are complex systems and include a number of components.

Components
For the purposes of this study, component refers to the sub-category of an asset that meets both of the following criteria:

1. Its replacement value is material enough to track.

2. A need to replace the component does not necessarily warrant replacing the entire asset.

An *asset* may be comprised of more than one component, each with independent failure modes and degradation mechanisms that may result in a substantially different useful life than that of the overall asset. A component may also be managed under an independent maintenance and replacement schedule.

Typical Useful Life (TUL)

TUL is defined differently, depending on the asset category and component type, and can be categorized under one of the following three scenarios:

i. Assets Are Replaced Only When Failed

   TUL= Age when most of the assets fail and are replaced and is equal to the asset's physical EOL (physical EOL is defined as an asset's inability to perform its functions as designed).

ii. Assets Are Replaced Due to Reasons Not Related to Their Performance

   TUL = Typical age when assets are replaced before they reach their physical EOL due to reasons such as lack of spare parts or replacement assets, incompatibility with system requirements, external drivers (e.g., road widening, or PCB Regulation), or internal initiatives (e.g., carbon print reduction or voltage conversion).

iii. Assets are Replaced for Economic Reason

   TUL = Typical age when assets reach their "economic life", i.e., although physical EOL is not reached, high risk of failure cost makes it economical to replace them.

Depending on the utility's circumstances, replace vs. refurbish strategy and type and age distribution of a particular asset category/component, TUL may reflect a combination of all three scenarios described above. The degradation mechanism is discussed for each asset studied in this report.

Useful Life Ranges

TUL falls between Minimal Useful Life (MIN UL) and Maximum Useful Life (MAX UL) which for the purposes of this report are defined as:

MIN UL = Age when a small percentage of assets reach their physical EOL, usually at the beginning section of the statistical "bath-tub curve", where failure rate starts increasing exponentially

MAX UL = Age when most of the assets reach their physical EOL, usually at the end section of the statistical "bath-tub curve", where failure rate increases exponentially

The exact percentage of assets/components that fail before reaching MIN UL or MAX UL varies from utility to utility as well as among different asset categories/components. Although MIN UL and MAX UL are most often related to physical EOL, in some cases the range is defined by economic or other reasons. In such cases, the range is usually less than when MIN UL and MAX UL are dictated by the physical EOL alone.

It is worth noting that an asset category can have a typical life that is equal to either the maximum or minimum life. This fact is simply an indication that the majority of the units within a population will be operational for either the minimum or maximum number of years; i.e. the statistical data is skewed towards either the maximum or minimum values. This could also happen, for example, when assets are replaced for economic reasons to alleviate failure risk cost.

A statistical analysis that estimates the percentage of assets/components whose useful lives are within the range defined by MIN UL and MAX UL is presented in Subsection E - 6 of this report.

The range in useful lives that are found in practice reflects differences in various factors described in the "Utilization Factors" subsection below.

Utilization Factors

For the purposes of this Report, the term Utilization Factors (UFs) refers to factors that are expected to affect TUL of assets and their components and to a certain extent MIN UL and MAX UL. The degree of their effect is qualitatively described as High (H), Medium (M), Low (L), or No Impact (NI). The following UFs were identified:

1. **Mechanical stress** refers to forces and loads applied to an asset that may lead to degradation over time, e.g. wind load, ice load, gravitational and spring forces on components, etc.

2. **Electrical loading** refers to stresses such as continuous loading, temporary overloading and exposure to short circuit fault current.

3. **Operating practices** refers to how frequently an asset is subject to operations (automatic or manual) that impact its useful life, e.g. reclosers, switch or breaker operations.

4. **Environmental conditions** include pollution, salt, acid rain, humidity, extreme temperature, and animals that are prevalent and cause long-term degradation over a period of time.

5. **Maintenance Practices** refers to how frequently and regularly Routine Inspection or Routine Testing/ Maintenance is performed on assets/components.

6. **Non-Physical Factors** refers to things that are not directly related to physical condition of assets, e.g. obsolescence, economic considerations related to life cycle cost management, increased rating requirements due to system growth, regulatory changes, construction activities, etc. These factors could lead to asset replacement even when assets can still perform as designed.

Each asset may be impacted by one or more of the UFs, resulting in different degradation rates for the same assets and/or components in different jurisdictions. Therefore, it is expected that some of the utility-specific total lives chosen will be different than the TULs provided in this Report based on the qualitative assessment of the above factors.

As part of the interview, each of the six utilities was asked to rank the degree to which each UF impacts the life of each of their assets. For each UF, a singular degree of impact value (H, M, L, NI), based on a composite of the rankings provided by the utilities, is reported. The degree of impact (DI) is determined by the following formulation:

$$DI = \frac{\sum_{m=1}^{6} \alpha_m (RS)}{\sum_{m=1}^{6} \alpha_m (RS_{\max})}$$

m Utility number. Six (6) utilities were interviewed.

RS Ranking Score. This is a numerical score assigned to the qualitative rakings of H, M, L, and NI (no impact).

Qualitative Ranking	**Ranking Score (RS)**
H	4
M	3
L	1.5
NI (no impact)	0

α_m Data availability coefficient (1 when data is provided by utility, 0 otherwise).

RS_{max} Maximum possible Ranking Score. The maximum value is equal to the score of a qualitative ranking of “H”; in this case the numerical value is 4.

The numerical percentage of degree of impact (DI) is then translated into a singular, qualitative ranking as per the following:

Degree of Impact (%)	Qualitative Rating
< 10%	NI
10% – 44%	L
45% - 78%	M
79% - 100%	H

Consider, for example, the Mechanical Stress for Fully Dressed Concrete Poles. Three of six utilities provided qualitative rankings, as shown on the "Qualitative Ranking" column. The numerical scores for each of the rankings are shown on the "Ranking Score RS" column. The data availability coefficient and maximum ranking score are also shown.

Utility	Qualitative Ranking	Ranking Score RS	α	Maximum Ranking Score (RS_{max})
Utility 1	n/a	n/a	0	n/a
Utility 2	H	4	1	4
Utility 3	n/a	n/a	0	n/a
Utility 4	n/a	n/a	0	n/a
Utility 5	M	3	1	3
Utility 6	H	4	1	4

For the above data, the Degree of Impact (DI) = (0 + 1*4 + 0 + 0 + 1*3 + 1*4) / (0 + 1*4 + 0 + 0 + 1*4 + 1*4) = 92%. A score of 92% translates to a ranking of high (H). Thus, as per the utility interviews, Mechanical Stress has a high impact on the useful lives of concrete poles.

E - 2 INDUSTRY RESEARCH

Kinectrics compiled degradation and useful life data from several different sources to develop what Kinectrics refers to as the "industry" values for TUL, MIN UL and MAX UL in the tables provided in Section H – APPENDIX – DERIVATION OF USEFUL LIVES. These sources are:

- Industry statistics
- Information provided by manufacturers
- Research studies and reports by individuals and corporate entities, such as universities, utilities, research organizations, etc.
- Research studies conducted by working groups of international organizations such as CIGRE, EPRI, etc.
- Kinectrics applied its own extensive expertise in failure investigations conducted for many utilities across North America, knowledge gained from numerous completed Asset Condition Assessment project that involved determining appropriate EOL for different assets, testing of distribution assets and their components, and IFRS studies performed for many large Ontario LDCs.

All the sources are listed in Section J - REFERENCES of this Report.

E - 3 UTILITY INTERVIEWS

Kinectrics interviewed staff members from six utilities across Ontario. The utilities were selected in conjunction with OEB staff and the sample represents a good cross-section of Ontario's distributors based on their size, geographical location, and asset mix as follows:

- One utility from GTA
- One utility from the Niagara Escarpment Region
- One utility from South Western Ontario
- One utility from Eastern Ontario
- Two utilities from Northern Ontario

The interviews were focused on obtaining information from the utilities technical staff regarding:

- Appropriateness of the assets/components break down
- Utility-specific TUL, MIN UL and MAX UL
- Utilization factors affecting the above values

Actual asset failure information was not available so utility staff relied on existing age distribution information when available, hands-on field experience or budgetary forecasting experience to provide the required information. The utilities sampled had a good grasp of the challenge related to establishing realistic useful life and their responses were based on the mix of available data, actual experience and informed judgment.

E - 4 COMBINING INDUSTRY RESEARCH AND UTILITY INTERVIEW FINDINGS

Industry research was combined with interview results to ensure that the recommended values, although still based on the industry-wide experience, properly reflect Ontario's perspective.

The more utilities that provided input regarding a certain asset, the more weight utility input was given in arriving at the overall TUL, MIN UL and MAX UL as shown in the table below:

Number of Utility Inputs	Ontario Weight	Industry Weight
6	50%	50%
5	42%	58%
4	33%	67%
3	25%	75%
2	16%	84%
1	4%	96%

The overall values shown in the summary tables in Section F and H incorporate the logic described in the above table.

The summary of the results of combining both industry research and Ontario LDC survey findings is provided in Table F-1 of this Report for TUL, MIN UL and MAX UL along with summary assessments by the distributors of the impact of UFs on useful lives. A detailed description of degradation mechanism(s), TUL, MIN UL, MAX UL and UFs for each asset category and component is provided in Section H of this Report. Recommended ranges for the Minor Assets that do not fall under any of the "parent" systems are provided in the Table F-2.

E - 5 EXAMPLE OF USING THE REPORT

Following is an example demonstrating how an appropriate depreciation period could be selected by a utility for Power Transformers:

1. TUL from either Table F-1 in Section 0 or the detailed description in Section 12 of Section H- APPENDIX - DERIVATION OF USEFUL LIVES for the overall Fully Dressed Pole is 45 years, with MIN UL and MAX UL at 30 and 60 years, respectively.

2. The UFs are as follows:
    - Mechanical Stress – no impact
    - Electrical Stress – medium impact
    - Environmental Conditions – medium impact
    - Operating Practices – low impact
    - Maintenance Practices – low impact
    - Non-Physical Factors – no impact

3. A utility may select an appropriate depreciation period based on the specific UFs reflecting the actual utility conditions. For example, if electrical stress is not significant (lightly loaded transformer), environment in terms of pollution or weather extremes is not very harsh, the units are regularly maintained, and tap changers are operated not very frequently, the utility could select a depreciation period above the TUL but below MAX UL, say 50 years. Should the conditions and factors be more severe, the depreciation period chosen by the utility may be less than the TUL shown, (e.g., 40 years).

4. As more information is accumulated over time (e.g., several years of failure history), a utility may decide to adjust the depreciation period based on empirical information to better reflect its specific circumstances.

The decision on whether TUL should be the same as the one in the table or whether it should be shortened or prolonged and by how much is not an exact science and depends on the informed judgment of the utility's technical staff and the utility's approach to life cycle cost management.

Although the values provided in this study for the UFs are those that underwrite TUL in each case, statistical analysis described in Section E-6 suggests that there is between 67% and 91% probability that the selected depreciation period will fall within the prescribed range (i.e., between MIN UL and MAX UL). Therefore, it is possible that the selected depreciation period could be outside of the Min UL or Max UL provided in this report depending on the impact of the various UFs. In such cases, and particularly if the depreciation period is significantly longer or shorter than the recommended TUL, a utility's auditors and the OEB will likely require the utility to explain with more rigour the reasons for selecting the particular depreciation period.

E - 6 STATISTICAL ANALYSIS

Once Kinectrics determined the useful life values of TUL, MIN UL, and MAX UL using industry and Ontario LDC information, Kinectrics performed a statistical analysis to estimate what percentage of assets is expected to fall between MIN UL and MAX UL. A detailed description of the methodology is presented in APPENDIX I – PERCENT OF ASSETS IN THE USEFUL LIFE RANGE of this Report. The following assumptions were made in the analysis:

1. EOL distribution for all the assets is uni-modal with the peak potentially skewed towards MIN UL or MAX UL depending on the asset category/component.

2. The value corresponding to the peak of failure density function is the same as TUL.

3. In defining the useful life range, the MIN UL and MAX UL are within (√3 times standard deviation б) from the mean value μ of the useful life distribution, regardless of where TUL is relative to the mean value μ.

4. For any specific asset category/component TUL always lies within the useful life range.

Based on these assumptions, the percentage of assets with useful life within the range between MIN UL and MAX UL is found to be equal to 91% for a normally distributed useful life (i.e., TUL is the same as the mean value). If the useful life distribution is not normal (i.e., TUL is not the same as the mean value) the percentage of assets within the range between MIN UL and MAX UL will be less than 91% but more than the minimum value of 67%.

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F SUMMARY OF RESULTS

Table F - 1 summarizes useful lives, and factors impacting those lives as developed by this report.

Table F - 1 Summary of Componentized Assets, Service Life and Factors

PARENT*	#	ASSET DETAILS Category| Component | Type			USEFUL LIFE MIN UL	TUL	MAX UL	FACTORS ** MC	EL	EN	OP	MP	NPF
OH	1	Fully Dressed Wood Poles	Overall		35	45	75	H	L	M	NI	L	L
			Cross Arm	Wood	20	40	55						
				Steel	30	70	95						
	2	Fully Dressed Concrete Poles	Overall		50	60	80	H	L	M	NI	L	NI
			Cross Arm	Wood	20	40	55						
				Steel	30	70	95						
	3	Fully Dressed Steel Poles	Overall		60	60	80	H	M	L	NI	L	NI
			Cross Arm	Wood	20	40	55						
				Steel	30	70	95						
	4	OH Line Switch			30	45	55	L	L	L	L	M	L
	5	OH Line Switch Motor			15	25	25	L	NI	L	L	M	L
	6	OH Line Switch RTU			15	20	20	NI	NI	L	L	L	M
	7	OH Integral Switches			35	45	60	L	M	M	M	L	H
	8	OH Conductors			50	60	75	M	L	M	NI	NI	L
	9	OH Transformers & Voltage Regulators			30	40	60	L	M	M	NI	NI	M
	10	OH Shunt Capacitor Banks			25	30	40	-	-	-	-	-	-
	11	Reclosers			25	40	55	L	L	L	M	L	M
TS & MS	12	Power Transformers	Overall		30	45	60	NI	M	M	L	L	NI
			Bushing		10	20	30						
			Tap Changer		20	30	60						
	13	Station Service Transformer			30	45	55	NI	L	M	L	NI	L
	14	Station Grounding Transformer			30	40	40	-	-	-	-	-	-
	15	Station DC System	Overall		10	20	30	NI	M	L	L	M	M
			Battery bank		10	15	15						
			Charger		20	20	30						
	16	Station Metal Clad Switchgear	Overall		30	40	60	L	L	M	M	M	M
			Removable Breaker		25	40	60						
	17	Station Independent Breakers			35	45	65	M	M	M	M	M	M
	18	Station Switch			30	50	60	M	L	M	M	M	L

* **OH = Overhead Lines System** **TS & MS = Transformer and Municipal Stations**

** MC = Mechanical Stress EL = Electrical Loading OP = Operating Practices EN = Environmental Conditions
MP = Maintenance Practices NPF=Non-Physical Factors
H=High M=Medium L=Low NI=No Impact

PARENT*	#	ASSET DETAILS		USEFUL LIFE			FACTORS **					
		Category| Component | Type		MIN UL	TUL	MAX UL	MC	EL	EN	OP	MP	NPF
TS & MS	19	Electromechanical Relays		25	35	50	NI	NI	NI	NI	NI	H
	20	Solid State Relays		10	30	45	NI	NI	NI	NI	NI	H
	21	Digital & Numeric Relays		15	20	20	NI	NI	NI	NI	NI	H
	22	Rigid Busbars		30	55	60	L	L	L	NI	NI	L
	23	Steel Structure		35	50	90	L	NI	M	NI	NI	L
UG	24	Primary Paper Insulated Lead Covered (PILC) Cables		60	65	75	L	L	M	L	NI	M
	25	Primary Ethylene-Propylene Rubber (EPR) Cables		20	25	25	NI	M	L	NI	NI	NI
	26	Primary Non-Tree Retardant (TR) Cross Linked Polyethylene (XLPE) Cables Direct Buried		20	25	30	M	M	M	L	L	L
	27	Primary Non-TR XLPE Cables In Duct		20	25	30	M	M	M	L	L	M
	28	Primary TR XLPE Cables Direct Buried		25	30	35	M	M	M	L	L	L
	29	Primary TR XLPE Cables In Duct		35	40	55	M	M	M	L	L	L
	30	Secondary PILC Cables		70	75	80	NI	L	L	NI	NI	H
	31	Secondary Cables Direct Buried		25	35	40	M	M	M	L	NI	NI
	32	Secondary Cables In Duct		35	40	60	M	M	M	L	NI	NI
	33	Network Transformers	Overall	20	35	50	NI	L	H	NI	NI	NI
			Protector	20	35	40						
	34	Pad-Mounted Transformers		25	40	45	L	M	M	NI	L	L
	35	Submersible/Vault Transformers		25	35	45	L	M	M	NI	L	L
	36	UG Foundations		35	55	70	M	NI	M	L	L	M
	37	UG Vaults	Overall	40	60	80	M	NI	M	L	L	L
			Roof	20	30	45						
	38	UG Vault Switches		20	35	50	L	L	L	L	L	NI
	39	Pad-Mounted Switchgear		20	30	45	L	L	H	L	L	L
	40	Ducts		30	50	85	H	NI	M	NI	NI	L
	41	Concrete Encased Duct Banks		35	55	80	M	NI	M	NI	NI	L
	42	Cable Chambers		50	60	80	M	NI	H	NI	L	NI
S	43	Remote SCADA		15	20	30	NI	NI	L	NI	L	H

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

** MC = Mechanical Stress EL = Electrical Loading OP = Operating Practices EN = Environmental Conditions
MP = Maintenance Practices NPF=Non-Physical Factors
H=High M=Medium L=Low NI=No Impact

Table F - 2 summarizes useful life ranges for Ontario's Local Distribution Companies' non-distribution assets. Table F - 2 contains assets that were not studied in detail in this analysis and represent recommended ranges based on the experience of Ontario LDCs interviewed. A further analysis of these assets is not considered necessary.

Table F - 2 Summary Useful Life of Minor Assets

#	ASSET DETAILS Category - Component - Type		USEFUL LIFE RANGE
1	Office Equipment		5-15
2	Vehicles	Trucks & Buckets	5-15
		Trailers	5-20
		Vans/Cars	5-10
3	Administrative Buildings		50-75
4	Leasehold Improvements		Lease dependent
5	Station Buildings	Station Building	50-75
		Parking	25-30
		Fence	25-60
		Roof	20-30
6	Computer Equipment	Hardware	3-5
		Software	2-5
7	Equipment	Power Operated	5-10
		Stores	5-10
		Tools, Shop, Garage Equipment	5-10
		Measurement & Testing Equipment	5-10
8	Communication	Towers	60-70
		Wireless	2-10
9	Residential Energy Meters		25-35
10	Industrial/Commercial Energy Meters		25-35
11	Wholesale Energy Meters		15-30
12	Current & Potential Transformer (CT & PT)		35-50
13	Smart Meters		5-15
14	Repeaters - Smart Metering		10-15
15	Data Collectors - Smart Metering		15-20

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G CONCLUSIONS

This Report provides reference information that will assist Ontario's electrical distribution utilities in selecting appropriate useful lives for typical distribution asset categories. The ultimate decision on what the appropriate useful lives are lies with utilities and they are expected to justify their selection based on the local circumstances vis-à-vis utilization factors that affect TUL and other relevant considerations such as empirical data and manufacturers recommendations.

This Report combines available industry information, Kinectrics expertise and survey results from 6 of Ontario's LDC. Thus, Kinectrics considers that the total service lives recommended are sufficiently reliable so that another independent expert would reasonably arrive at the same conclusion. Nevertheless, it is expected that for most asset categories/components TUL, and thus the selected depreciation period, will vary among utilities..,. The utility should be prepared and be able to provide a rationale for selecting a particular depreciation period based on the information in this Report and the utility's specific experience.

Asset categories and their componentization as presented in this report represent typical assets componentization in Ontario. In most cases utilities will only have a subset of the asset categories included in the Report. Furthermore, utilities may choose not to have some of the asset categories componentized as suggested in this Report and have depreciation tracked at the asset level.

In the course of our work Kinectrics identified several areas for improvement that, once addressed, should enhance distributors' ability to improve the accuracy of their determination of asset service lives. At the present time most distributors have limited data available on actual asset retirement history. One consequence of this is that the range of asset service lives from minimum to maximum tends to be broader that it would be if reliable asset retirement histories were available. To improve the overall process of managing depreciation cost, from this study Kinectrics concludes there is a need:

- For distributors to improve availability of asset retirement records that identify both the end of life and its causes (e.g., failures, non-physical factors (obsolescence), high risk of failure, etc).
- For ongoing comparison of the depreciation period selected with actual physical useful lives based on empirical evidence.
- To gather data to support probability of failure curves for assets that are run to failure.
- To consider whether there are other Utilization Factors that have significance and develop ways to quantify their impacts on Typical Useful Life.
- For distributors to acquire and maintain planned and corrective maintenance records in a manner that can be easily accessed and analyzed.
- To develop and maintain a record of assets replaced as a result of major projects (e.g., road widening or voltage conversion).

The depreciation periods selected are expected to be reviewed periodically and adjusted if and when required based on the knowledge and experience gained in the future.

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H APPENDIX - DERIVATION OF USEFUL LIVES

A results section has been created for each asset category. Each includes:

Description - The description of the asset category including componentization, design configurations, alternative design configurations and system hierarchy. For some assets their attributes such as type and material (e.g. wood poles) or interrupting mechanism (e.g. reclosers) were also mentioned. In such cases, although these attributes may result in useful lives being somewhat different, the useful lives information provided in this Report is for the overall asset category and Kinectrics recommends not breaking these asset categories down further based on their attributes.

1. Degradation Mechanism – A discussion of the degradation mechanism including end of life criteria. This describes physical EOL referred to in Section E-1 - DEFINITIONS.

2. Useful Life - The useful life values (MIN UL, TUL and MAX UL) for the asset and their respective components. This section presents both industry and survey values as well as the combined values.

3. Impact of Utilization Factors – This section discusses the factors (UFs) impacting useful life and includes qualitative degree of impact based on the utilities surveyed. If utilities considered the TUL to be impacted by a factor, they rated the magnitude of the impact on a scale of high, medium or low (displayed on the graph as red, orange and yellow, respectively). For the case where utilities felt that the factor has no impact on the TUL the space is left light gray. Finally, "No Response" is displayed as dark grey and signifies that one or more utility did not provide information for that asset.

Please refer to Table F - 1 for a summary of these results.

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1. Fully Dressed Wood Poles

1.1 Description

The asset referred to in this category is the fully dressed wood pole ranging in size from 30 to 75 feet. This includes the wood pole, cross arm, bracket, insulator, cutouts, arresters, and anchor and guys. Wood poles are typically the most common form of support for overhead distribution feeders and low voltage secondary lines.

1.1.1 Componentization Assumptions

For the purposes of this report, the Fully Dressed Wood Poles asset category has been componentized so that the cross arm can be regarded as a separate component. Therefore the Fully Dressed Wood Pole has overall useful life values based on the useful life of the pole itself, and useful life values for the cross arm component.

The most significant component of this asset is the wood pole itself. The wood species predominately used for distribution systems are Red Pine, Jack Pine, and Western Red Cedar (WRC), either butt treated or full length treated. Smaller numbers of Larch, Fir, White Pine and Southern Yellow Pine have also been used. Preservative treatments applied prior to 1980, range from none on some WRC poles, to butt treated and full length Creosote or Pentachlorophenol (PCP) in oil. The present day treatment, regardless of species, is CCA-Peg (Chromated Copper Arsenate, in a Polyethylene Glycol solution). Other treatments such as Copper Naphthenate and Ammoniacal Copper Arsenate have also been used, but these are relatively uncommon.

1.1.2 System Hierarchy

Fully Dressed Wood Poles are considered to be a part of the Overhead Lines asset grouping.

1.2 Degradation Mechanism

The end of life criteria for wood poles includes loss of strength, functionality, or safety (typically due to rot, decay, or physical damage). As wood is a natural material the degradation processes are somewhat different from those which affect other physical assets on the electricity distribution systems. The critical processes are biological, involving naturally occurring fungi that attack and degrade wood, resulting in decay. The nature and severity of the degradation depends both on the type of wood and the environment. Some fungi attack the external surfaces of the pole and some the internal heartwood. Therefore, the mode of degradation can be split into either external rot or internal rot. Wood poles can also be degraded by damage inflicted by woodpeckers, and insects such as carpenter ants. As a structural item the sole concern when assessing the condition for a wood pole is the reduction in mechanical strength due to degradation or damage.

1.3 Useful Life

Based on the Industry Values and Utility Interviews the Useful Life Values, Minimum (MIN UL), Typical (TUL) and Maximum (MAX UL) for Fully Dressed Wood Poles are displayed in Table 1-1.

Table 1-1 Useful Life Values for Fully Dressed Wood Poles

ASSET COMPONENTIZATION		USEFUL LIFE (years)		
		MIN UL	TUL	MAX UL
Overall		35	45	75
Cross Arm	Wood	20	40	55
	Steel	30	70	95

1.3.1 Useful Life Data

This section displays the data used to determine the Useful Life Values for Fully Dressed Wood Poles. All six of the interviewed utilities gave Minimum, Typical and Maximum Useful Life (MIN UL, TUL and MAX UL) Values for Fully Dressed Wood Poles (Figure 1-1). For the cross arm component, five of the Utilities gave MIN UL, TUL and MAX UL Values for Wood Cross Arms (Figure 1-2) and two of the Utilities gave MIN UL, TUL and MAX UL Values for Steel Cross Arms (Figure 1-3).

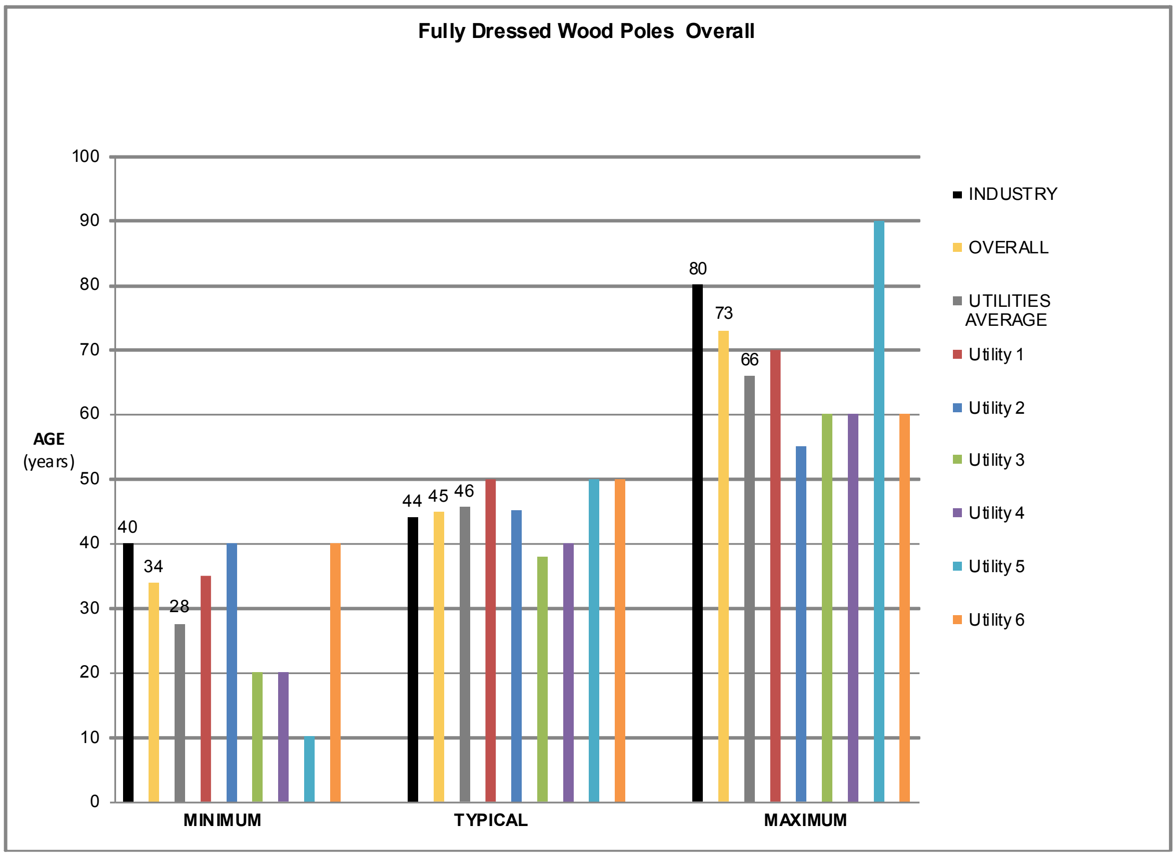


Figure 1-1 Useful Life Values for Fully Dressed Wood Poles

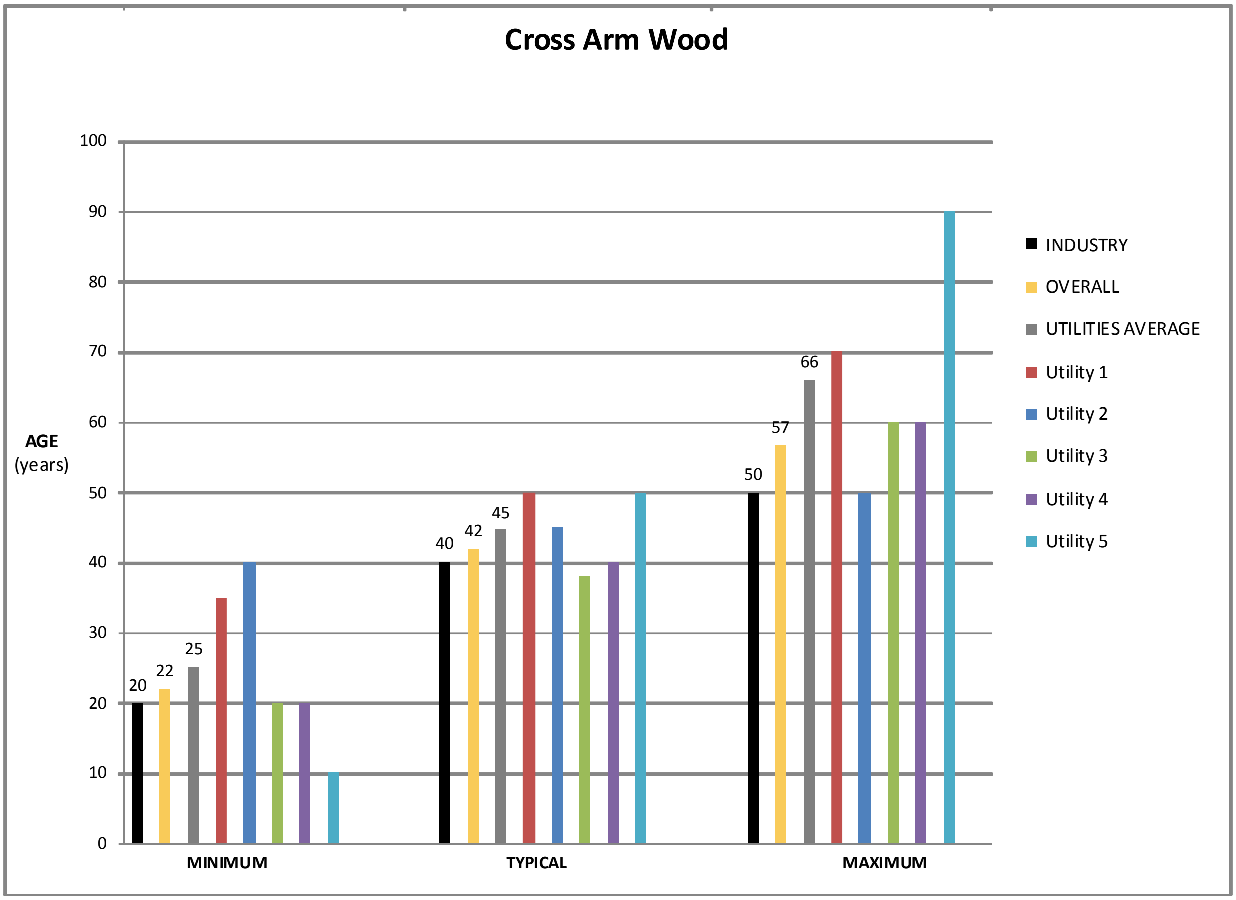


Figure 1-2 Useful Life Values for Fully Dressed Wood Poles – Cross Arm – Wood

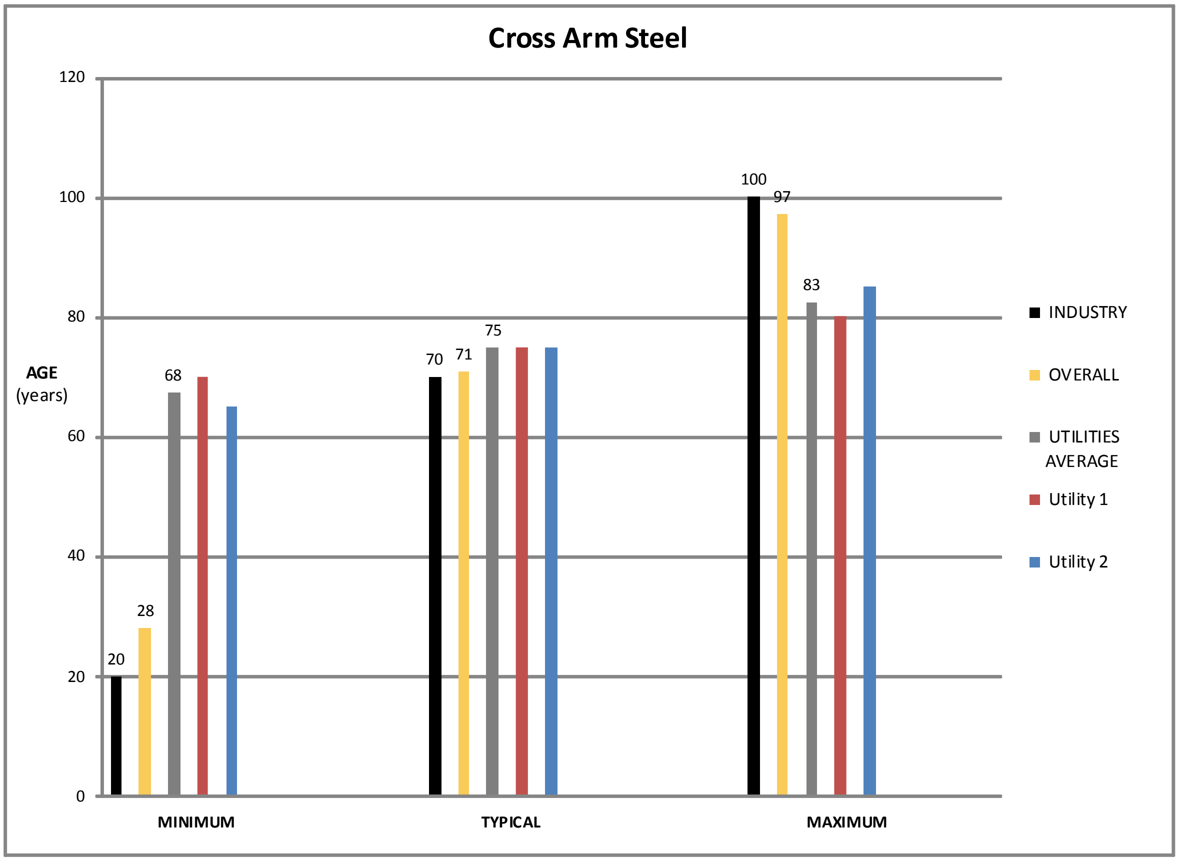


Figure 1-3 Useful Life Values for Fully Dressed Wood Poles – Cross Arm - Steel

1.4 Impact of Utilization Factors

Based on the Utility Interviews the composite score and overall impact (high medium, low), if any, of each factor on the typical useful life of Fully Dressed Wood Poles are displayed in Table 1-2.

Table 1-2 - Composite Score for Fully Dressed Wood Poles

	Utilization Factors					
	Mechanical Stress	Electrical Loading	Environmental Factors	Operating Practices	Maintenance Practices	Non-Physical Factors
Composite Score	100%	13%	75%	0%	19%	31%
Overall Rating*	**H**	**L**	**M**	**NI**	**L**	**L**
* H = High Impact M = Medium Impact L = Low Impact NI = No Impact						

1.4.1 Utility Interview Data

This section displays the data used to determine the composite score and overall impact (high, medium, low) of each factor on the typical useful life of Fully Dressed Wood Poles. All six of the interviewed utilities provided their input regarding the UFs for Fully Dressed Wood Poles (Figure 1-4). The UFs impacts were the same for poles and cross-arms.

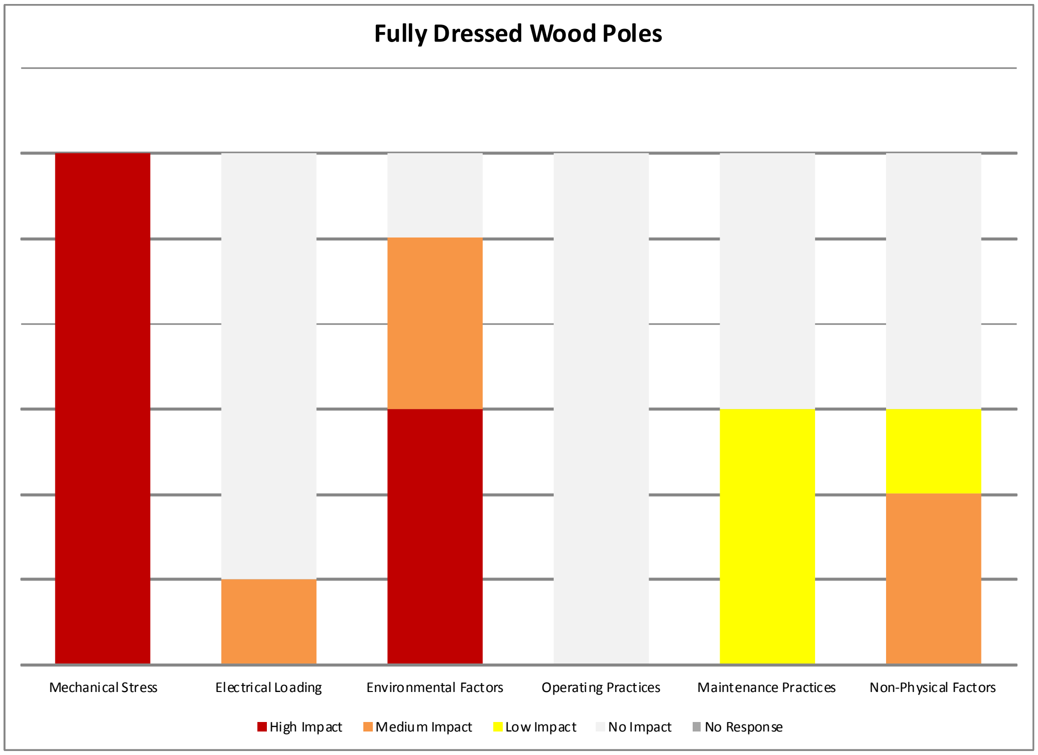


Figure 1-4 Impact of Utilization Factors of the Useful Life of Fully Dressed Wood Poles

2. Fully Dressed Concrete Poles

2.1 Description

The asset referred to in this category is the fully dressed concrete pole ranging in size from 30 to 75 feet. This includes the concrete pole, cross arm, bracket, insulator, cutouts, arresters, and anchor and guys. Concrete poles are a common form of support for overhead distribution feeders particularly in urban utilities.

2.1.1 Componentization Assumptions

For the purposes of this report, the Fully Dressed Concrete Poles asset category has been componentized so that the cross arm can be regarded as a separate component. Therefore the Fully Dressed Concrete Pole has an overall useful life value based on the useful life of the pole itself, and also a useful life value for the cross arm component.

2.1.2 System Hierarchy

Fully Dressed Concrete Poles are considered to be a part of the Overhead Lines asset grouping.

2.2 Degradation Mechanism

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

2.3 Useful Life

Based on the Industry Values and Utility Interviews the Useful Life Values, Minimum (MIN UL), Typical (TUL) and Maximum (MAX UL) for Fully Dressed Concrete Poles are displayed in Table 2-1.

Table 2-1 Useful Life Values for Fully Dressed Concrete Poles

ASSET COMPONENTIZATION		USEFUL LIFE (years)		
		MIN UL	TUL	MAX UL
Overall		50	60	80
Cross Arm	Wood	20	40	55
	Steel	30	70	95

2.3.1 Useful Life Data

This section displays the data used to determine the Useful Life Values for Fully Dressed Concrete Poles. Two of the interviewed utilities gave MIN UL Values and three of the interviewed utilities gave TUL and MAX UL Values for Fully Dressed Concrete Poles (Figure 2-1 Useful Life Values for Fully Dressed Concrete Poles). For the cross arm component, refer to Section 1.3.1 for Fully Dressed Wood Poles.

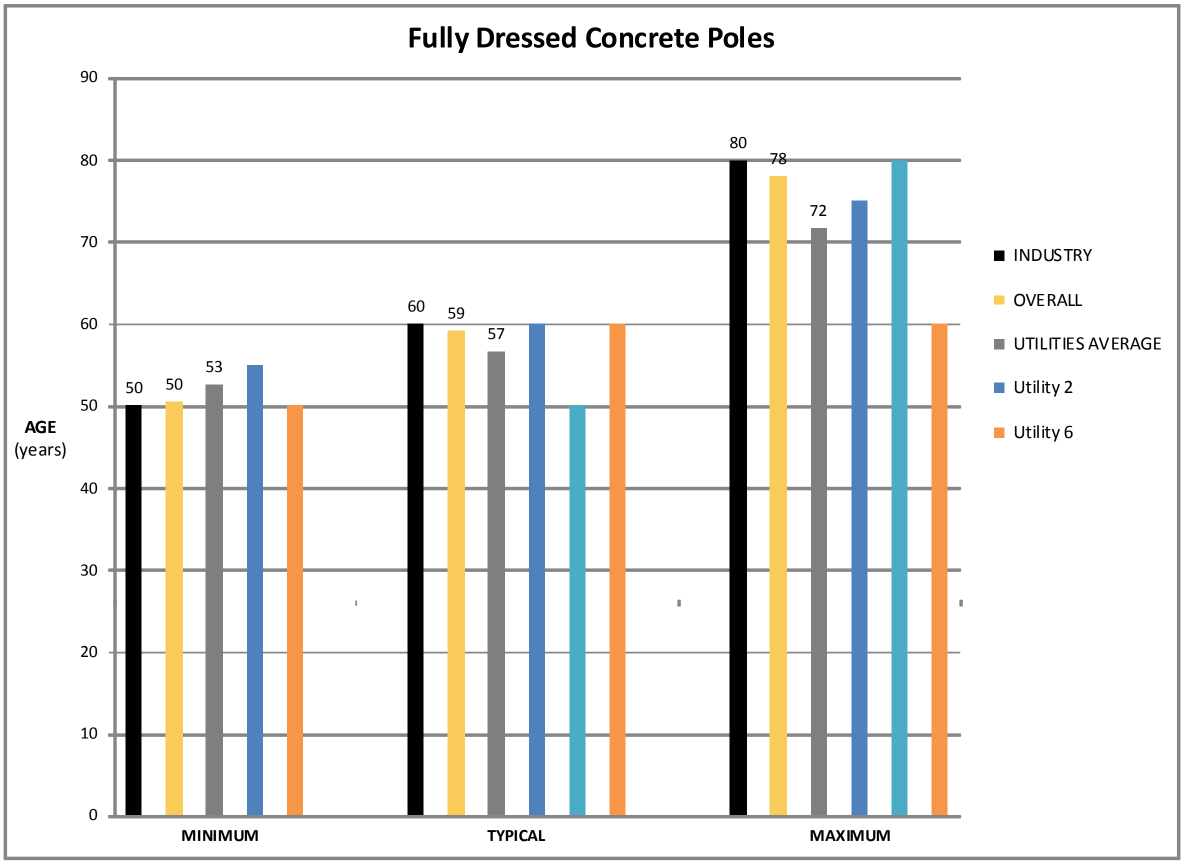


Figure 2-1 Useful Life Values for Fully Dressed Concrete Poles

2.4 Impact of Utilization Factors

Based on the Utility Interviews the composite score and overall impact (high medium, low), if any, of each factor on the typical useful life of Fully Dressed Concrete Poles are displayed in Table 2-2.

Table 2-2 - Composite Score for Fully Dressed Concrete Poles

	Utilization Factors					
	Mechanical Stress	Electrical Loading	Environmental Factors	Operating Practices	Maintenance Practices	Non-Physical Factors
Composite Score	92%	25%	58%	0%	13%	0%
Overall Rating*	H	L	M	NI	L	NI
* H = High Impact M = Medium Impact L = Low Impact NI = No Impact						

2.4.1 Utility Interview Data

This section displays the data used to determine the composite score and overall impact (high, medium, low) of each factor on the typical useful life of Fully Dressed Concrete Poles. Three of the interviewed utilities provided their input regarding the UFs for Fully Dressed Concrete Poles (Figure 1-42).

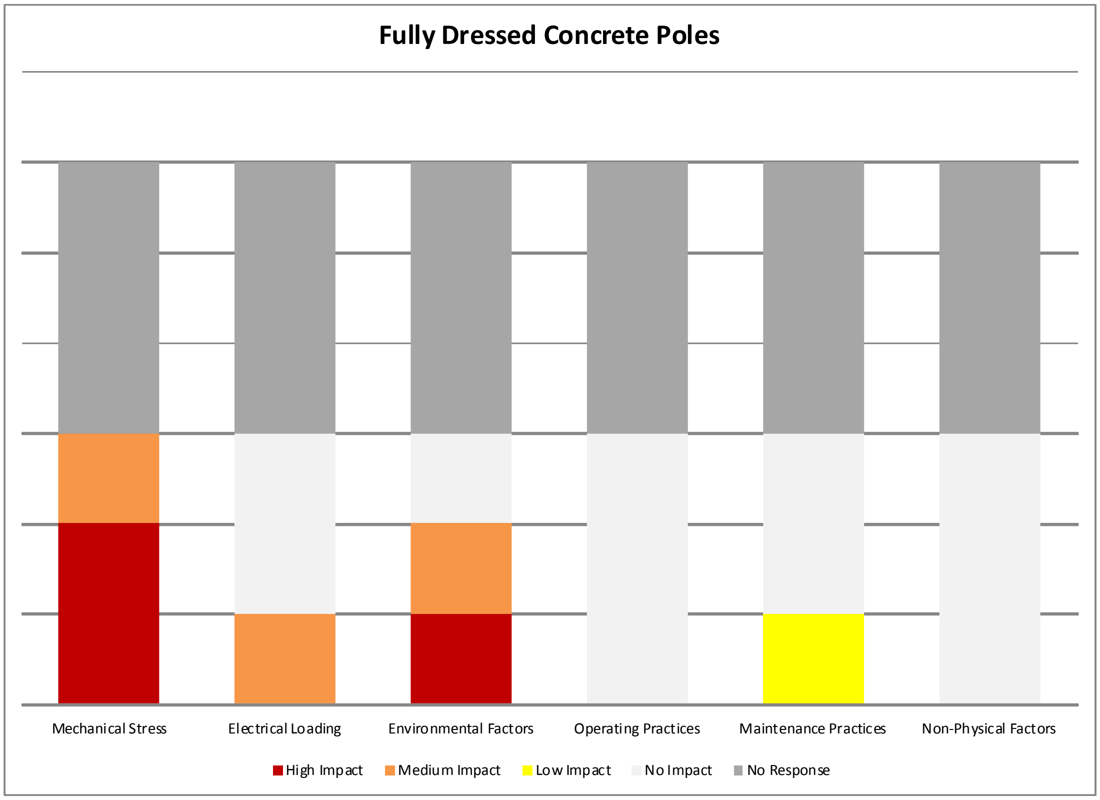


Figure 2-2 Impact of Utilization Factors on the Useful Life of Fully Dressed Concrete Poles

3. Fully Dressed Steel Poles

3.1 Description

The asset referred to in this category is the fully dressed steel pole ranging in size from 30 to 75 feet. This includes the steel pole, cross arm, bracket, insulator, cutouts, arresters, and anchor and guys. Steel poles are an alternative form of support for some overhead distribution feeders, used primarily by urban distribution utilities.

3.1.1 Componentization Assumptions

For the purposes of this report, the Fully Dressed Steel Poles asset category has been componentized so that the cross arm can be regarded as a separate component. Therefore the Fully Dressed Steel Pole has overall useful life values based on the useful life of the pole itself, and separate useful life values for the cross arm component.

3.1.2 System Hierarchy

Fully Dressed Steel Poles are considered to be a part of the Overhead Lines asset grouping.

3.2 Degradation Mechanism

The degradation of directly buried steel poles is mainly due to steel corrosion in-ground and at the ground line. In-ground situations are vastly different from one installation to anther because of the wide local variations in soil chemistry, moisture content and conductivity that will affect the way coated or uncoated steel will perform in the ground. There are two issues that determine the life of buried steel. The first is the life of the protective coating and the second is the corrosion rate of the steel. The item can be deemed to have failed when the steel loss is sufficient to prevent the steel performing its structural function. Where polymer coatings are applied to buried steel items, the failures are rarely caused by general deterioration of the coating. Localized failures due to defects in the coating, pin holing or large-scale corrosion related to electrolysis are common causes of failure in these installations. Metallic coatings, specifically galvanizing, and to a lesser extent aluminum, fail through progressive consumption of the coating by oxidation or chemical degradation. The rate of degradation is approximately linear, and with galvanized coatings of known thickness, the life of the galvanized coating then becomes a function of the coating thickness and the corrosion rate.

3.3 Useful Life

Based on the Industry Values and Utility Interviews the Useful Life Values, Minimum (MIN UL), Typical (TUL) and Maximum (MAX UL) for Fully Dressed Steel Poles are displayed in Table 3-1.

Table 3-1 Useful Life Values for Fully Dressed Steel Poles

ASSET COMPONENTIZATION		USEFUL LIFE (years)		
		MIN UL	TUL	MAX UL
Overall		60	60	80
Cross Arm	Wood	20	40	55
	Steel	30	70	95

3.3.1 Useful Life Data

This section displays the data used to determine the Useful Life Values for Fully Dressed Steel Poles. Two of the interviewed utilities gave Minimum, Typical and Maximum Useful Life (MIN UL, TUL and MAX

UL) Values for Fully Dressed Steel Poles (Figure 3-1). For the cross arm component, refer to Section 1.3.1 for Fully Dressed Wood Poles.

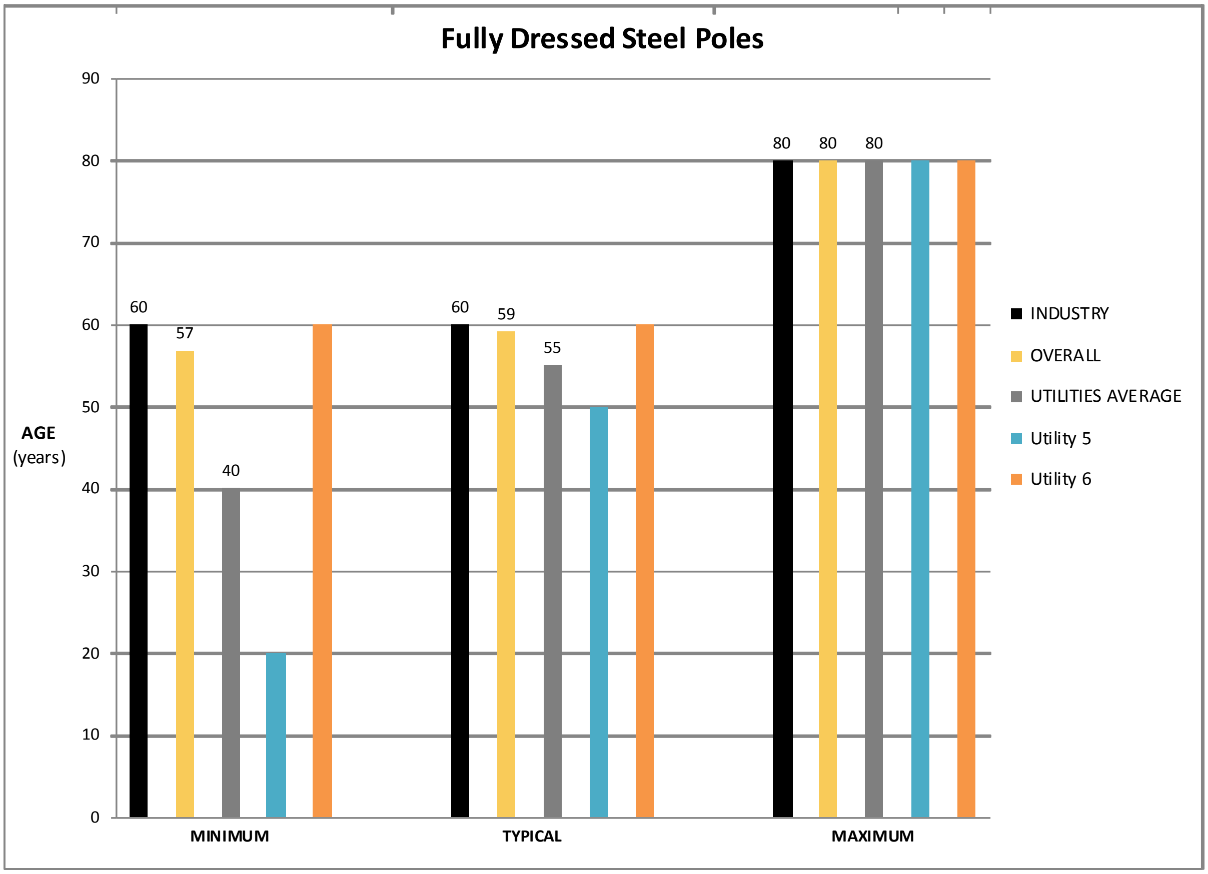


Figure 3-1 Useful Life Values for Fully Dressed Steel Poles

3.4 Impact of Utilization Factors

Based on the Utility Interviews the composite score and overall impact (high medium, low), if any, of each factor on the typical useful life of Fully Dressed Steel Poles are displayed in Table 3-2.

Table 3-2 - Composite Score for Fully Dressed Steel Poles

	Utilization Factors					
	Mechanical Stress	Electrical Loading	Environmental Factors	Operating Practices	Maintenance Practices	Non-Physical Factors
Composite Score	88%	56%	38%	0%	19%	0%
Overall Rating*	**H**	**M**	**L**	**NI**	**L**	**NI**
* H = High Impact	M = Medium Impact		L = Low Impact		NI = No Impact	

3.4.1 Utility Interview Data

This section displays the data used to determine the composite score and overall impact (high, medium, low) of each factor on the typical useful life of Fully Dressed Steel Poles. Two of the interviewed utilities provided their input regarding the UFs for Fully Dressed Steel Poles (Figure 1-42).

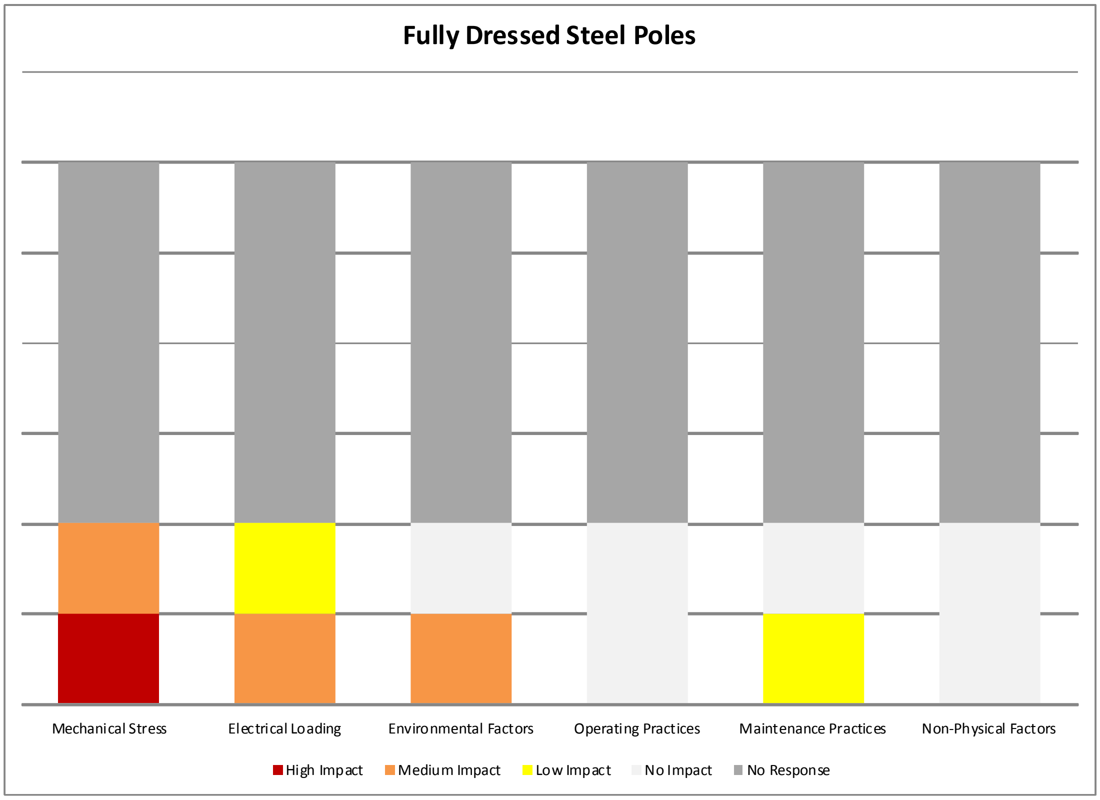


Figure 3-2 Impact of Utilization Factors on the Useful Life of Fully Dressed Steel Poles

4. Overhead Line Switch

4.1 Asset Description

This asset class consists of overhead line switches, focusing primarily on 3-phase outdoor pole-mounted switches but also including in-line switches. The primary function of switches is to allow for isolation of line sections or equipment for maintenance, safety or other operating requirements. The operating mechanism can be either a manual gang operating linkage or a simple hook stick.

4.1.1 Componentization Assumptions

For the purposes of this report, the Overhead Line Switch asset category has not been componentized.

4.1.2 Design Configuration

There are several types of Overhead Line Switches. For the purposes of this report, the types are air, oil, vacuum and gas (SF6). Also for the purpose of this study it is considered that the switch type does not make a significant difference to the degradation or useful life of this asset.

4.1.3 System Hierarchy

Overhead Line Switch is considered to be a part of the Overhead Lines asset grouping.

4.2 Degradation Mechanism

The main degradation processes associated with overhead line switches include the following, with rate and severity depending on operating duties and environment:

- Corrosion of steel hardware or operating rod
- Mechanical deterioration of linkages
- Switch blades falling out of alignment
- Loose connections
- Insulators damage

The rate and severity of these degradation processes depends on a number of inter-related factors including the operating duties and environment in which the equipment is installed. In most cases, corrosion or rust represents a critical degradation process. The rate of deterioration depends heavily on environmental conditions in which the equipment operates. Corrosion typically occurs around the mechanical linkages of these switches. Corrosion can cause seizing. When lubrication dries out, the switch operating mechanism may seize making the disconnect switch inoperable. In addition, when blades fall out of alignment, excessive arcing may result. While a lesser mode of degradation, air pollution also can affect support insulators. Typically, this occurs in heavy industrial areas or where road salt is used.

4.3 Useful Life

Based on the Industry Values and Utility Interviews the Useful Life Values, Minimum (MIN UL), Typical (TUL) and Maximum (MAX UL) for Overhead Line Switch are displayed in Table 4-1.

Table 4-1 Useful Life Values for Overhead Line Switch

ASSET COMPONENTIZATION	USEFUL LIFE		
	MIN UL	TUL	MAX UL
OH Line Switch	30	45	55

4.3.1 Useful Life Data

This section displays the data used to determine the Useful Life Values for Overhead Line Switch. All six of the interviewed utilities gave Minimum, Typical and Maximum Useful Life (MIN UL, TUL and MAX UL) Values for Overhead Line Switch (Figure 4-1).

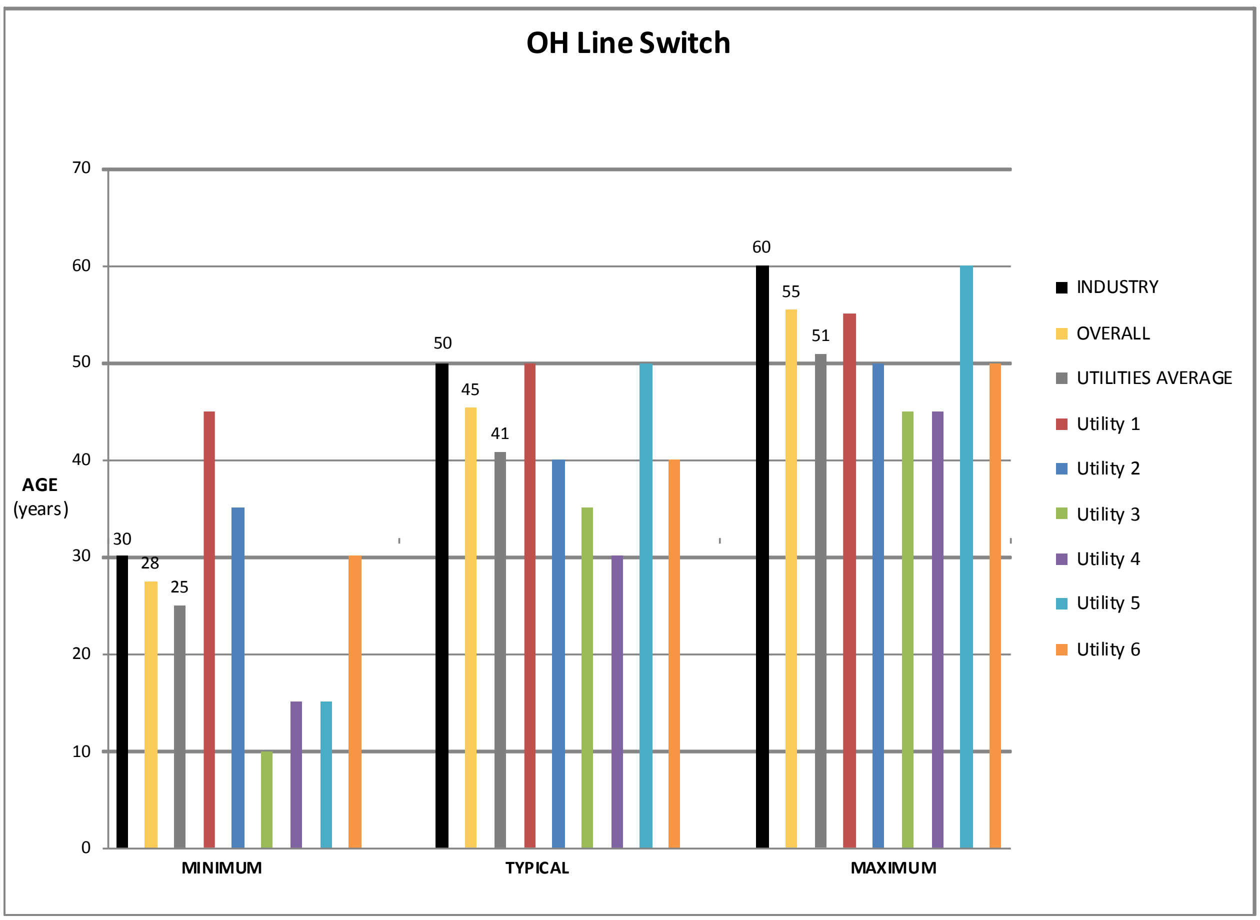


Figure 4-1 Useful Life Values for Overhead Line Switch

4.4 Impact of Utilization Factors

Based on the Utility Interviews the composite score and overall impact (high medium, low), if any, of each factor on the typical useful life of Overhead Line Switch are displayed in Table 4-2.

Table 4-2 - Composite Score for Overhead Line Switch

	Utilization Factors					
	Mechanical Stress	**Electrical Loading**	**Environmental Factors**	**Operating Practices**	**Maintenance Practices**	**Non-Physical Factors**
Composite Score	35%	25%	35%	44%	65%	42%
Overall Rating*	**L**	**L**	**L**	**L**	**M**	**L**

* H = High Impact M = Medium Impact L = Low Impact NI = No Impact

4.4.1 Utility Interview Data

This section displays the data used to determine the composite score and overall impact (high, medium, low) of each factor on the typical useful life of Overhead Line Switch. All six of the interviewed utilities provided their input regarding the UFs for Overhead Line Switches (Figure 1-42).

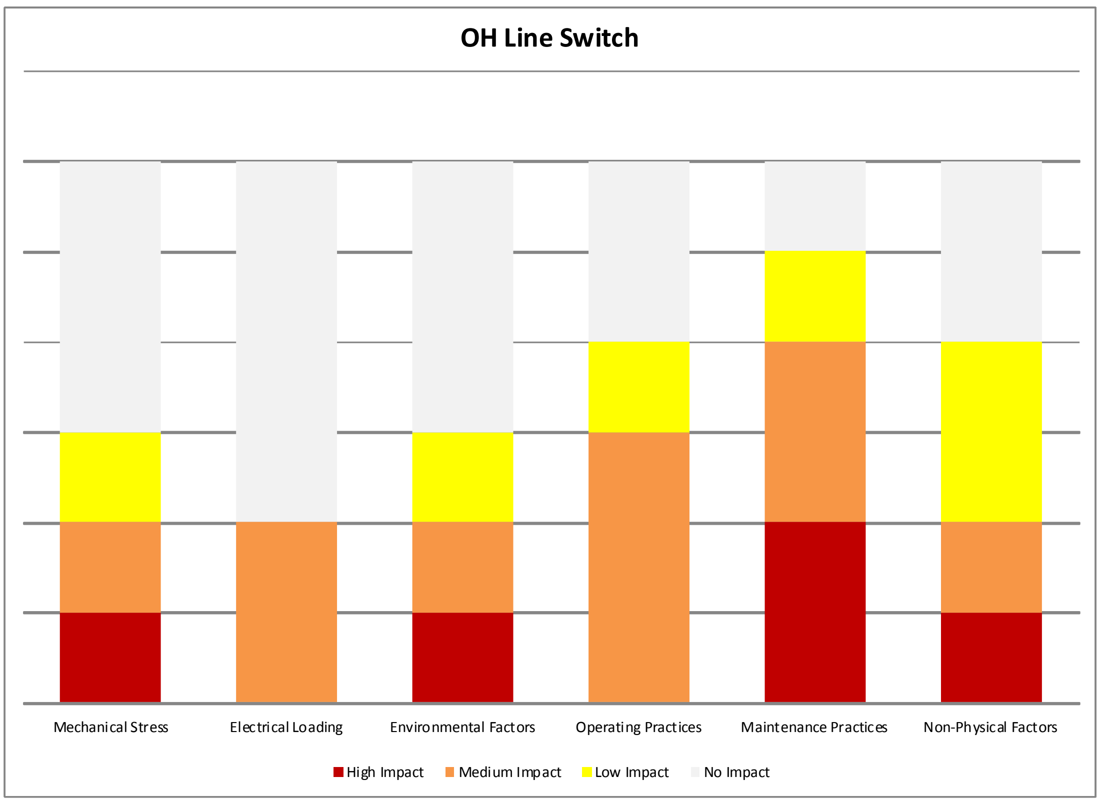


Figure 4-2 Impact of Utilization Factors on the Useful Life of Overhead Line Switch

5. Overhead Line Switch Motor

5.1 Asset Description

This asset class consists of the motor component of overhead line three-phase, gang operated switches. The primary function of switches is to allow for isolation of line sections or equipment for maintenance, safety or other operating requirements. .

5.1.1 Componentization Assumptions

For the purposes of this report, the Overhead Line Switch Motor asset category has not been componentized.

5.1.2 System Hierarchy

Overhead Line Switch Motor is considered to be a part of the Overhead Lines asset grouping.

5.2 Degradation Mechanism

The main degradation processes associated with local motor for operating overhead switches include the following:

- Corrosion of the housing
- Mechanical deterioration of linkages and bearings
- Loose connections
- Winding deterioration

The rate and severity of degradation are a function on operating duties and environment.

5.3 Useful Life

Based on the Industry Values and Utility Interviews the Useful Life Values, Minimum (MIN UL), Typical (TUL) and Maximum (MAX UL) for Overhead Line Switch Motor are displayed in Table 5-1.

Table 5-1 Useful Life Values for Overhead Line Switch Motor

ASSET COMPONENTIZATION	USEFUL LIFE		
	MIN UL	TUL	MAX UL
OH Line Switch Motor	15	25	25

5.3.1 Useful Life Data

This section displays the data used to determine the Useful Life Values for Overhead Line Switch Motor. Four of the interviewed utilities gave Minimum and Maximum Useful Life (Min UL and MAX UL) Values and five of the interviewed utilities gave TUL Values for Overhead Line Switch Motor (Figure 5-1).

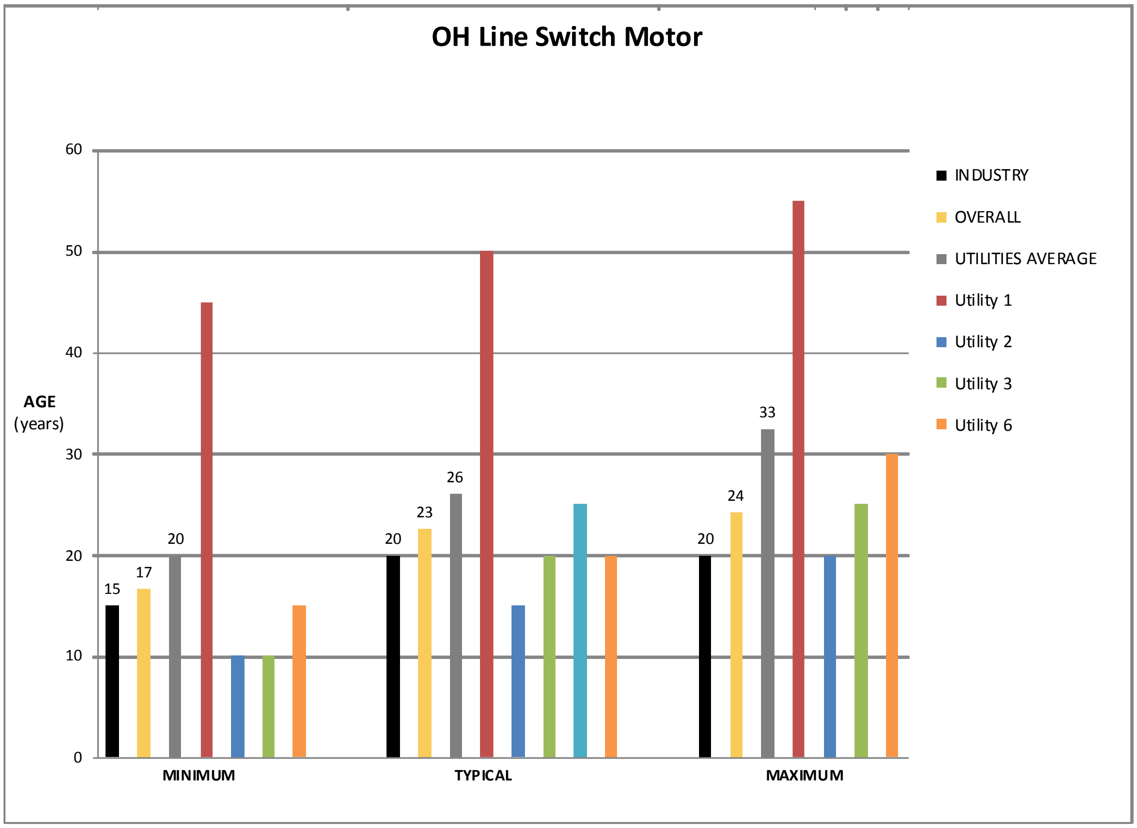


Figure 5-1 Useful Life Values for Overhead Line Switch Motor

5.4 Impact of Utilization Factors

Based on the Utility Interviews the composite score and overall impact (high medium, low), if any, of each factor on the typical useful life of Overhead Line Switch Motor are displayed in Table 5-2.

Table 5-2 - Composite Score for Overhead Line Switch Motor

	Utilization Factors					
	Mechanical Stress	Electrical Loading	Environmental Factors	Operating Practices	Maintenance Practices	Non-Physical Factors
Composite Score	35%	0%	20%	30%	50%	33%
Overall Rating*	L	NI	L	L	M	L
* H = High Impact M = Medium Impact L = Low Impact NI = No Impact						

5.4.1 Utility Interview Data

This section displays the data used to determine the composite score and overall impact (high, medium, low) of each factor on the typical useful life of Overhead Line Switch Motor. Five of the interviewed utilities provided their input regarding the UFs for Overhead Line Switch Motors (Figure 1-42).

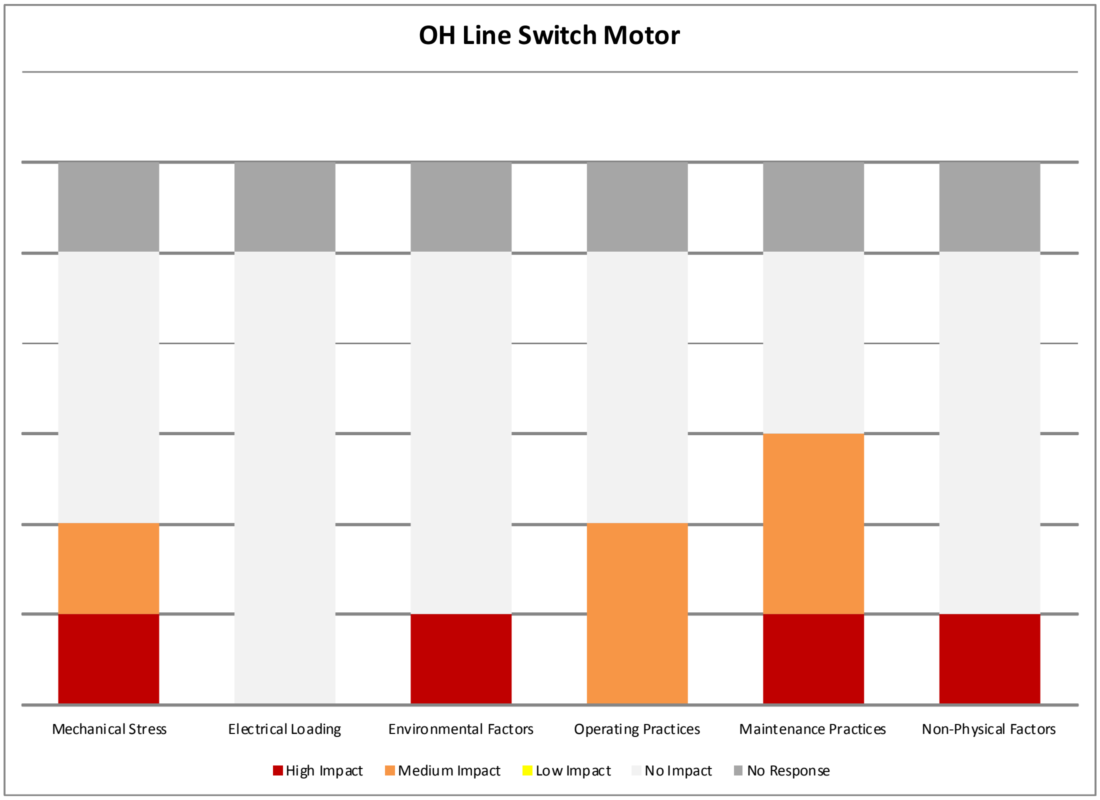


Figure 5-2 Impact of Utilization Factors on the Useful Life of Overhead Line Switch Motor

6. Overhead Line Switch Remote Terminal Unit

6.1 Asset Description

This asset class consists of remote terminal unit (RTU) component of overhead line three-phase, gang operated switches. The primary function of switches is to allow for isolation of line sections or equipment for maintenance, safety or other operating requirements.

6.1.1 Componentization Assumptions

For the purposes of this report, the Overhead Line Switch Remote Terminal Unit asset category has not been componentized.

6.1.2 System Hierarchy

Overhead Line Switch Remote Terminal Unit is considered to be a part of the Overhead Lines asset grouping.

6.2 Degradation Mechanism

The main degradation processes associated with the remote terminal units include the following:

- Corrosion of the housing
- Contamination of the circuitry
- Loose connections
- Failure of electronic components

The rate and severity of degradation are a function on operating duties and environment.

6.3 Useful Life

Based on the Industry Values and Utility Interviews the Useful Life Values, Minimum (MIN UL), Typical (TUL) and Maximum (MAX UL) for Overhead Line Switch Remote Terminal Unit are displayed in Table 6-1.

Table 6-1 Useful Life Values for Overhead Line Switch Remote Terminal Unit

ASSET COMPONENTIZATION	USEFUL LIFE		
	MIN UL	TUL	MAX UL
OH Line Switch RTU	15	20	20

6.3.1 Useful Life Data

This section displays the data used to determine the Useful Life Values for Overhead Line Switch Remote Terminal Unit. Four of the interviewed utilities gave Typical and Maximum Useful Life (TUL and MAX UL) Values and five of the interviewed utilities gave MIN UL Values for Overhead Line Switch Remote Terminal Unit (Table 6-1).

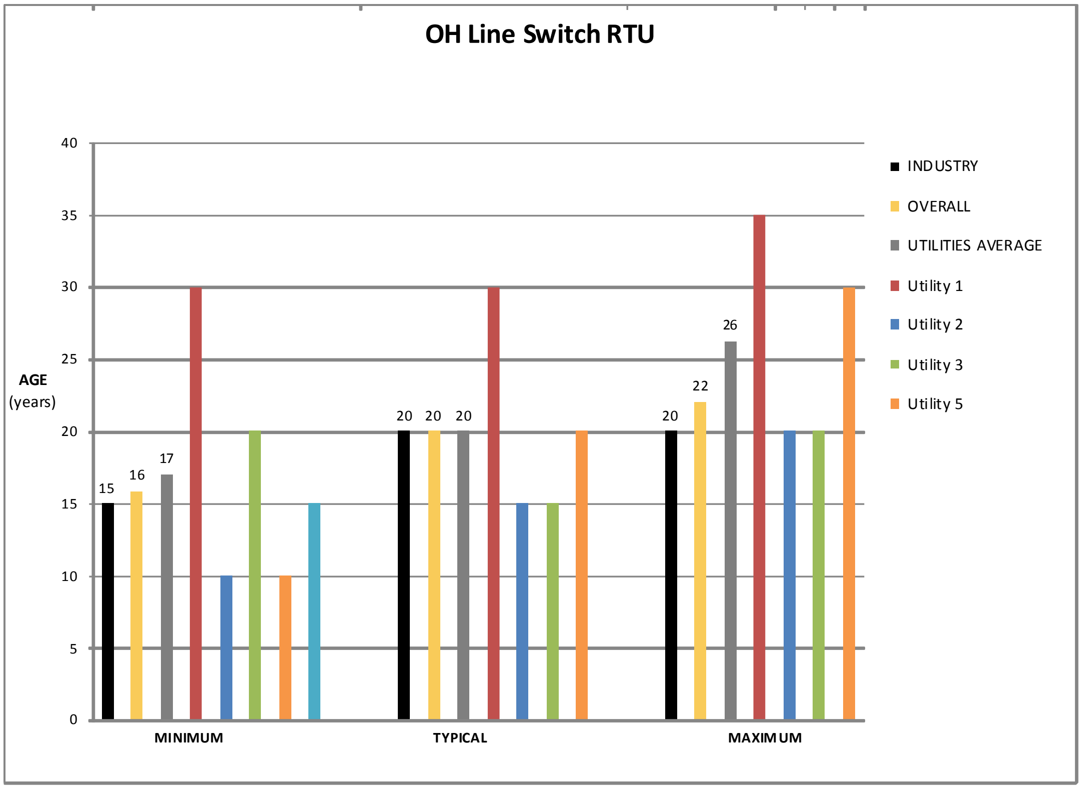


Figure 6-1 Useful Life Values for Overhead Line Switch Remote Terminal Unit

6.4 Impact of Utilization Factors

Based on the Utility Interviews the composite score and overall impact (high medium, low), if any, of each factor on the typical useful life of Overhead Line Switch Remote Terminal Unit are displayed in Table 6-2.

Table 6-2 - Composite Score for Overhead Line Switch Remote Terminal Unit

	Utilization Factors					
	Mechanical Stress	Electrical Loading	Environmental Factors	Operating Practices	Maintenance Practices	Non-Physical Factors
Composite Score	0%	0%	28%	15%	30%	75%
Overall Rating*	NI	NI	L	L	L	M

* H = High Impact M = Medium Impact L = Low Impact NI = No Impact

6.4.1 Utility Interview Data

This section displays the data used to determine the composite score and overall impact (high, medium, low) of each factor on the typical useful life of Overhead Line Switch Remote Terminal Unit. Five of the interviewed utilities provided their input regarding the UFs for Overhead Line Switch RTUs (Figure 1-4).

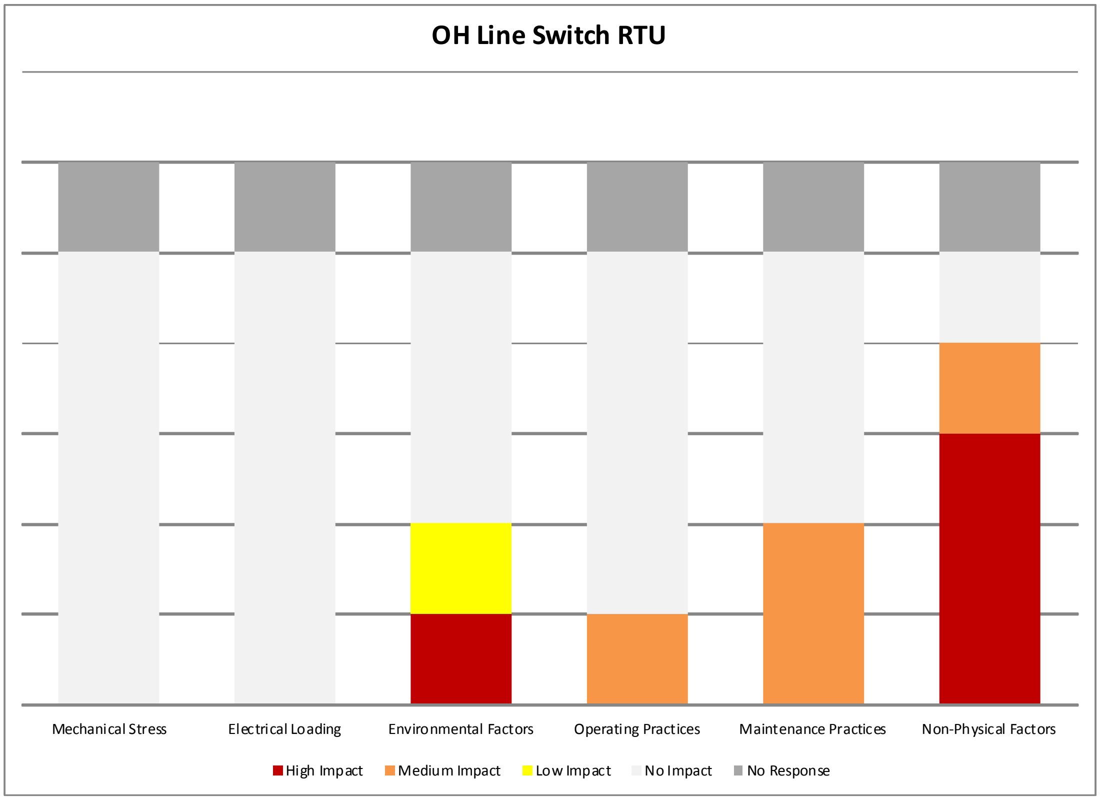


Figure 6-2 Impact of Utilization Factors on the Useful Life of Overhead Line Switch Remote Terminal Unit

7. Overhead Integral Switch

7.1 Asset Description

This asset class consists of integral switches. Integral switches are considered to be overhead line switches with integrated remotely operable opening and closing mechanisms and communication capability that can receive signals from and be monitored by a SCADA system. These units include the switch, communications, and RTU. As with other line switches, this asset allows for the isolation of overhead line sections or equipment for maintenance, safety, and any other operating requirements.

7.1.1 Componentization Assumptions

For the purposes of this report, the Overhead Integral Switch asset category has not been componentized.

7.1.2 System Hierarchy

Overhead Integral Switch is considered to be a part of the Overhead Lines asset grouping.

7.2 Degradation Mechanism

The main degradation processes associated with line switches include those associated with the switch, motor and communication circuitry:

- Corrosion of the housing, hardware and linkages
- Mechanical deterioration of linkages and bearings
- Loose connections
- Motor winding deterioration
- Contamination of the circuitry
- Failure of electronic components
- Switch blades falling out of alignment
- Insulators damage

7.3 Useful Life

Based on the Industry Values and Utility Interviews the Useful Life Values, Minimum (MIN UL), Typical (TUL) and Maximum (MAX UL) for Overhead Integral Switch are displayed in Table 7-1.

Table 7-1 Useful Life Values for Overhead Integral Switch

ASSET COMPONENTIZATION	USEFUL LIFE		
	MIN UL	TUL	MAX UL
OH Integral Switches	35	45	60

7.3.1 Useful Life Data

This section displays the data used to determine the Useful Life Values for Overhead Integral Switch. Three of the interviewed utilities gave Minimum, Typical and Maximum Useful Life (MIN UL, TUL and MAX UL) Values for Overhead Integral Switch (Figure 7-1).

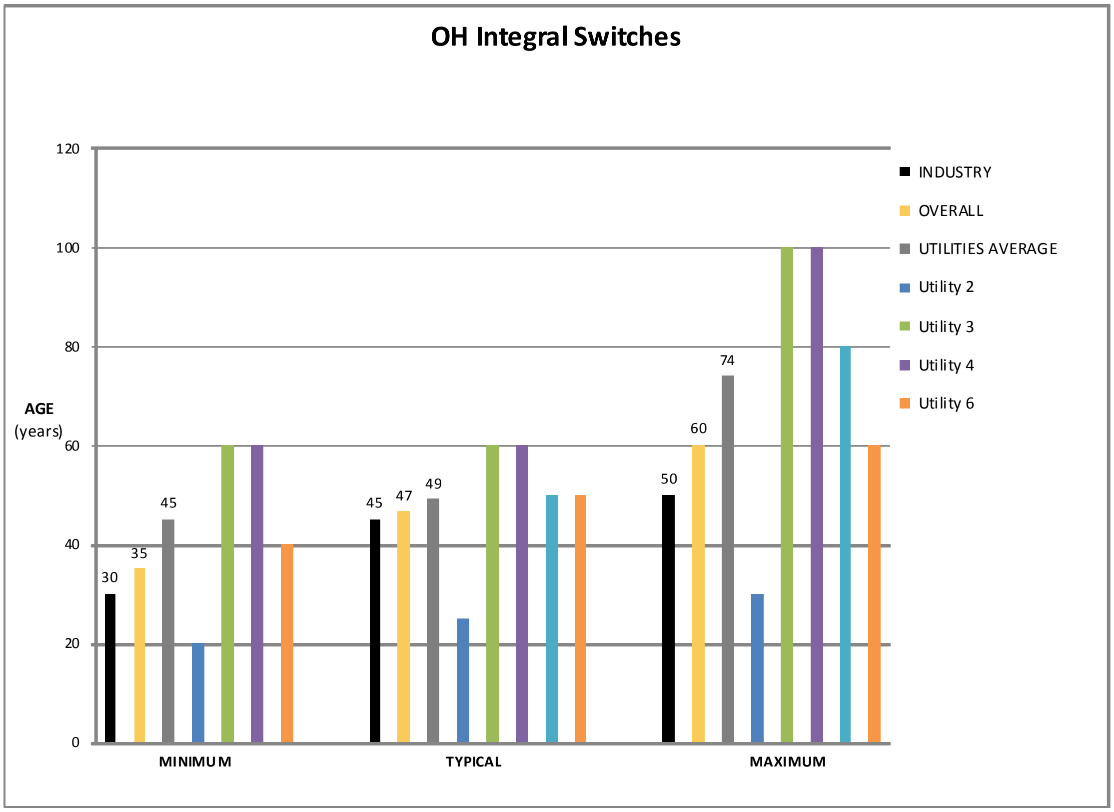


Figure 7-1 Useful Life Values for Overhead Integral Switch

7.4 Impact of Utilization Factors

Based on the Utility Interviews the composite score and overall impact (high medium, low), if any, of each factor on the typical useful life of Overhead Integral Switch are displayed in Table 7-2.

Table 7-2 - Composite Score for Overhead Integral Switch

	Utilization Factors					
	Mechanical Stress	Electrical Loading	Environmental Factors	Operating Practices	Maintenance Practices	Non-Physical Factors
Composite Score	13%	50%	46%	67%	25%	100%
Overall Rating*	L	M	M	M	L	H
* H = High Impact M = Medium Impact L = Low Impact NI = No Impact						

7.4.1 Utility Interview Data

This section displays the data used to determine the composite score and overall impact (high, medium, low) of each factor on the typical useful life of Overhead Integral Switch. Three of the interviewed utilities provided their input regarding the UFs for Overhead Integral Switches (Figure 1-42).

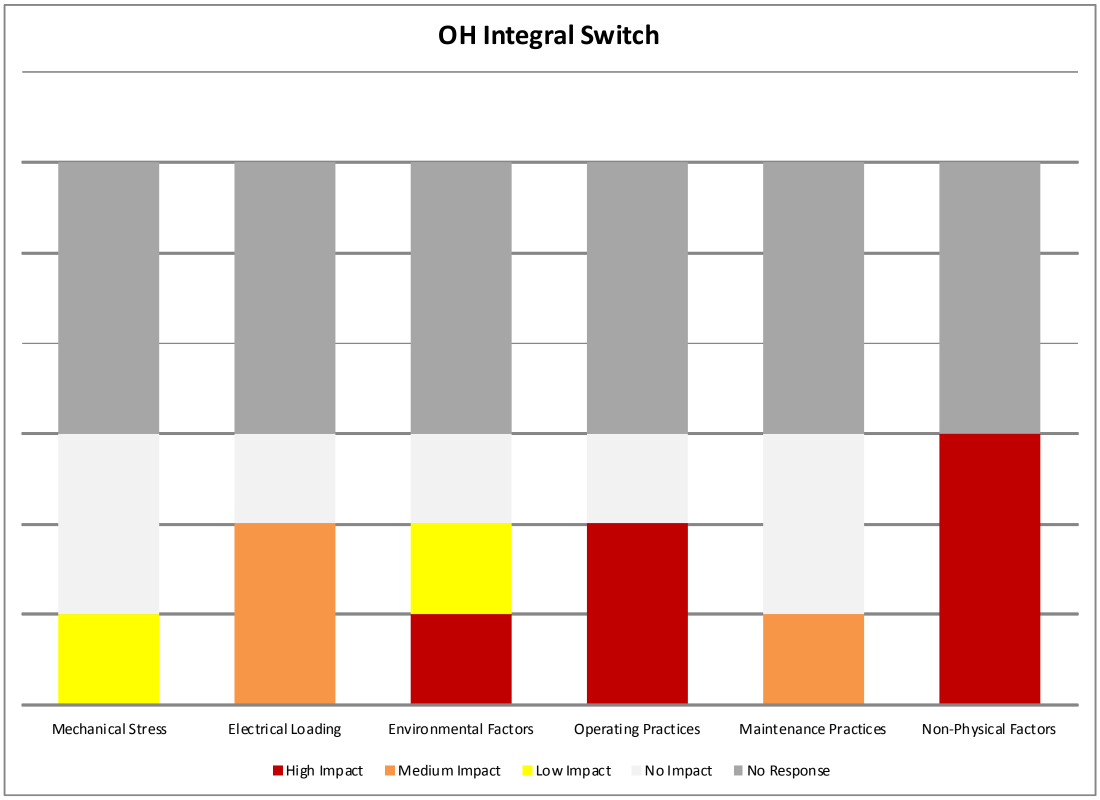


Figure 7-2 Impact of Utilization Factors on the Useful Life of Overhead Integral Switch

8. Overhead Conductors

8.1 Asset Description

Overhead conductors along with structures that support them constitute overhead lines or feeders that distribute electrical energy to customers from the distribution or transmission station. These conductors are sized to carry a specified maximum current and to meet other design criteria, i.e. mechanical loading.

8.1.1 Componentization Assumptions

For the purposes of this report, the Overhead Conductors asset category has not been componentized.

8.1.2 Design Configuration

There are several types of Overhead Line Switches. For the purposes of this report, the types are aluminum conductor steel reinforced (ACSR), all aluminum conductor (AAC), and copper.

8.1.3 System Hierarchy

Overhead Conductors is considered to be a part of the Overhead Lines asset grouping.

8.2 Degradation Mechanism

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

Generally, corrosion represents the most critical life-limiting factor for aluminum-based conductors. Visual inspection cannot detect corrosion readily in conductors. Environmental conditions affect degradation rates from corrosion. Both aluminum and zinc-coated steel core conductors are particularly susceptible to corrosion from chlorine-based pollutants, even in low concentrations.

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

In designing distribution lines, engineers ensure that conductors have adequate rated tensile strength (RTS) to withstand the heaviest anticipated weather loads. The tensile strength of conductors gradually decreases over time. When conductors experience unexpectedly large mechanical loads and tensions, they begin to undergo permanent stretching with noticeable increases in sagging.

Overloading lines beyond their thermal capacity causes elevated operating temperatures. When operating at elevated temperatures, aluminum conductors begin to anneal and lose tensile strength. Each elevated temperature event adds further damage to the conductor. After a loss of 10% of a conductor’s RTS, significant sag occurs, requiring either re-sagging or replacement of the conductor.

Phase to phase power arcs can result from conductor galloping during severe storm events. This can cause localized burning and melting of a conductor’s aluminum strands, reducing strength at those sites and potentially leading to conductor failures. Visual inspection readily detects arcing damage.

Other forms of conductor damage include:

- Broken strands (i.e., outer and inners)
- Strand abrasion
- Elongation (i.e., change in sags and tensions)
- Burn damage (i.e., power arc/clashing)
- Birdcaging

The degradation of copper wire is mostly due to corrosion. Oxidization gives copper a high resistance to corrosion. Derivatives of chlorine and sulfur contained in coastal atmospheres start the oxidation by forming a blackish or greenish film. The film is very dense, has low solubility, high electric resistance and high resistance to chemical attack and to corrosion. Despite this, mechanical vibrations, abrasion, erosion and thermal variations may cause fissures and faults in this layer. When this happens, the metal is uncovered and corrosion may occur. Also electrolytes with low chlorine content could enter, causing a change in the chemical passivity. This may also be the result of a deficit of oxygen which would make the area anodic and rapidly accelerate corrosion.

Note that the weather protection and insulation on the Cables is for improving reliability of the distribution system as opposed to improving the useful life of this asset. The conductive properties of the wire are what degradation impacts, although Utilities may choose to replace weather protected cables if called for by their own system reliability practices.

8.3 Useful Life

Based on the Industry Values and Utility Interviews the Useful Life Values, Minimum (MIN UL), Typical (TUL) and Maximum (MAX UL) for Overhead Conductors are displayed in Table 8-1.

Table 8-1 Useful Life Values for Overhead Conductors

ASSET COMPONENTIZATION	USEFUL LIFE		
	MIN UL	TUL	MAX UL
OH Conductors	50	60	75

8.3.1 Useful Life Data

This section displays the data used to determine the Useful Life Values for Overhead Conductors. Four of the interviewed utilities gave Minimum (Min UL) Values and five of the interviewed utilities gave TUL and MAX UL Values for Overhead Conductors (Figure 8-1).

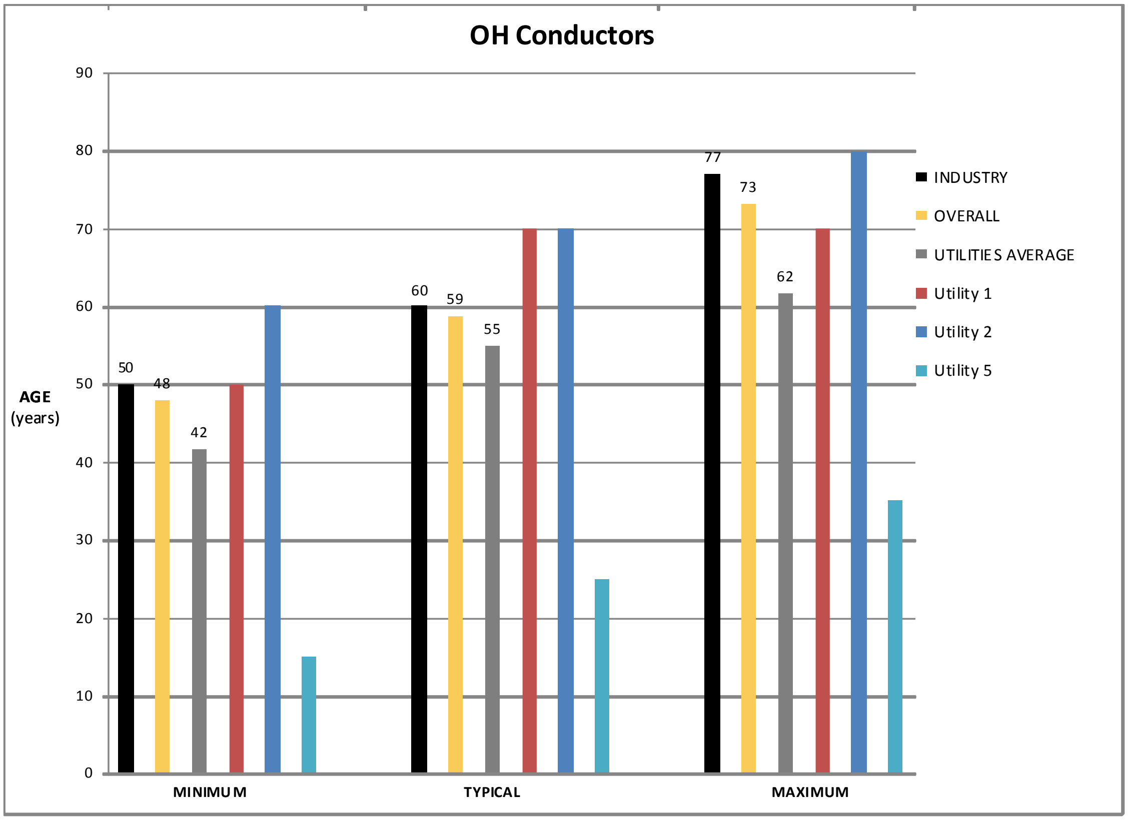


Figure 8-1 Useful Life Values for Overhead Conductors

8.4 Impact of Utilization Factors

Based on the Utility Interviews the composite score and overall impact (high medium, low), if any, of each factor on the typical useful life of Overhead Conductors are displayed in Table 8-1.

Table 8-2 Composite Score for Overhead Conductors

	Utilization Factors					
	Mechanical Stress	**Electrical Loading**	**Environmental Factors**	**Operating Practices**	**Maintenance Practices**	**Non-Physical Factors**
Composite Score	50%	38%	65%	0%	8%	28%
Overall Rating*	**M**	**L**	**M**	**NI**	**NI**	**L**

* H = High Impact M = Medium Impact L = Low Impact NI = No Impact

8.4.1 Utility Interview Data

This section displays the data used to determine the composite score and overall impact (high, medium, low) of each factor on the typical useful life of Overhead Conductors. Five of the interviewed utilities provided their input regarding the UFs for Overhead Conductors (Figure 1-42).

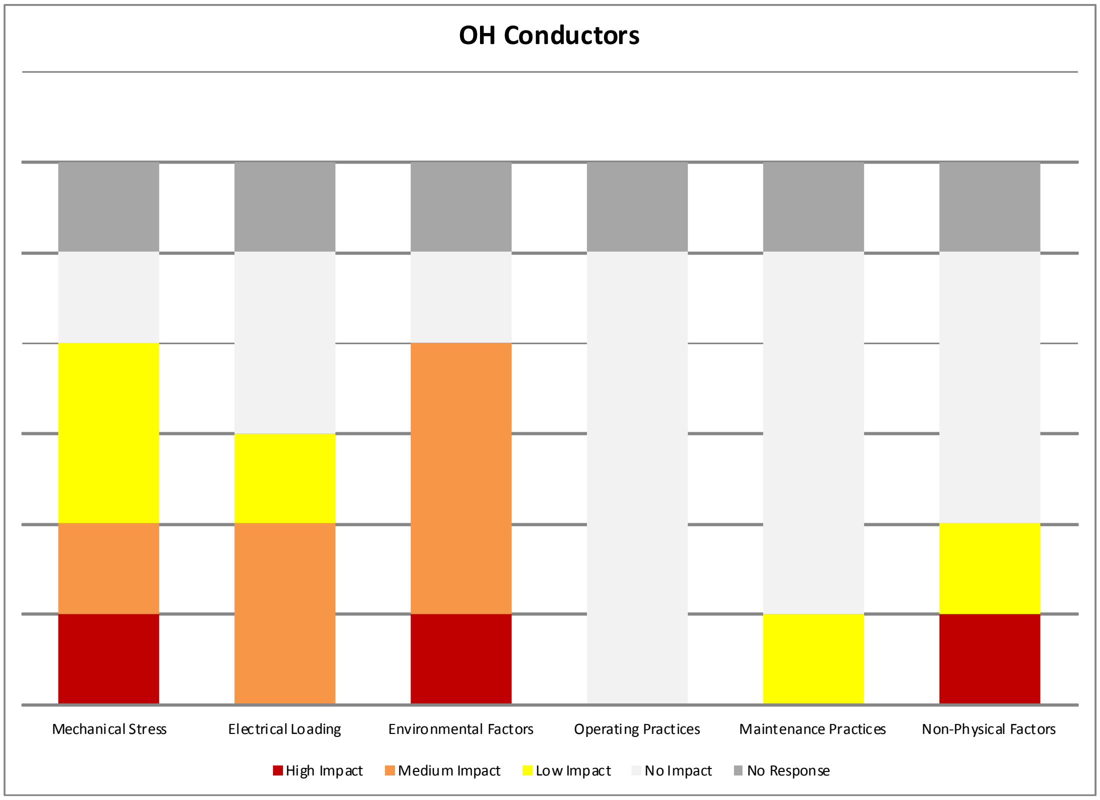


Figure 8-2 Impact of Utilization Factors on the Useful Life of Overhead Conductors

9. Overhead Transformers and Voltage Regulators

9.1 Asset Description

Distribution pole top transformers change sub-transmission or primary distribution voltages to secondary voltages such as 120/240 V or other common voltages for use in residential and commercial applications.

9.1.1 Componentization Assumptions

For the purposes of this report, the Overhead Transformers and Voltage Regulators asset category has not been componentized.

9.1.2 Design Configuration

For the purposes of this report, Overhead Transformers and Voltage Regulators refers to both single phase and three phase Transformers.

9.1.3 System Hierarchy

Overhead Transformers and Voltage Regulators is considered to be a part of the Overhead Lines asset grouping.

9.2 Degradation Mechanism

It has been demonstrated that the life of the transformer's internal insulation is related to temperature-rise and duration. Therefore, transformer life is affected by electrical loading profiles and length of time in service. Other factors such as mechanical damage, exposure to corrosive salts, and voltage and current surges also have a strong effect. Therefore, a combination of condition, age and load based criteria is commonly considered in determining the useful remaining life of distribution transformers.

The impacts of loading profiles, load growth, and ambient temperature on asset condition, loss-of-life, and life expectancy can be assessed using methods outlined in ANSI/IEEE Loading Guides. This also provides an initial baseline for the size of transformer that should be selected for a given number and type of end users to obtain optimal life.

The life of the voltage regulator's internal insulation is related to temperature-rise and duration. Therefore, voltage regulator life is affected by electrical loading profiles and length of time in service. Other factors such as mechanical damage, exposure to corrosive salts, and voltage and current surges also have a strong effect. Therefore, a combination of condition, age and load based criteria is commonly considered in determining the useful remaining life of voltage regulators.

The impacts of loading profiles, load growth, and ambient temperature on asset condition, loss-of-life, and life expectancy can be assessed. There is also the operating practice affect on voltage regulators in terms of the number of operations that it is required to perform on a daily basis.

9.3 Useful Life

Based on the Industry Values and Utility Interviews the Useful Life Values, Minimum (MIN UL), Typical (TUL) and Maximum (MAX UL) for Overhead Transformers and Voltage Regulators are displayed in Table 9-1.

Table 9-1 Useful Life Values for Overhead Transformers and Voltage Regulators

ASSET COMPONENTIZATION	USEFUL LIFE		
	MIN UL	TUL	MAX UL
OH Transformers	30	40	60

9.3.1 Useful Life Data

This section displays the data used to determine the Useful Life Values for Overhead Transformers and Voltage Regulators. All six of the interviewed utilities gave Minimum, Typical and Maximum Useful Life (MIN UL, TUL and MAX UL) Values for Overhead Transformers and Voltage Regulators (Figure 9-1).

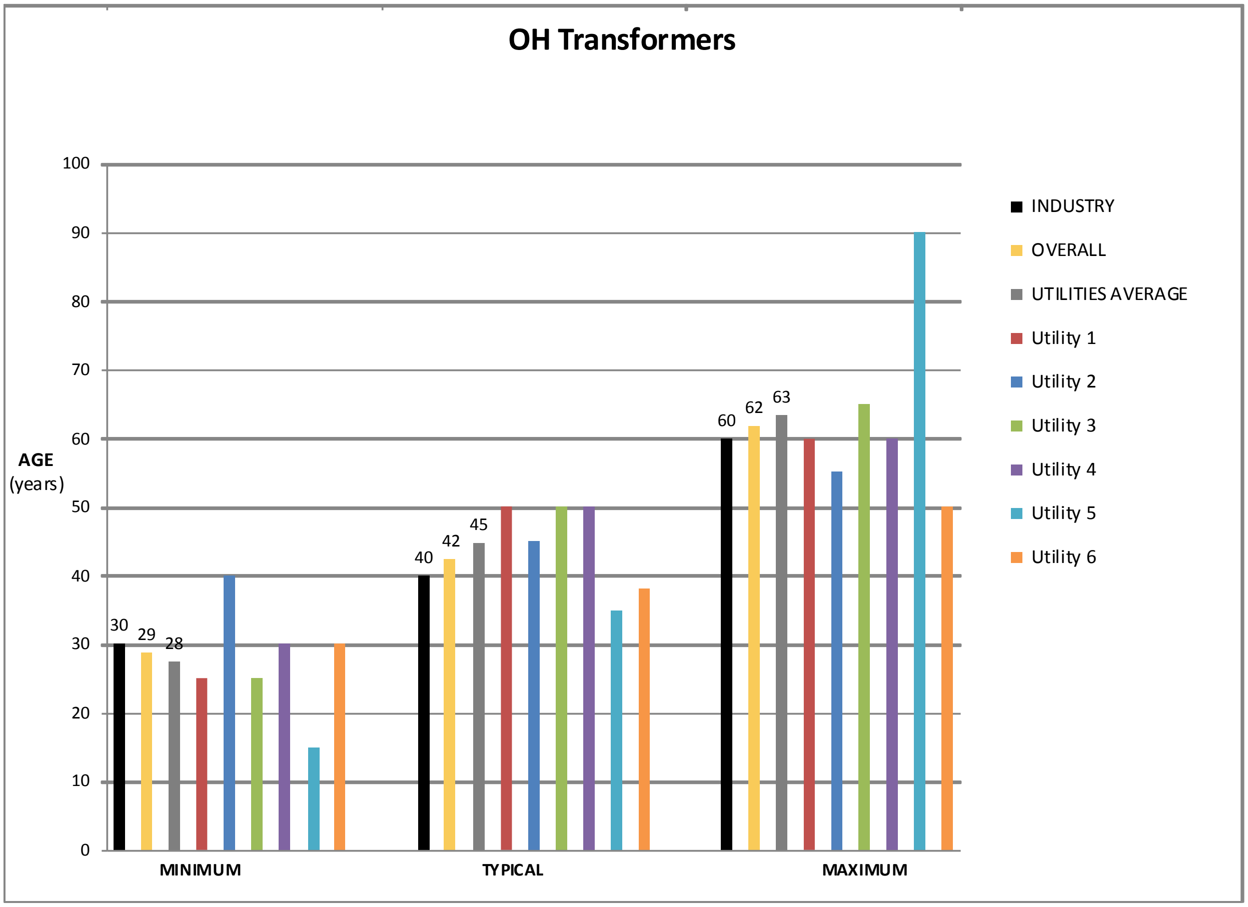


Figure 9-1 Useful Life Values for Overhead Transformers and Voltage Regulators

9.4 Impact of Utilization Factors

Based on the Utility Interviews the composite score and overall impact (high medium, low), if any, of each factor on the typical useful life of Overhead Transformers and Voltage Regulators are displayed in Table 9-2.

Table 9-2 - Composite Score for Overhead Transformers and Voltage Regulators

	Utilization Factors					
	Mechanical Stress	**Electrical Loading**	**Environmental Factors**	**Operating Practices**	**Maintenance Practices**	**Non-Physical Factors**
Composite Score	13%	65%	56%	0%	6%	58%
Overall Rating*	**L**	**M**	**M**	**NI**	**NI**	**M**

* H = High Impact M = Medium Impact L = Low Impact NI = No Impact

9.4.1 Utility Interview Data

This section displays the data used to determine the composite score and overall impact (high, medium, low) of each factor on the typical useful life of Overhead Transformers and Voltage Regulators. All six of the interviewed utilities provided their input regarding the UFs for Overhead Transformers (Figure 1-42).

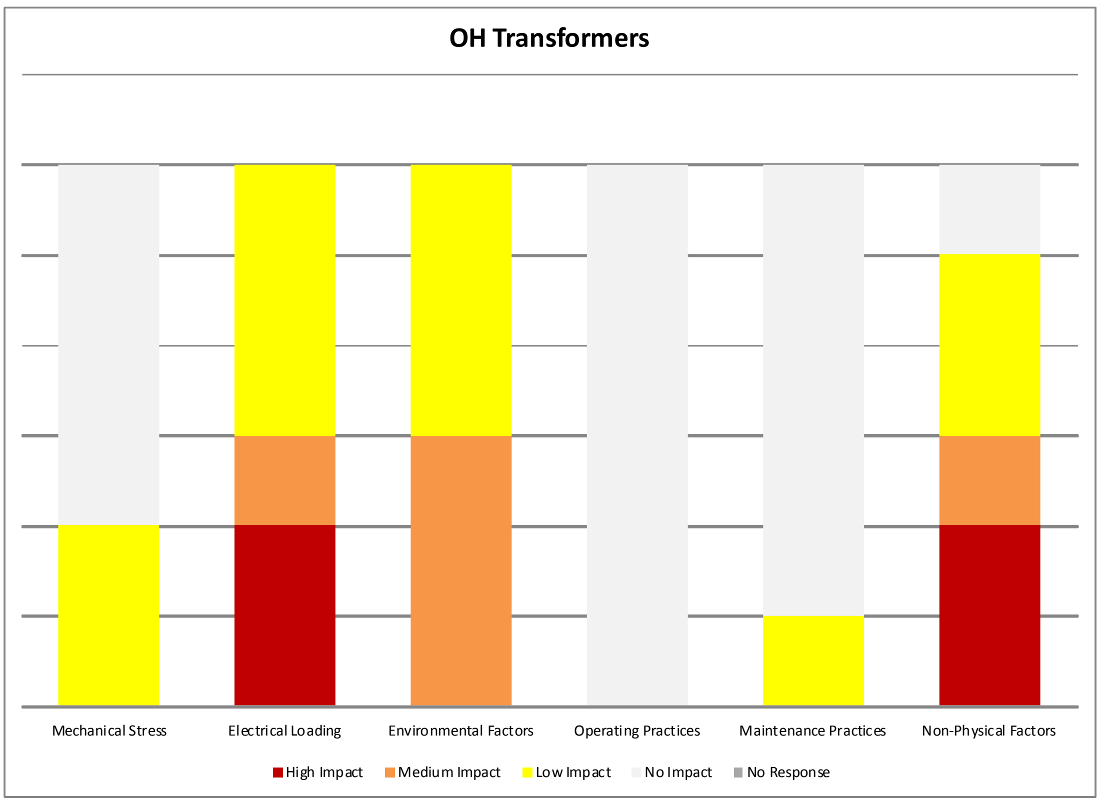


Figure 9-2 Impact of Utilization Factors on the Useful Life of Overhead Transformers and Voltage Regulators

10. Overhead Shunt Capacitor Banks

10.1 Asset Description

This asset category refers to pole mounted shunt capacitor banks and their supporting hardware. The capacitor bank also includes the control switches and devices, fuse cutout, surge arrester and in some cases current-limiting fuses. Shunt capacitors regulate voltage in distribution systems, and provide reactive compensation.

10.1.1 Componentization Assumptions

For the purposes of this report, the Overhead Shunt Capacitor Banks asset category has not been componentized.

10.1.2 System Hierarchy

Overhead Shunt Capacitor Banks is considered to be a part of the Overhead Lines asset grouping.

10.2 Degradation Mechanism

The major degradation of overhead capacitor banks is related to the capacitors themselves. They are exposed to detrimental environmental factors including: extreme temperatures, contamination, birds etc. They also experience steady state, transient and dynamic over voltage conditions. The switching devices add an additional stress to the capacitors. These environmental conditions, electrical loading and operating practices cause non-reversible degradation of the insulation in capacitor units and external insulation.

Fuse and bushing degradation result primarily from the failure of seals (hence moisture seeps in). Based on the surrounding environmental conditions this may cause corrosion of the capacitor units and support frame. Internal degradation can also occur in insulators.

10.3 Useful Life

Based on the Industry Values and Utility Interviews the Useful Life Values, Minimum (MIN UL), Typical (TUL) and Maximum (MAX UL) for Overhead Shunt Capacitor Banks are displayed in Table 10-1 Useful Life Values for Overhead Shunt Capacitor Banks

Table 10-1 Useful Life Values for Overhead Shunt Capacitor Banks

ASSET COMPONENTIZATION	USEFUL LIFE		
	MIN UL	TUL	MAX UL
OH Shunt Capacitor Banks	25	30	40

10.3.1 Useful Life Data

This section displays the data used to determine the Useful Life Values for Overhead Shunt Capacitor Banks. None of the interviewed utilities gave Minimum, Typical and Maximum Useful Life (MIN UL, TUL and MAX UL) Values for Overhead Shunt Capacitor Banks (Figure 10-1).

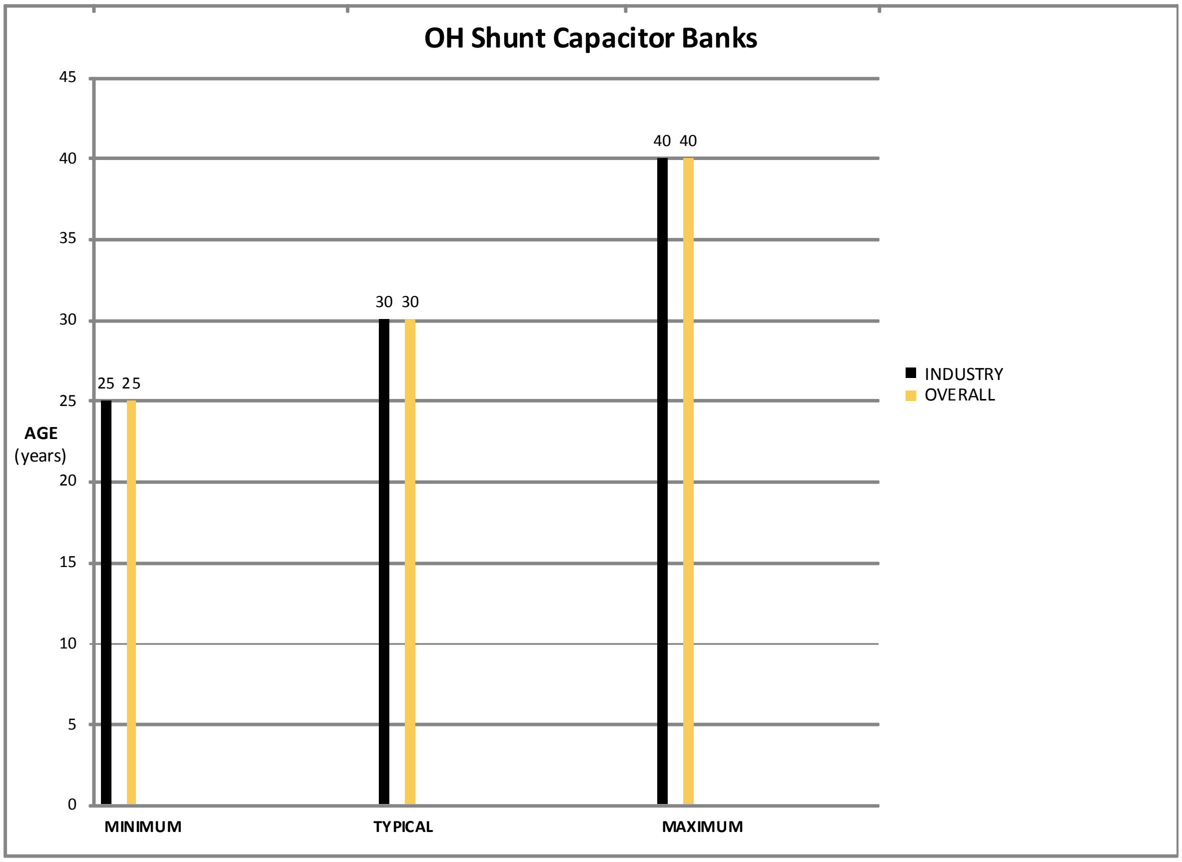


Figure 10-1 Useful Life Values for Overhead Shunt Capacitor Banks

10.4 Impact of Utilization Factors

No Impact of Utilization Factors Data was available from the Utility Interviews.

11. Reclosers

11.1 Asset Description

This asset class consists of reclosers which are light duty circuit breakers equipped with control units. The recloser unit accomplishes the breaking and making of fault current. The interrupters use oil or vacuum as the insulating agent. The controllers are either integral hydraulic or local electric units. Reclosers are designed for either single phase or three phase use.

11.1.1 Componentization Assumptions

For the purposes of this report, the Reclosers asset category has not been componentized.

11.1.2 Design Configuration

There are several circuit breakers types associated with reclosers. For the purposes of this report, the breaker types are oil, gas (SF6) and vacuum.

11.1.3 System Hierarchy

Reclosers are considered to be a part of the Overhead Lines asset grouping.

11.2 Degradation Mechanism

The degradation processes associated with reclosers involves the effects of making and breaking fault current, the mechanism itself and deterioration of components. The effects of making and breaking fault current affect arc suppression devices as well as the contacts, and the oil condition. The degradation of these devices depends on the available fault current, if it is well below the rated capability of the recloser, the deteriorating effects will be small. For the mechanism itself, deterioration or mal-operation of the mechanism causes deterioration during operation. Typically lack of use, corrosion and poor lubrication are the main causes of mechanism malfunction. For deterioration, exposure to weather is a potentially significant degradation process

11.3 Useful Life

Based on the Industry Values and Utility Interviews the Useful Life Values, Minimum (MIN UL), Typical (TUL) and Maximum (MAX UL) for Reclosers are displayed in Table 11-1.

Table 11-1 Useful Life Values for Reclosers

ASSET COMPONENTIZATION	USEFUL LIFE		
	MIN UL	TUL	MAX UL
Reclosers	25	40	55

11.3.1 Useful Life Data

This section displays the data used to determine the Useful Life Values for Reclosers. Five of the interviewed utilities gave Minimum, Typical and Maximum Useful Life (MIN UL, TUL and MAX UL) Values for Reclosers (Figure 11-1).

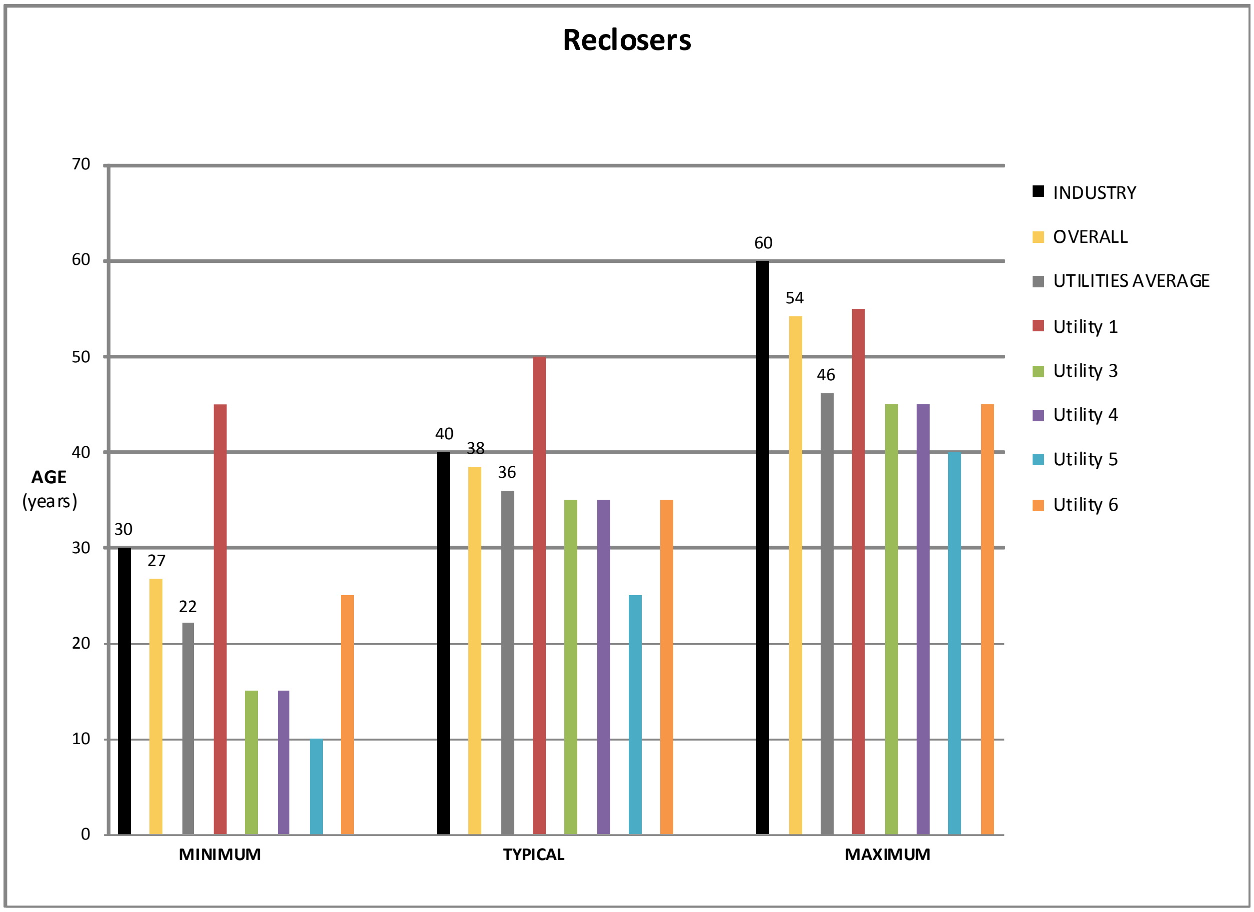


Figure 11-1 Useful Life Values for Reclosers

11.4 Impact of Utilization Factors

Based on the Utility Interviews the composite score and overall impact (high medium, low), if any, of each factor on the typical useful life of Reclosers are displayed in Table 11-2.

Table 11-2 - Composite Score for Reclosers

	Utilization Factors					
	Mechanical Stress	**Electrical Loading**	**Environmental Factors**	**Operating Practices**	**Maintenance Practices**	**Non-Physical Factors**
Composite Score	15%	38%	38%	53%	23%	55%
Overall Rating*	**L**	**L**	**L**	**M**	**L**	**M**
* H = High Impact	M = Medium Impact	L = Low Impact	NI = No Impact			

11.4.1 Utility Interview Data

This section displays the data used to determine the composite score and overall impact (high, medium, low) of each factor on the typical useful life of Reclosers. Five of the interviewed utilities provided their input regarding the UFs for Reclosers (Figure 1-42).

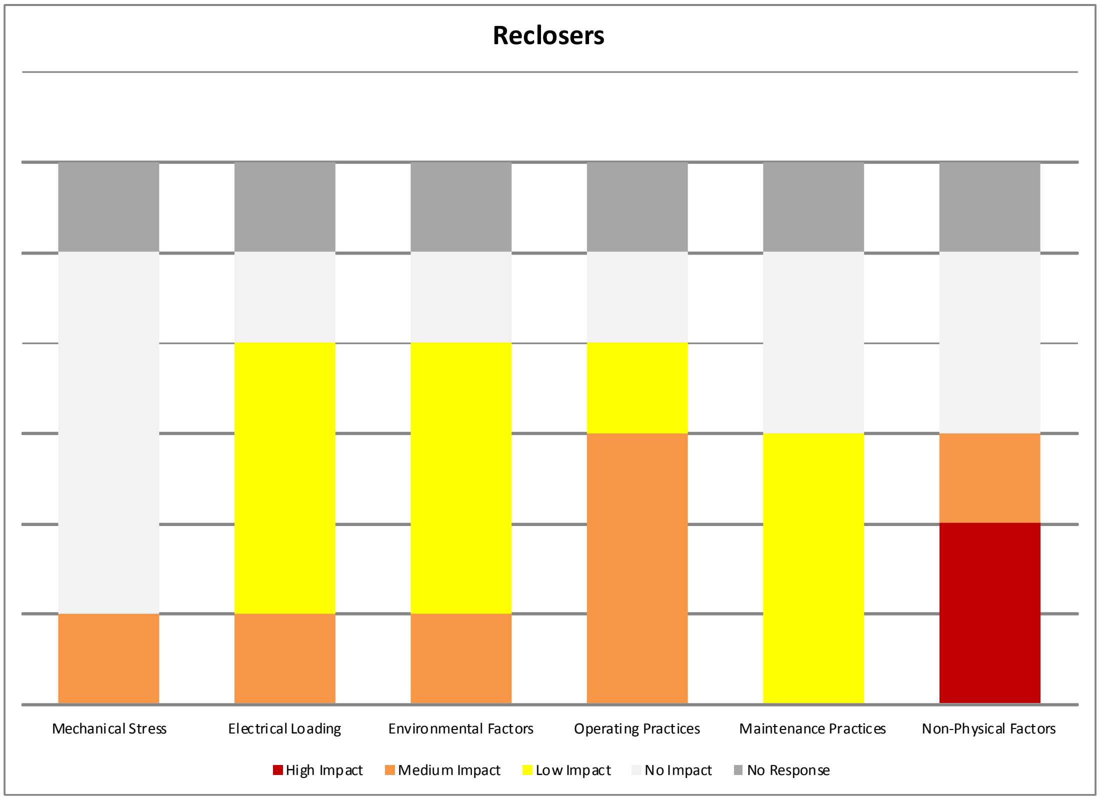


Figure 11-2 Impact of Utilization Factors on the Useful Life of Reclosers

12. Power Transformers

12.1 Asset Description

While power transformers can be employed in either step-up or step-down mode, a majority of the applications in transmission and distribution stations involve step down of the transmission or sub-transmission voltage to distribution voltage levels. Power transformers vary in capacity and ratings over a broad range. There are two general classifications of power transformers: transmission station transformers and distribution station transformers. For transformer stations, when step down from 230kV or 115kV to distribution voltage is required, ratings may range from 30MVA to 125 MVA.

12.1.1 Componentization Assumptions

For the purposes of this report, the Power Transformers asset category has been componentized so that the bushing and tap changer may be regarded as separate components. Therefore the Power Transformer has overall useful life values based on the useful life of the transformer itself and useful life values for the specific components, bushing and tap changer.

12.1.2 System Hierarchy

Power Transformers is considered to be a part of the Transformer and Municipal Stations asset grouping.

12.2 Degradation Mechanism

Transformers operate under many extreme conditions, and both normal and abnormal conditions affect their aging and breakdown. They are subject to thermal, electrical, and mechanical aging. Overloads cause above-normal temperatures, through-faults can cause displacement of coils and insulation, and lightning and switching surges can cause internal localized over-voltages.

For a majority of transformers, end of life is a result of the failure of insulation, more specifically, the failure of pressboard and paper insulation. While the insulating oil can be treated or changed, it is not practical to change the paper and pressboard insulation. The condition and degradation of the insulating oil, however, plays a significant role in aging and deterioration of the transformer, as it directly influences the speed of degradation of the paper insulation. The degradation of oil and paper in transformers is essentially an oxidation process. The three important factors that impact the rate of oxidation of oil and paper insulation are the presence of oxygen, high temperature, and moisture. Particles and acids, as well as static electricity in oil cooled units, also affect the insulation.

Tap changers and bushing are major components of the power transformer. Tap changers are complex mechanical devices and are therefore prone to failure resulting from either mechanical or electrical degradation. Bushings are subject to aging from both electrical and thermal stresses.

12.3 Useful Life

Based on the Industry Values and Utility Interviews the Useful Life Values, Minimum (MIN UL), Typical (TUL) and Maximum (MAX UL) for Power Transformers are displayed in Table 12-1.

Table 12-1 Useful Life Values for Power Transformers

ASSET COMPONENTIZATION	USEFUL LIFE		
	MIN UL	TUL	MAX UL
Overall	30	45	60
Bushing	10	20	30
Tap Changer	20	30	60

12.3.1 Useful Life Data

This section displays the data used to determine the Useful Life Values for Power Transformers. All six of the interviewed utilities gave Minimum, Typical and Maximum Useful Life (MIN UL, TUL and MAX UL) Values for Power Transformers (Figure 12-1).

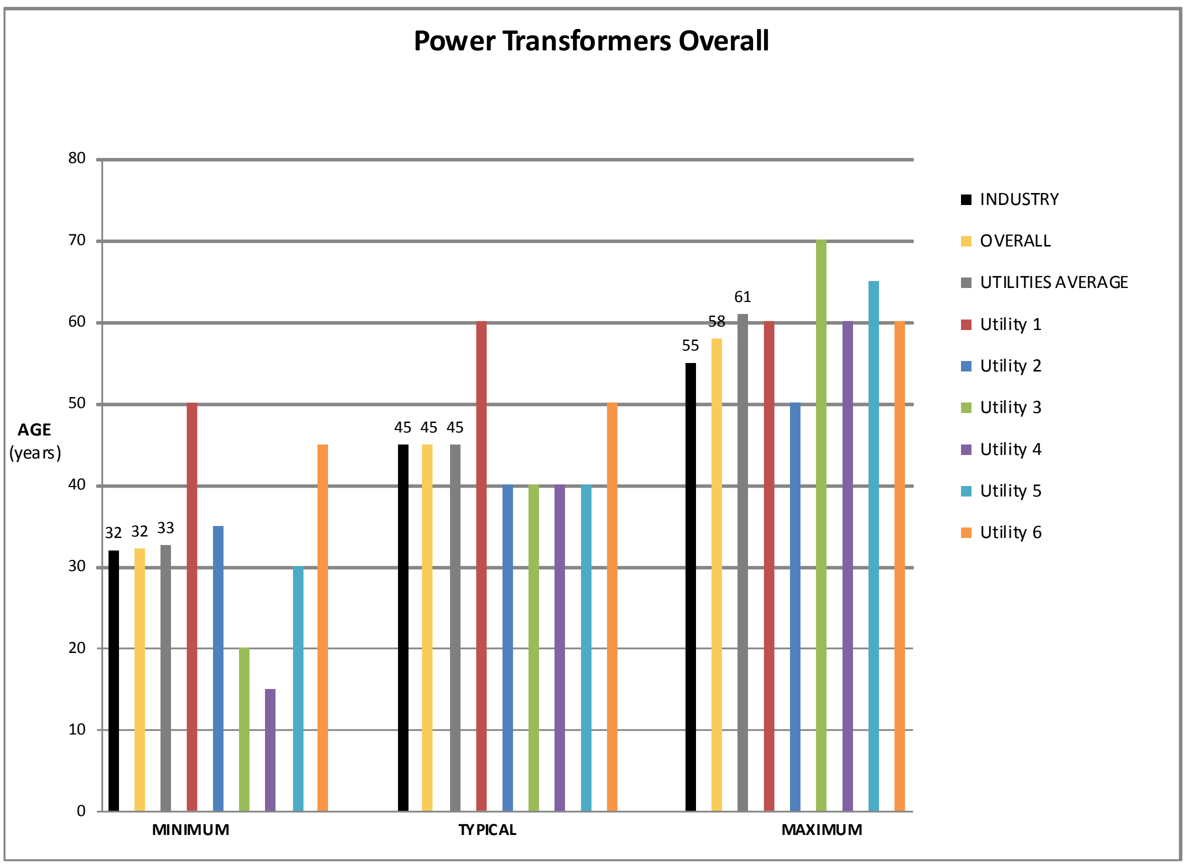


Figure 12-1 Useful Life Values for Power Transformers

12.4 Impact of Utilization Factors

Based on the Utility Interviews the composite score and overall impact (high medium, low), if any, of each factor on the typical useful life of Power Transformers are displayed in Table 12-2.

Table 12-2 - Composite Score for Power Transformers

	Utilization Factors					
	Mechanical Stress	**Electrical Loading**	**Environmental Factors**	**Operating Practices**	**Maintenance Practices**	**Non-Physical Factors**
Composite Score	0%	75%	50%	44%	42%	0%
Overall Rating*	**NI**	**M**	**M**	**L**	**L**	**NI**
* H = High Impact	M = Medium Impact		L = Low Impact		NI = No Impact	

12.4.1 Utility Interview Data

This section displays the data used to determine the composite score and overall impact (high, medium, low) of each factor on the typical useful life of Power Transformers. All six of the interviewed utilities provided their input regarding the UFs for Power Transformers (Figure 12-2).

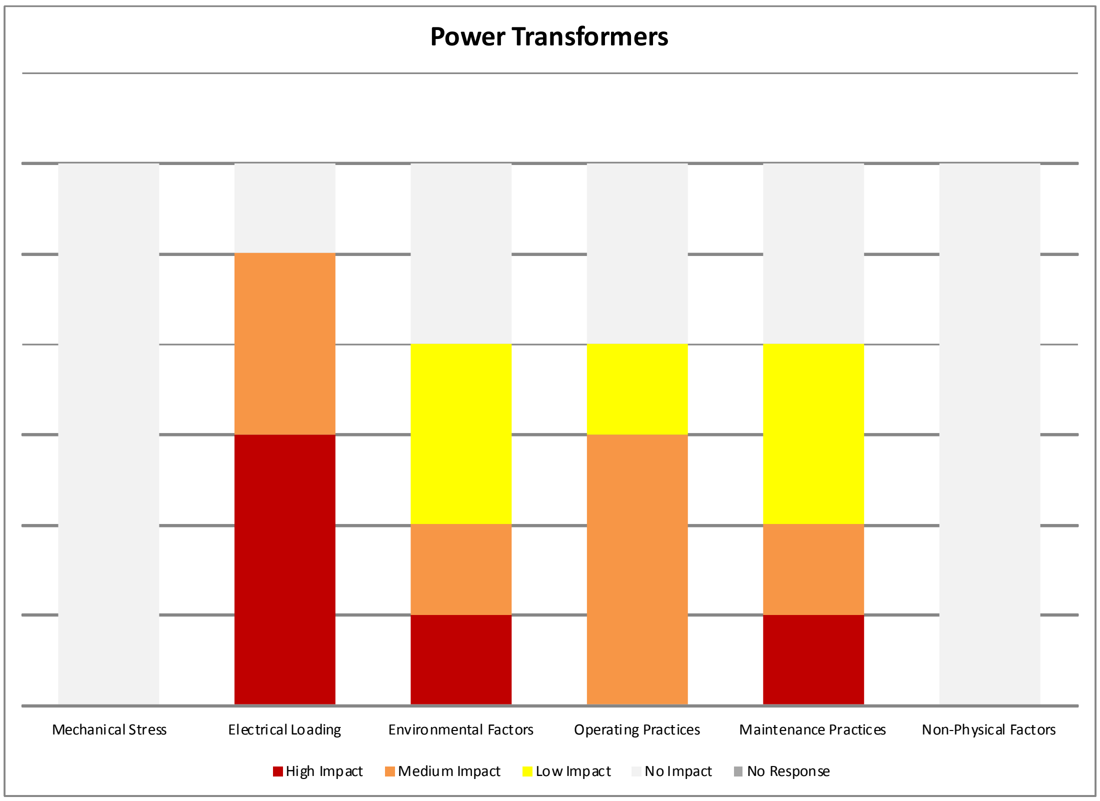


Figure 12-2 Impact of Utilization Factors on the Useful Life of Power Transformers

13. Station Service Transformers

13.1 Asset Description

The station service transformer provides power to the auxiliary equipment, such as fans, pumps, heating, or lighting, in the distribution station. Small power transformers are configured to provide this requirement.

13.1.1 Componentization Assumptions

For the purposes of this report, the Station Service Transformers has not been componentized.

13.1.2 System Hierarchy

Station Service Transformers is considered to be a part of the Transformer and Municipal Stations asset grouping.

13.2 Degradation Mechanism

As with most transformers, end of life is typically a result of insulation failure, particularly paper insulation. The oil and paper insulation degrade as oxidation takes place in the presence of oxygen, high temperature, and moisture. Acids, particles, and static electricity also have degrading effects to the insulation.

13.3 Useful Life

Based on the Industry Values and Utility Interviews the Useful Life Values, Minimum (MIN UL), Typical (TUL) and Maximum (MAX UL) for Station Service Transformers are displayed in Table 13-1.

Table 13-1 Useful Life Values for Station Service Transformers

ASSET COMPONENTIZATION	USEFUL LIFE		
	MIN UL	TUL	MAX UL
Station Service Transformer	30	45	55

13.3.1 Useful Life Data

This section displays the data used to determine the Useful Life Values for Station Service Transformers. Five of the interviewed utilities gave Minimum, Typical and Maximum Useful Life (MIN UL, TUL and MAX UL) Values for Station Service Transformers (Figure 13-1).

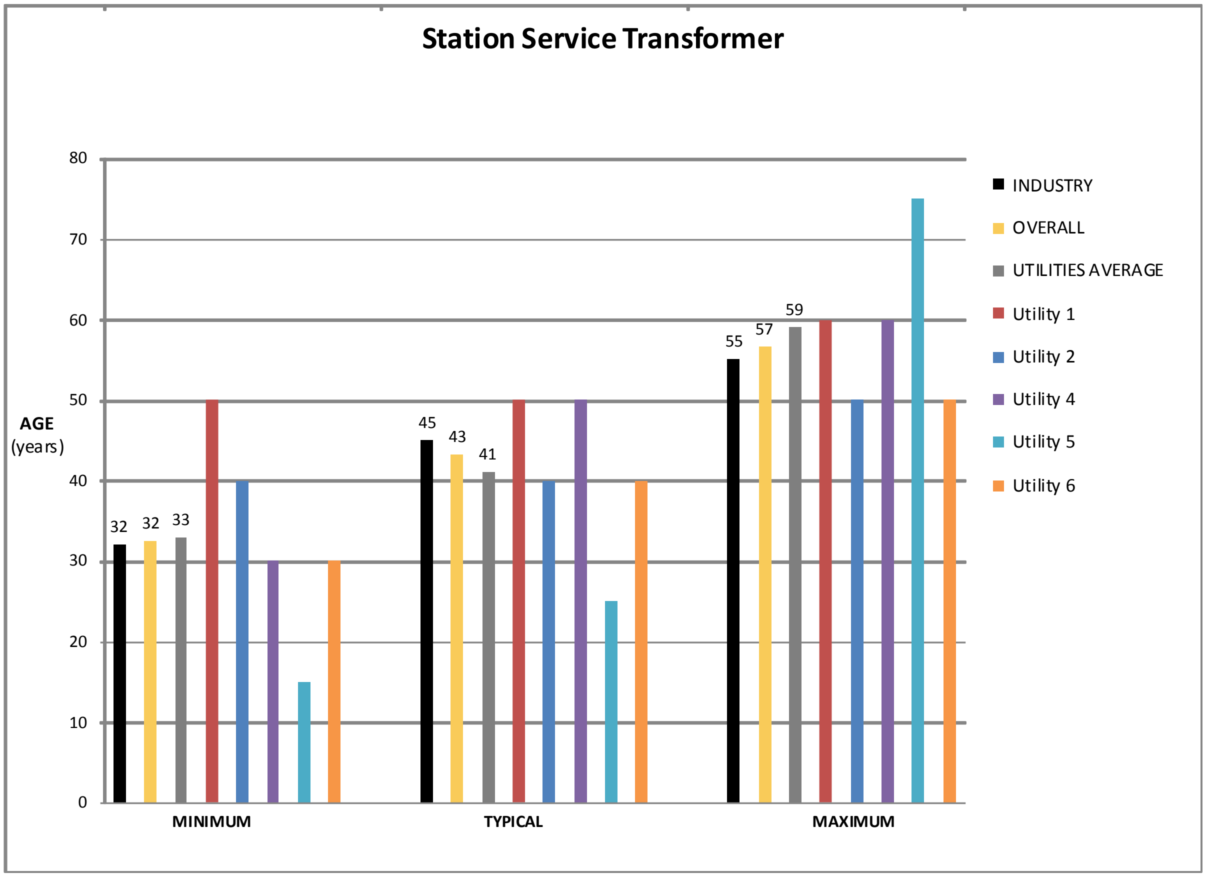


Figure 13-1 Useful Life Values for Station Service Transformers

13.4 Impact of Utilization Factors

Based on the Utility Interviews the composite score and overall impact (high medium, low), if any, of each factor on the typical useful life of Station Service Transformers are displayed in Table 13-2.

Table 13-2 - Composite Score for Station Service Transformers

	Utilization Factors					
	Mechanical Stress	**Electrical Loading**	**Environmental Factors**	**Operating Practices**	**Maintenance Practices**	**Non-Physical Factors**
Composite Score	0%	35%	65%	15%	8%	40%
Overall Rating*	**NI**	**L**	**M**	**L**	**NI**	**L**
* H = High Impact M = Medium Impact L = Low Impact NI = No Impact						

13.4.1 Utility Interview Data

This section displays the data used to determine the composite score and overall impact (high, medium, low) of each factor on the typical useful life of Station Service Transformers. Five of the interviewed utilities provided their input regarding the UFs for Station Service (Figure 1-42).

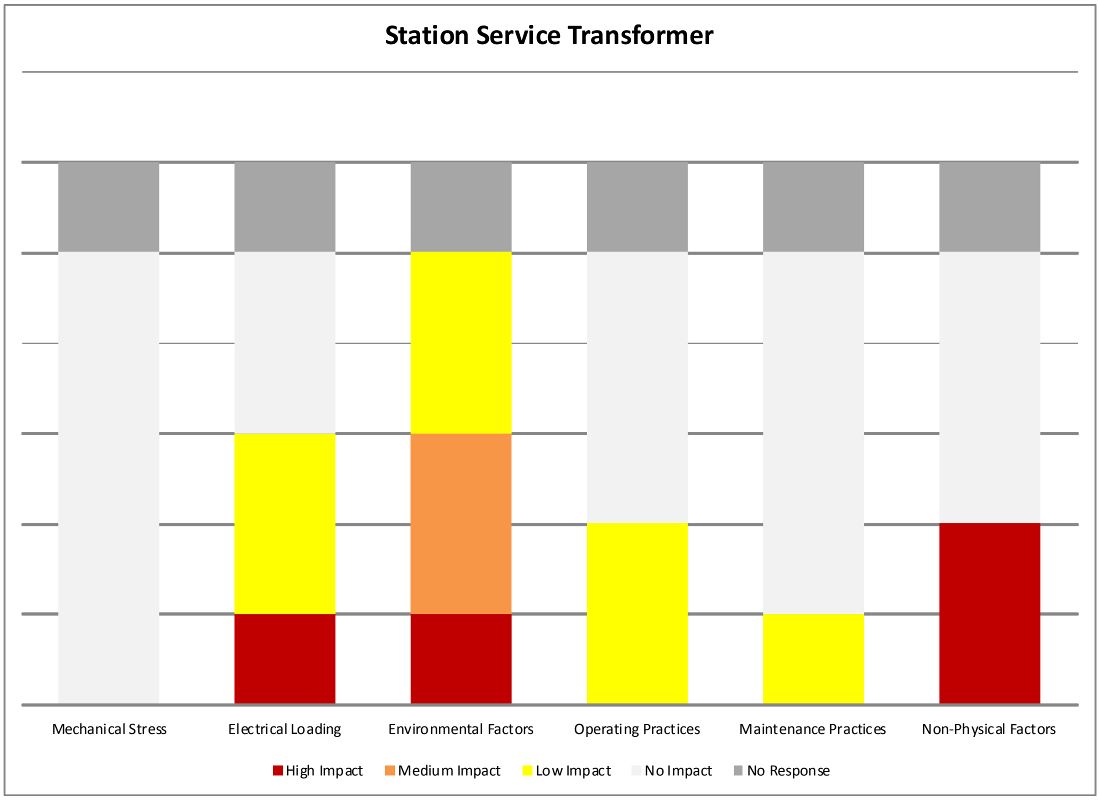


Figure 13-2 Impact of Utilization Factors on the Useful Life of Station Service Transformers

14. Station Grounding Transformers

14.1 Asset Description

Electrical distribution systems can be configured as a grounded or ungrounded system. A grounded system has an electrical connection generally between star-point of a wye configured transformer and the earth, whereas an ungrounded system has no intentional connection. Sometimes it is necessary to create a virtual ground on an ungrounded system for safety or to aid in protective relaying applications. Grounding transformers, smaller transformers similar in construction to power transformers, are used in this application.

14.1.1 Componentization Assumptions

For the purposes of this report, the Station Grounding Transformers has not been componentized.

14.1.2 System Hierarchy

Station Grounding Transformers is considered to be a part of the Transformer and Municipal Stations asset grouping.

14.2 Degradation Mechanism

Like a majority of transformers, the end of life for this asset is a result of insulation degradation, more specifically, the failure of pressboard and paper insulation. Degradation of the insulating oil, and more significantly, paper insulation, typically results in end of life. Insulation degradation is a result of oxidation, a process that occurs in the presence of oxygen, high temperature, and moisture. For oil cooled transformers, particles, acids, and static electricity will also deteriorate the insulation.

14.3 Useful Life

Based on the Industry Values and Utility Interviews the Useful Life Values, Minimum (MIN UL), Typical (TUL) and Maximum (MAX UL) for Station Grounding Transformers are displayed in Table 14-1.

Table 14-1 Useful Life Values for Station Grounding Transformers

ASSET COMPONENTIZATION	USEFUL LIFE		
	MIN UL	TUL	MAX UL
Station Grounding Transformer	30	40	40

14.3.1 Useful Life Data

This section displays the data used to determine the Useful Life Values for Station Grounding Transformers. None of the interviewed utilities gave Minimum, Typical and Maximum Useful Life (MIN UL, TUL and MAX UL) Values for Station Grounding Transformers (Figure 14-1).

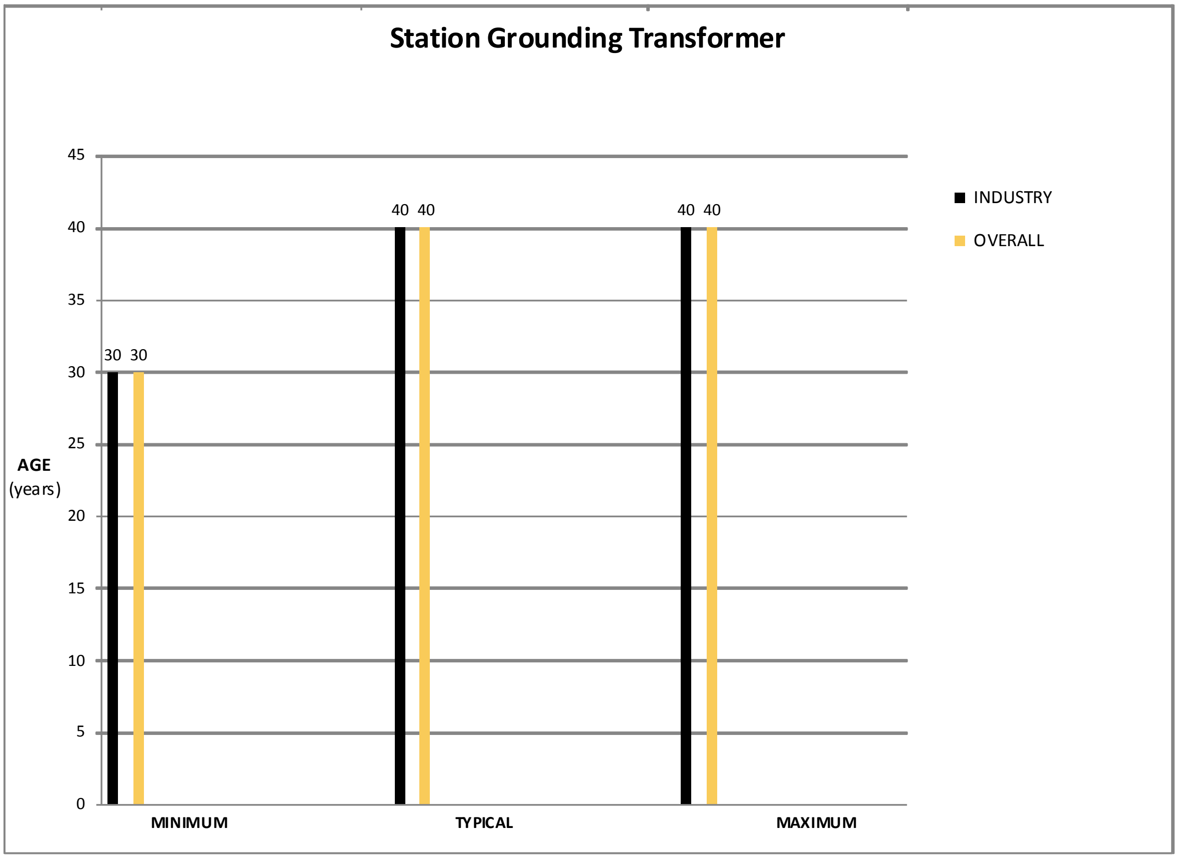


Figure 14-1 Useful Life Values for Station Grounding Transformers

14.4 Impact of Utilization Factors

No Impact of Utilization Factors Data was available from the Utility Interviews.

15. Station Direct Current System

15.1 Asset Description

Station direct current (DC) systems are the critical supply for station protection and control equipment and other auxiliary devices such as transformer cooling. This asset category has been componentized into batteries, chargers and other DC distribution equipment. Maintaining batteries in a condition capable of delivering the necessary energy as required is essential.

Batteries consist of multiple individual cells. For the purposes of this report, these are lead-acid battery banks. Battery chargers are relatively simple electronic devices that have a high degree of reliability and a significantly longer lifetime than the battery banks.

15.1.1 Componentization Assumptions

For the purposes of this report, the Station Direct Current System has been componentized so that the battery bank and charger are regarded as separated components. Therefore the Station Direct Current System has overall useful life values based and useful life values for the specific components, battery bank and charger.

15.1.2 System Hierarchy

Station Direct Current System is considered to be a part of the Transformer and Municipal Stations asset grouping.

15.2 Degradation Mechanism

The deterioration of a battery from an apparently healthy condition to a functional failure can be rapid. This makes condition assessment very difficult. However, careful inspection and testing of individual cells often enables the identification of high risk units in the short term.

Although battery deterioration is difficult to detect, any changes in the electrical characteristics or observation of significant internal damage can be used as sensitive measures of impending failure. While the significant deterioration/failure of an individual cell may be an isolated incident, detection of deterioration in a number of cells in a battery is usually the precursor to widespread failure and functional failure of the total battery. The ability to detect significant deterioration and pre-empt battery failure is especially critical if monitoring and alarm systems are not installed.

Historically, battery end-of-life was determined mainly by a number of factors including age, appearance (indication of physical deterioration) and the history of specific gravity and cell voltage measurements. Presently, the battery load test is now considered the “best” indicator of battery condition. This test is now used to identify and confirm the condition of suspect batteries identified from the preceding tests.

Battery chargers are also critical to the satisfactory performance of the whole battery system. As with other electronic devices, it is difficult to detect deterioration prior to failure. It is normal practice during the regular maintenance and inspection process to check the functionality of the battery chargers, in particular the charging rates. Where any functional failures are detected it would be normal to replace the battery charger.

For battery chargers, diagnostic testing programs are coordinated with the battery maintenance program. This involves a number of functional tests and each test has a defined test passed/test failed (TP/TF) criteria. Failure of any functional test may lead to further investigations or consideration of replacement.

Due to the critical functionality of batteries, most utilities take a conservative approach towards battery replacement: any significant evidence of battery deterioration usually leads to decisions to replace the battery.

15.3 Useful Life

Based on the Industry Values and Utility Interviews the Useful Life Values, Minimum (MIN UL), Typical (TUL) and Maximum (MAX UL) for Station Direct Current System are displayed in Table 15-1.

Table 15-1 Useful Life Values for Station Direct Current System

ASSET COMPONENTIZATION	USEFUL LIFE		
	MIN UL	TUL	MAX UL
Overall	10	20	30
Battery bank	10	15	15
Charger	20	20	30

15.3.1 Useful Life Data

This section displays the data used to determine the Useful Life Values for Station Direct Current System. Four of the interviewed utilities gave Minimum, Typical and Maximum Useful Life (MIN UL, TUL and MAX UL) Values for Station Direct Current System (Figure 15-1).

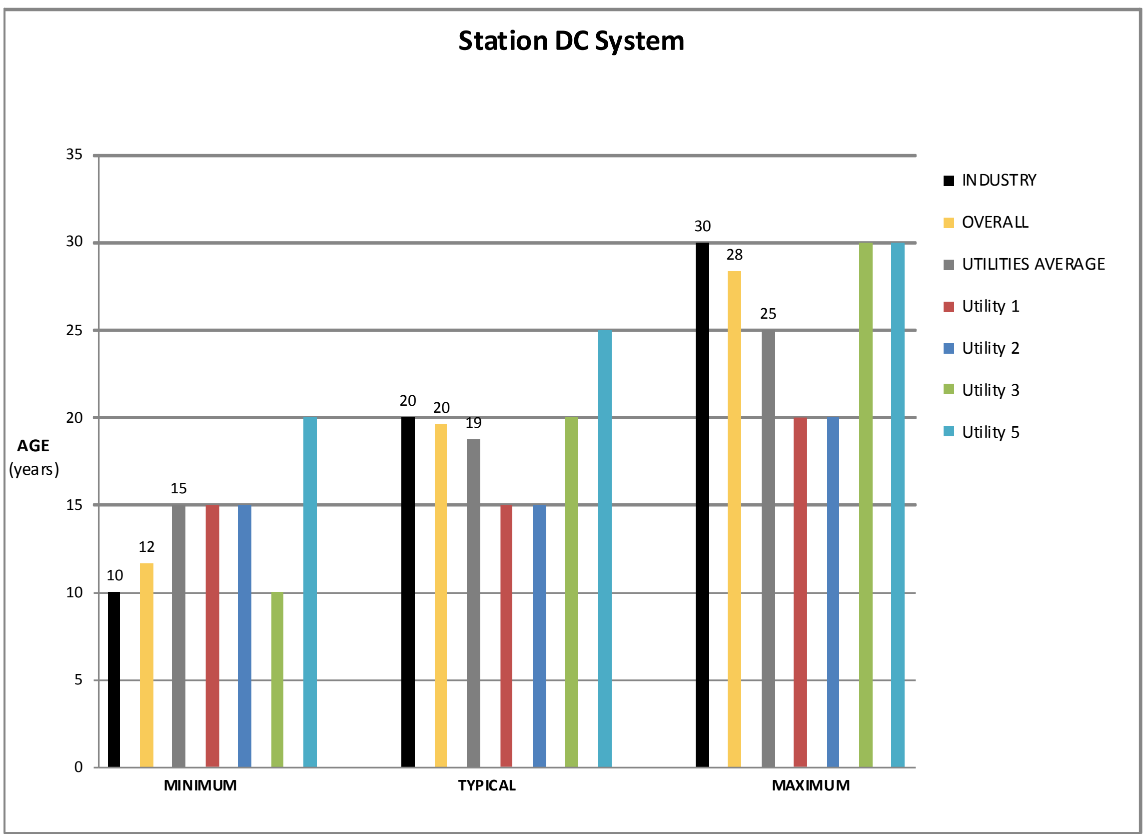


Figure 15-1 Useful Life Values for Station Direct Current System

15.4 Impact of Utilization Factors

Based on the Utility Interviews the composite score and overall impact (high medium, low), if any, of each factor on the typical useful life of Station Direct Current System are displayed in Table 15-2.

Table 15-2 - Composite Score for Station Direct Current System

	Utilization Factors					
	Mechanical Stress	**Electrical Loading**	**Environmental Factors**	**Operating Practices**	**Maintenance Practices**	**Non-Physical Factors**
Composite Score	8%	50%	15%	23%	52%	53%
Overall Rating*	**NI**	**M**	**L**	**L**	**M**	**M**

* H = High Impact M = Medium Impact L = Low Impact NI = No Impact

15.4.1 Utility Interview Data

This section displays the data used to determine the composite score and overall impact (high, medium, low) of each factor on the typical useful life of Station Direct Current System. Five of the interviewed utilities provided their input regarding the UFs for Station Direct Current System (Figure 15-2).

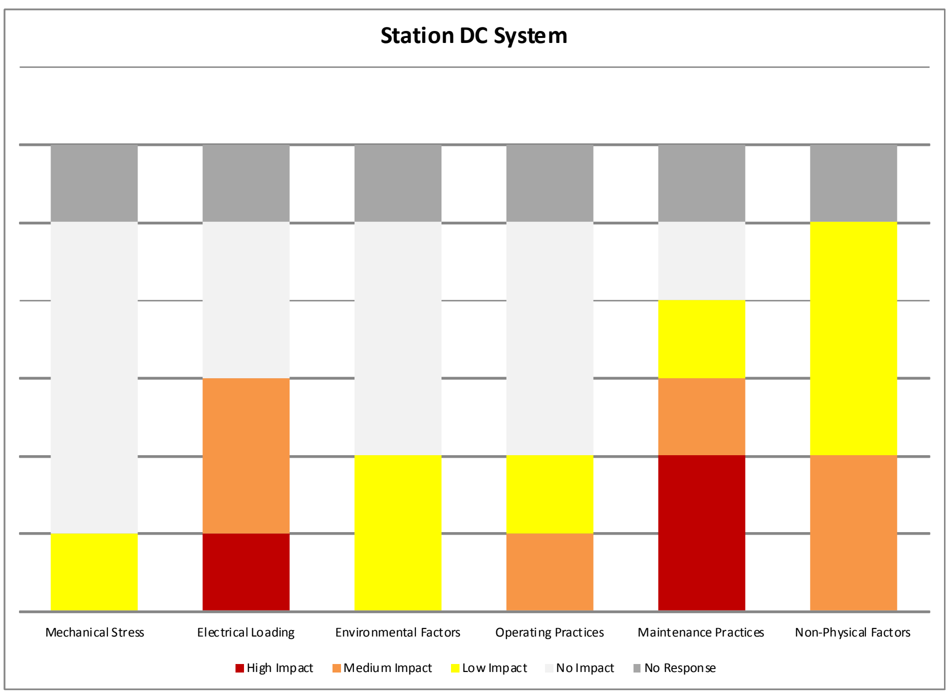


Figure 15-2 Impact of Utilization Factors on the Useful Life of Station Direct Current System

16. Station Metal Clad Switchgear

16.1 Asset Description

Station Metal Clad Switchgear comprises the metal enclosure, the circuit breakers and the associated protection and control devices. Metal clad switchgear is used for protection and switching of distribution system circuits.

16.1.1 Componentization Assumptions

For the purposes of this report, the Station Metal Clad Switchgear has been componentized so that the removable breaker may be regarded as a separate component. Therefore the Station Metal Clad Switchgear has overall useful life values based and useful life values for the specific component, the removable breaker.

16.1.2 Design Configuration

For the purposes of this report, station metal clad switchgear asset category can be classified in two types: gas insulated and air insulated switchgear. There are also several interrupting mediums associated with the removable breaker component of station metal clad switchgear. For the purposes of this report, the types are oil, air, gas (SF6) and vacuum.

16.1.3 System Hierarchy

Station Metal Clad Switchgear is considered to be a part of the Transformer and Municipal Stations asset grouping.

16.2 Degradation Mechanism

Switchgear degradation is a function of a number of different factors: mechanism operation and performance, degradation of solid insulation, general degradation/corrosion, environmental factors, or post fault maintenance (condition of contacts and arc control devices).

16.3 Useful Life

Based on the Industry Values and Utility Interviews the Useful Life Values, Minimum (MIN UL), Typical (TUL) and Maximum (MAX UL) for Station Metal Clad Switchgear are displayed in Table 16-1.

Table 16-1 Useful Life Values for Station Metal Clad Switchgear

ASSET COMPONENTIZATION	USEFUL LIFE		
	MIN UL	TUL	MAX UL
Overall	30	40	60
Removable Breaker	25	40	60

16.3.1 Useful Life Data

This section displays the data used to determine the Useful Life Values for Station Metal Clad Switchgear. All six of the interviewed utilities gave Minimum, Typical and Maximum Useful Life (MIN UL, TUL and MAX UL) Values for Station Metal Clad Switchgear (Figure 16-1).

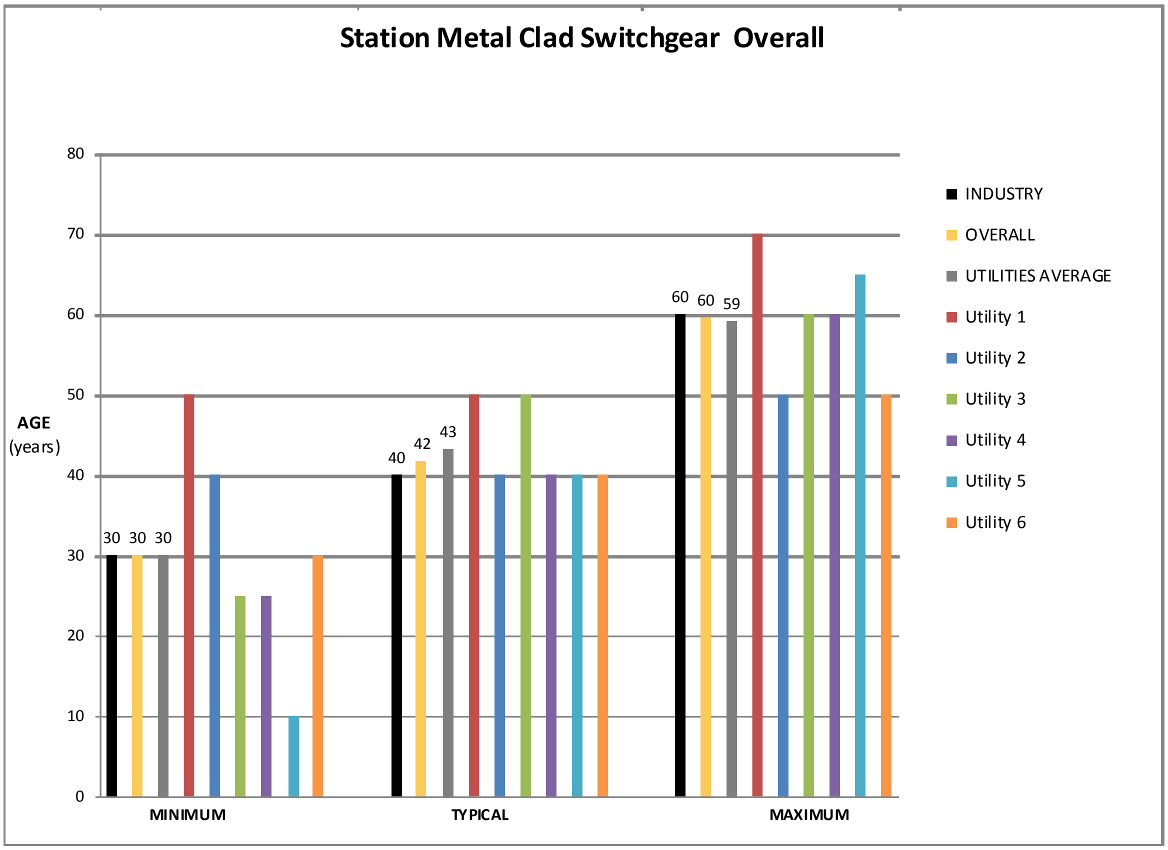


Figure 16-1 Useful Life Values for Station Metal Clad Switchgear

16.4 Impact of Utilization Factors

Based on the Utility Interviews the composite score and overall impact (high medium, low), if any, of each factor on the typical useful life of Station Metal Clad Switchgear are displayed in Table 16-2.

Table 16-2 - Composite Score for Station Metal Clad Switchgear

	Utilization Factors					
	Mechanical Stress	Electrical Loading	Environmental Factors	Operating Practices	Maintenance Practices	Non-Physical Factors
Composite Score	31%	44%	48%	56%	69%	50%
Overall Rating*	L	L	M	M	M	M
* H = High Impact M = Medium Impact L = Low Impact NI = No Impact						

16.4.1 Utility Interview Data

This section displays the data used to determine the composite score and overall impact (high, medium, low) of each factor on the typical useful life of Station Metal Clad Switchgear. All six of the interviewed utilities provided their input regarding the UFs for Station Metal Clad Switchgear (Figure 15-2).

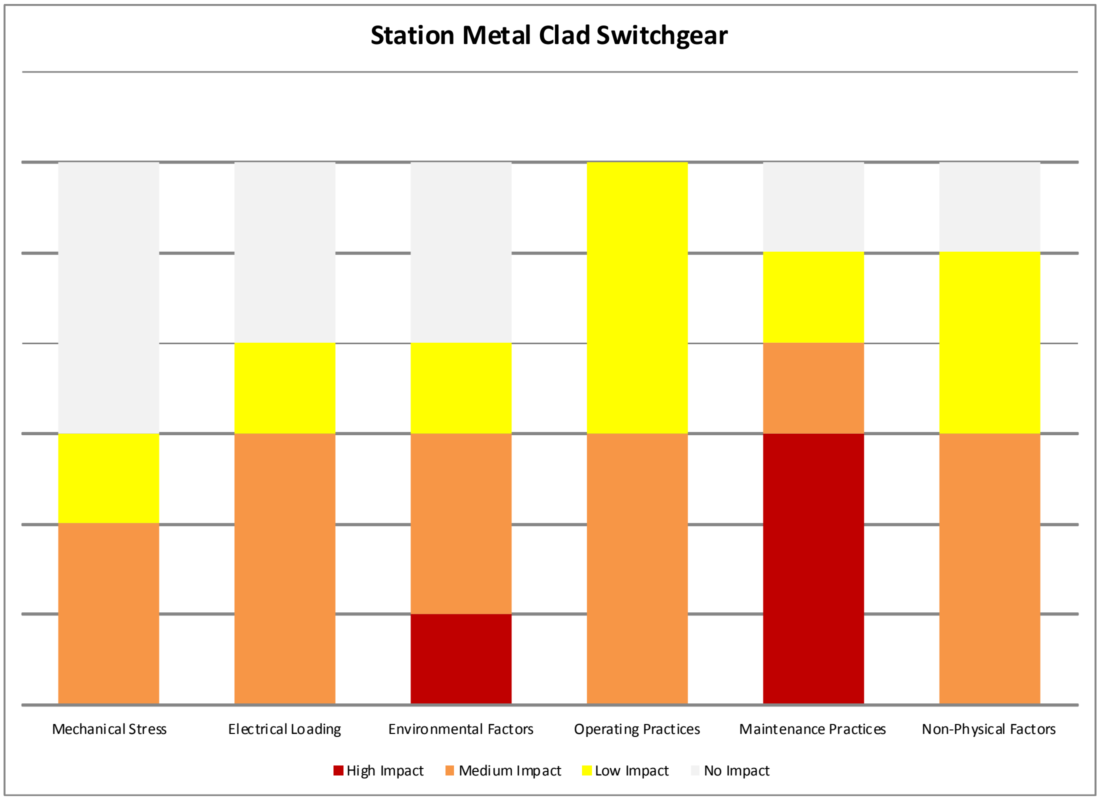


Figure 16-2 Impact of Utilization Factors on the Useful Life of Station Metal Clad Switchgear

17. Station Independent Breakers

17.1 Asset Description

Circuit breakers are automated switching devices that can make, carry and interrupt electrical currents under normal and abnormal conditions. Breakers are required to operate infrequently, however, when an electrical fault occurs, breakers must operate reliably and with adequate speed to minimize damage. This asset category refers to five types of independent station circuit breakers: oil, gas (SF6), air magnetic, air blast and vacuum.

17.1.1 Componentization Assumptions

For the purposes of this report, the Station Independent Breakers has not been componentized.

17.1.2 Design Configuration

For the purposes of this report, the independent breakers could be either indoor or outdoor. The breaker types are oil, gas (SF6), air magnetic, air blast and vacuum.

The oil circuit breaker (OCB) is the oldest type of breaker design and has been in use for over 70 years. Two types of designs exist among OCBs: bulk oil breakers (in which oil serves as the insulating and arc quenching medium) and minimum oil breakers (in which oil provides the arc quenching function only).

Gas, sulfur hexafluoride (SF6) insulated equipment is a relatively young technology. The first SF6 equipment was developed in the late 1960s. After some initial design and manufacturing problems equipment was increasingly used to replace oil filled equipment with widespread adoption and utilization since the mid 1980s. One of the more remarkable features of SF6 is its performance when subjected to an arc, or during a fault operation. SF6 is extremely stable and even at the high temperatures associated with an arc, limited breakdown occurs. Furthermore, most of the products of the breakdown recombine to form SF6. Consequently, SF6 circuit breakers can operate under fault conditions many more times than oil breakers before requiring maintenance.

In air magnetic circuit breakers, magnetic blowout coils are used to create a strong magnetic field that draws the arc into specially designed arc chutes. The breaker current flows through the blowout coils and produces a magnetic flux. This magnetic field drives the arc against barriers built perpendicular to the length of the arc. The cross sectional area of the arc is thereby reduced, and its resistance is considerably increased. The surface of the barriers cool and de-ionize the arc, thus collaborating to extinguish the arc.

Air-blast breakers use compressed air as the quenching, insulating and actuating medium. In normal operation, a blast of compressed air carries the arc into an arc chute where it is quickly extinguished. A combination cooler-muffler is often provided to cool ionized exhaust gases before they pass out into the atmosphere and to reduce noise during operation.

Vacuum Breakers consist of fixed and moving butt type contacts in small evacuated chambers (i.e. bottles). A bellows attached to the moving contact permits the required short stroke to occur with no vacuum losses. Arc interruption occurs at current zero after withdrawal of the moving contact. Current medium voltage vacuum breakers require low mechanical drive energy, have high endurance, can interrupt fully rated short circuits up to 100 times, and operate reliably over 30,000 or more switching operations. Vacuum breakers also are safe and protective of the environment.

17.1.3 System Hierarchy

Station Independent Breakers is considered to be a part of the Transformer and Municipal Stations asset grouping.

17.2 Degradation Mechanism

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

The rate and severity of degradation depends on many factors, including insulating and conducting materials, operating environments, and a breaker’s specific duties. The following additional factors could lead to end-of-life for this asset class:

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

Many of the earlier breakers relied on hydraulic or pneumatic assisted mechanisms. These have proved problematic in some cases and contributed significantly to the higher failure rates associated with this generation of equipment. More recent equipment usually utilize spring assisted mechanisms that have proved more reliable and require less maintenance.

17.2.1 Oil Breakers

For oil type circuit breakers the key degradation processes associated is as follows:

- Corrosion
- Effects of moisture
- Mechanical
- Bushing deterioration

The rate and severity of these degradation processes is dependent on a number of inter-related factors, in particular the operating duties and environment in which the equipment is installed. Often the critical degradation process is either corrosion or moisture ingress or a combination of the two, resulting in degradation to internal insulation, deterioration of the mechanism affecting the critical performance of the breaker, damage to major components such as bushings or widespread degradation to oil seals and structurally components.

A significant area of concern is barrier-bushing deterioration resulting from moisture ingress. The Synthetic Resin Bonded Paper (SRBP) insulation absorbs the moisture, which can result in discharge tracking across its surface leading to eventual failure of the bushing. Oil impregnated paper bushings are particularly sensitive to moisture. Once moisture finds its way into the oil and then into the paper insulation, it is very difficult to remove and can eventually lead to failure. Significant levels of moisture in the main tank can lead to general degradation of internal components and in acute cases free water can collect at the bottom of the tank. This creates a condition where a catastrophic failure could occur during operation.

Corrosion of the main tank and other structural components is also a concern. One area that is particularly susceptible to corrosion is underneath the main tank on the “bell end”, this problem is common to both single and three tank circuit breakers.

Corrosion of the mechanical linkages associated with the oil circuit breaker operating mechanism is also a widespread problem that can lead to the eventual seizure of the links.

A lesser mode of degradation, although still serious in certain circumstances, is pollution of bushings, particularly where the equipment is located by the sea or in a heavy industrial area.

Other areas of degradation include:

- Deterioration of contacts
- Wear of mechanical components such as bearings
- Loose primary connections
- Deterioration of concrete plinth affecting stability of the circuit breaker

17.2.2 Gas (SF6) Breakers

Failures relating to internal degradation and ultimate breakdown of insulation are limited to early life failures where design or manufacture led to specific problems. There is virtually no experience of failures resulting from long term degradation within the SF6 chambers. Failures and incorrect operations are primarily related to gas leaks and problems with the mechanism and other ancillary systems. Gas seals and valves are a potential weak point. Clearly, loss of SF6 or ingress of moisture and air compromise the performance of the breaker. As would be expected the earlier SF6 equipment was more prone to these problems. Seals and valves have progressively been improved in more modern equipment.

17.2.3 Air Blast Breakers

The air blast circuit breaker has a similar degradation to other types of circuit breakers. The key degradation processes associated with air blast circuit breakers are:

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

Severity and rate are dependent on factors such as operating duty and environment. Corrosion is a problem for most types of breakers. It can degrade internal insulators, performance mechanisms, major components (e.g. bushings), structural components, and oil seals. Moisture causes degradation of the insulating system. Mechanical degradation presents greater end-of-life concerns than electrical degradation. Generally, operating mechanisms, bearings, linkages, and drive rods represent components that experience most mechanical degradation problems. Contacts, nozzles, and highly stressed components can also experience electrical-related degradation and deterioration. Other defects that arise with aging include:

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

17.2.4 Air Magnetic Breakers

Air magnetic breakers have a similar degradation mechanism to other breakers in that corrosion; moisture, bushing/insulator deterioration, and mechanical degradation are factors.

17.2.5 Vacuum Breakers

The vacuum breakers in this asset class have a similar degradation mechanism to other breakers, where corrosion, moisture, bushing/insulator deterioration, and mechanical degradation are factors.

17.3 Useful Life

Based on the Industry Values and Utility Interviews the Useful Life Values, Minimum (MIN UL), Typical (TUL) and Maximum (MAX UL) for Station Independent Breakers are displayed in Table 17-1.

Table 17-1 Useful Life Values for Station Independent Breakers

ASSET COMPONENTIZATION	USEFUL LIFE		
	MIN UL	TUL	MAX UL
Station Independent Breakers	35	45	65

17.3.1 Useful Life Data

This section displays the data used to determine the Useful Life Values for Station Independent Breakers. One of the interviewed utilities gave Minimum Useful Life (MIN UL) Values and three of the interviewed utilities gave TUL and MAX UL Values for Station Independent Breakers (Figure 17-1).

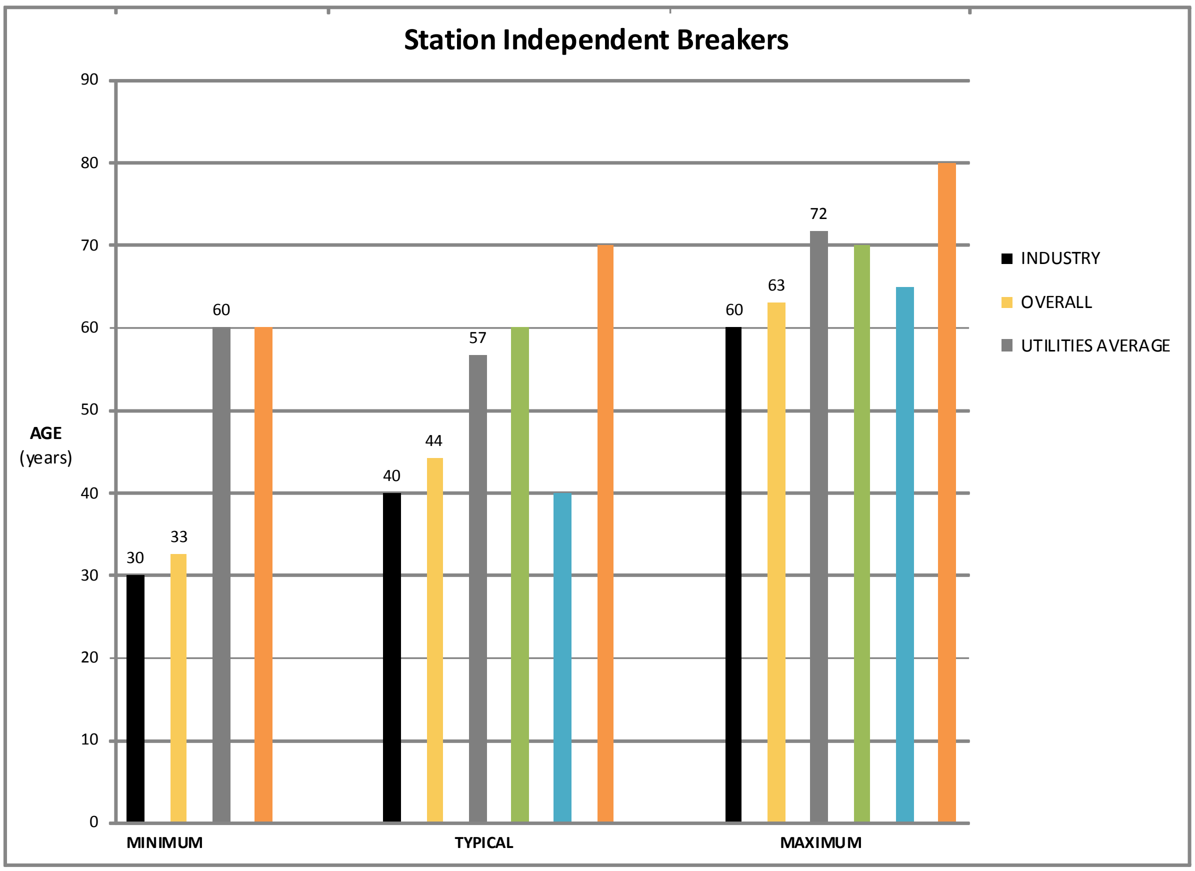


Figure 17-1 Useful Life Values for Station Independent Breakers

17.4 Impact of Utilization Factors

Based on the Utility Interviews the composite score and overall impact (high, medium, low), if any, of each factor on the typical useful life of Station Independent Breakers are displayed in Table 17-2.

Table 17-2 - Composite Score for Station Independent Breakers

	Utilization Factors					
	Mechanical Stress	**Electrical Loading**	**Environmental Factors**	**Operating Practices**	**Maintenance Practices**	**Non-Physical Factors**
Composite Score	58%	63%	50%	63%	50%	67%
Overall Rating*	**M**	**M**	**M**	**M**	**M**	**M**
* H = High Impact	M = Medium Impact		L = Low Impact		NI = No Impact	

17.4.1 Utility Interview Data

This section displays the data used to determine the composite score and overall impact (high, medium, low) of each factor on the typical useful life of Station Independent Breakers. Three of the interviewed utilities provided their input regarding the UFs for Station Independent Breakers (Figure 17-2).

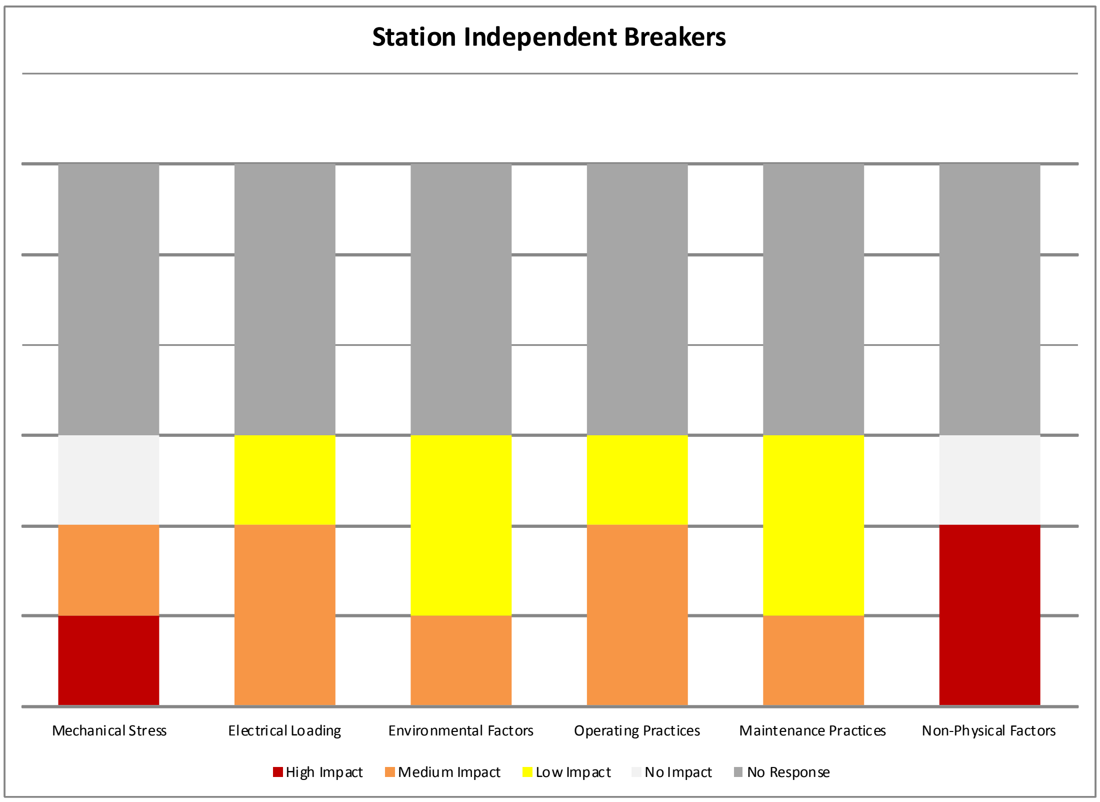


Figure 17-2 Impact of Utilization Factors on the Useful Life of Station Independent Breakers

18. Station Switch

18.1 Asset Description

This asset class consists of the station switches used to physically and electrically isolate sections of the power system for the purposes of maintenance, safety, and other operational requirements. Station switches typically consist of manual or motor operated isolating devices mounted on support insulators and metal support structures. Many high voltage station switches (e.g. line and transformer isolating switches) have motor-operators and the capability of remote-controlled operation. These switches are normally operated when there is no current through the switch, unless specifically designed to be capable of operating under load.

18.1.1 Componentization Assumptions

For the purposes of this report, the Station Switch has not been componentized.

18.1.2 Design Configuration

For the purposes of this report, the station switch refers to both insulting and load interrupting switches. The types included are oil, air magnetic, air blast, gas (SF6) and vacuum.

18.1.3 System Hierarchy

Station Switch is considered to be a part of the Transformer and Municipal Stations asset grouping.

18.2 Degradation Mechanism

Disconnect switches have many moving parts that are subject to wear and operational stress. Except for parts contained in motor-operator cabinets, switch components are exposed to the ambient environment. Thus, environmental factors, along with operating conditions, vintage, design, and configuration all contribute to switch degradation. Critical degradation processes include corrosion, moisture ingress, and ice formation. A combination of these factors that may result in permanent damage to major components such as contacts, blades, bearings, drives and support insulators.

Generally, the following represent key end-of-life factors for disconnect switches:

- Decreasing reliability, availability, and maintainability
- High maintenance and operating costs
- Maintenance overhaul requirements
- Obsolete design, lack of parts and service support

Application criticality and manufacturer also play key roles in determining the end-of-life for disconnect switches. Generally, widespread deterioration of live components, support insulators, motor-operators, and drive linkages define the end-of-life for these switches. However, routine maintenance programs usually provide ample opportunity to assess switch condition and viability.

Disconnect switches have components fabricated from dissimilar materials, and use of these different materials influences degradation. For example, blade, hinge and jaw contacts may consist of combinations of copper, aluminum, silver and stainless steel, several of which have tin, silver and chrome plating. Further switch bases may consist of galvanized steel or aluminum.

Most disconnect switches have porcelain support and rotating insulators. The porcelain offers rigidity, strength and dielectric characteristics needed for reliability. However, excessive deflection or deformation of support or rotating stack insulators can cause blade misalignment and other problems, resulting in operational failures.

Disconnect switches must have the ability to open and close properly even with heavy ice build-up on their blades and contacts. However, these switches may sit idle for several months or more. This infrequent operation may lead to corrosion and water ingress damage, increasing the potential for component seizures. Bearings commonly seize from poor lubrication and sealing, despite manufacturers' claims that such components are sealed, greaseless and maintenance-free for life.

Normally, when blades enter or leave jaw contacts, they rotate to clean accumulated ice from contact surfaces. To accomplish this, hinge ends have rotating or other current transfer contacts. These contacts are often simple, long-life copper braids. However, some switches have more complex rotating contacts in grease-filled chambers. Without proper maintenance these more complex switches may degrade, causing blade failures.

18.3 Useful Life

Based on the Industry Values and Utility Interviews the Useful Life Values, Minimum (MIN UL), Typical (TUL) and Maximum (MAX UL) for Station Switch are displayed in Table 18-1.

Table 18-1 Useful Life Values for Station Switch

ASSET COMPONENTIZATION	USEFUL LIFE		
	MIN UL	TUL	MAX UL
Station Switch	30	50	60

18.3.1 Useful Life Data

This section displays the data used to determine the Useful Life Values for Station Switch. Four of the interviewed utilities gave Minimum, Typical and Maximum Useful Life (MIN UL, TUL and MAX UL) Values for Station Switch (Figure 18-1).

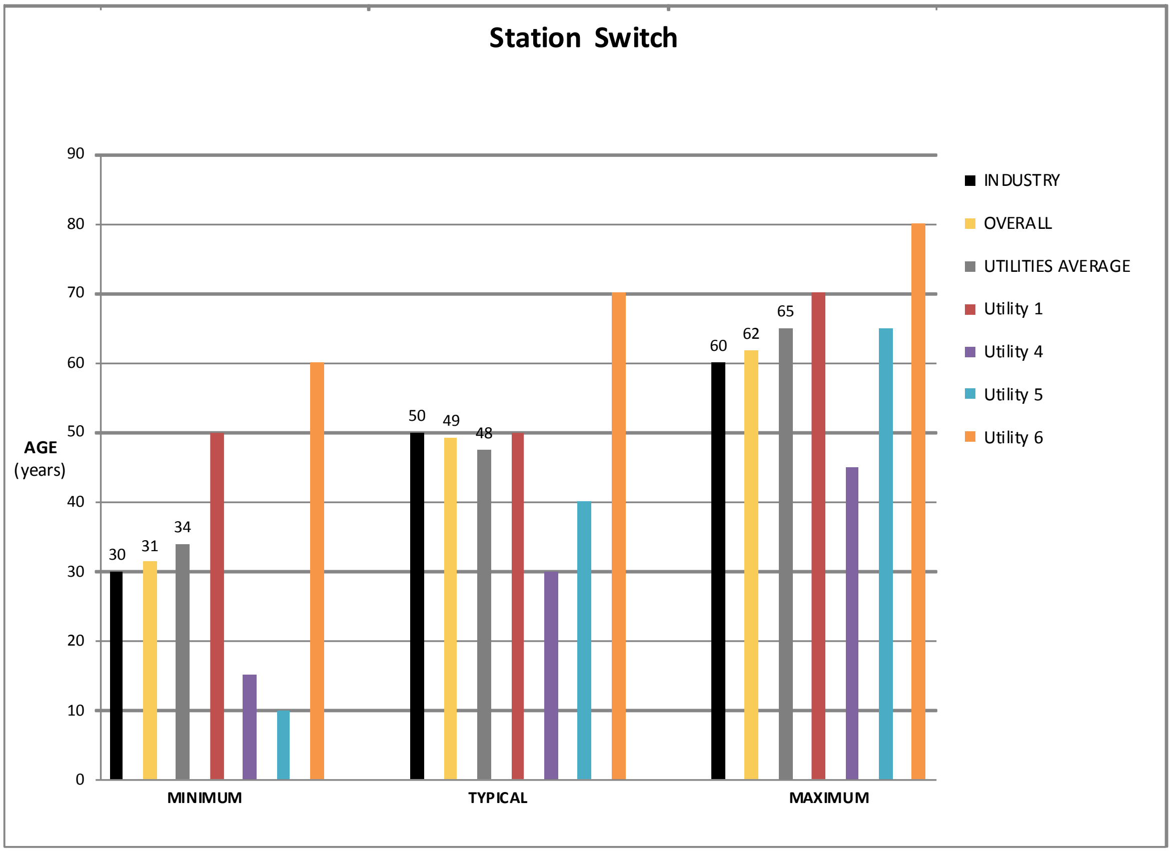


Figure 18-1 Useful Life Values for Station Switch

18.4 Impact of Utilization Factors

Based on the Utility Interviews the composite score and overall impact (high, medium, low), if any, of each factor on the typical useful life of Station Switch are displayed in Table 18-2.

Table 18-2 - Composite Score for Station Switch

	Utilization Factors					
	Mechanical Stress	**Electrical Loading**	**Environmental Factors**	**Operating Practices**	**Maintenance Practices**	**Non-Physical Factors**
Composite Score	47%	38%	72%	47%	53%	19%
Overall Rating*	**M**	**L**	**M**	**M**	**M**	**L**
* H = High Impact	M = Medium Impact	L = Low Impact	NI = No Impact			

18.4.1 Utility Interview Data

This section displays the data used to determine the composite score and overall impact (high, medium, low) of each factor on the typical useful life of Station Switch. Four of the interviewed utilities provided their input regarding the UFs for Station Switch (Figure 18-2).

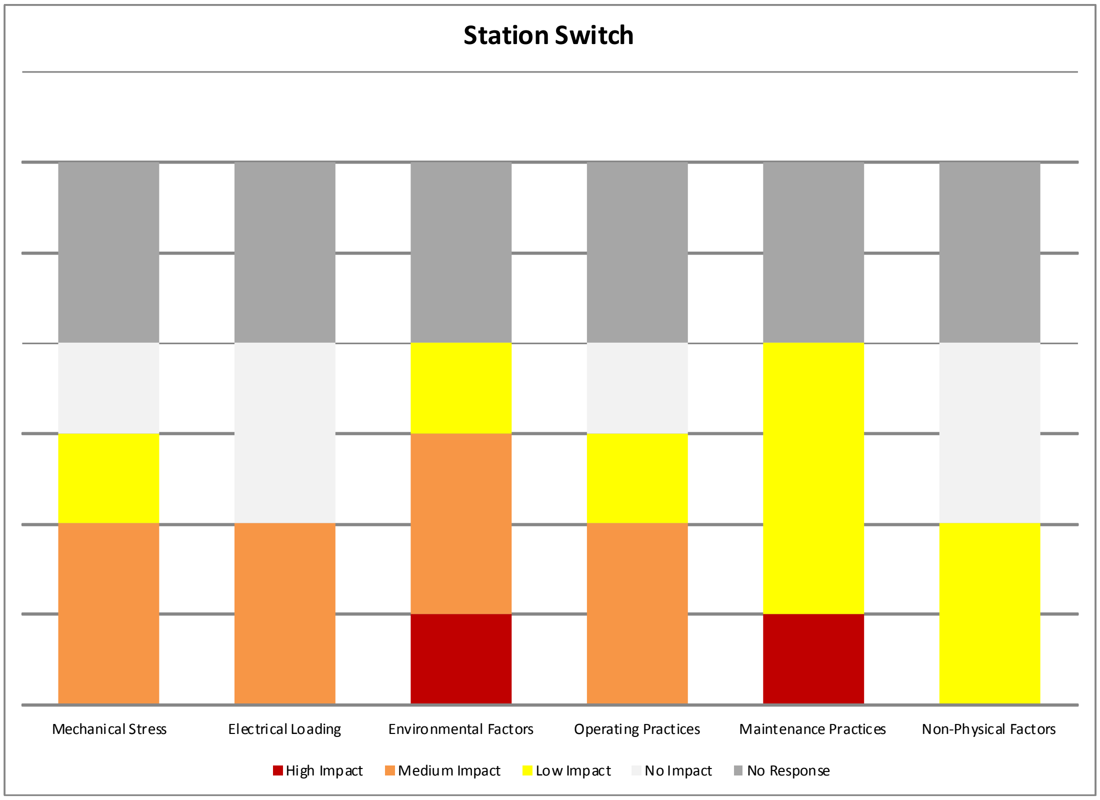


Figure 18-2 Impact of Utilization Factors on the Useful Life of Station Switch

19. Electromechanical Relays

19.1 Asset Description

Protection relays work to detect faults and isolate the system by triggering the opening and closing of the circuit breakers. This asset class includes the older designs of protective relays which had primarily electromechanical mechanisms.

19.1.1 Componentization Assumptions

For the purposes of this report, the Electromechanical Relays has not been componentized.

19.1.2 System Hierarchy

Electromechanical Relays is considered to be a part of the Transformer and Municipal Stations asset grouping.

19.2 Degradation Mechanism

The degradation of electromechanical relays is primarily related to the wear and seizing of the mechanical mechanisms. For instance relay contacts age due to the following factors:

- Contact oxidation
- Contact welding or pitting due to excessive current
- Chemical corrosion

In the case of degradation of relay moving parts, such as wear of moving parts like spring/armature, the major contributing factor is the wear after numerous switching cycles.

Degradation on relay coils is mainly a thermal aging issue due to continuous energization or elevated cabinet temperatures. Excessive heat generated by coil or associated components may cause the coil to burn out or adversely affect other nearby components or components within the relay or nearby (e.g. chemical breakdown of varnishes causing contact contamination, or change in component dimensions).

As a consequence, the failure mode of an electromechanical relay can be:

- Failure to actuate when commanded
- Actuates without command
- Does not make or break current
- Failure to carry current
- High contact resistance
- Set-point shift
- Time delay shift

19.3 Useful Life

Based on the Industry Values and Utility Interviews the Useful Life Values, Minimum (MIN UL), Typical (TUL) and Maximum (MAX UL) for Electromechanical Relays are displayed in Table 19-1.

Table 19-1 Useful Life Values for Electromechanical Relays

ASSET COMPONENTIZATION	USEFUL LIFE		
	MIN UL	TUL	MAX UL
Electromechanical Relays	25	35	50

19.3.1 Useful Life Data

This section displays the data used to determine the Useful Life Values for Electromechanical Relays. Five of the interviewed utilities gave Minimum Useful Life (MAX UL) Values and all six of the utilities interviewed gave TUL and MAX UL Values for Electromechanical Relays (Figure 19-1).

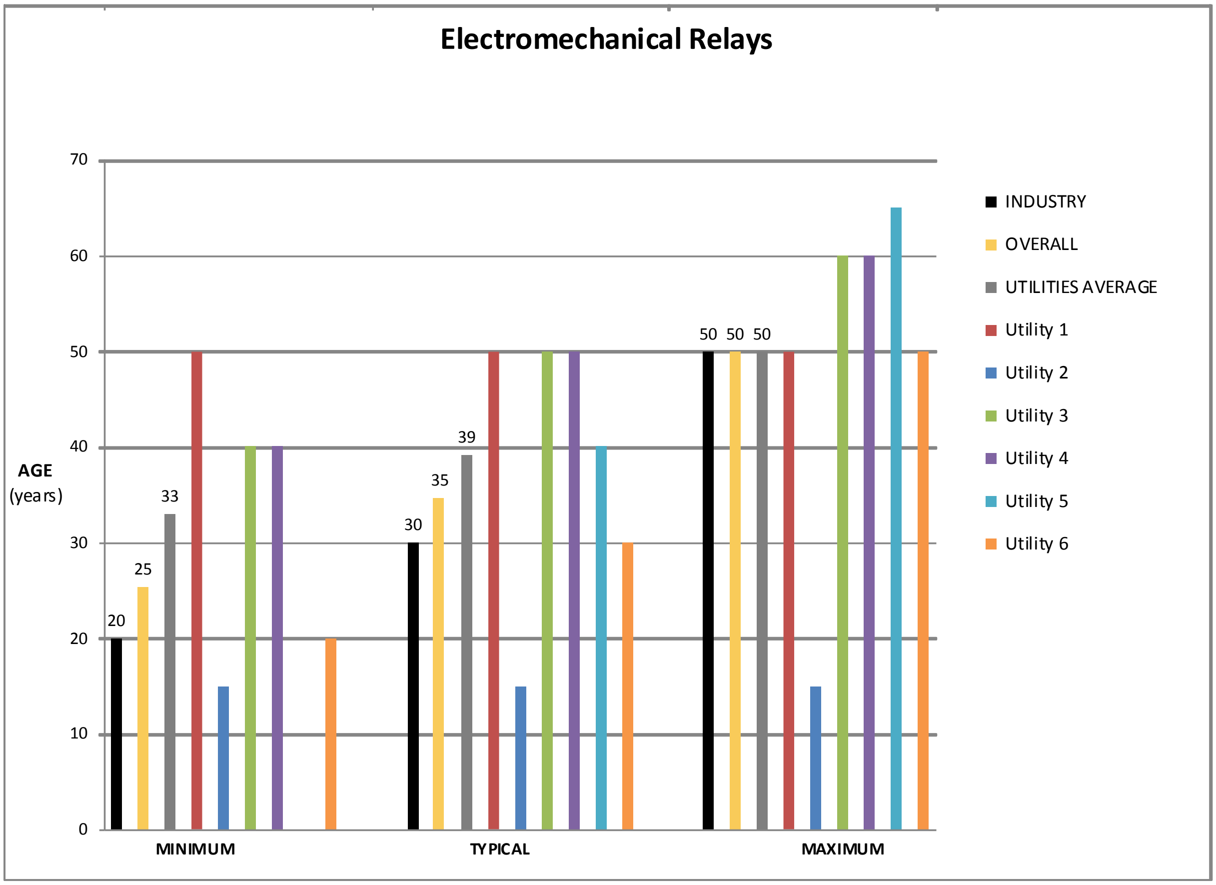


Figure 19-1 Useful Life Values for Electromechanical Relays

19.4 Impact of Utilization Factors

Based on the Utility Interviews the composite score and overall impact (high medium, low), if any, of each factor on the typical useful life of Electromechanical Relays are displayed in Table 19-2.

Table 19-2 - Composite Score for Electromechanical Relays

	Utilization Factors					
	Mechanical Stress	**Electrical Loading**	**Environmental Factors**	**Operating Practices**	**Maintenance Practices**	**Non-Physical Factors**
Composite Score	6%	6%	6%	6%	6%	100%
Overall Rating*	**NI**	**NI**	**NI**	**NI**	**NI**	**H**
* H = High Impact M = Medium Impact L = Low Impact NI = No Impact						

19.4.1 Utility Interview Data

This section displays the data used to determine the composite score and overall impact (high, medium, low) of each factor on the typical useful life of Electromechanical Relays. All six of the interviewed utilities provided their input regarding the UFs for Electromechanical Relays (Figure 19-2).

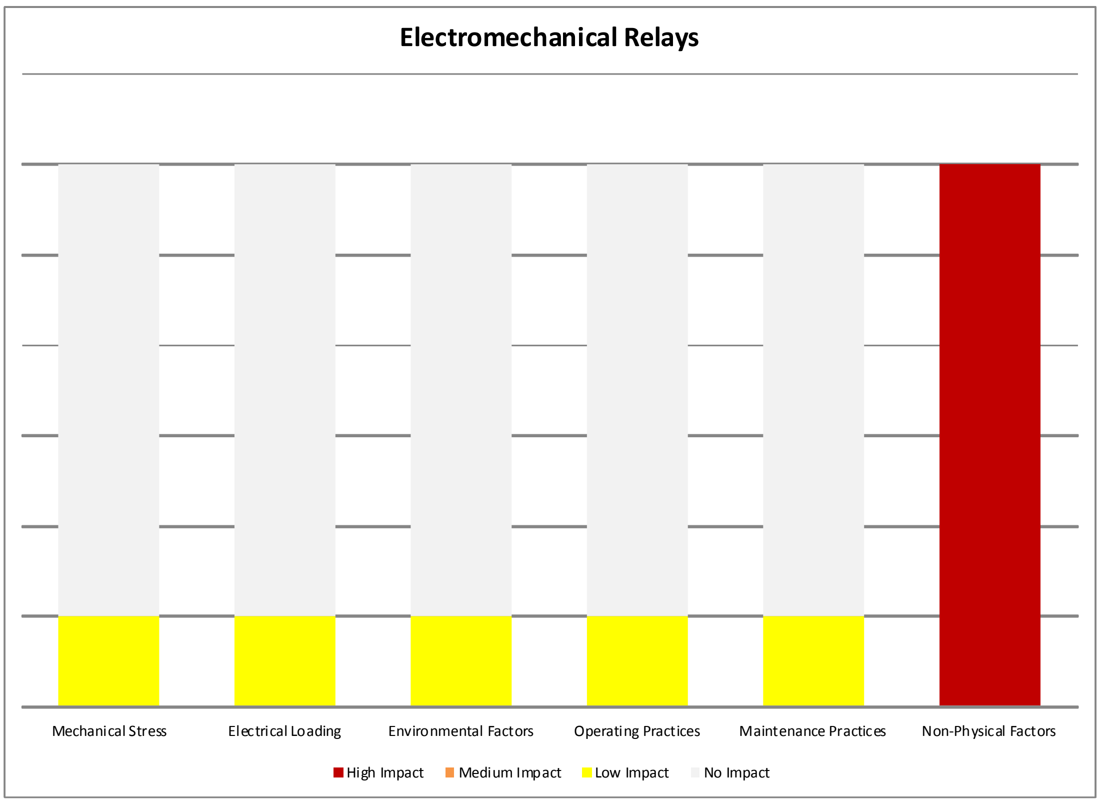


Figure 19-2 Impact of Utilization Factors on the Useful Life of Electromechanical Relays

20. Solid State Relays

20.1 Asset Description

Protection relays work to detect faults and isolate the system by triggering the opening and closing of the circuit breakers. This asset class includes electronic relays that were designed with discrete solid –state components.

20.1.1 Componentization Assumptions

For the purposes of this report, the Solid State Relays has not been componentized.

20.1.2 System Hierarchy

Solid State Relays is considered to be a part of the Transformer and Municipal Stations asset grouping.

20.2 Degradation Mechanism

The degradation of solid state relays is related to the deterioration of contacts and the aging of electronic components. Degradation of relay contacts is due to the following factors:

- Contact oxidation
- Contact welding or pitting due to excessive current
- Chemical corrosion

Degradation on relay coils is mainly a thermal aging issue due to continuous energization or elevated cabinet temperatures. Excessive heat generated by coil or associated components may cause the coil to burn out or adversely affect other nearby components or components within the relay or nearby (e.g. chemical breakdown of varnishes causing contact contamination, or change in component dimensions).

Physical degradation of a solid state relay is particularly sensitive to ambient environmental conditions.

20.3 Useful Life

Based on the Industry Values and Utility Interviews the Useful Life Values, Minimum (MIN UL), Typical (TUL) and Maximum (MAX UL) for Solid State Relays are displayed in Table 20-1.

Table 20-1 Useful Life Values for Solid State Relays

ASSET COMPONENTIZATION	USEFUL LIFE		
	MIN UL	TUL	MAX UL
Solid State Relays	10	30	45

20.3.1 Useful Life Data

This section displays the data used to determine the Useful Life Values for Solid State Relays. Two of the interviewed utilities gave Minimum, Typical and Maximum Useful Life (MIN UL, TUL and MAX UL) Values for Solid State Relays (Figure 20-1).

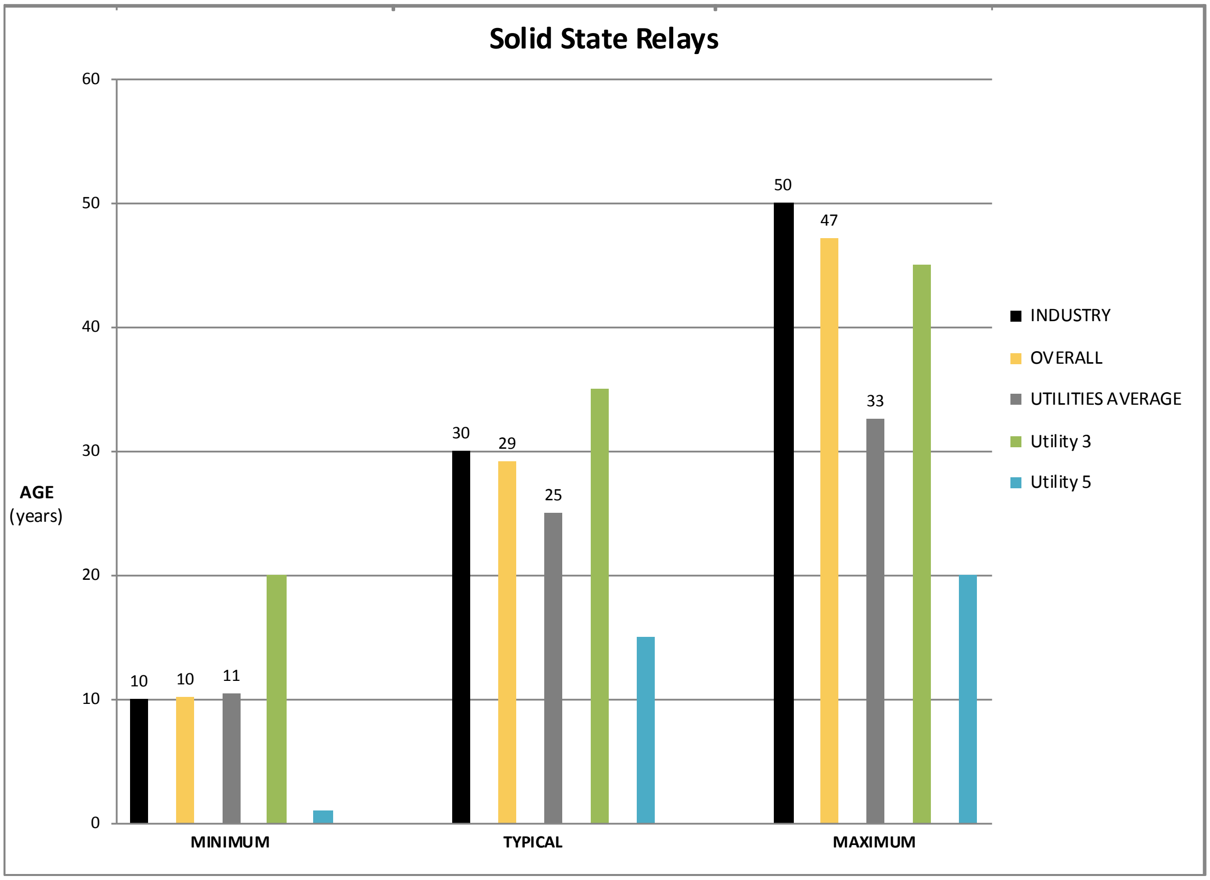


Figure 20-1 Useful Life Values for Solid State Relays

20.4 Impact of Utilization Factors

Based on the Utility Interviews the composite score and overall impact (high, medium, low), if any, of each factor on the typical useful life of Solid State Relays are displayed in Table 20-2.

Table 20-2 - Composite Score for Solid State Relays

	Utilization Factors					
	Mechanical Stress	Electrical Loading	Environmental Factors	Operating Practices	Maintenance Practices	Non-Physical Factors
Composite Score	0%	0%	0%	0%	0%	100%
Overall Rating*	**NI**	**NI**	**NI**	**NI**	**NI**	**H**
* H = High Impact M = Medium Impact L = Low Impact NI = No Impact						

20.4.1 Utility Interview Data

This section displays the data used to determine the composite score and overall impact (high, medium, low) of each factor on the typical useful life of Solid State Relays. Two of the interviewed utilities provided their input regarding the UFs for Solid State Relays (Figure 20-2).

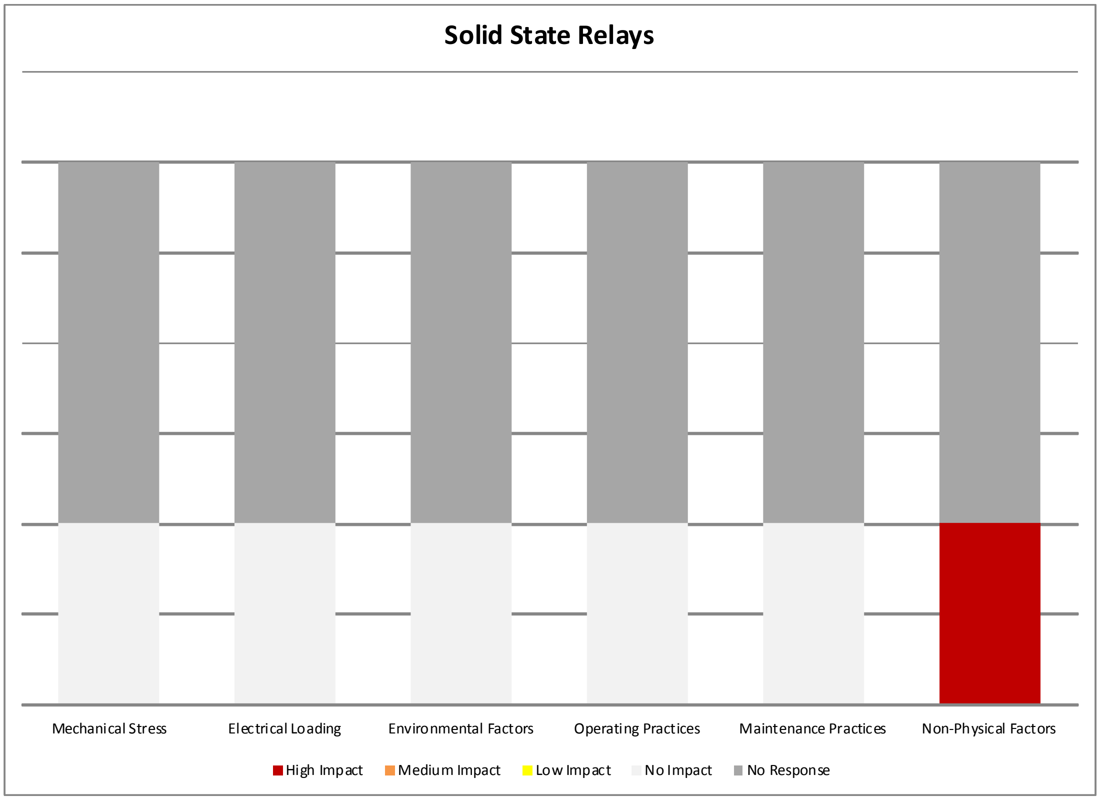


Figure 20-2 Impact of Utilization Factors on the Useful Life of Solid State Relays

21. Digital Microprocessor Relays

21.1 Asset Description

Protection relays work to detect faults and isolate the system by triggering the opening and closing of the circuit breakers. This asset class includes microprocessor based digital relays that have been used in recent years.

21.1.1 Componentization Assumptions

For the purposes of this report, the Digital Microprocessor Relays has not been componentized.

21.1.2 System Hierarchy

Digital Microprocessor Relays is considered to be a part of the Transformer and Municipal Stations asset grouping.

21.2 Degradation Mechanism

The degradation of microprocessor based relays is primarily related to the deterioration of electronic components.

Physical degradation of microprocessor relays is sensitive to ambient environmental conditions.

21.3 Useful Life

Based on the Industry Values and Utility Interviews the Useful Life Values, Minimum (MIN UL), Typical (TUL) and Maximum (MAX UL) for Digital Microprocessor Relays are displayed in Table 21-1.

Table 21-1 Useful Life Values for Digital Microprocessor Relays

ASSET COMPONENTIZATION	USEFUL LIFE		
	MIN UL	TUL	MAX UL
Digital & Numeric Relays	15	20	20

21.3.1 Useful Life Data

This section displays the data used to determine the Useful Life Values for Digital Microprocessor Relays. Three of the interviewed utilities gave Minimum Useful Life (MIN UL) Values and four of the interviewed utilities gave TUL and MAX UL Values for Digital Microprocessor Relays (Figure 21-1).

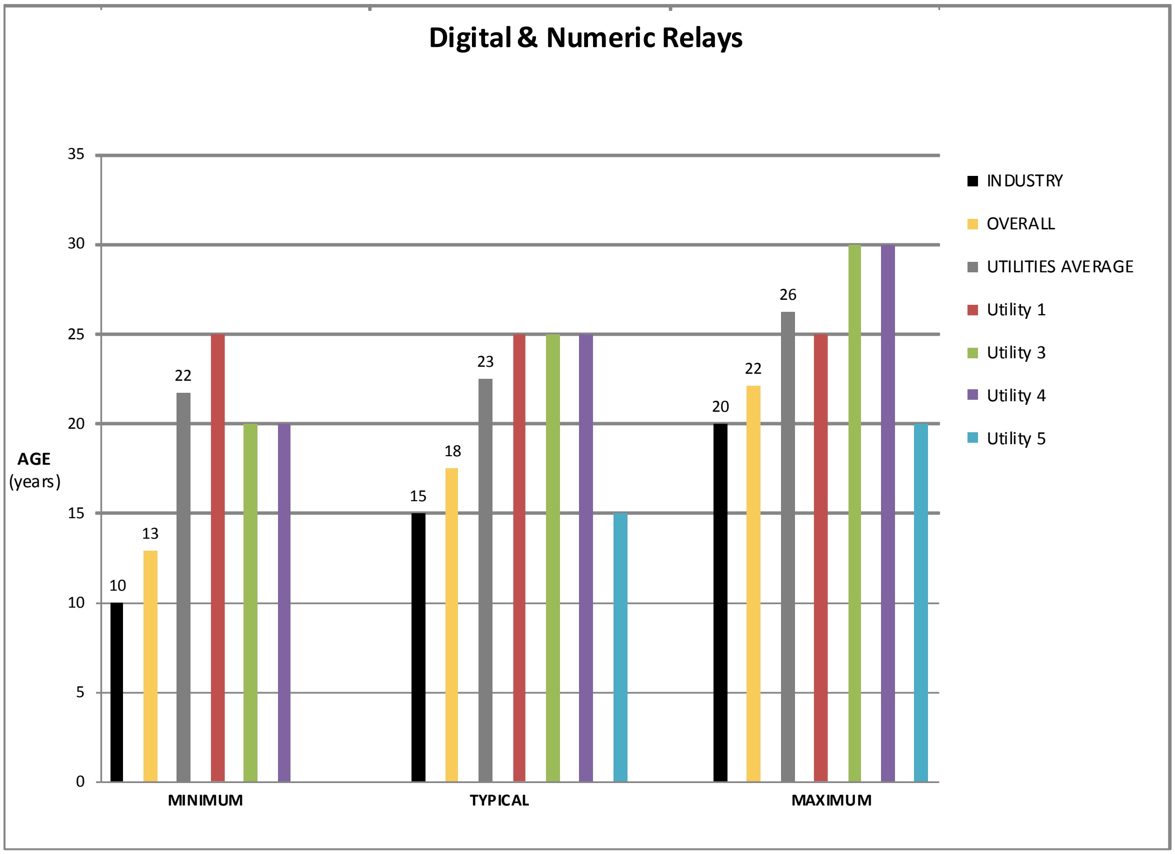


Figure 21-1 Useful Life Values for Digital Microprocessor Relays

21.4 Impact of Utilization Factors

Based on the Utility Interviews the composite score and overall impact (high medium, low), if any, of each factor on the typical useful life of Digital Microprocessor Relays are displayed in Table 21-2.

Table 21-2 - Composite Score for Digital Microprocessor Relays

	Utilization Factors					
	Mechanical Stress	Electrical Loading	Environmental Factors	Operating Practices	Maintenance Practices	Non-Physical Factors
Composite Score	0%	0%	0%	0%	0%	100%
Overall Rating*	**NI**	**NI**	**NI**	**NI**	**NI**	**H**
* H = High Impact	M = Medium Impact		L = Low Impact		NI = No Impact	

21.4.1 Utility Interview Data

This section displays the data used to determine the composite score and overall impact (high, medium, low) of each factor on the typical useful life of Digital Microprocessor Relays. Five of the interviewed utilities provided their input regarding the UFs for Digital Microprocessor Relays (Figure 21-2).

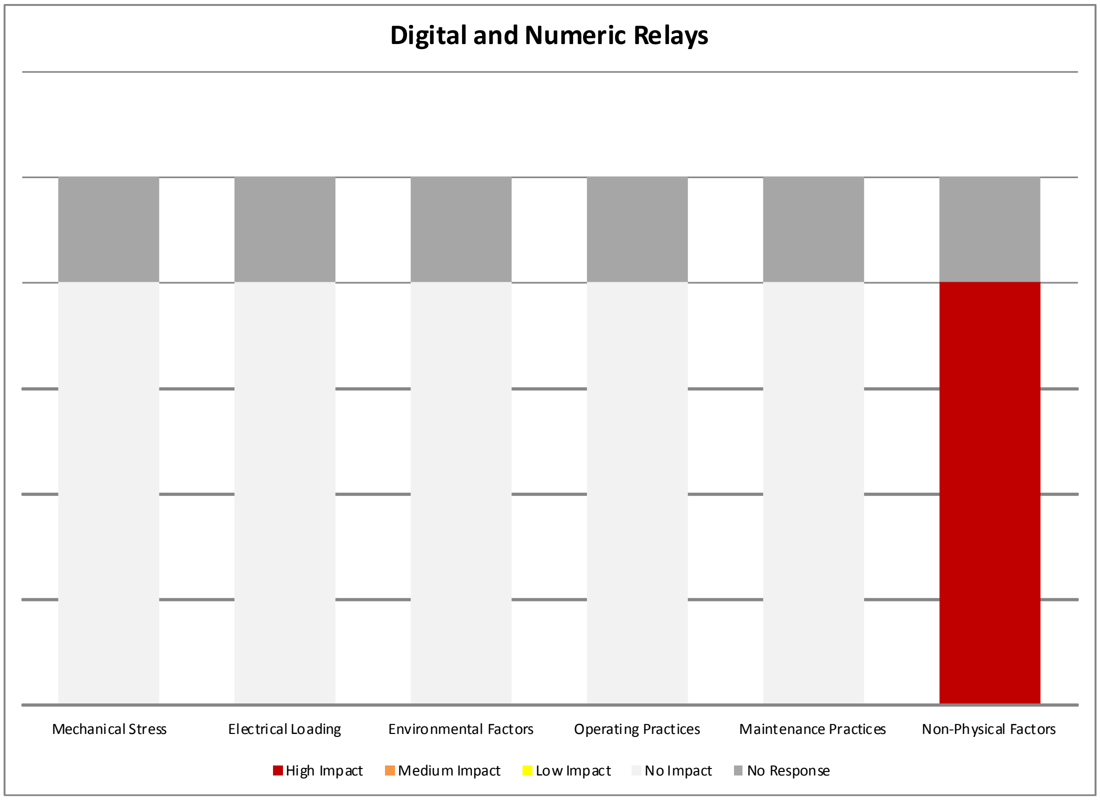


Figure 21-2 Impact of Utilization Factors on the Useful Life of Digital Microprocessor Relays

22. Rigid Busbars

22.1 Asset Description

This asset class includes the current carrying bus in the station. The buses are generally fashioned from aluminum or copper tube or bar.

22.1.1 Componentization Assumptions

For the purposes of this report, the Rigid Busbars has not been componentized.

22.1.2 System Hierarchy

Rigid Busbars is considered to be a part of the Transformer and Municipal Stations asset grouping.

22.2 Degradation Mechanism

Degradation of busbars can result from environmentally induced chemical corrosion, electrical overheating or mechanical damage.

22.3 Useful Life

Based on the Industry Values and Utility Interviews the Useful Life Values, Minimum (MIN UL), Typical (TUL) and Maximum (MAX UL) for Rigid Busbars are displayed in Table 22-1.

Table 22-1 Useful Life Values for Rigid Busbars

ASSET COMPONENTIZATION	USEFUL LIFE		
	MIN UL	TUL	MAX UL
Rigid Busbars	30	55	60

22.3.1 Useful Life Data

This section displays the data used to determine the Useful Life Values for Rigid Busbars. Three of the interviewed utilities gave Minimum Useful Life (MIN UL) Values and four of the interviewed utilities gave TUL and MAX UL Values for Rigid Busbars (Figure 22-1).

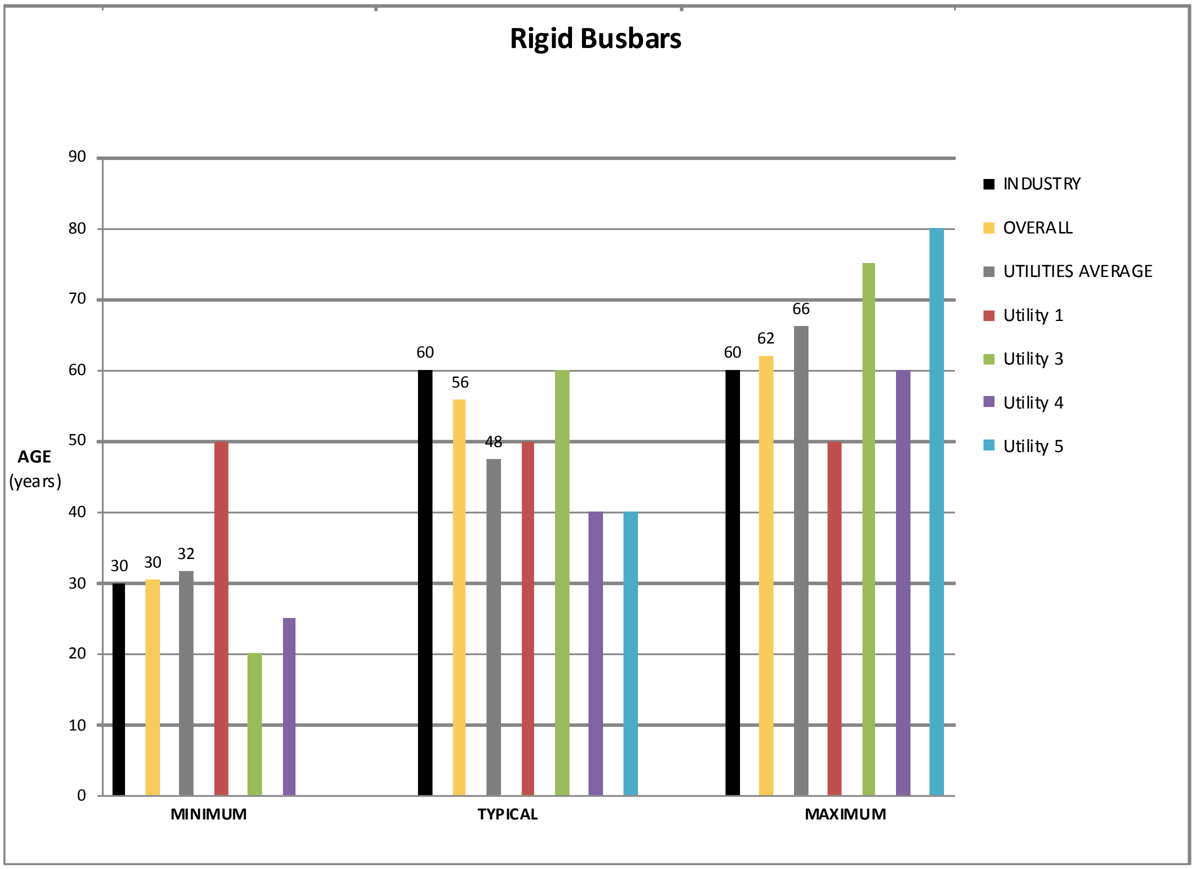


Figure 22-1 Useful Life Values for Rigid Busbars

22.4 Impact of Utilization Factors

Based on the Utility Interviews the composite score and overall impact (high, medium, low), if any, of each factor on the typical useful life of Rigid Busbars are displayed in Table 22-2.

Table 22-2 - Composite Score for Rigid Busbars

	Utilization Factors					
	Mechanical Stress	**Electrical Loading**	**Environmental Factors**	**Operating Practices**	**Maintenance Practices**	**Non-Physical Factors**
Composite Score	19%	34%	44%	0%	9%	25%
Overall Rating*	**L**	**L**	**L**	**NI**	**NI**	**L**
* H = High Impact	M = Medium Impact		L = Low Impact		NI = No Impact	

22.4.1 Utility Interview Data

This section displays the data used to determine the composite score and overall impact (high, medium, low) of each factor on the typical useful life of Rigid Busbars. Four of the interviewed utilities provided their input regarding the UFs for Rigid Busbars (Figure 22-2).

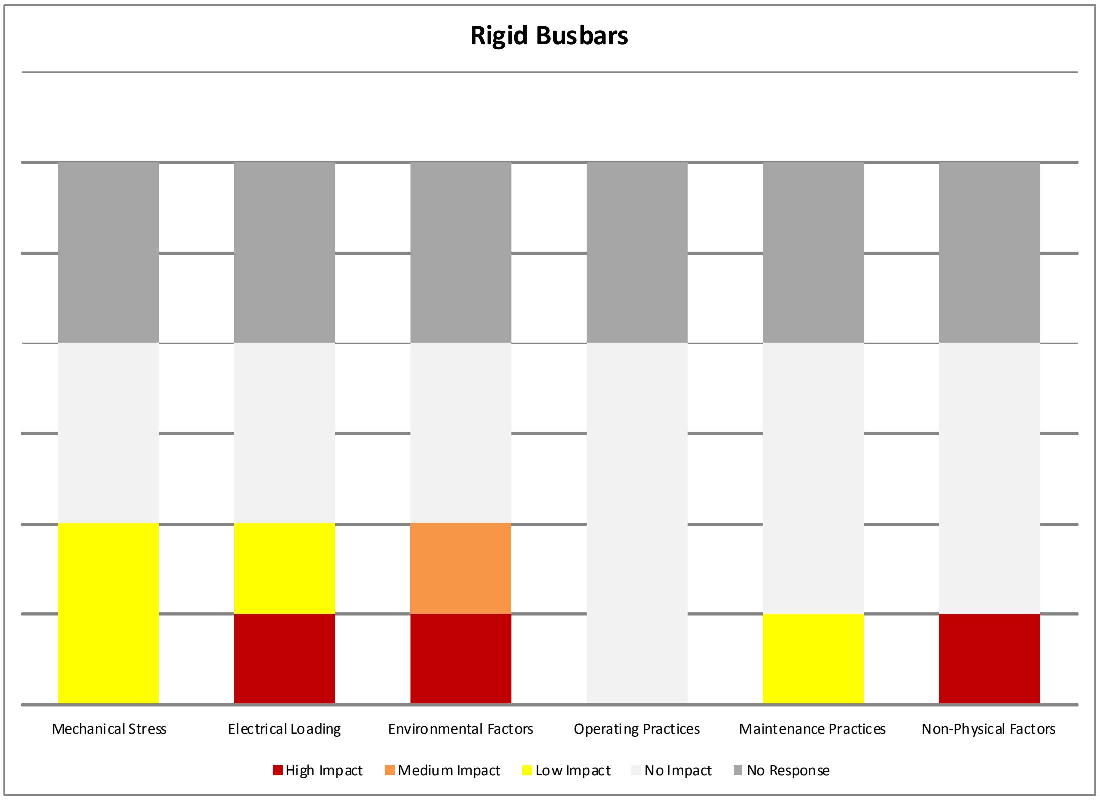


Figure 22-2 Impact of Utilization Factors on the Useful Life of Rigid Busbars

23. Steel Structure

23.1 Asset Description

There are a number of different types of structures at distribution stations for supporting bus and equipment. The predominant types are galvanized steel, either lattice or hollow sections.

23.1.1 Componentization Assumptions

For the purposes of this report, the Steel Structure has not been componentized.

23.1.2 System Hierarchy

Steel Structure is considered to be a part of the Transformer and Municipal Stations asset grouping.

23.2 Degradation Mechanism

Degradation or reduction in strength of steel structures can result from corrosion, structural fatigue, or gradual deterioration of foundation components.

Corrosion of lattice steel members and hardware reduces their cross-sectional area causing a reduction in strength. Similarly, corrosion of tubular steel poles reduces the effectiveness of the tubular walls. Rates of corrosion may vary, depending upon environmental and climatic conditions (e.g., the presence of salt spray in coastal areas or heavy industrial pollution).

Structural fatigue results from repeated structural loading and unloading of support members. Temperature variations, plus wind and ice loadings lead to changes in conductor tension. Tension changes result in structural load variations on angle and dead end towers. Other changes such as foundation displacements and breaks in wires, guys and anchors may result in abnormal tower loading.

Typically, steel pole foundations are cylindrical steel reinforced concrete structures with anchor bolts connecting the pole to its base. Common degradation processes include corrosion of foundation rebar, concrete spalling and storm damage.

23.3 Useful Life

Based on the Industry Values and Utility Interviews the Useful Life Values, Minimum (MIN UL), Typical (TUL) and Maximum (MAX UL) for Steel Structure are displayed in Table 23-1.

Table 23-1 Useful Life Values for Steel Structure

ASSET COMPONENTIZATION	USEFUL LIFE		
	MIN UL	TUL	MAX UL
Steel Structure	35	50	90

23.3.1 Useful Life Data

This section displays the data used to determine the Useful Life Values for Steel Structure. Four of the interviewed utilities gave Minimum Useful Life (MIN UL) Values and five of the interviewed utilities gave TUL and MAX UL Values for Steel Structure (Figure 23-1).

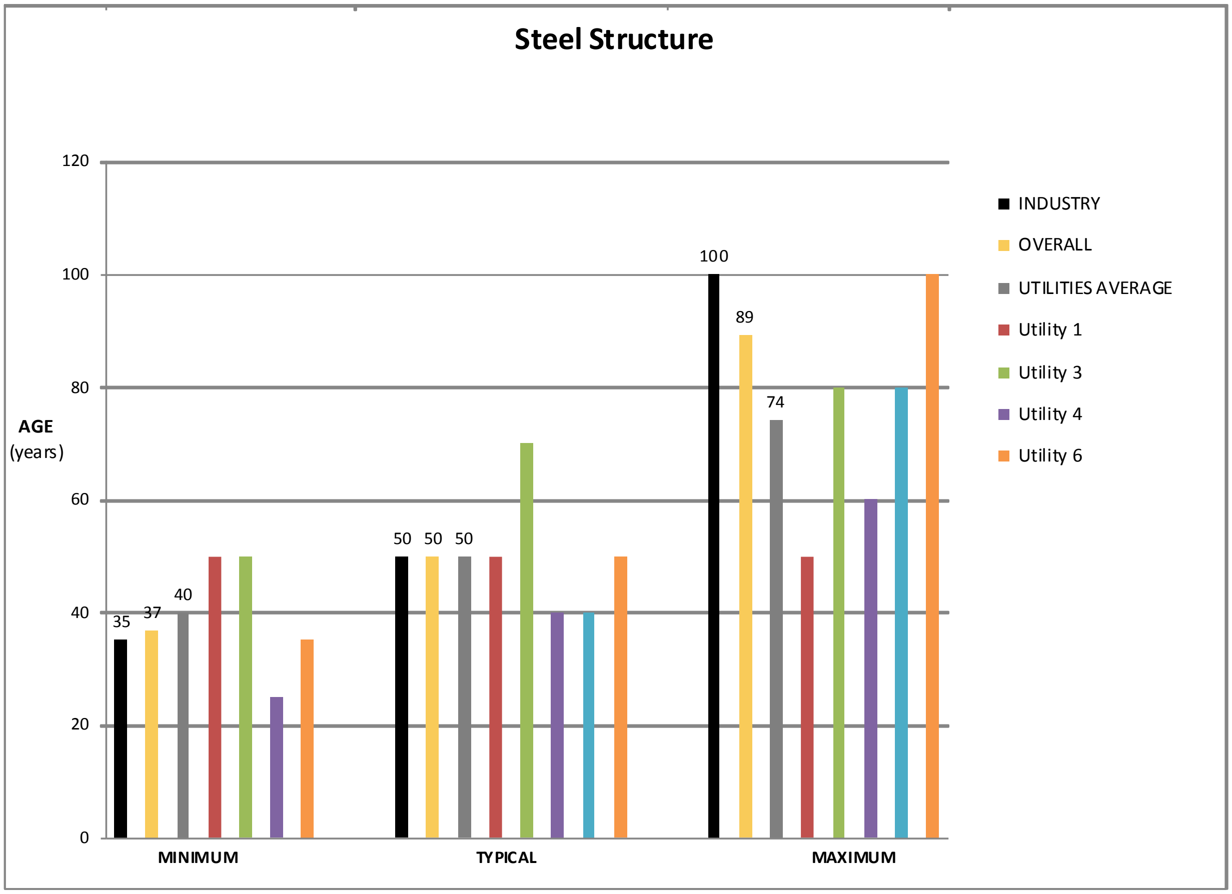


Figure 23-1 Useful Life Values for Steel Structure

23.4 Impact of Utilization Factors

Based on the Utility Interviews the composite score and overall impact (high, medium, low), if any, of each factor on the typical useful life of Steel Structure are displayed in Table 23-2.

Table 23-2 - Composite Score for Steel Structure

	Utilization Factors					
	Mechanical Stress	Electrical Loading	Environmental Factors	Operating Practices	Maintenance Practices	Non-Physical Factors
Composite Score	35%	0%	55%	8%	8%	28%
Overall Rating*	**L**	**NI**	**M**	**NI**	**NI**	**L**
* H = High Impact	M = Medium Impact		L = Low Impact		NI = No Impact	

23.4.1 Utility Interview Data

This section displays the data used to determine the composite score and overall impact (high, medium, low) of each factor on the typical useful life of Steel Structure. Five of the interviewed utilities provided their input regarding the UFs for Steel Structure (Figure 23-2).

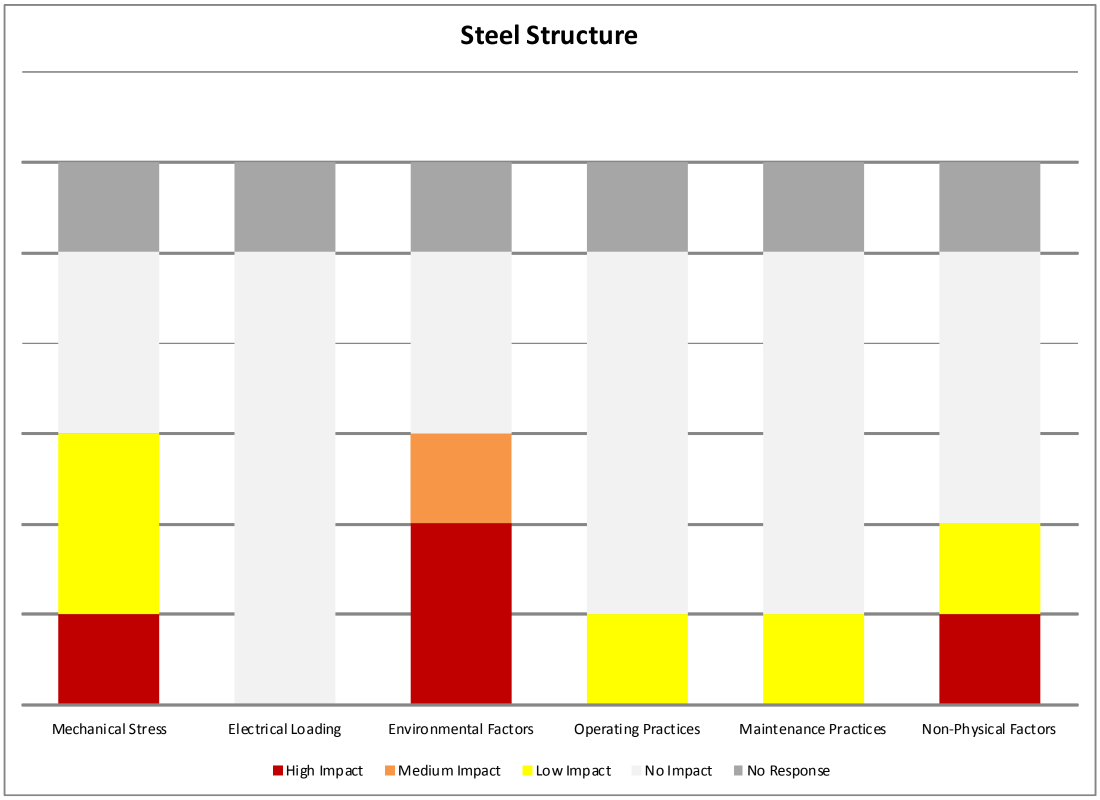


Figure 23-2 Impact of Utilization Factors on the Useful Life of Steel Structure

24. Primary Paper Insulated Lead Covered Cables

24.1 Asset Description

Distribution underground cables are mainly used in urban areas where it is either impossible or extremely difficult to build overhead lines due to aesthetic, legal, environmental and safety reasons. This asset group includes paper insulated lead covered cables.

24.1.1 Componentization Assumptions

For the purposes of this report, the Primary Paper Insulated Lead Covered Cables has not been componentized.

24.1.2 System Hierarchy

Primary Paper Insulated Lead Covered Cables is considered to be a part of the Underground Systems asset grouping.

24.2 Degradation Mechanism

For Paper Insulated Lead Covered (PILC) cables, the two significant long-term degradation processes are corrosion of the lead sheath and dielectric degradation of the oil impregnated paper insulation. Isolated sites of corrosion resulting in moisture penetration or isolated sites of dielectric deterioration resulting in insulation breakdown can result in localized failures. However, if either of these conditions becomes widespread there will be frequent cable failures and the cable can be deemed to be at effective end-of-life.

24.3 Useful Life

Based on the Industry Values and Utility Interviews the Useful Life Values, Minimum (MIN UL), Typical (TUL) and Maximum (MAX UL) for Primary Paper Insulated Lead Covered Cables are displayed in Table 24-1.

Table 24-1 Useful Life Values for Primary Paper Insulated Lead Covered Cables

ASSET COMPONENTIZATION	USEFUL LIFE		
	MIN UL	TUL	MAX UL
Primary Paper Insulated Lead Covered (PILC) Cables	60	65	75

24.3.1 Useful Life Data

This section displays the data used to determine the Useful Life Values for Primary Paper Insulated Lead Covered Cables. Five of the interviewed utilities gave Minimum, Typical and Maximum Useful Life (MIN UL, TUL and MAX UL) Values for Primary Paper Insulated Lead Covered Cables (Figure 24-1).

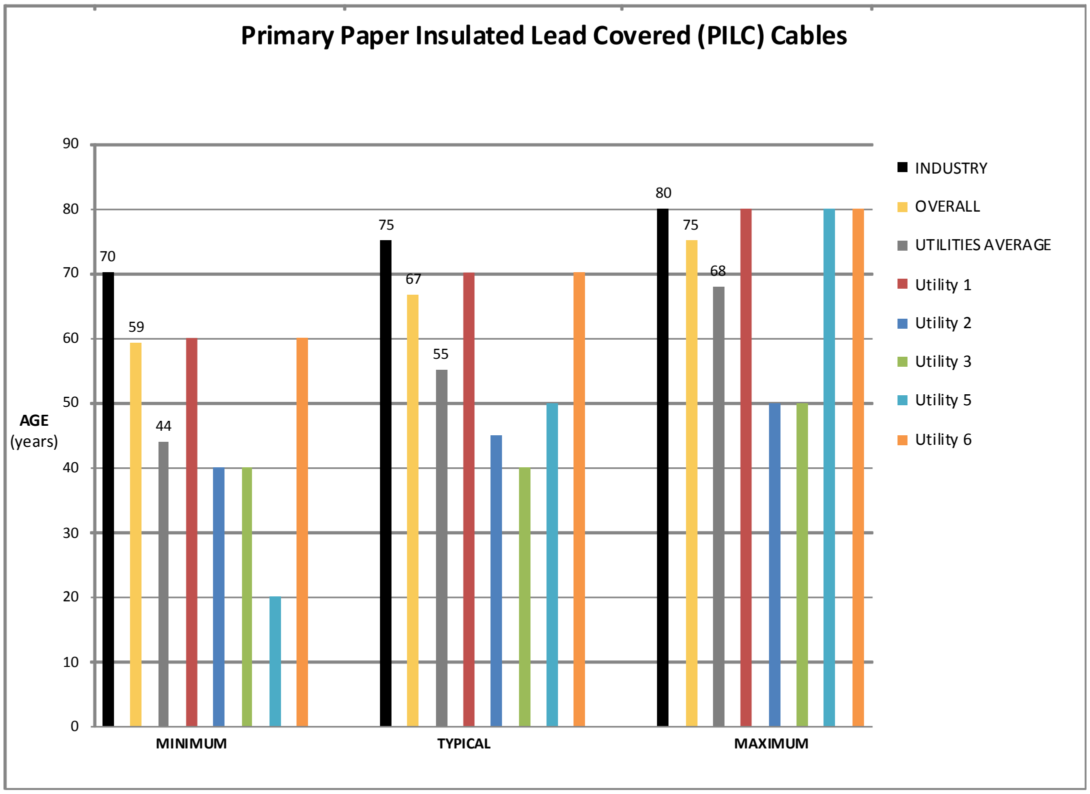


Figure 24-1 Useful Life Values for Primary Paper Insulated Lead Covered Cables

24.4 Impact of Utilization Factors

Based on the Utility Interviews the composite score and overall impact (high medium, low), if any, of each factor on the typical useful life of Primary Paper Insulated Lead Covered Cables are displayed in Table 24-2.

Table 24-2 - Composite Score for Primary Paper Insulated Lead Covered Cables

	Utilization Factors					
	Mechanical Stress	**Electrical Loading**	**Environmental Factors**	**Operating Practices**	**Maintenance Practices**	**Non-Physical Factors**
Composite Score	23%	44%	65%	15%	0%	75%
Overall Rating*	**L**	**L**	**M**	**L**	**NI**	**M**
* H = High Impact	M = Medium Impact	L = Low Impact	NI = No Impact			

24.4.1 Utility Interview Data

This section displays the data used to determine the composite score and overall impact (high, medium, low) of each factor on the typical useful life of Primary Paper Insulated Lead Covered Cables. Five of the interviewed utilities provided their input regarding the UFs for Primary Paper Insulated Lead Covered Cables (Figure 24-2).

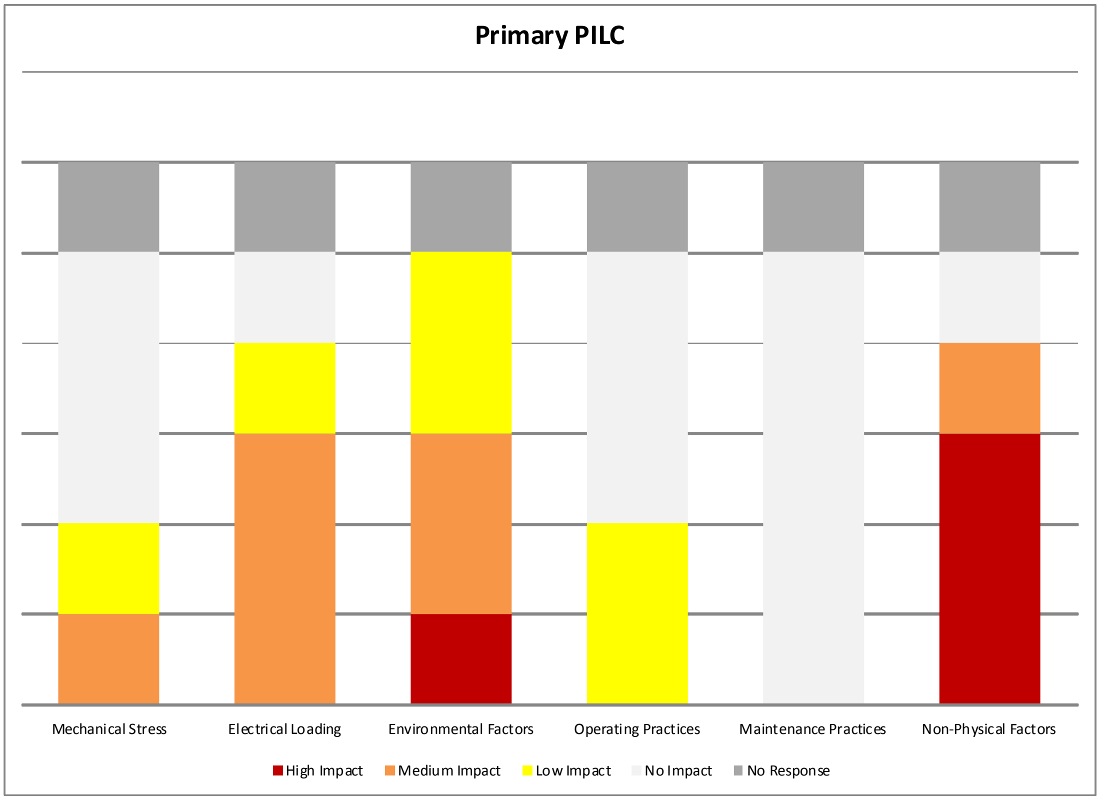


Figure 24-2 Impact of Utilization Factors on the Useful Life of Primary Paper Insulated Lead Covered Cables

25. Primary Ethylene-Propylene Rubber Cables

25.1 Asset Description

Distribution underground cables are mainly used in urban areas where it is either impossible or extremely difficult to build overhead lines due to aesthetic, legal, environmental and safety reasons. This asset group includes ethylene-propylene rubber insulated cables.

25.1.1 Componentization Assumptions

For the purposes of this report, the Primary Ethylene-Propylene Rubber Cables has not been componentized.

25.1.2 System Hierarchy

Primary Ethylene-Propylene Rubber Cables is considered to be a part of the Underground Systems asset grouping.

25.2 Degradation Mechanism

For Ethylene-Propylene Rubber Cables (EPR) cables long term degradation can occur due to mechanical damage, overheating, or the impact of moisture ingress and chemical deterioration.

25.3 Useful Life

Based on the Industry Values and Utility Interviews the Useful Life Values, Minimum (MIN UL), Typical (TUL) and Maximum (MAX UL) for Primary Ethylene-Propylene Rubber Cables are displayed in Table 25-1.

Table 25-1 Useful Life Values for Primary Ethylene-Propylene Rubber Cables

ASSET COMPONENTIZATION	USEFUL LIFE		
	MIN UL	TUL	MAX UL
Primary Ethylene-Propylene Rubber (EPR) Cables	20	25	25

25.3.1 Useful Life Data

This section displays the data used to determine the Useful Life Values for Primary Ethylene-Propylene Rubber Cables. One of the interviewed utilities gave Minimum, Typical and Maximum Useful Life (MIN UL, TUL and MAX UL) Values for Primary Ethylene-Propylene Rubber Cables (Figure 25-1).

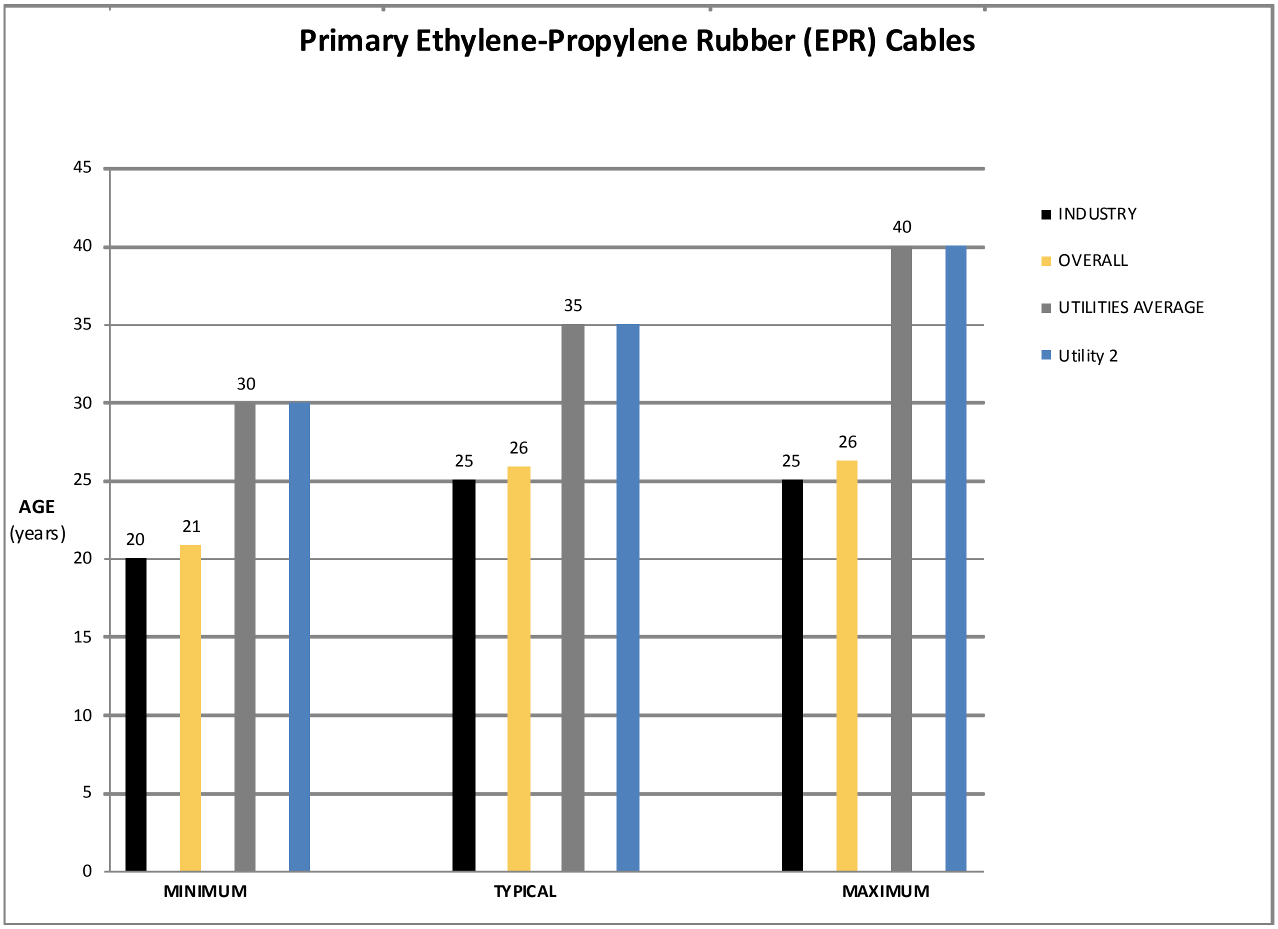


Figure 25-1 Useful Life Values for Primary Ethylene-Propylene Rubber Cables

25.4 Impact of Utilization Factors

Based on the Utility Interviews the composite score and overall impact (high medium, low), if any, of each factor on the typical useful life of Primary Ethylene-Propylene Rubber Cables are displayed in Table 25-2.

Table 25-2 - Composite Score for Primary Ethylene-Propylene Rubber Cables

	Utilization Factors					
	Mechanical Stress	**Electrical Loading**	**Environmental Factors**	**Operating Practices**	**Maintenance Practices**	**Non-Physical Factors**
Composite Score	0%	75%	38%	0%	0%	0%
Overall Rating*	**NI**	**M**	**L**	**NI**	**NI**	**NI**
* H = High Impact M = Medium Impact L = Low Impact NI = No Impact						

25.4.1 Utility Interview Data

This section displays the data used to determine the composite score and overall impact (high, medium, low) of each factor on the typical useful life of Primary Ethylene-Propylene Rubber Cables. One of the interviewed utilities provided their input regarding the UFs for Primary Ethylene-Propylene Rubber Cables (Figure 25-2).

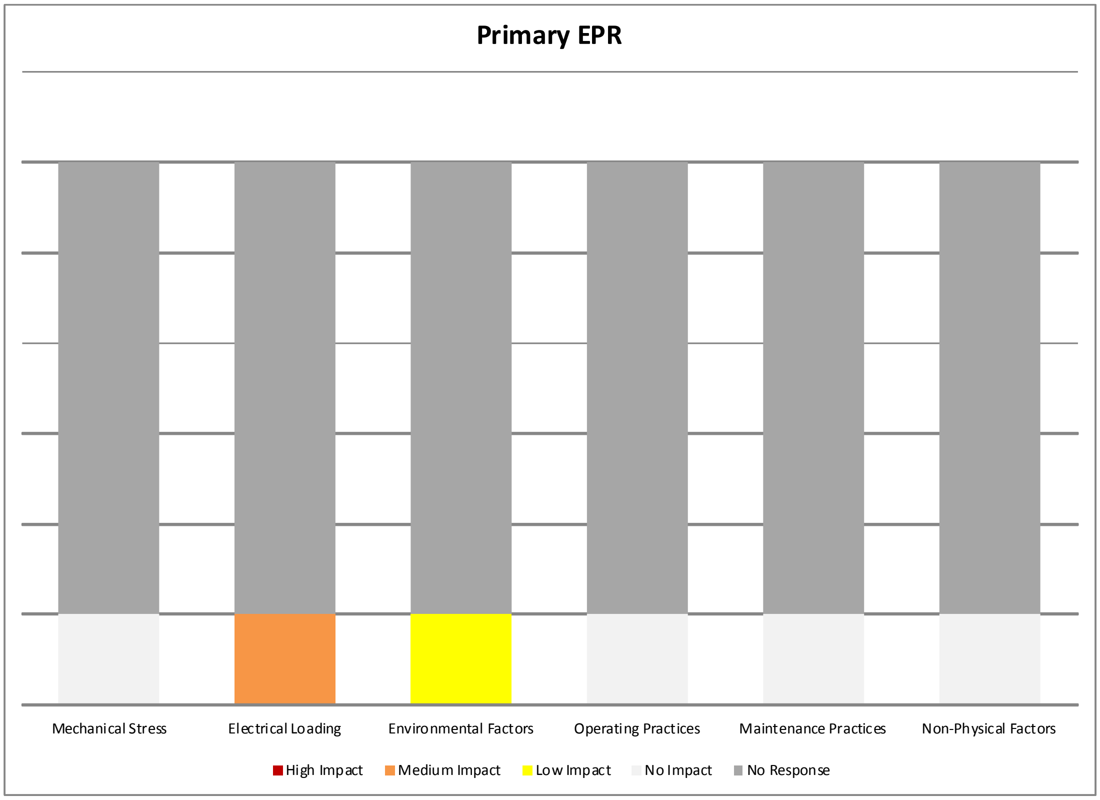


Figure 25-2 Impact of Utilization Factors on the Useful Life of Primary Ethylene-Propylene Rubber Cables

26. Primary Non-Tree Retardant Cross Linked Polyethylene Cables – Direct Buried

26.1 Asset Description

Distribution underground cables are mainly used in urban areas where it is either impossible or extremely difficult to build overhead lines due to aesthetic, legal, environmental and safety reasons. This asset group includes directly buried non-tree retardant cross linked polyethylene insulated cables with copper or aluminum conductor.

26.1.1 Componentization Assumptions

For the purposes of this report, the Primary Non-Tree Retardant Cross Linked Polyethylene Cables – Direct Buried has not been componentized.

26.1.2 System Hierarchy

Primary Non-Tree Retardant Cross Linked Polyethylene Cables – Direct Buried is considered to be a part of the Underground Systems asset grouping.

26.2 Degradation Mechanism

Over the past 30 years XLPE insulated cables have all but replaced paper-insulated cables. These cables can be manufactured by a simple extrusion of the insulation over the conductor and therefore are much more economic to produce. In normal cable lifetime terms XLPE cables are still relatively young. Therefore, failures that have occurred can be classified as early life failures. Certainly in the early days of polymeric insulated cables their reliability was questionable. Many of the problems were associated with joints and accessories or defects introduced in the manufacturing process. Over the past 30 years many of these problems have been addressed and modern XLPE cables and accessories are generally very reliable.

Polymeric insulation is very sensitive to discharge activity. It is therefore very important that the cable, joints and accessories are discharge free when installed. Discharge testing is, therefore, an important factor for these cables. This type of testing is conducted during commissioning and is not typically used for detection of deterioration of the insulation. These commissioning tests are an area of some concern for polymeric cables because the tests themselves are suspected of causing permanent damage and reducing the life of polymeric cables.

26.3 Useful Life

Based on the Industry Values and Utility Interviews the Useful Life Values, Minimum (MIN UL), Typical (TUL) and Maximum (MAX UL) for Primary Non-Tree Retardant Cross Linked Polyethylene Cables – Direct Buried are displayed in Table 26-1.

Table 26-1 Useful Life Values for Primary Non-Tree Retardant Cross Linked Polyethylene Cables – Direct Buried

ASSET COMPONENTIZATION	USEFUL LIFE		
	MIN UL	TUL	MAX UL
Primary Non-Tree Retardant (TR) Cross Linked Polyethylene (XLPE) Cables - Direct Buried	20	25	30

26.3.1 Useful Life Data

This section displays the data used to determine the Useful Life Values for Primary Non-Tree Retardant Cross Linked Polyethylene Cables – Direct Buried. All six of the interviewed utilities gave Minimum, Typical and Maximum Useful Life (MIN UL, TUL and MAX UL) Values for Primary Non-Tree Retardant Cross Linked Polyethylene Cables – Direct Buried (Figure 26-1).

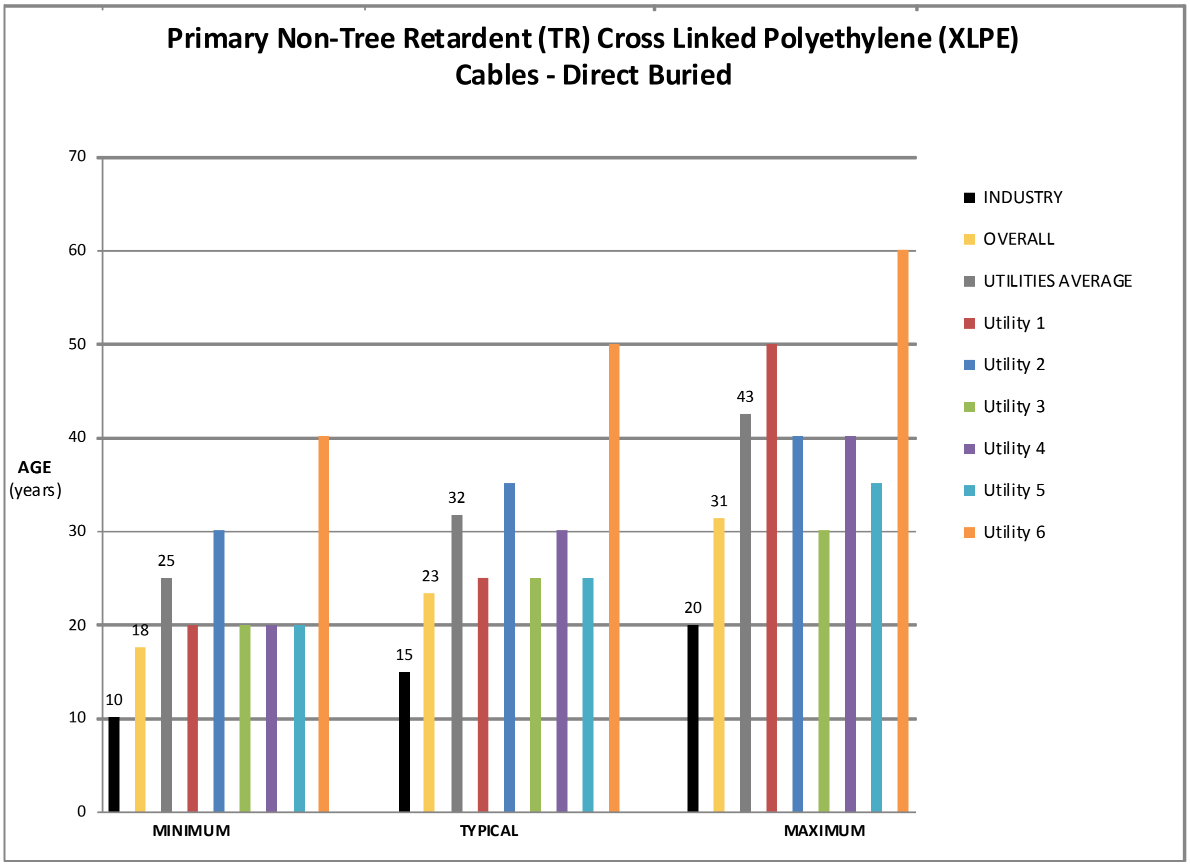


Figure 26-1 Useful Life Values for Primary Non-Tree Retardant Cross Linked Polyethylene Cables – Direct Buried

26.4 Impact of Utilization Factors

Based on the Utility Interviews the composite score and overall impact (high medium, low), if any, of each factor on the typical useful life of Primary Non-Tree Retardant Cross Linked Polyethylene Cables – Direct Buried are displayed in Table 26-2

Table 26-2 - Composite Score for Primary Non-Tree Retardant Cross Linked Polyethylene Cables – Direct Buried

	Utilization Factors					
	Mechanical Stress	**Electrical Loading**	**Environmental Factors**	**Operating Practices**	**Maintenance Practices**	**Non-Physical Factors**
Composite Score	54%	60%	71%	29%	19%	33%
Overall Rating*	**M**	**M**	**M**	**L**	**L**	**L**
* H = High Impact	M = Medium Impact		L = Low Impact		NI = No Impact	

26.4.1 Utility Interview Data

This section displays the data used to determine the composite score and overall impact (high, medium, low) of each factor on the typical useful life of Primary Non-Tree Retardant Cross Linked Polyethylene Cables – Direct Buried. All six of the interviewed utilities provided their input regarding the UFs for Primary Non-Tree Retardant Cross Linked Polyethylene Cables – Direct Buried (Figure 26-2).

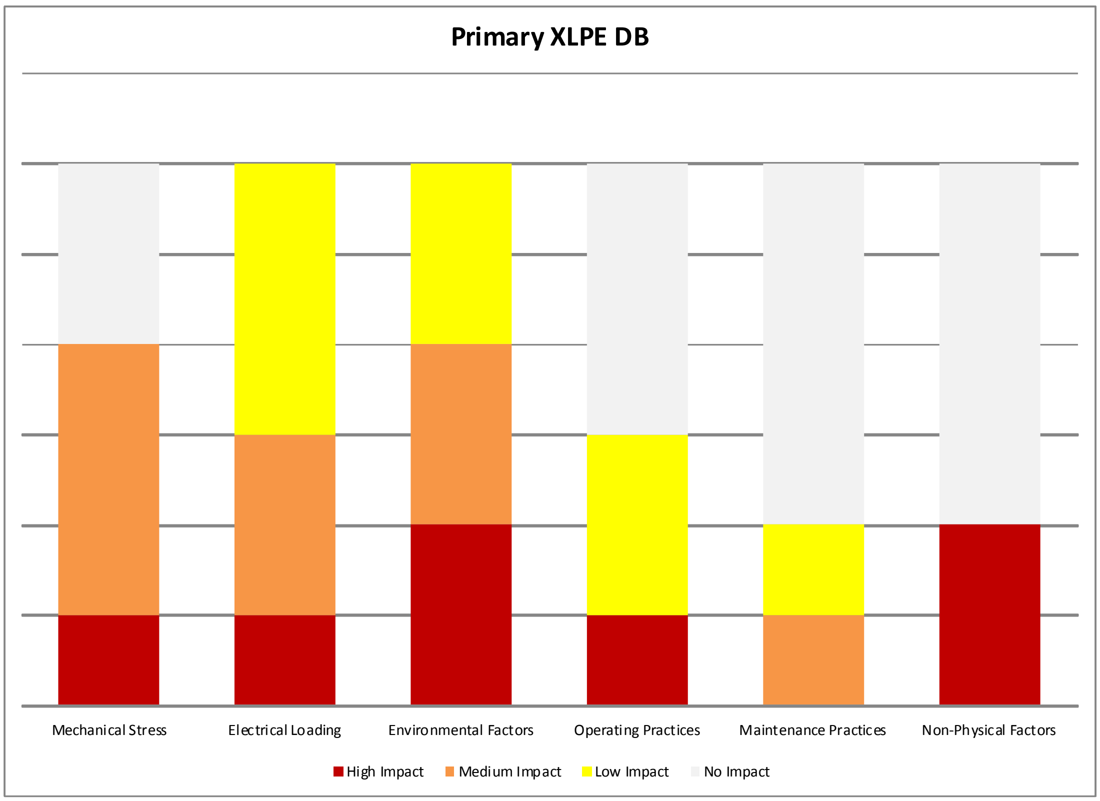


Figure 26-2 Impact of Utilization Factors on the Useful Life of Primary Non-Tree Retardant Cross Linked Polyethylene Cables – Direct Buried

27. Primary Non-Tree Retardant Cross Linked Polyethylene Cables – In Duct

27.1 Asset Description

Distribution underground cables are mainly used in urban areas where it is either impossible or extremely difficult to build overhead lines due to aesthetic, legal, environmental and safety reasons. This asset group includes non-tree retardant cross linked polyethylene insulated cables with copper or aluminum conductor installed in duct.

27.1.1 Componentization Assumptions

For the purposes of this report, the Primary Non-Tree Retardant Cross Linked Polyethylene Cables – In Duct has not been componentized.

27.1.2 System Hierarchy

Primary Non-Tree Retardant Cross Linked Polyethylene Cables – In Duct is considered to be a part of the Underground Systems asset grouping.

27.2 Degradation Mechanism

Over the past 30 years XLPE insulated cables have all but replaced paper-insulated cables. These cables can be manufactured by a simple extrusion of the insulation over the conductor and therefore are much more economic to produce. In normal cable lifetime terms XLPE cables are still relatively young. Therefore, failures that have occurred can be classified as early life failures. Certainly in the early days of polymeric insulated cables their reliability was questionable. Many of the problems were associated with joints and accessories or defects introduced in the manufacturing process. Over the past 30 years many of these problems have been addressed and modern XLPE cables and accessories are generally very reliable.

Polymeric insulation is very sensitive to discharge activity. It is therefore very important that the cable, joints and accessories are discharge free when installed. Discharge testing is, therefore, an important factor for these cables. This type of testing is conducted during commissioning and is not typically used for detection of deterioration of the insulation. These commissioning tests are an area of some concern for polymeric cables because the tests themselves are suspected of causing permanent damage and reducing the life of polymeric cables.

27.3 Useful Life

Based on the Industry Values and Utility Interviews the Useful Life Values, Minimum (MIN UL), Typical (TUL) and Maximum (MAX UL) for Primary Non-Tree Retardant Cross Linked Polyethylene Cables – In Duct are displayed in Table 27-1.

Table 27-1 Useful Life Values for Primary Non-Tree Retardant Cross Linked Polyethylene Cables – In Duct

ASSET COMPONENTIZATION	USEFUL LIFE		
	MIN UL	TUL	MAX UL
Primary Non-TR XLPE Cables - In Duct	20	25	30

27.3.1 Useful Life Data

This section displays the data used to determine the Useful Life Values for Primary Non-Tree Retardant Cross Linked Polyethylene Cables – In Duct. Three of the interviewed utilities gave Minimum, Typical and Maximum Useful Life (MIN UL, TUL and MAX UL) Values for Primary Non-Tree Retardant Cross Linked Polyethylene Cables – In Duct (Figure 27-1).

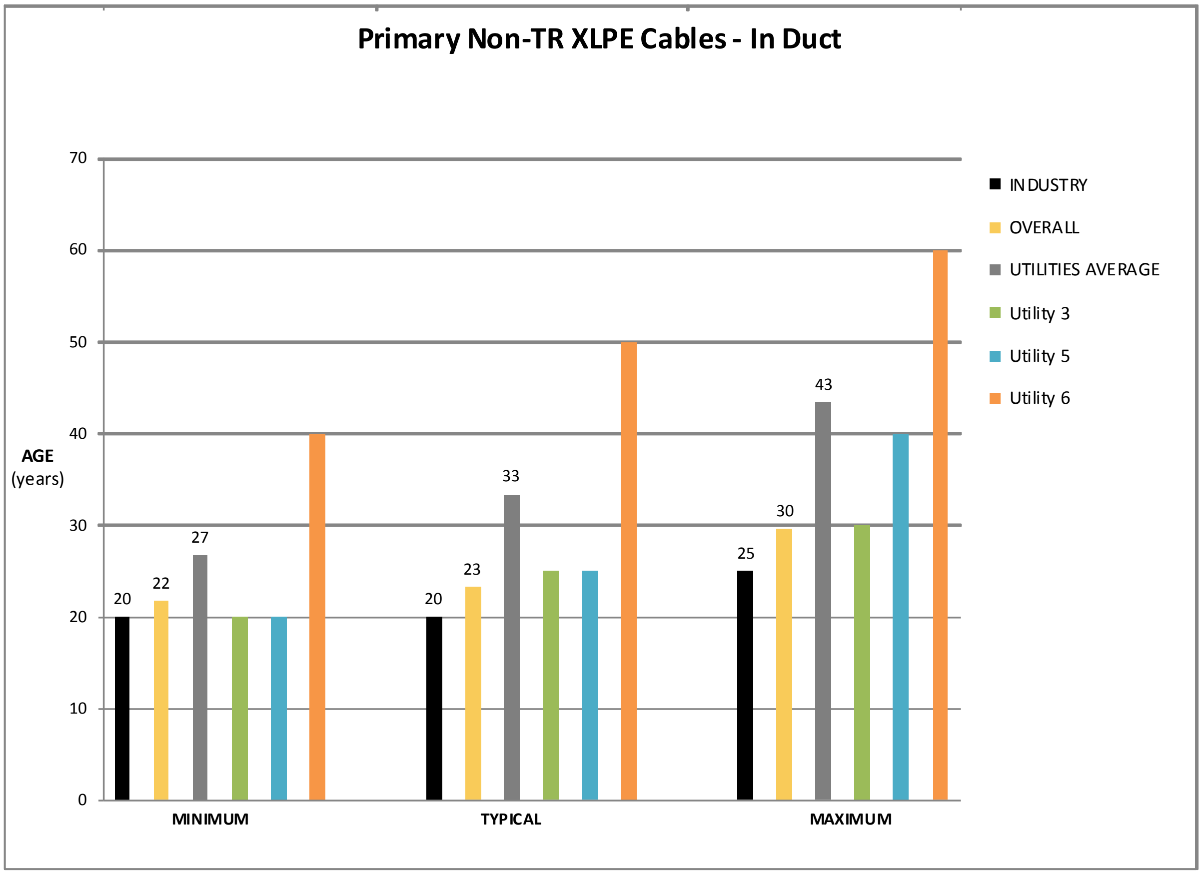


Figure 27-1 Useful Life Values for Primary Non-Tree Retardant Cross Linked Polyethylene Cables – In Duct

27.4 Impact of Utilization Factors

Based on the Utility Interviews the composite score and overall impact (high, medium, low), if any, of each factor on the typical useful life of Primary Non-Tree Retardant Cross Linked Polyethylene Cables – In Duct are displayed in Table 27-2.

Table 27-2 - Composite Score for Primary Non-Tree Retardant Cross Linked Polyethylene Cables – In Duct

	Utilization Factors					
	Mechanical Stress	Electrical Loading	Environmental Factors	Operating Practices	Maintenance Practices	Non-Physical Factors
Composite Score	71%	71%	71%	25%	38%	67%
Overall Rating*	M	M	M	L	L	M

* H = High Impact M = Medium Impact L = Low Impact NI = No Impact

27.4.1 Utility Interview Data

This section displays the data used to determine the composite score and overall impact (high, medium, low) of each factor on the typical useful life of Primary Non-Tree Retardant Cross Linked Polyethylene Cables – In Duct. Three of the interviewed utilities provided their input regarding the UFs for Primary Non-Tree Retardant Cross Linked Polyethylene Cables – In Duct (Figure 27-2).

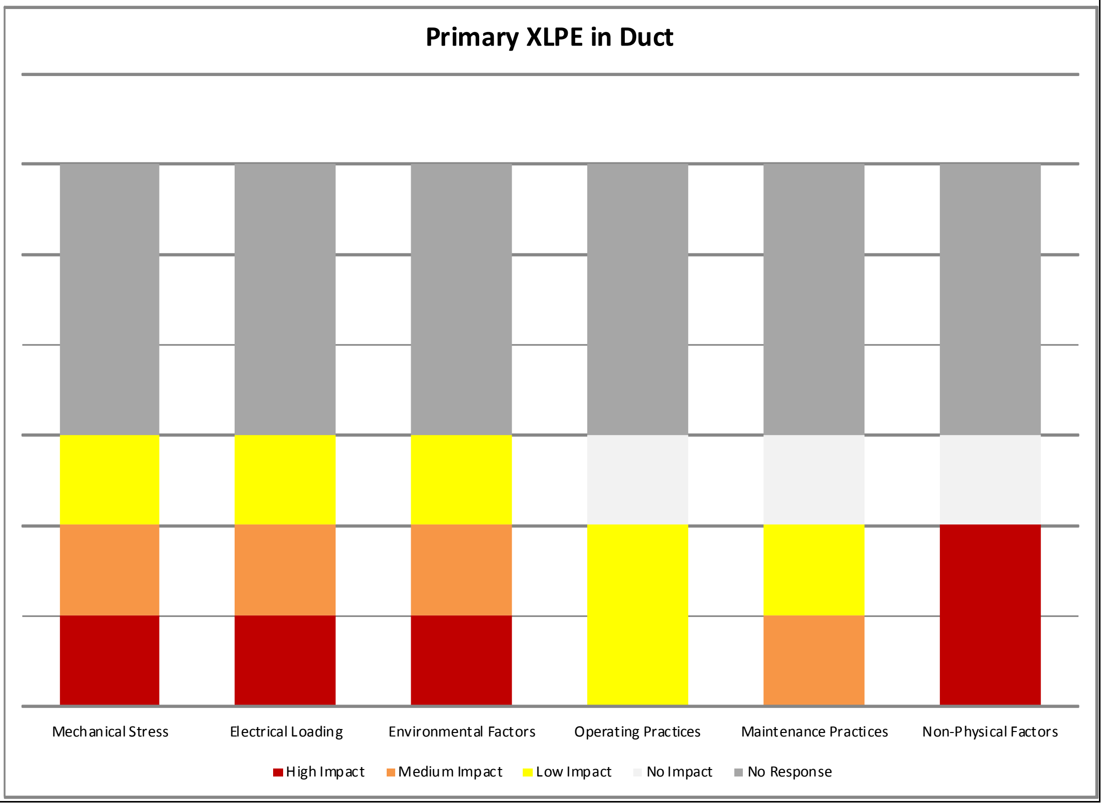


Figure 27-2 Impact of Utilization Factors on the Useful Life of Primary Non-Tree Retardant Cross Linked Polyethylene Cables – In Duct

28. Primary Tree Retardant Cross Linked Polyethylene Cables – Direct Buried

28.1 Asset Description

Distribution underground cables are mainly used in urban areas where it is either impossible or extremely difficult to build overhead lines due to aesthetic, legal, environmental and safety reasons. This asset group includes direct buried tree retardant cross linked polyethylene insulated cables with copper or aluminum conductor.

28.1.1 Componentization Assumptions

For the purposes of this report, the Primary Tree Retardant Cross Linked Polyethylene Cables – Direct Buried has not been componentized.

28.1.2 System Hierarchy

Primary Tree Retardant Cross Linked Polyethylene Cables – Direct Buried is considered to be a part of the Underground Systems asset grouping.

28.2 Degradation Mechanism

Over the past 30 years XLPE insulated cables have all but replaced paper-insulated cables. These cables can be manufactured by a simple extrusion of the insulation over the conductor and therefore are much more economic to produce. In normal cable lifetime terms XLPE cables are still relatively young. Therefore, failures that have occurred can be classified as early life failures. Certainly in the early days of polymeric insulated cables their reliability was questionable. Many of the problems were associated with joints and accessories or defects introduced in the manufacturing process. Over the past 30 years many of these problems have been addressed and modern XLPE cables and accessories are generally very reliable.

Polymeric insulation is very sensitive to discharge activity. It is therefore very important that the cable, joints, splices and terminations are discharge free when installed. Discharge testing is, therefore, an important factor for these cables. This type of testing is conducted during commissioning and is not typically used for detection of deterioration of the insulation. These commissioning tests are an area of some concern for polymeric cables because the tests themselves are suspected of causing permanent damage and reducing the life of polymeric cables.

Water treeing is the most significant degradation process for polymeric cables. The original design of cables with polymeric sheaths allowed water to penetrate and come into contact with the insulation. In the presence of electric fields water migration can result in treeing and ultimately breakdown. The rate of growth of water trees is dependent on the quality of the polymeric insulation and the manufacturing process. Any contamination voids or discontinuities will accelerate degradation. This is assumed to be the reason for poor reliability and relatively short lifetimes of early (non-tree retardant) polymeric cables. As manufacturing processes have improved and tree retardant cables have become the predominant underground cable type, the performance and ultimate life of this type of cable has also improved.

The major degradation problems with the cable terminations concern mostly flashover and tracking associated with the outside and interior surfaces of joints, splices and terminations. . However, there are also problems of overheating at connections and voltage control at the end of the cable shield.

28.3 Useful Life

Based on the Industry Values and Utility Interviews the Useful Life Values, Minimum (MIN UL), Typical (TUL) and Maximum (MAX UL) for Primary Tree Retardant Cross Linked Polyethylene Cables – Direct Buried are displayed in Table 28-1.

Table 28-1 Useful Life Values for Primary Tree Retardant Cross Linked Polyethylene Cables – Direct Buried

ASSET COMPONENTIZATION	USEFUL LIFE		
	MIN UL	TUL	MAX UL
Primary TR XLPE Cables - Direct Buried	25	30	35

28.3.1 Useful Life Data

This section displays the data used to determine the Useful Life Values for Primary Tree Retardant Cross Linked Polyethylene Cables – Direct Buried. Five of the interviewed utilities gave Minimum, Typical and Maximum Useful Life (MIN UL, TUL and MAX UL) Values for Primary Tree Retardant Cross Linked Polyethylene Cables – Direct Buried (Figure 28-1).

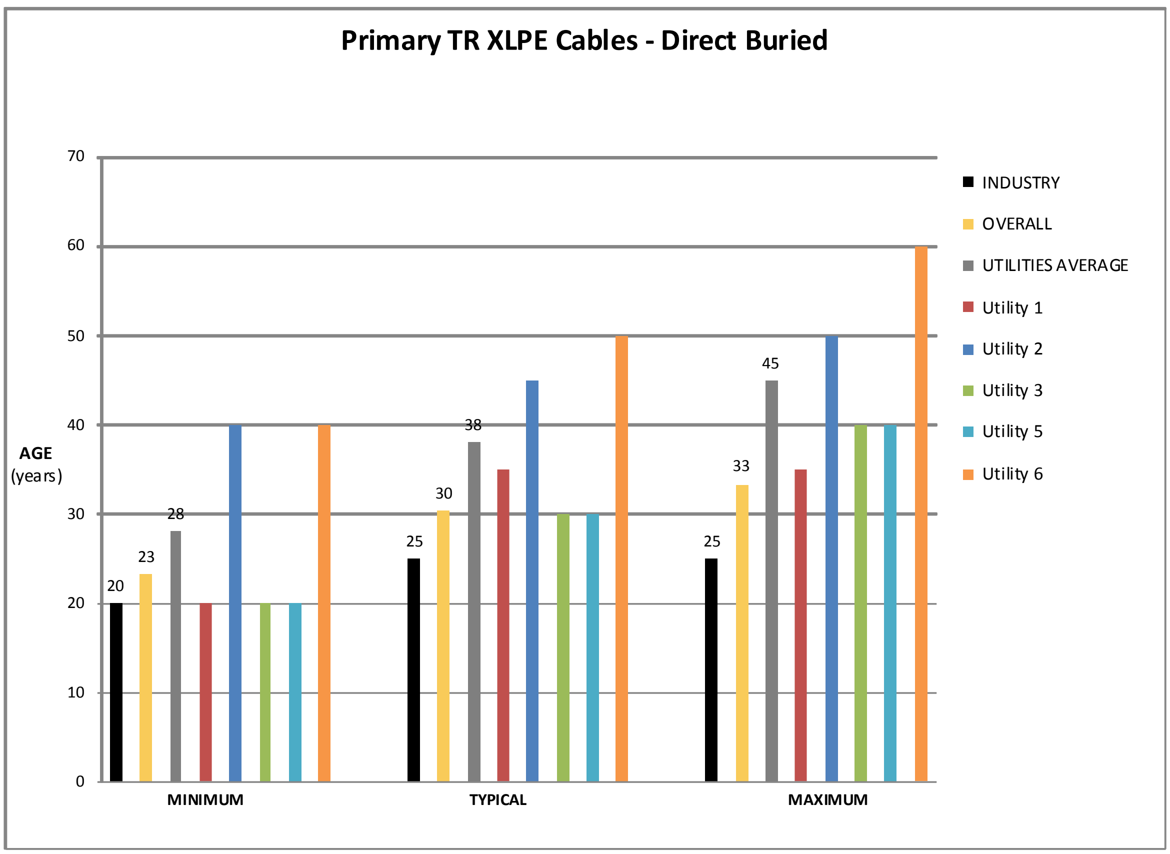


Figure 28-1 Useful Life Values for Primary Tree Retardant Cross Linked Polyethylene Cables – Direct Buried

28.4 Impact of Utilization Factors

Based on the Utility Interviews the composite score and overall impact (high, medium, low), if any, of each factor on the typical useful life of Primary Tree Retardant Cross Linked Polyethylene Cables – Direct Buried are displayed in Table 28-2.

Table 28-2 - Composite Score for Primary Tree Retardant Cross Linked Polyethylene Cables – Direct Buried

	Utilization Factors					
	Mechanical Stress	Electrical Loading	Environmental Factors	Operating Practices	Maintenance Practices	Non-Physical Factors
Composite Score	50%	60%	70%	15%	15%	15%
Overall Rating*	M	M	M	L	L	L
* H = High Impact M = Medium Impact L = Low Impact NI = No Impact						

28.4.1 Utility Interview Data

This section displays the data used to determine the composite score and overall impact (high, medium, low) of each factor on the typical useful life of Primary Tree Retardant Cross Linked Polyethylene Cables – Direct Buried. Five of the interviewed utilities provided their input regarding the UFs for Primary Tree Retardant Cross Linked Polyethylene Cables – Direct Buried (Figure 28-2).

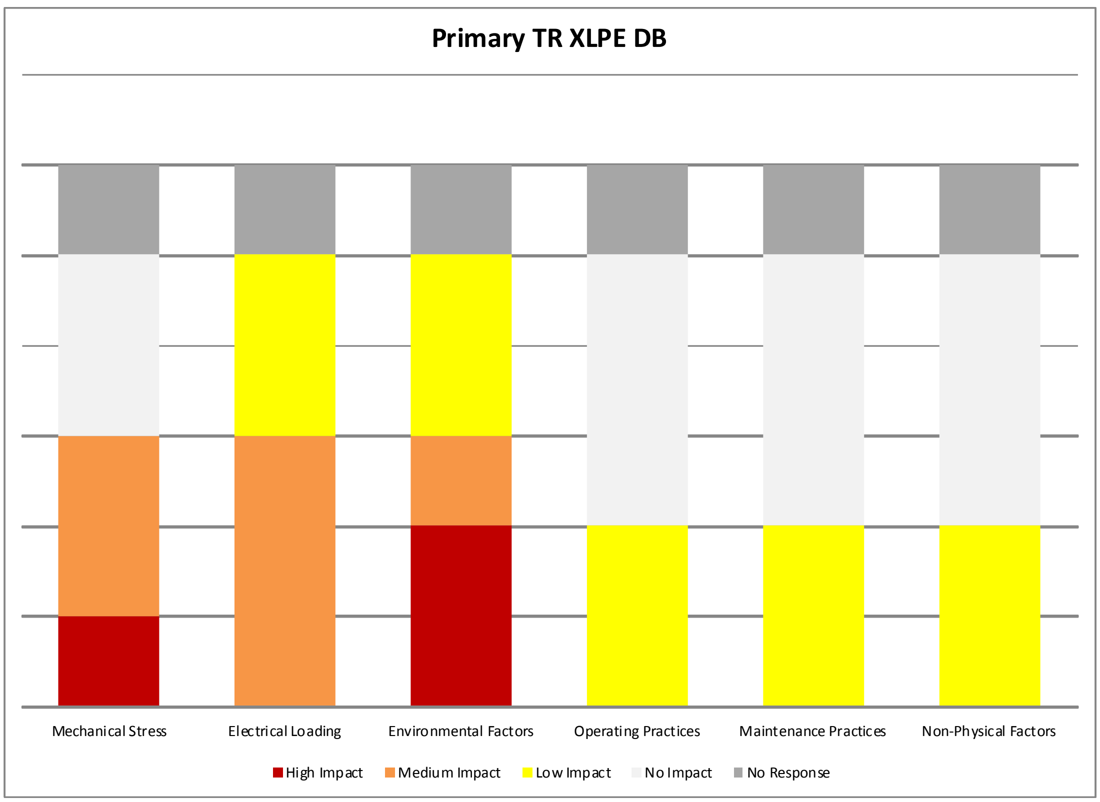


Figure 28-2 Impact of Utilization Factors on the Useful Life of Primary Tree Retardant Cross Linked Polyethylene Cables – Direct Buried

29. Primary Tree Retardant Cross Linked Polyethylene Cables – In Duct

29.1 Asset Description

Distribution underground cables are mainly used in urban areas where it is either impossible or extremely difficult to build overhead lines due to aesthetic, legal, environmental and safety reasons. This asset group includes tree retardant cross linked polyethylene insulated cables with copper or aluminum conductor installed in duct.

29.1.1 Componentization Assumptions

For the purposes of this report, the Primary Tree Retardant Cross Linked Polyethylene Cables – In Duct has not been componentized.

29.1.2 System Hierarchy

Primary Tree Retardant Cross Linked Polyethylene Cables – In Duct is considered to be a part of the Underground Systems asset grouping.

29.2 Degradation Mechanism

Over the past 30 years XLPE insulated cables have all but replaced paper-insulated cables. These cables can be manufactured by a simple extrusion of the insulation over the conductor and therefore are much more economic to produce. In normal cable lifetime terms XLPE cables are still relatively young. Therefore, failures that have occurred can be classified as early life failures. Certainly in the early days of polymeric insulated cables their reliability was questionable. Many of the problems were associated with joints and accessories or defects introduced in the manufacturing process. Over the past 30 years many of these problems have been addressed and modern XLPE cables and accessories are generally very reliable.

Polymeric insulation is very sensitive to discharge activity. It is therefore very important that the cable, joints and accessories are discharge free when installed. Discharge testing is, therefore, an important factor for these cables. This type of testing is conducted during commissioning and is not typically used for detection of deterioration of the insulation. These commissioning tests are an area of some concern for polymeric cables because the tests themselves are suspected of causing permanent damage and reducing the life of polymeric cables.

Water treeing is the most significant degradation process for polymeric cables. The original design of cables with polymeric sheaths allowed water to penetrate and come into contact with the insulation. In the presence of electric fields water migration can result in treeing and ultimately breakdown. The rate of growth of water trees is dependent on the quality of the polymeric insulation and the manufacturing process. Any contamination voids or discontinuities will accelerate degradation. This is assumed to be the reason for poor reliability and relatively short lifetimes of early (non-tree retardant) polymeric cables. As manufacturing processes have improved and tree retardant cables have become the predominant underground cable type, the performance and ultimate life of this type of cable has also improved.

The major degradation problems with the cable terminations concern mostly flashover and tracking associated with the outside and interior surfaces of the accessory. However, there are also problems of overheating at connections and voltage control at the end of the cable shield.

29.3 Useful Life

Based on the Industry Values and Utility Interviews the Useful Life Values, Minimum (MIN UL), Typical (TUL) and Maximum (MAX UL) for Primary Tree Retardant Cross Linked Polyethylene Cables – In Duct are displayed in Table 29-1.

Table 29-1 Useful Life Values for Primary Tree Retardant Cross Linked Polyethylene Cables – In Duct

ASSET COMPONENTIZATION	USEFUL LIFE		
	MIN UL	TUL	MAX UL
Primary TR XLPE Cables - In Duct	35	40	55

29.3.1 Useful Life Data

This section displays the data used to determine the Useful Life Values for Primary Tree Retardant Cross Linked Polyethylene Cables – In Duct. Five of the interviewed utilities gave Minimum, Typical and Maximum Useful Life (MIN UL, TUL and MAX UL) Values for Primary Tree Retardant Cross Linked Polyethylene Cables – In Duct (Figure 29-1).

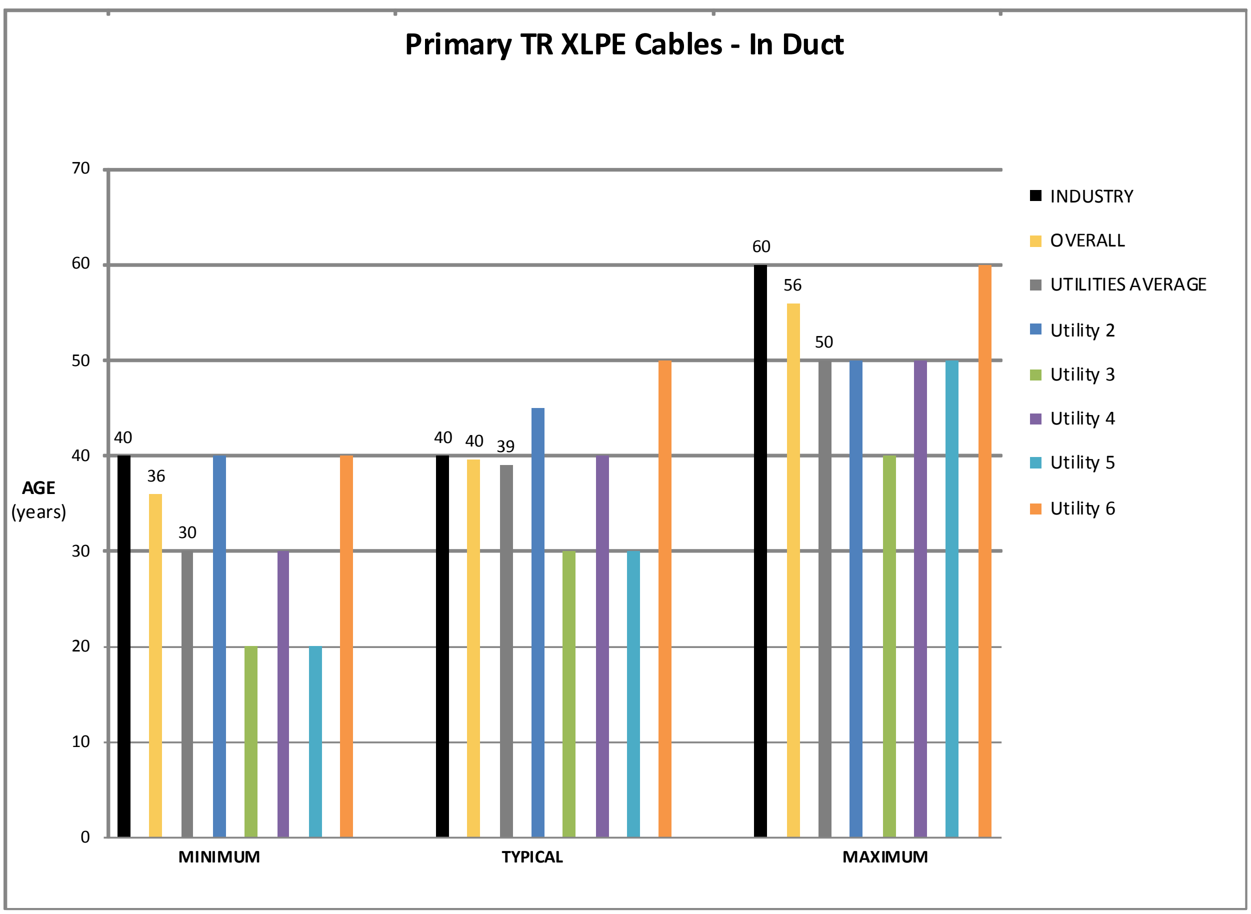


Figure 29-1 Useful Life Values for Primary Tree Retardant Cross Linked Polyethylene Cables – In Duct

29.4 Impact of Utilization Factors

Based on the Utility Interviews the composite score and overall impact (high, medium, low), if any, of each factor on the typical useful life of Primary Tree Retardant Cross Linked Polyethylene Cables – In Duct are displayed in Table 29-2.

Table 29-2 - Composite Score for Primary Tree Retardant Cross Linked Polyethylene Cables – In Duct

	Utilization Factors					
	Mechanical Stress	Electrical Loading	Environmental Factors	Operating Practices	Maintenance Practices	Non-Physical Factors
Composite Score	58%	56%	54%	35%	15%	15%
Overall Rating*	M	M	M	L	L	L
* H = High Impact	M = Medium Impact		L = Low Impact		NI = No Impact	

29.4.1 Utility Interview Data

This section displays the data used to determine the composite score and overall impact (high, medium, low) of each factor on the typical useful life of Primary Tree Retardant Cross Linked Polyethylene Cables – In Duct. All six of the interviewed utilities provided their input regarding the UFs for Primary Tree Retardant Cross Linked Polyethylene Cables – In Duct (Figure 29-2).

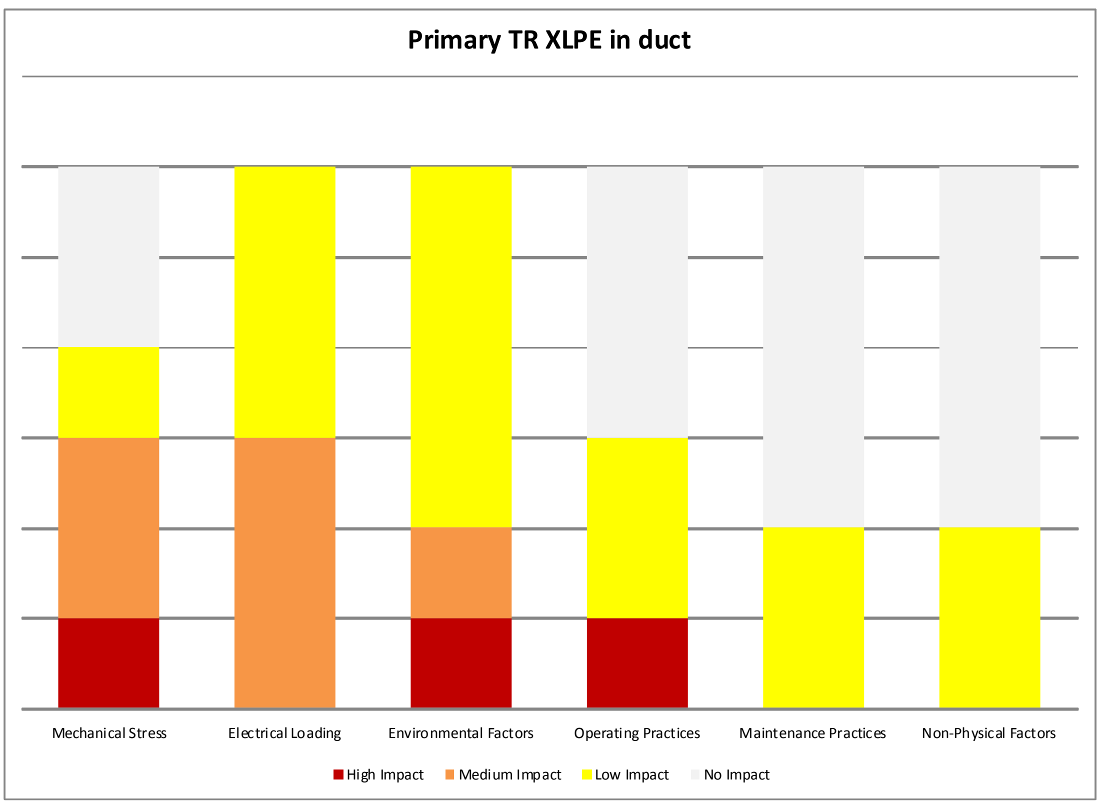


Figure 29-2 Impact of Utilization Factors on the Useful Life of Primary Tree Retardant Cross Linked Polyethylene Cables – In Duct

30. Secondary Paper Insulated Lead Covered Cables

30.1 Asset Description

Distribution underground cables are mainly used in urban areas where it is either impossible or extremely difficult to build overhead lines due to aesthetic, legal, environmental and safety reasons. Secondary underground cables are used to supply customer premises.

30.1.1 Componentization Assumptions

For the purposes of this report, the Secondary Paper Insulated Lead Covered Cables has not been componentized.

30.1.2 System Hierarchy

Secondary Paper Insulated Lead Covered Cables is considered to be a part of the Underground Systems asset grouping.

30.2 Degradation Mechanism

For Paper Insulated Lead Covered (PILC) cables, the two significant long-term degradation processes are corrosion of the lead sheath and dielectric degradation of the oil impregnated paper insulation. Isolated sites of corrosion resulting in moisture penetration or isolated sites of dielectric deterioration resulting in insulation breakdown can result in localized failures. However, if either of these conditions becomes widespread there will be frequent cable failures and the cable can be deemed to be at effective end-of-life.

30.3 Useful Life

Based on the Industry Values and Utility Interviews the Useful Life Values, Minimum (MIN UL), Typical (TUL) and Maximum (MAX UL) for Secondary Paper Insulated Lead Covered Cables are displayed in Table 30-1.

Table 30-1 Useful Life Values for Secondary Paper Insulated Lead Covered Cables

ASSET COMPONENTIZATION	USEFUL LIFE		
	MIN UL	TUL	MAX UL
Secondary PILC Cables	70	75	80

30.3.1 Useful Life Data

This section displays the data used to determine the Useful Life Values for Secondary Paper Insulated Lead Covered Cables. None of the interviewed utilities gave Minimum, Typical and Maximum Useful Life (MIN UL, TUL and MAX UL) Values for Secondary Paper Insulated Lead Covered Cables (Figure 30-1).

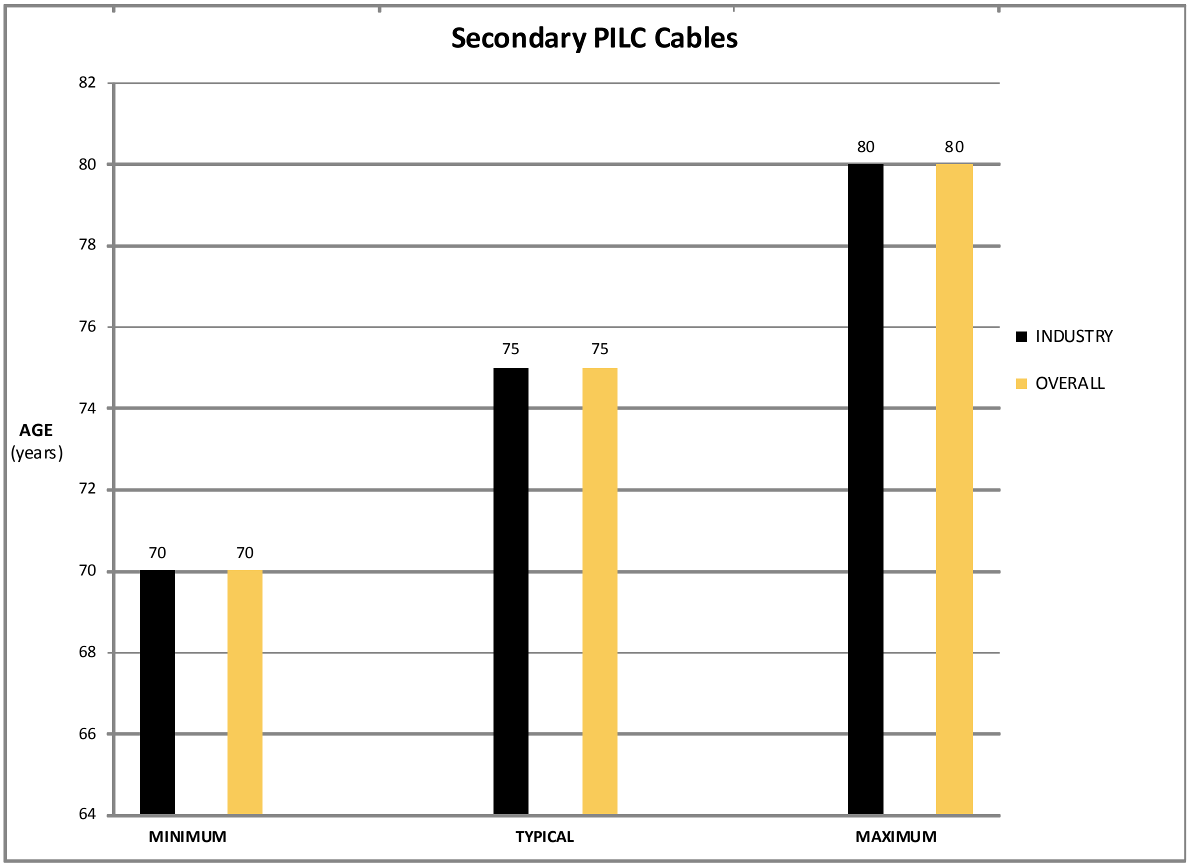


Figure 30-1 Useful Life Values for Secondary Paper Insulated Lead Covered Cables

30.4 Impact of Utilization Factors

Based on the Utility Interviews the composite score and overall impact (high, medium, low), if any, of each factor on the typical useful life of Secondary Paper Insulated Lead Covered Cables are displayed in Table 30-2.

Table 30-2 - Composite Score for Secondary Paper Insulated Lead Covered Cables

	Utilization Factors					
	Mechanical Stress	Electrical Loading	Environmental Factors	Operating Practices	Maintenance Practices	Non-Physical Factors
Composite Score	0%	38%	38%	0%	0%	100%
Overall Rating*	NI	L	L	NI	NI	H

* H = High Impact M = Medium Impact L = Low Impact NI = No Impact

30.4.1 Utility Interview Data

This section displays the data used to determine the composite score and overall impact (high, medium, low) of each factor on the typical useful life of Secondary Paper Insulated Lead Covered Cables. One of the interviewed utilities provided their input regarding the UFs for Secondary Paper Insulated Lead Covered Cables (Figure 30-2).

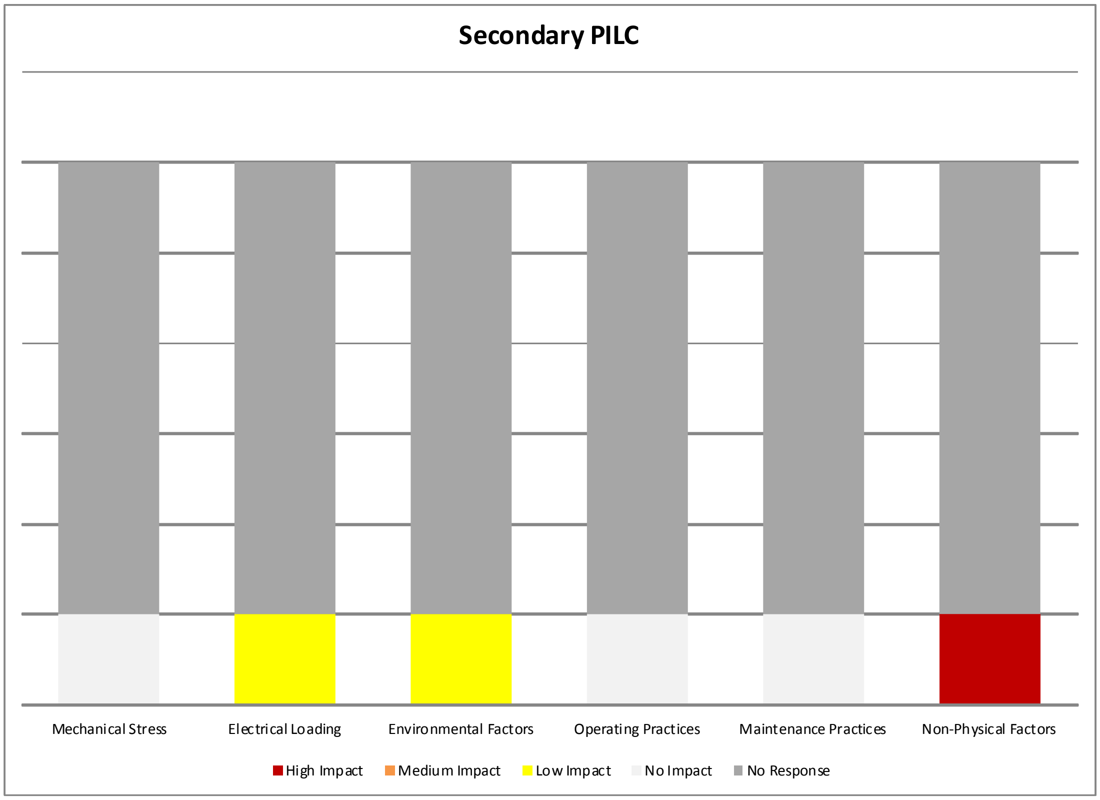


Figure 30-2 Impact of Utilization Factors on the Useful Life of Secondary Paper Insulated Lead Covered Cables

31. Secondary Cables – Direct Buried

31.1 Asset Description

Secondary underground cables are used to supply customer premises.

31.1.1 Componentization Assumptions

For the purposes of this report, the Secondary Cables – Direct Buried has not been componentized.

31.1.2 System Hierarchy

Secondary Cables – Direct Buried is considered to be a part of the Underground Systems asset grouping.

31.2 Degradation Mechanism

Degradation of secondary cables is commonly due to mechanical damage, overloading and chemical and environmental impacts on the insulation material.

31.3 Useful Life

Based on the Industry Values and Utility Interviews the Useful Life Values, Minimum (MIN UL), Typical (TUL) and Maximum (MAX UL) for Secondary Cables – Direct Buried are displayed in Table 32-1.

Table 31-1 Useful Life Values for Secondary Cables – Direct Buried

ASSET COMPONENTIZATION	USEFUL LIFE		
	MIN UL	TUL	MAX UL
Secondary Cables - Direct Buried	25	35	40

31.3.1 Useful Life Data

This section displays the data used to determine the Useful Life Values for Secondary Cables – Direct Buried. All six of the interviewed utilities gave Minimum, Typical and Maximum Useful Life (MIN UL, TUL and MAX UL) Values for Secondary Cables – Direct Buried (Figure 31-1).

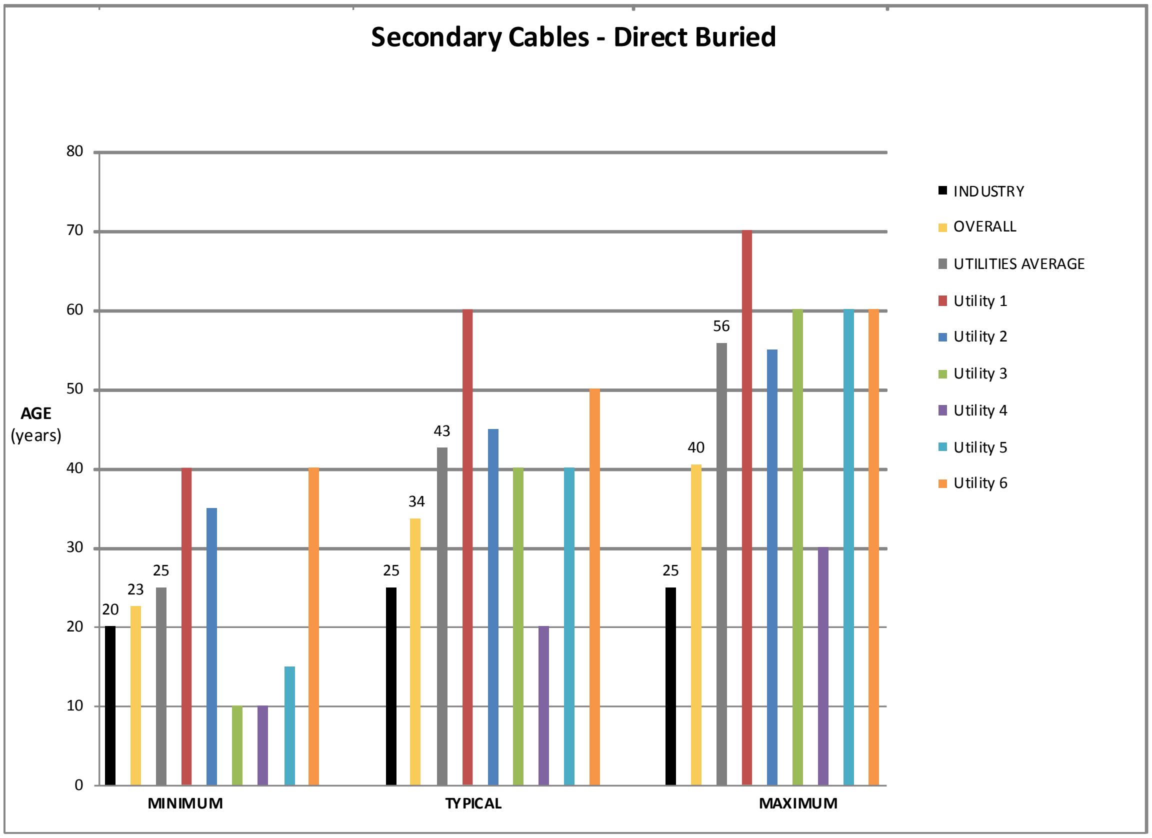


Figure 31-1 Useful Life Values for Secondary Cables – Direct Buried

31.4 Impact of Utilization Factors

Based on the Utility Interviews the composite score and overall impact (high medium, low), if any, of each factor on the typical useful life of Secondary Cables – Direct Buried are displayed in Table 32-2.

Table 31-2 - Composite Score for Secondary Cables – Direct Buried

	Utilization Factors					
	Mechanical Stress	Electrical Loading	Environmental Factors	Operating Practices	Maintenance Practices	Non-Physical Factors
Composite Score	67%	50%	58%	23%	6%	0%
Overall Rating*	M	M	M	L	NI	NI
* H = High Impact	M = Medium Impact		L = Low Impact		NI = No Impact	

31.4.1 Utility Interview Data

This section displays the data used to determine the composite score and overall impact (high, medium, low) of each factor on the typical useful life of Secondary Cables – Direct Buried. All six of the interviewed utilities provided their input regarding the UFs for Secondary Cables – Direct Buried (Figure 31-2).

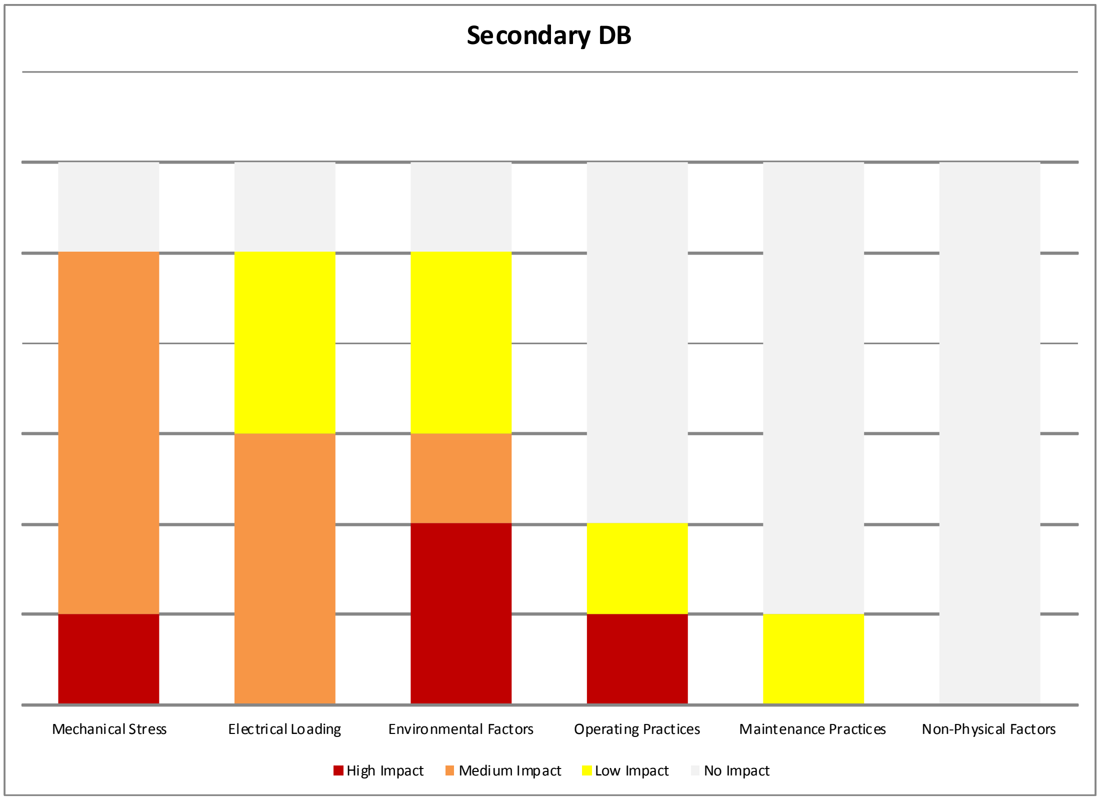


Figure 31-2 Impact of Utilization Factors on the Useful Life of Secondary Cables – Direct Buried

32. Secondary Cables – In Duct

32.1 Asset Description

Secondary underground cables are used to supply customer premises.

32.1.1 Componentization Assumptions

For the purposes of this report, the Secondary Cables – In Duct has not been componentized.

32.1.2 System Hierarchy

Secondary Cables – In Duct is considered to be a part of the Underground Systems asset grouping.

32.2 Degradation Mechanism

Degradation of secondary cables is commonly due to mechanical damage, overloading and chemical and environmental impacts on the insulation material. Placement of the cable in duct mitigates some of the mechanical and chemical damage mechanisms.

32.3 Useful Life

Based on the Industry Values and Utility Interviews the Useful Life Values, Minimum (MIN UL), Typical (TUL) and Maximum (MAX UL) for Secondary Cables – In Duct are displayed in Table 33-1.

Table 32-1 Useful Life Values for Secondary Cables – In Duct

ASSET COMPONENTIZATION	USEFUL LIFE		
	MIN UL	TUL	MAX UL
Secondary Cables - In Duct	35	40	60

32.3.1 Useful Life Data

This section displays the data used to determine the Useful Life Values for Secondary Cables – In Duct. Five of the interviewed utilities gave Minimum, Typical and Maximum Useful Life (MIN UL, TUL and MAX UL) Values for Secondary Cables – In Duct (Figure 32-1).

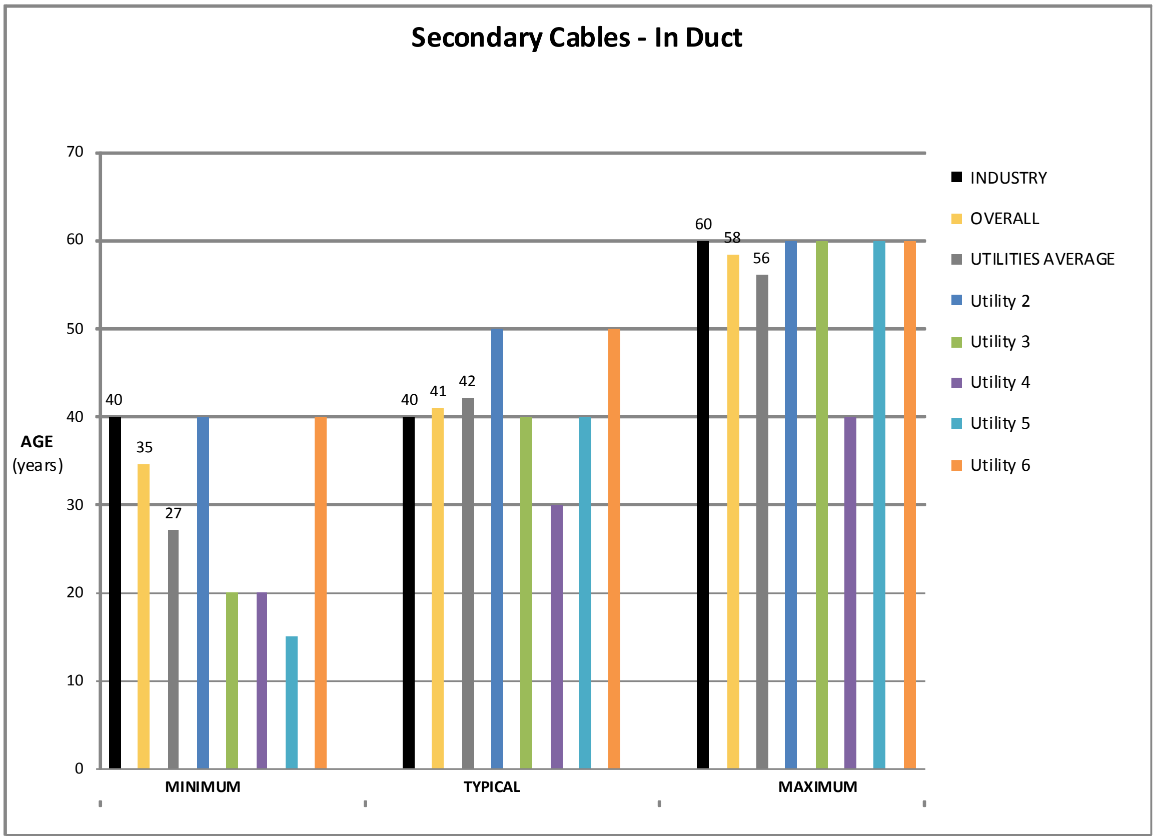


Figure 32-1 Useful Life Values for Secondary Cables – In Duct

32.4 Impact of Utilization Factors

Based on the Utility Interviews the composite score and overall impact (high medium, low), if any, of each factor on the typical useful life of Secondary Cables – In Duct are displayed in Table 33-2.

Table 32-2 - Composite Score for Secondary Cables – In Duct

	Utilization Factors					
	Mechanical Stress	Electrical Loading	Environmental Factors	Operating Practices	Maintenance Practices	Non-Physical Factors
Composite Score	58%	45%	50%	28%	8%	0%
Overall Rating*	M	M	M	L	NI	NI
* H = High Impact	M = Medium Impact	L = Low Impact	NI = No Impact			

32.4.1 Utility Interview Data

This section displays the data used to determine the composite score and overall impact (high, medium, low) of each factor on the typical useful life of Secondary Cables – In Duct. Five of the interviewed utilities provided their input regarding the UFs for Secondary Cables – In Duct (Figure 32-2).

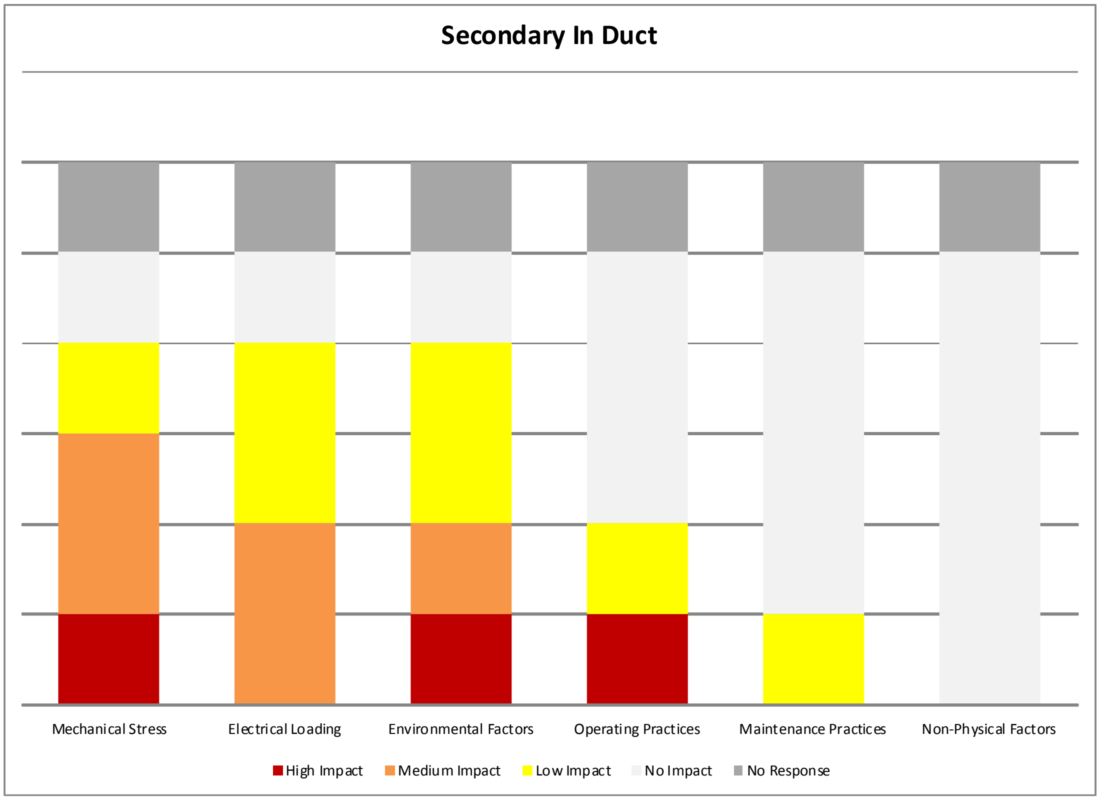


Figure 32-2 Impact of Utilization Factors on the Useful Life of Secondary Cables – In Duct

33. Network Transformers

33.1 Asset Description

Network transformers are special purpose distribution transformers, designed and constructed for successful operation in a parallel mode with a large number of transformers with similar characteristic. The primary winding of the transformers is connected in Delta configuration while the secondary is in grounded star configuration. The network transformers are provided with a primary disconnect, which has no current interrupting rating and is used merely as in isolating device after the transformer has been de-energized both from primary and secondary source. The secondary bushings are mounted on the side wall of the transformer in a throat, suitable for mounting of the network protector.

33.1.1 Componentization Assumptions

For the purposes of this report, the Network Transformers has been componentized so that the network protector is regarded as separated components. Therefore the Network Transformers has overall useful life values based and useful life values for the specific component, the network protector.

Network protectors are special purpose low voltage air circuit breakers, designed for successful parallel operation of network transformers. Network protectors are fully self contained units, equipped with protective relays and instrument transformers to allow automatic closing and opening of the protector. The relays conduct a line test before initiating close command and allow closing of the breaker only if the associated transformer has the correct voltage condition in relation to the grid to permit flow of power from the transformer to the grid. If the conditions are not right, protector closing is blocked. The protector is also equipped with a reverse current relay that trips if the power flow reverses from its normal direction, i.e. if the power flows from grid into the transformer.

33.1.2 System Hierarchy

Network Transformers is considered to be a part of the Underground Systems asset grouping.

33.2 Degradation Mechanism

Since in a majority of the applications transformers are installed in below grade vaults, the transformer is designed for partially submersible operation with additional protection against corrosion. While network transformers are available in dry-type (cast coil and epoxy impregnation) designs, a vast majority of the network transformers employ mineral oil for insulation and cooling. The network transformer has a similar degradation mechanism to other distribution transformers.

The life of the transformer's internal insulation is related to temperature rise and duration. Therefore, the transformer life is affected by electrical loading profiles and length of service life. Other factors such as mechanical damage, exposure to corrosive salts, and voltage current surges also have strong effects. Therefore, a combination of condition, age, and load based criteria is commonly used to determine the useful remaining life.

The breaker design in network protectors employs mechanical linkages, rollers, springs and cams for operation which require periodic maintenance. All network protectors are equipped with special load-side fuses, mounted either internally or external to the network protector housing. The fuses are intended to allow normal load current and overloads while providing backup protection in the event that the protector fails to open on reverse fault current (due to faults internal to the protector or near transformer low voltage terminals). Every time arcing occurs in open air within the network protector housing, whether due to operation of the air breaker or because of fuse blowing (except silver sand), a certain amount of metal vapour is liberated and dispersed over insulating parts. Fuses evidently liberate more vapour than breaker operation. Over time, this buildup reduces the dielectric strength of insulating barriers. Eventually this may result in a breakdown, unless care is taken to clean the network protector internally, particularly after fuse operations.

Various parameters that impact the health and condition and eventually lead to end of life of a network include condition of mechanical moving parts, condition of inter phase barriers, number of protector operations (counter reading), accumulation of dirt or debris in protector housing, corrosion of protector housing, condition of fuses, condition of arc chutes and time period elapsed since last major overhaul of the protector.

The health of network protector is established by taking into account the following:

- Number of operations since last overhaul
- Operating age of protector
- Condition of operating mechanism
- Condition of fuses
- Condition of arc chutes
- Condition of protector relays
- Condition of gaskets and seals for submersible units

33.3 Useful Life

Based on the Industry Values and Utility Interviews the Useful Life Values, Minimum (MIN UL), Typical (TUL) and Maximum (MAX UL) for Network Transformers are displayed in Table 33-1.

Table 33-1 Useful Life Values for Network Transformers

ASSET COMPONENTIZATION	USEFUL LIFE		
	MIN UL	TUL	MAX UL
Overall	20	35	50
Protector	20	35	40

33.3.1 Useful Life Data

This section displays the data used to determine the Useful Life Values for Network Transformers. One of the interviewed utilities gave Minimum, Typical and Maximum Useful Life (MIN UL, TUL and MAX UL) Values for Network Transformers (Figure 33-1).

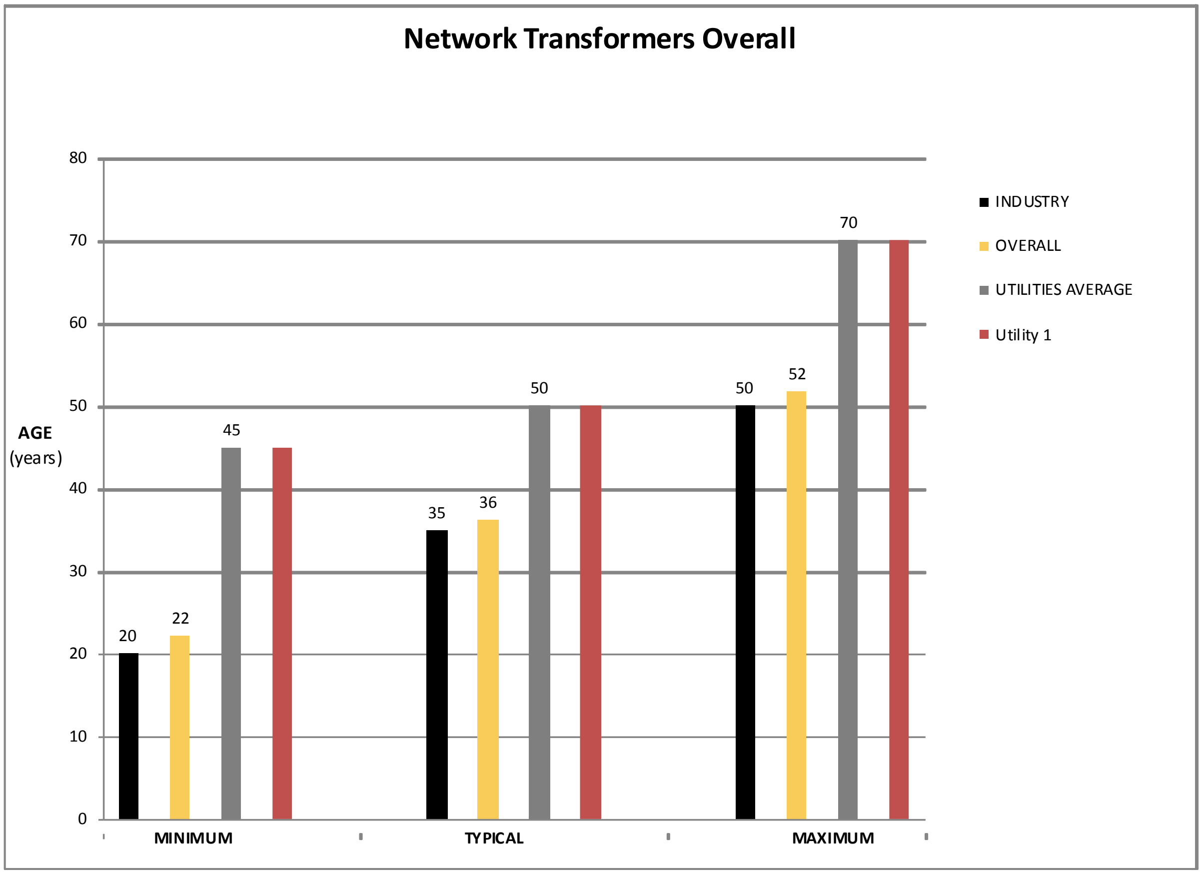


Figure 33-1 Useful Life Values for Network Transformers

33.4 Impact of Utilization Factors

Based on the Utility Interviews the composite score and overall impact (high medium, low), if any, of each factor on the typical useful life of Network Transformers are displayed in Table 33-2.

Table 33-2 - Composite Score for Network Transformers

	Utilization Factors					
	Mechanical Stress	Electrical Loading	Environmental Factors	Operating Practices	Maintenance Practices	Non-Physical Factors
Composite Score	0%	38%	100%	0%	0%	0%
Overall Rating*	NI	L	H	NI	NI	NI
* H = High Impact	M = Medium Impact	L = Low Impact	NI = No Impact			

33.4.1 Utility Interview Data

This section displays the data used to determine the composite score and overall impact (high, medium, low) of each factor on the typical useful life of Network Transformers. One of the interviewed utilities provided their input regarding the UFs for Network Transformers (Figure 33-2).

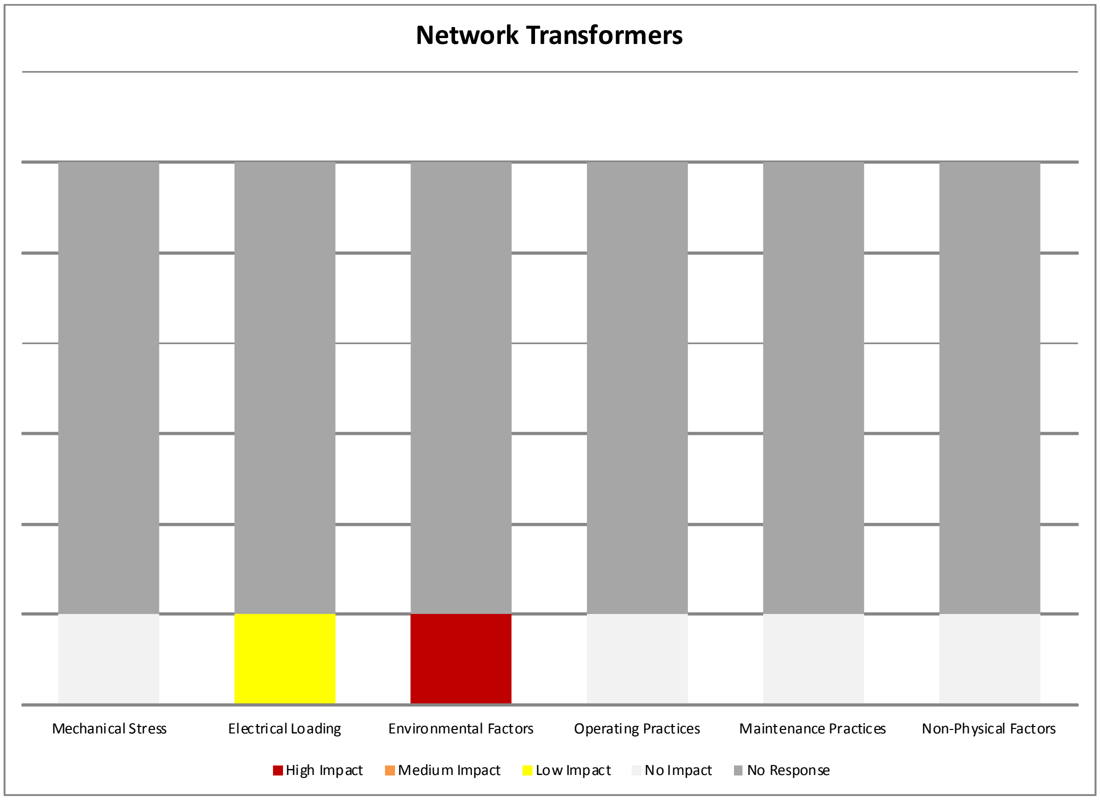


Figure 33-2 Impact of Utilization Factors on the Useful Life of Network Transformers

34. Pad-Mounted Transformers

34.1 Asset Description

Pad-Mounted transformers typically employ sealed tank construction and are liquid filled, with mineral insulating oil being the predominant liquid.

34.1.1 Componentization Assumptions

For the purposes of this report, the Pad-Mounted Transformers has not been componentized.

34.1.2 System Hierarchy

Pad-Mounted Transformers is considered to be a part of the Underground Systems asset grouping.

34.2 Degradation Mechanism

It has been demonstrated that the life of the transformer's internal insulation is related to temperature rise and duration. Therefore, the transformer life is affected by electrical loading profiles and length of service life. Other factors such as mechanical damage, exposure to corrosive salts, and voltage current surges also have strong effects. Therefore, a combination of condition, age, and load based criteria is commonly used to determine the useful remaining life.

In general, the following are considered when determining the health of the pad-mounted transformer:

- Tank corrosion, condition of paint
- Extent of oil leaks
- Condition of bushings
- Condition of padlocks, warning signs, etc.
- Transfer operating age and winding temperature profile

34.3 Useful Life

Based on the Industry Values and Utility Interviews the Useful Life Values, Minimum (MIN UL), Typical (TUL) and Maximum (MAX UL) for Pad-Mounted Transformers are displayed in Table 34-1.

Table 34-1 Useful Life Values for Pad-Mounted Transformers

ASSET COMPONENTIZATION	USEFUL LIFE		
	MIN UL	TUL	MAX UL
Pad-Mounted Transformers	25	40	45

34.3.1 Useful Life Data

This section displays the data used to determine the Useful Life Values for Pad-Mounted Transformers. All six of the interviewed utilities gave Minimum, Typical and Maximum Useful Life (MIN UL, TUL and MAX UL) Values for Pad-Mounted Transformers (Figure 34-1).

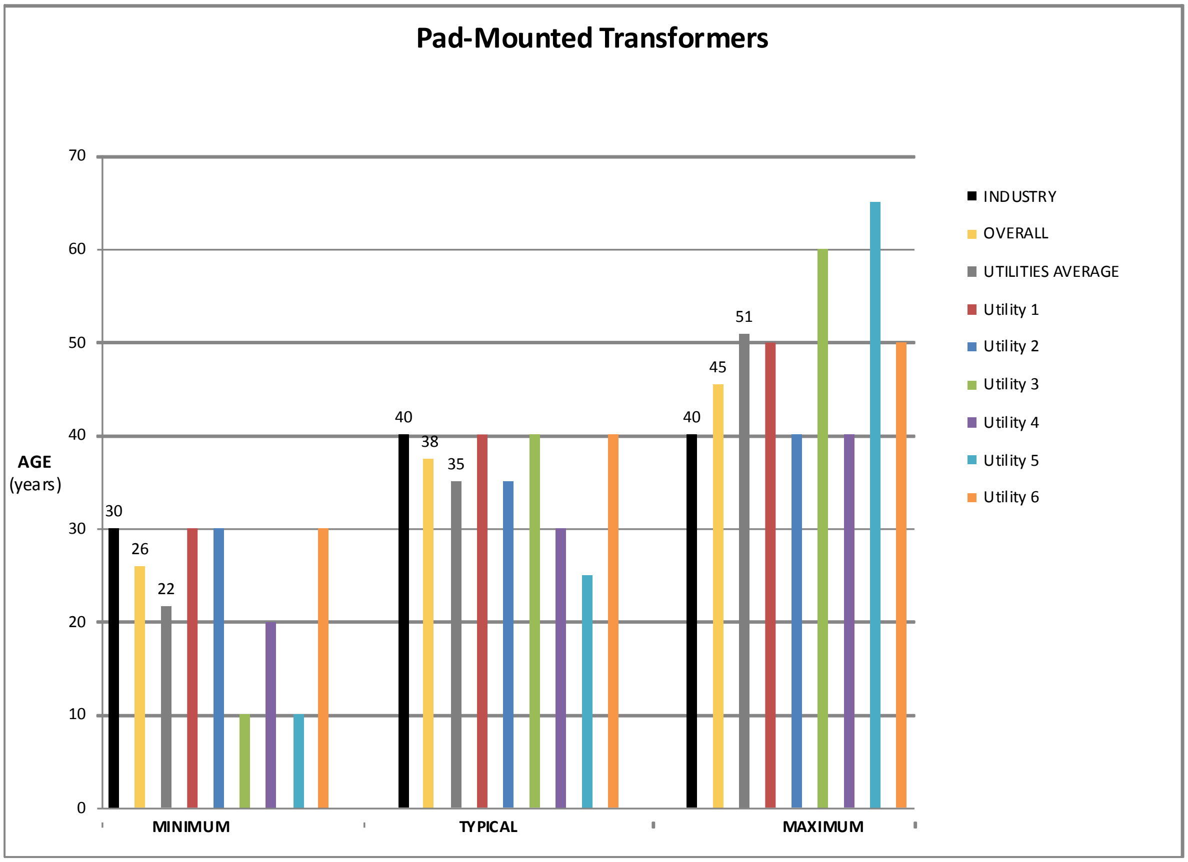


Figure 34-1 Useful Life Values for Pad-Mounted Transformers

34.4 Impact of Utilization Factors

Based on the Utility Interviews the composite score and overall impact (high medium, low), if any, of each factor on the typical useful life of Pad-Mounted Transformers are displayed in Table 34-2.

Table 34-2 - Composite Score for Pad-Mounted Transformers

	Utilization Factors					
	Mechanical Stress	**Electrical Loading**	**Environmental Factors**	**Operating Practices**	**Maintenance Practices**	**Non-Physical Factors**
Composite Score	19%	56%	71%	0%	13%	19%
Overall Rating*	**L**	**M**	**M**	**NI**	**L**	**L**
* H = High Impact	M = Medium Impact	L = Low Impact	NI = No Impact			

34.4.1 Utility Interview Data

This section displays the data used to determine the composite score and overall impact (high, medium, low) of each factor on the typical useful life of Pad-Mounted Transformers. All six of the interviewed utilities provided their input regarding the UFs for Pad-Mounted Transformers (Figure 34-2).

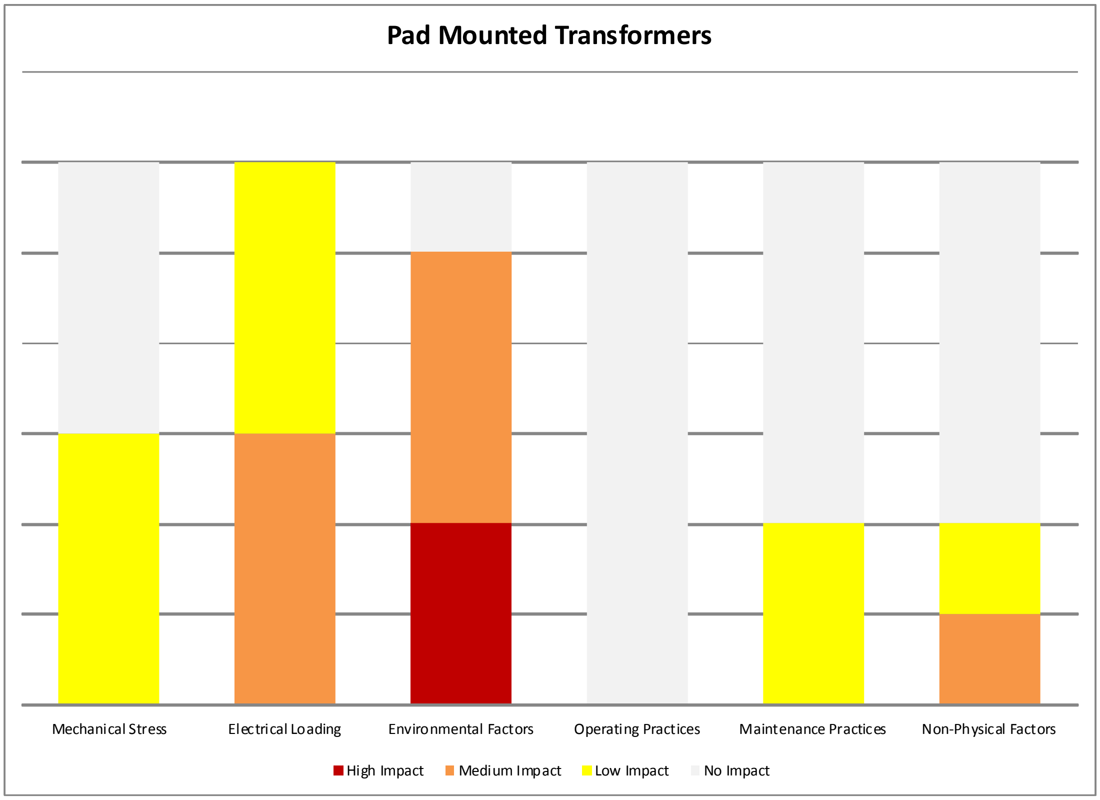


Figure 34-2 Impact of Utilization Factors on the Useful Life of Pad-Mounted Transformers

35. Submersible and Vault Transformers

35.1 Asset Description

Submersible transformers typically employ sealed tank construction with corrosion resistance hardware and are liquid filled with mineral insulating oil. Similar to submersible transformers, indoor vault transformers typically employ sealed tank construction and are liquid filled with mineral insulating oil.

35.1.1 Componentization Assumptions

For the purposes of this report, the Submersible and Vault Transformers has not been componentized.

35.1.2 System Hierarchy

Submersible and Vault Transformers is considered to be a part of the Underground Systems asset grouping.

35.2 Degradation Mechanism

The transformer has a similar degradation mechanism to other distribution transformers. The life of the transformer's internal insulation is related to temperature rise and duration, so transformer life is affected by electrical loading profiles and length of service life. Mechanical damage, exposure to corrosive salts, and voltage current surges has strong effects. In general, a combination of condition, age, and load based criteria is commonly used to determine the useful remaining life.

35.3 Useful Life

Based on the Industry Values and Utility Interviews the Useful Life Values, Minimum (MIN UL), Typical (TUL) and Maximum (MAX UL) for Submersible and Vault Transformers are displayed in Table 35-1.

Table 35-1 Useful Life Values for Submersible and Vault Transformers

ASSET COMPONENTIZATION	USEFUL LIFE		
	MIN UL	TUL	MAX UL
Submersible/Vault Transformers	25	35	45

35.3.1 Useful Life Data

This section displays the data used to determine the Useful Life Values for Submersible and Vault Transformers. Four of the interviewed utilities gave Minimum, Typical and Maximum Useful Life (MIN UL, TUL and MAX UL) Values for Submersible and Vault Transformers (Figure 35-1).

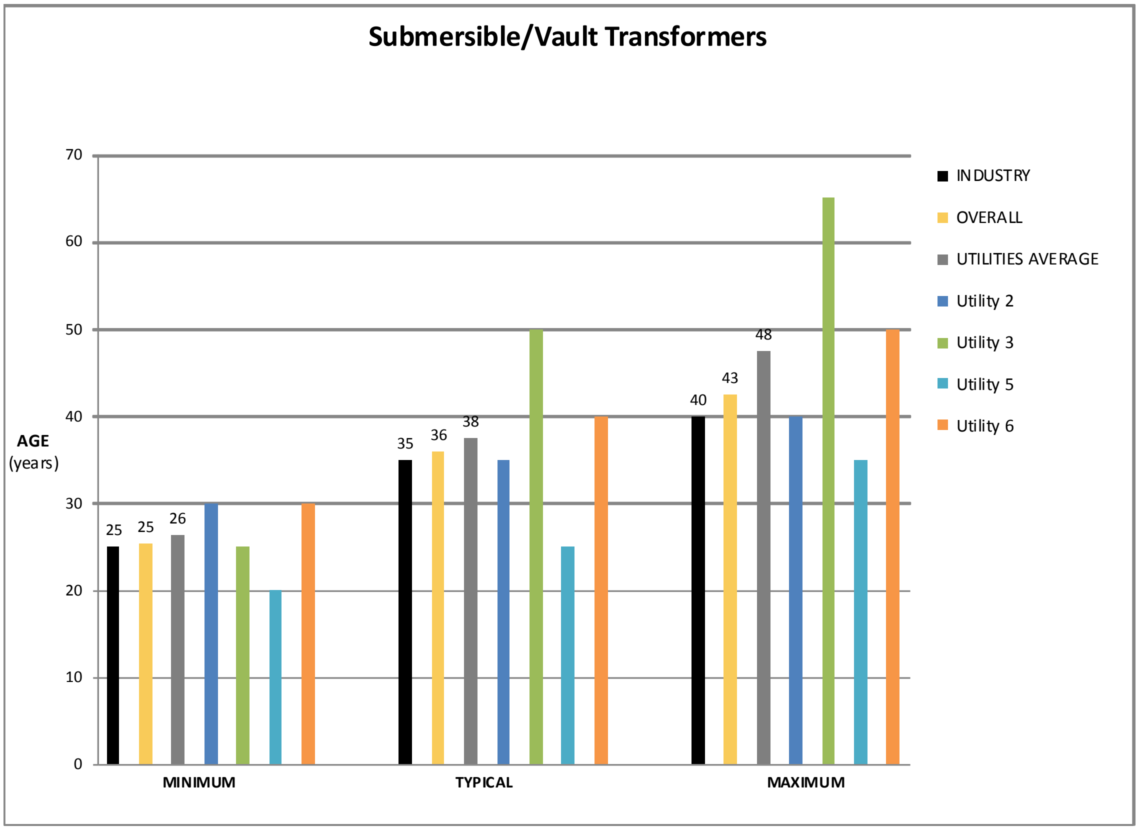


Figure 35-1 Useful Life Values for Submersible and Vault Transformers

35.4 Impact of Utilization Factors

Based on the Utility Interviews the composite score and overall impact (high medium, low), if any, of each factor on the typical useful life of Submersible and Vault Transformers are displayed in Table 35-2.

Table 35-2 - Composite Score for Submersible and Vault Transformers

	Utilization Factors					
	Mechanical Stress	Electrical Loading	Environmental Factors	Operating Practices	Maintenance Practices	Non-Physical Factors
Composite Score	28%	72%	75%	9%	19%	28%
Overall Rating*	L	M	M	NI	L	L
* H = High Impact	M = Medium Impact		L = Low Impact		NI = No Impact	

35.4.1 Utility Interview Data

This section displays the data used to determine the composite score and overall impact (high, medium, low) of each factor on the typical useful life of Submersible and Vault Transformers. Four of the interviewed utilities provided their input regarding the UFs for Submersible and Vault Transformers (Figure 35-2).

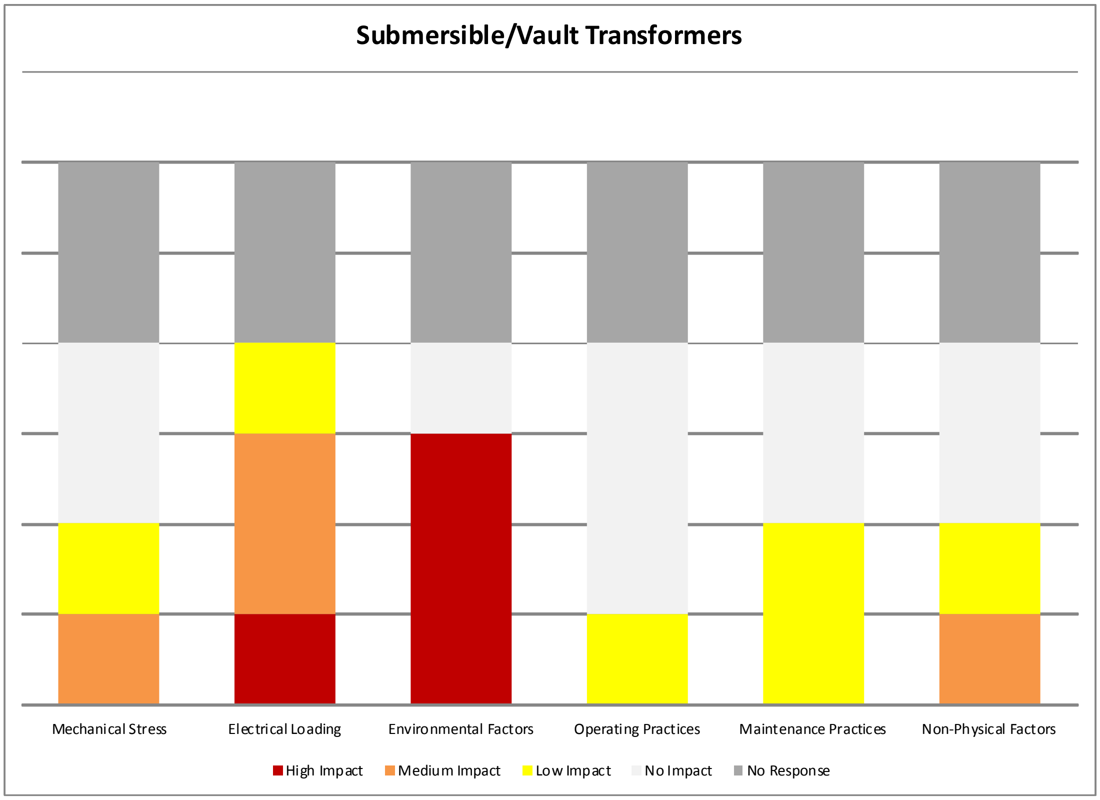


Figure 35-2 Impact of Utilization Factors on the Useful Life of Submersible and Vault Transformers

36. Underground Foundations

36.1 Asset Description

This asset class consists of a buried pre cast concrete vault on which pad-mounted transformers or switchgear are mounted. The foundation itself is buried; however the top portion is above ground.

36.1.1 Componentization Assumptions

For the purposes of this report, the Underground Foundations has not been componentized.

36.1.2 System Hierarchy

Underground Foundations is considered to be a part of the Underground Systems asset grouping.

36.2 Degradation Mechanism

These assets must withstand the heaviest structural loadings to which they might be subjected. For example, when located in streets, transformer and switchgear foundation must withstand heavy loads associated with traffic in the boulevard. When located in driving lanes, concrete vault must match street grading. Since vaults often experience flooding, they sometimes include drainage sumps and sump pumps. Nevertheless, environmental regulations in some jurisdictions may prohibit the pumping into sewer systems, without testing of the water for environmentally hazardous contaminants.

Although age is loosely related to the condition of underground civil structures, it is not a linear relationship. Other factors such as mechanical loading, exposure to corrosive salts, etc. have stronger effects. Transformer and switchgear foundation degradation commonly includes corrosion of reinforcing steel, spalling of concrete, and rusting of covers or rings. Acidic salts (i.e. sulfates or chlorides) affect corrosion rates. Transformer and switchgear foundation also may experience a number of deficiencies or defects. In roadways, defects exist when covers are not level with street surfaces. Conditions that lead to flooding, clogged sumps, and non-functioning sump-pumps also represent major deficiencies in a transformer and switchgear foundation. Similarly, transformer and switchgear foundation with lights that do not function properly constitute defective systems.

36.3 Useful Life

Based on the Industry Values and Utility Interviews the Useful Life Values, Minimum (MIN UL), Typical (TUL) and Maximum (MAX UL) for Underground Foundations are displayed in Table 36-1.

Table 36-1 Useful Life Values for Underground Foundations

ASSET COMPONENTIZATION	USEFUL LIFE		
	MIN UL	TUL	MAX UL
UG Foundations	35	55	70

36.3.1 Useful Life Data

This section displays the data used to determine the Useful Life Values for Underground Foundations. Five of the interviewed utilities gave Minimum Useful Life (MIN UL) Values and all six of the interviewed utilities gave TUL and MAX UL Values for Underground Foundations (Figure 36-1).

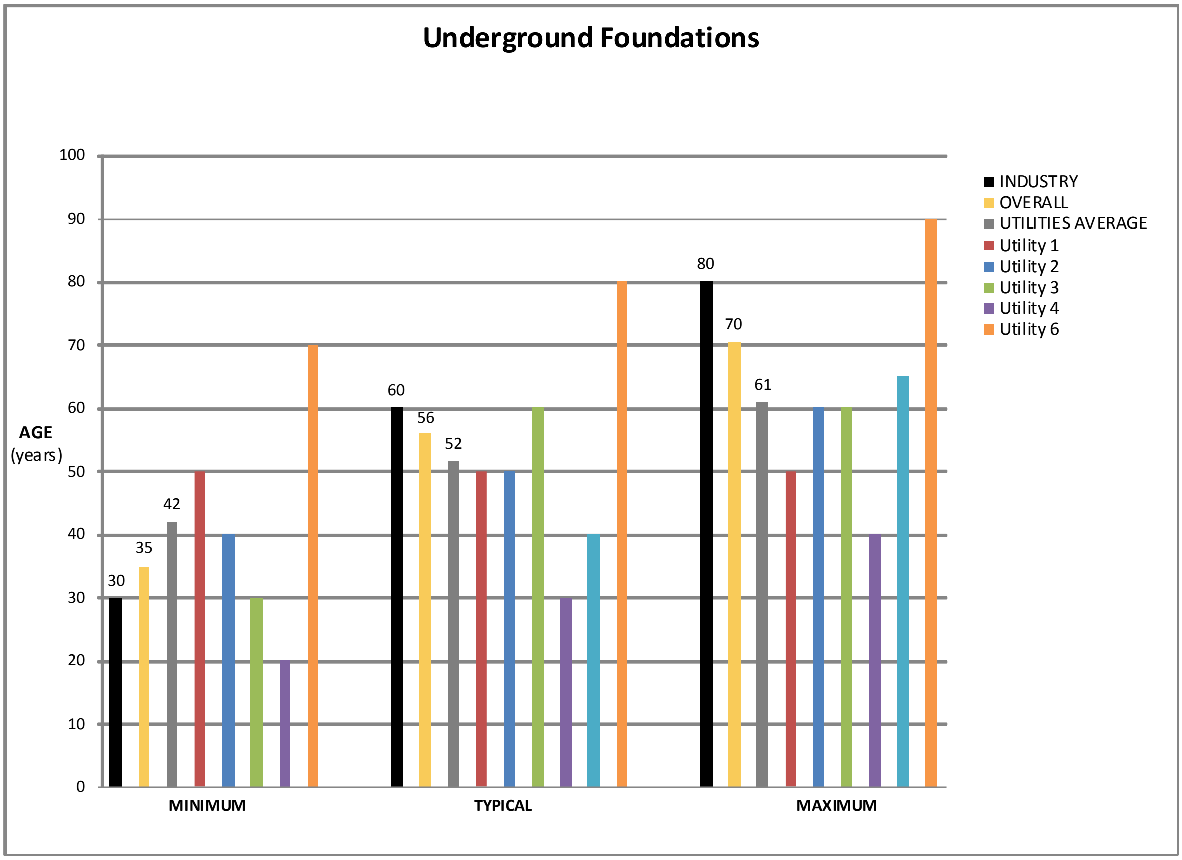


Figure 36-1 Useful Life Values for Underground Foundations

36.4 Impact of Utilization Factors

Based on the Utility Interviews the composite score and overall impact (high medium, low), if any, of each factor on the typical useful life of Underground Foundations are displayed in Table 36-2.

Table 36-2 - Composite Score for Underground Foundations

	Utilization Factors					
	Mechanical Stress	Electrical Loading	Environmental Factors	Operating Practices	Maintenance Practices	Non-Physical Factors
Composite Score	48%	6%	54%	13%	13%	48%
Overall Rating*	**M**	**NI**	**M**	**L**	**L**	**M**
* H = High Impact	M = Medium Impact	L = Low Impact	NI = No Impact			

36.4.1 Utility Interview Data

This section displays the data used to determine the composite score and overall impact (high, medium, low) of each factor on the typical useful life of Underground Foundations. All six of the interviewed utilities provided their input regarding the UFs for Underground Foundations (Figure 36-2).

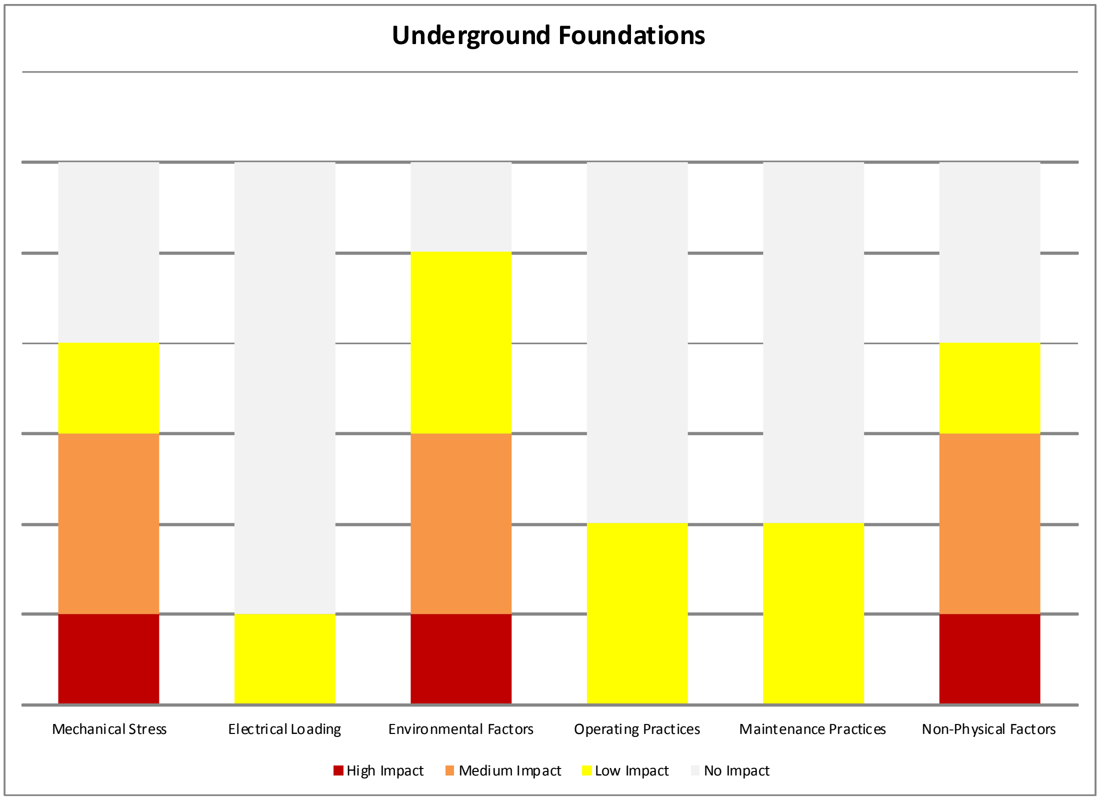


Figure 36-2 Impact of Utilization Factors on the Useful Life of Underground Foundations

37. Underground Vaults

37.1 Asset Description

Equipment vaults permit installation of transformers, switchgear or other equipment. They are often constructed out of reinforced or un-reinforced concrete. Vaults used for transformer installation are often equipped with ventilation grates to provide natural or forced cooling.

37.1.1 Componentization Assumptions

For the purposes of this report, the Underground Vaults has been componentized so that the roof is regarded as separated components. Therefore the Underground Vaults has overall useful life values based and useful life values for the specific component, the roof.

37.1.2 System Hierarchy

Underground Vaults is considered to be a part of the Underground Systems asset grouping.

37.2 Degradation Mechanism

Vaults should be capable of bearing the loads that are applied on them. As such, mechanical strength is a basic end of life parameter for a vault. Although age is loosely related to the condition of underground civil structures, it is not a linear relationship. Other factors such as mechanical loading, exposure to corrosive salts, etc. have a stronger effect. Degradation commonly includes corrosion of reinforcing steel, spalling of concrete, and rusting of covers or rings. Acidic salts (i.e. sulfates or chlorides) affect corrosion rates. In roadways, defects exist when covers are not level with street surfaces. Conditions that lead to flooding, clogged or non-functioning sump pumps also represent major deficiencies.

37.3 Useful Life

Based on the Industry Values and Utility Interviews the Useful Life Values, Minimum (MIN UL), Typical (TUL) and Maximum (MAX UL) for Underground Vaults are displayed in Table 37-1.

Table 37-1 Useful Life Values for Underground Vaults

ASSET COMPONENTIZATION	USEFUL LIFE		
	MIN UL	TUL	MAX UL
Overall	40	60	80
Roof	20	30	45

37.3.1 Useful Life Data

This section displays the data used to determine the Useful Life Values for Underground Vaults. Five of the interviewed utilities gave Minimum, Typical and Maximum Useful Life (MIN UL, TUL and MAX UL) Values for Underground Vaults (Figure 37-1).

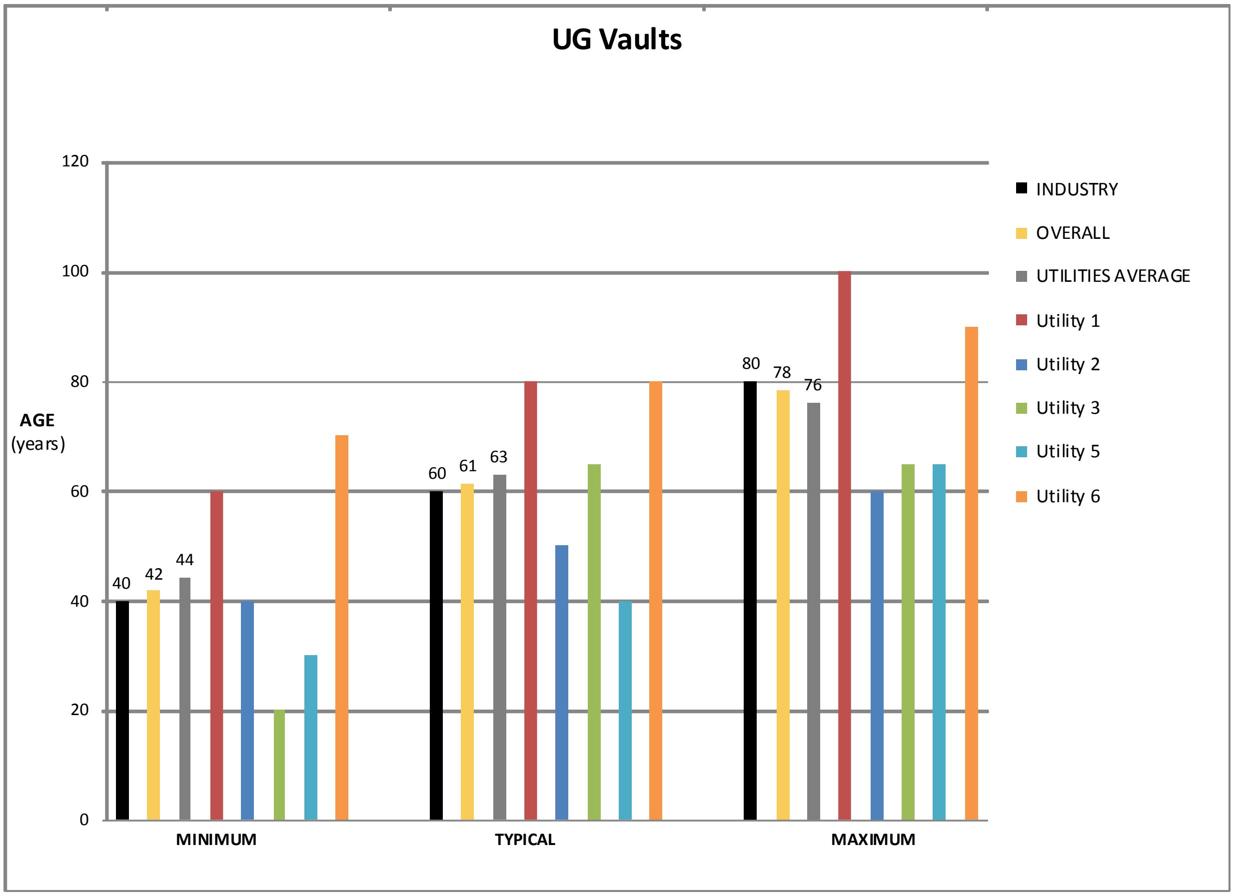


Figure 37-1 Useful Life Values for Underground Vaults

37.4 Impact of Utilization Factors

Based on the Utility Interviews the composite score and overall impact (high medium, low), if any, of each factor on the typical useful life of Underground Vaults are displayed in Table 37-2.

Table 37-2 - Composite Score for Underground Vaults

	Utilization Factors					
	Mechanical Stress	Electrical Loading	Environmental Factors	Operating Practices	Maintenance Practices	Non-Physical Factors
Composite Score	58%	0%	63%	15%	23%	43%
Overall Rating*	M	NI	M	L	L	L
* H = High Impact M = Medium Impact L = Low Impact NI = No Impact						

37.4.1 Utility Interview Data

This section displays the data used to determine the composite score and overall impact (high, medium, low) of each factor on the typical useful life of Underground Vaults. Five of the interviewed utilities provided their input regarding the UFs for Underground Vaults (Figure 37-2).

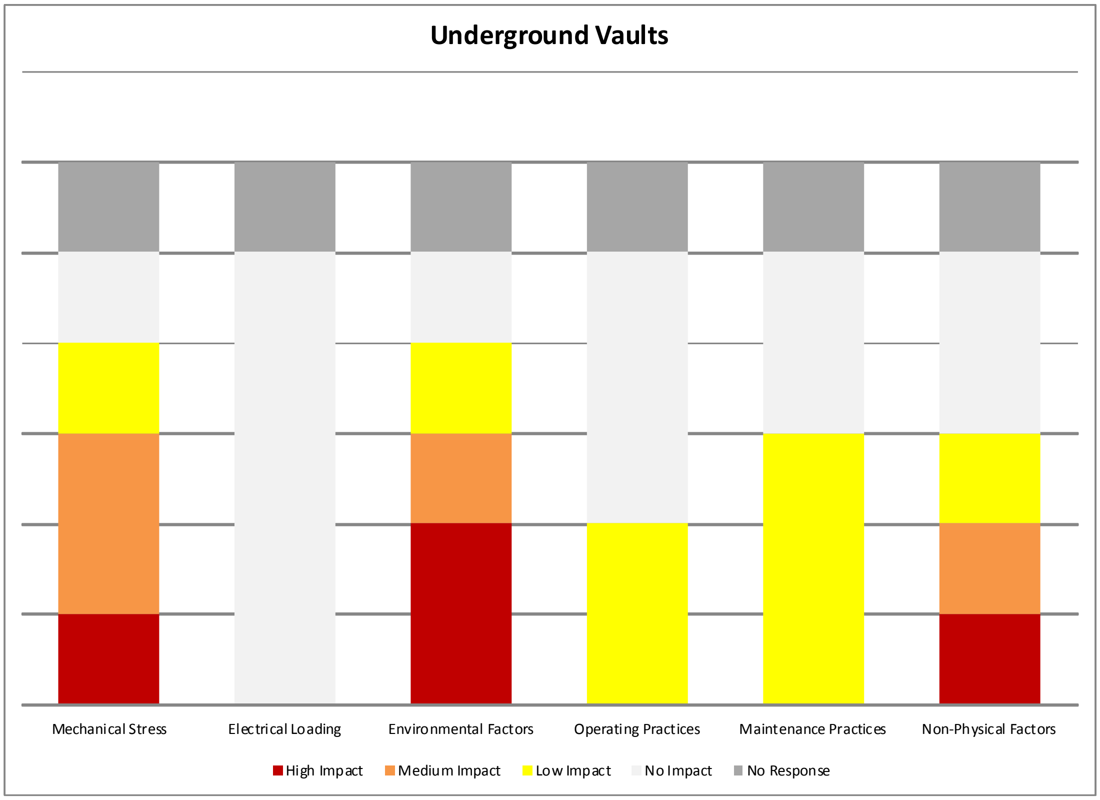


Figure 37-2 Impact of Utilization Factors on the Useful Life of Underground Vaults

38. Underground Vault Switches

38.1 Asset Description

Underground Vault Switches can be wall mounted air insulated switches or switchgear enclosed in stainless steel containers with the ability to be wall or ceiling mounted.

38.1.1 Componentization Assumptions

For the purposes of this report, the Underground Vault Switches has not been componentized.

38.1.2 Design Configuration

For the purposes of this report, the switch interrupting mediums include oil, gas (SF6) and air.

38.1.3 System Hierarchy

Underground Vault Switches is considered to be a part of the Underground Systems asset grouping.

38.2 Degradation Mechanism

Aging and end of life is established by mechanical failures, such as corrosion of operating mechanism from rusting of enclosure or moisture and dirt ingress. Switchgear failure is associated more with outside influences rather than age. For example, switchgear failure is more likely to be caused by rodents, dirt or contamination, vehicle accidents, rusting of the case, and broken insulators caused by misalignment during switching.

38.3 Useful Life

Based on the Industry Values and Utility Interviews the Useful Life Values, Minimum (MIN UL), Typical (TUL) and Maximum (MAX UL) for Underground Vault Switches are displayed in Table 38-1.

Table 38-1 Useful Life Values for Underground Vault Switches

ASSET COMPONENTIZATION	USEFUL LIFE		
	MIN UL	TUL	MAX UL
UG Vault Switches	20	35	50

38.3.1 Useful Life Data

This section displays the data used to determine the Useful Life Values for Underground Vault Switches. Three of the interviewed utilities gave Minimum Useful Life (MIN UL) Values and four of the utilities interviewed gave TUL and MAX UL for Underground Vault Switches (Figure 38-1).

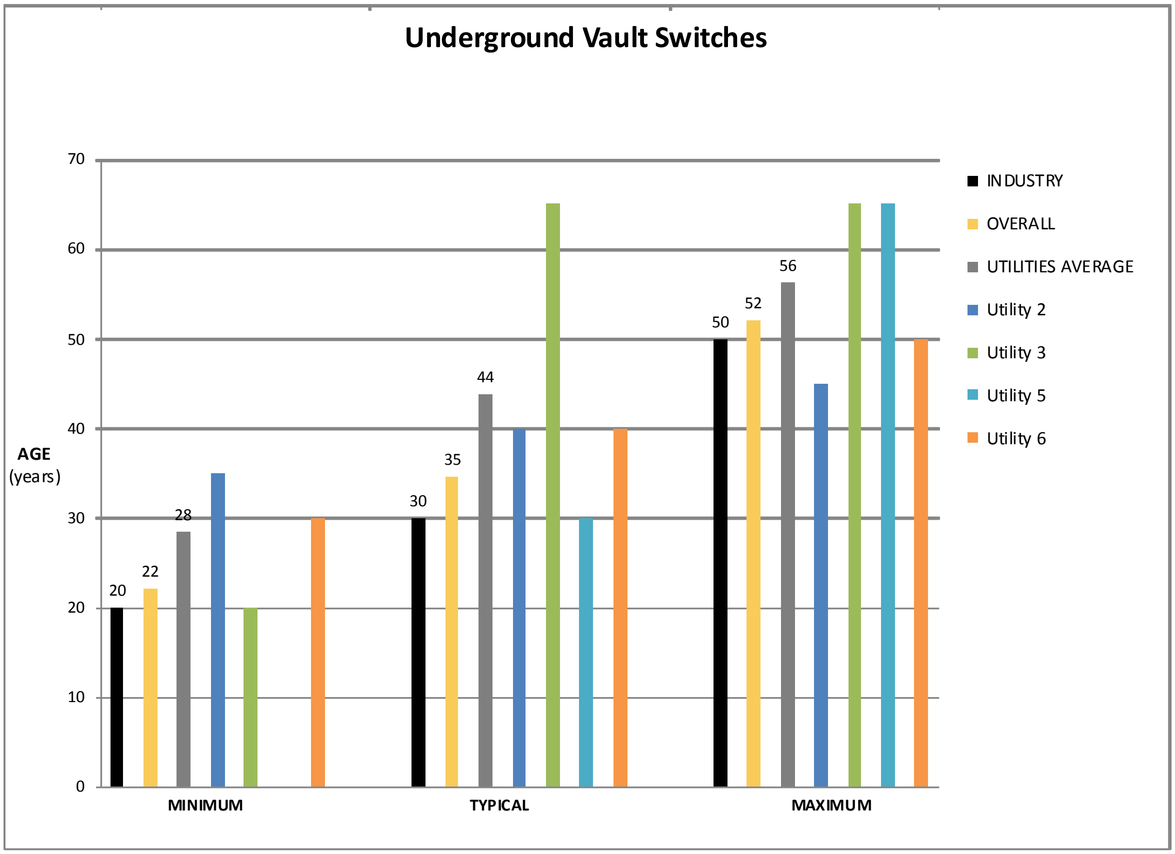


Figure 38-1 Useful Life Values for Underground Vault Switches

38.4 Impact of Utilization Factors

Based on the Utility Interviews the composite score and overall impact (high medium, low), if any, of each factor on the typical useful life of Underground Vault Switches are displayed in Table 38-2.

Table 38-2 - Composite Score for Underground Vault Switches

	Utilization Factors					
	Mechanical Stress	**Electrical Loading**	**Environmental Factors**	**Operating Practices**	**Maintenance Practices**	**Non-Physical Factors**
Composite Score	19%	38%	38%	38%	19%	9%
Overall Rating*	**L**	**L**	**L**	**L**	**L**	**NI**
* H = High Impact M = Medium Impact L = Low Impact NI = No Impact						

38.4.1 Utility Interview Data

This section displays the data used to determine the composite score and overall impact (high, medium, low) of each factor on the typical useful life of Underground Vault Switches. Four of the interviewed utilities provided their input regarding the UFs for Underground Vault Switches (Figure 38-2).

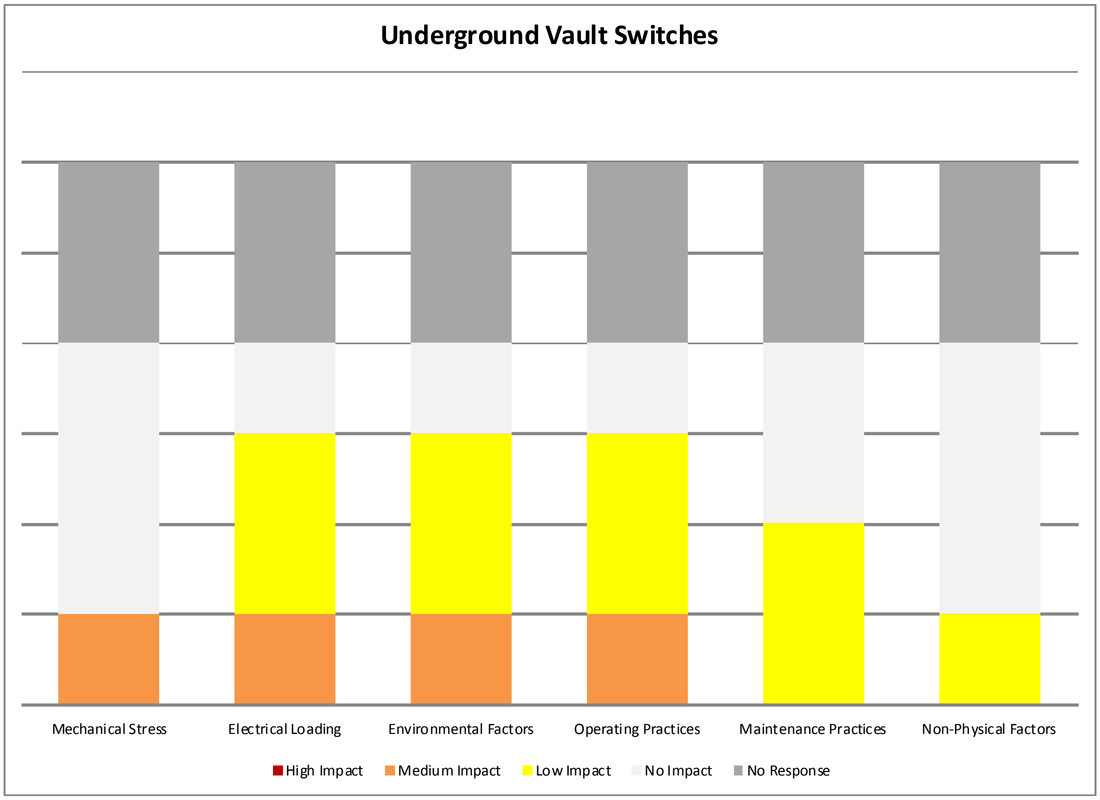


Figure 38-2 Impact of Utilization Factors on the Useful Life of Underground Vault Switches

39. Pad-Mounted Switchgear

39.1 Asset Description

Pad-mounted switchgear is used for protection and switching in the underground distribution system. The switching assemblies can be classified into air insulated, SF6 load break switches and vacuum fault interrupters. A majority of the pad mounted switchgear currently employs air-insulated gang operated load-break switches.

39.1.1 Componentization Assumptions

For the purposes of this report, the Pad-Mounted Switchgear has been componentized.

39.1.2 Design Configuration

For the purposes of this report, the interrupting medium types included are oil, air, gas (SF6), solid dielectric and vacuum.

39.1.3 System Hierarchy

Pad-Mounted Switchgear is considered to be a part of the Underground Systems asset grouping.

39.2 Degradation Mechanism

The pad-mounted switchgear may be used infrequently for switching and often used only to drop loads below its rating. Therefore, switchgear aging and eventual end of life is often established by mechanical failures, e.g. rusting of the enclosures or ingress of moisture and dirt into the switchgear causing corrosion of operating mechanism and degradation of insulated barriers.

The first generation of pad mounted switchgear was first introduced in early 1970's and many of these units are still in good operating condition. The life expectancy of pad-mounted switchgear is impacted by a number of factors that include frequency of switching operations, load dropped, presence or absence of corrosive environmental and absence of existence of dampness at the installation site.

In the absence of specifically identified problems, the common industry practice for distribution switchgear is running it to end of life, just short of failure. To extend the life of these assets and to minimize in-service failures, a number of intervention strategies are employed on a regular basis: e.g. inspection with thermographic analysis and cleaning with CO_2 for air insulated pad-mounted switchgear. If problems or defects are identified during inspection, often the affected component can be replaced or repaired without a total replacement of the switchgear.

Failures of switchgear are most often not directly related to the age of the equipment, but are associated instead with outside influences. For example, pad-mounted switchgear is most likely to fail due to rodents, dirt/contamination, vehicle accidents, rusting of the case, and broken insulators caused by misalignment during switching. All of these causes are largely preventable with good design and maintenance practices. Failures caused by fuse malfunctions can result in a catastrophic switchgear failure.

Aging and end of life is established by mechanical failures, such as corrosion of operating mechanism from rusting of enclosure or moisture and dirt ingress. Switchgear failure is associated more with outside influences rather than age. For example, switchgear failure is more likely to be caused by rodents, dirt or contamination, vehicle accidents, rusting of the case, and broken insulators caused by misalignment during switching.

39.3 Useful Life

Based on the Industry Values and Utility Interviews the Useful Life Values, Minimum (MIN UL), Typical (TUL) and Maximum (MAX UL) for Pad-Mounted Switchgear are displayed in Table 39-1.

Table 39-1 Useful Life Values for Pad-Mounted Switchgear

ASSET COMPONENTIZATION	USEFUL LIFE		
	MIN UL	TUL	MAX UL
Pad-Mounted Switchgear	20	30	45

39.3.1 Useful Life Data

This section displays the data used to determine the Useful Life Values for Pad-Mounted Switchgear. All six of the interviewed utilities gave Minimum, Typical and Maximum Useful Life (MIN UL, TUL and MAX UL) Values for Pad-Mounted Switchgear (Figure 39-1).

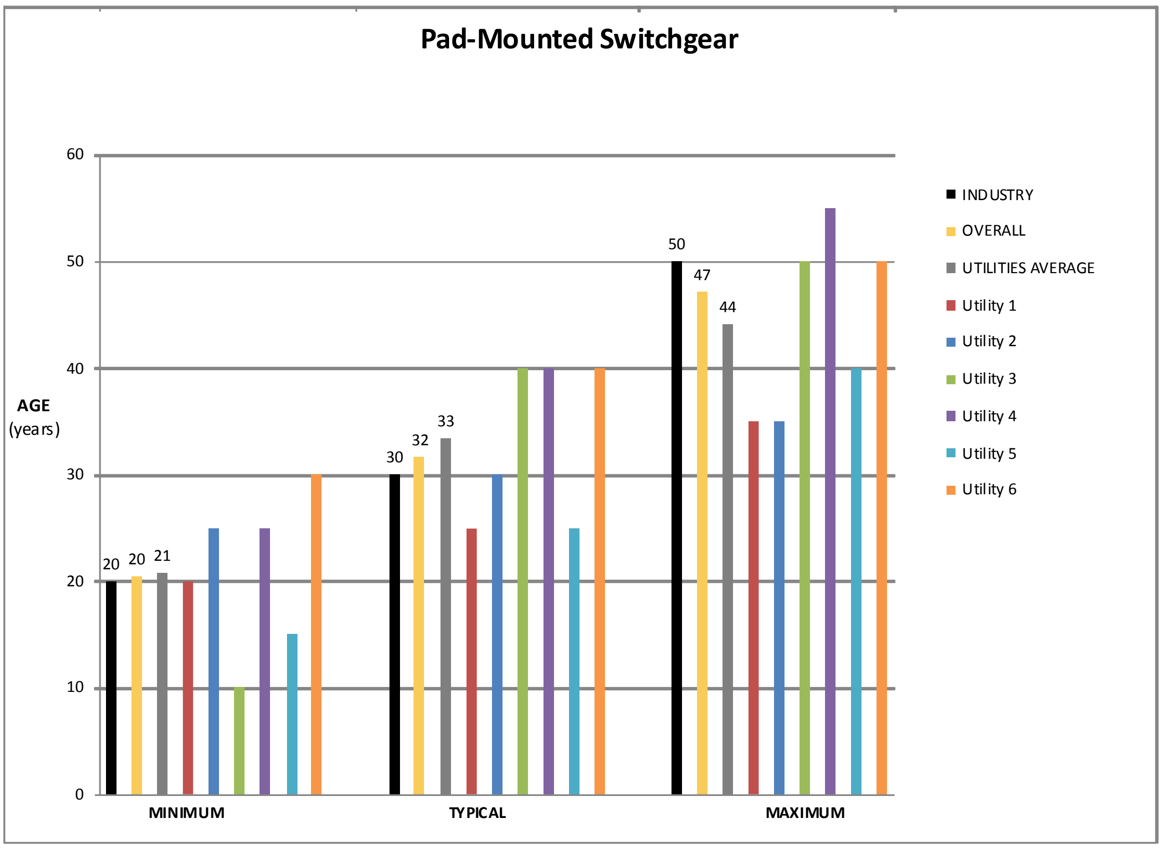


Figure 39-1 Useful Life Values for Pad-Mounted Switchgear

39.4 Impact of Utilization Factors

Based on the Utility Interviews the composite score and overall impact (high medium, low), if any, of each factor on the typical useful life of Pad-Mounted Switchgear are displayed in Table 39-2.

Table 39-2 - Composite Score for Pad-Mounted Switchgear

	Utilization Factors					
	Mechanical Stress	Electrical Loading	Environmental Factors	Operating Practices	Maintenance Practices	Non-Physical Factors
Composite Score	44%	44%	92%	25%	31%	38%
Overall Rating*	L	L	H	L	L	L
* H = High Impact M = Medium Impact L = Low Impact NI = No Impact						

39.4.1 Utility Interview Data

This section displays the data used to determine the composite score and overall impact (high, medium, low) of each factor on the typical useful life of Pad-Mounted Switchgear. All six of the interviewed utilities provided their input regarding the UFs for Pad-Mounted Switchgear (Figure 39-2).

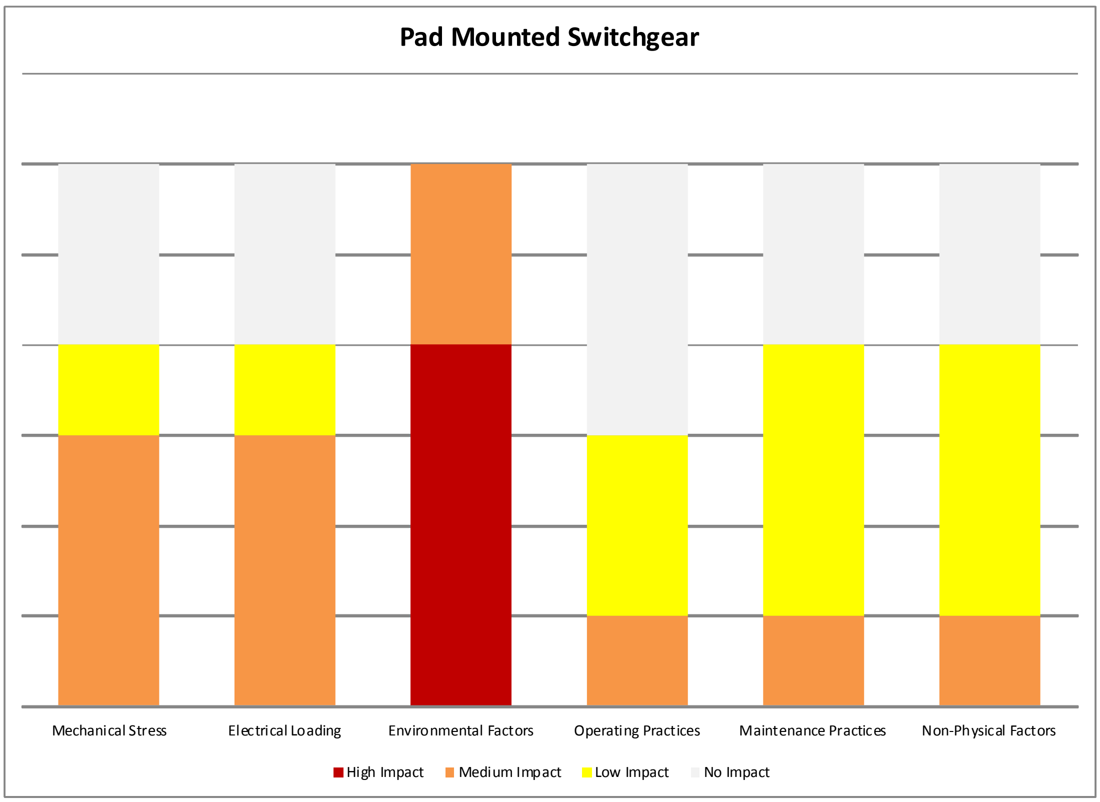


Figure 39-2 Impact of Utilization Factors on the Useful Life of Pad-Mounted Switchgear

40. Ducts

40.1 Asset Description

In areas such as road crossings, ducts provide a conduit for underground cables to travel. Ducts are sized as required and are usually two to six inches in diameter.

40.1.1 Componentization Assumptions

For the purposes of this report, the Ducts asset category has not been componentized.

40.1.2 Design Configuration

For the purposes of this report, the duct types included are clay, polyvinyl chloride (PVC), fiber reinforced epoxy (FRE), and high density polyethylene (HDPE).

40.1.3 System Hierarchy

Ducts are considered to be a part of the Underground Systems asset grouping.

40.2 Degradation Mechanism

The ducts connecting one utility chamber to another cannot easily be assessed for condition without excavating areas suspected of suffering failures. However, water ingress to a utility chamber that is otherwise in sound condition is a good indicator of a failure of a portion of the ductwork. Since there are no specific tests that can be conducted to determine duct integrity at reasonable cost, the duct system is typically treated on an ad hoc basis and repaired or replaced as is determined at the time of cable replacement or failure.

40.3 Useful Life

Based on the Industry Values and Utility Interviews the Useful Life Values, Minimum (MIN UL), Typical (TUL) and Maximum (MAX UL) for Ducts are displayed in Table 40-1.

Table 40-1 Useful Life Values for Ducts

ASSET COMPONENTIZATION	USEFUL LIFE		
	MIN UL	TUL	MAX UL
Ducts	30	50	85

40.3.1 Useful Life Data

This section displays the data used to determine the Useful Life Values for Ducts. Four of the interviewed utilities gave Minimum Useful Life (MIN UL) Values and five of the utilities interviewed gave TUL and MAX UL Values for Ducts (Figure 40-1).

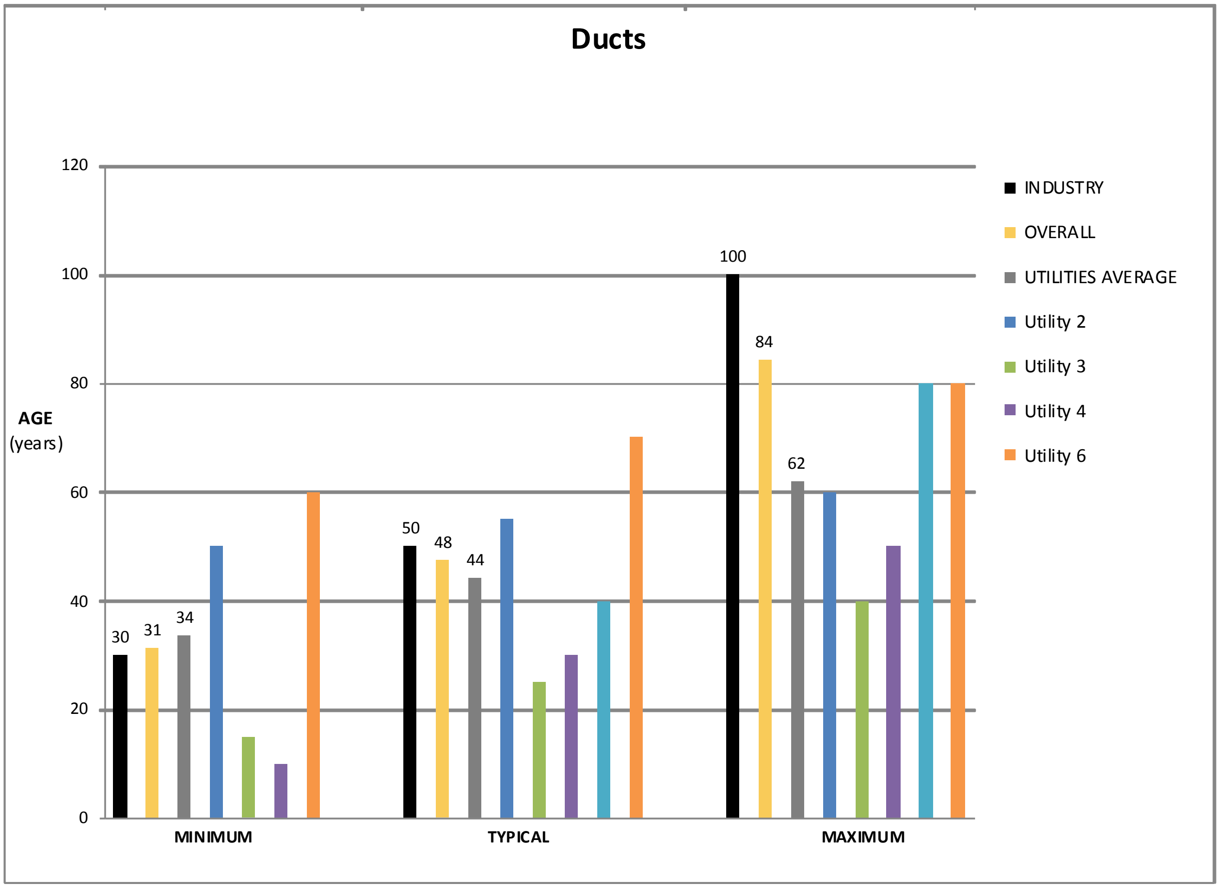


Figure 40-1 Useful Life Values for Ducts

40.4 Impact of Utilization Factors

Based on the Utility Interviews the composite score and overall impact (high medium, low), if any, of each factor on the typical useful life of Ducts are displayed in Table 40-2.

Table 40-2 - Composite Score for Ducts

	Utilization Factors					
	Mechanical Stress	**Electrical Loading**	**Environmental Factors**	**Operating Practices**	**Maintenance Practices**	**Non-Physical Factors**
Composite Score	85%	0%	65%	8%	8%	15%
Overall Rating*	**H**	**NI**	**M**	**NI**	**NI**	**L**
* H = High Impact M = Medium Impact L = Low Impact NI = No Impact						

40.4.1 Utility Interview Data

This section displays the data used to determine the composite score and overall impact (high, medium, low) of each factor on the typical useful life of Ducts. Five of the interviewed utilities provided their input regarding the UFs for Ducts (Figure 40-2).

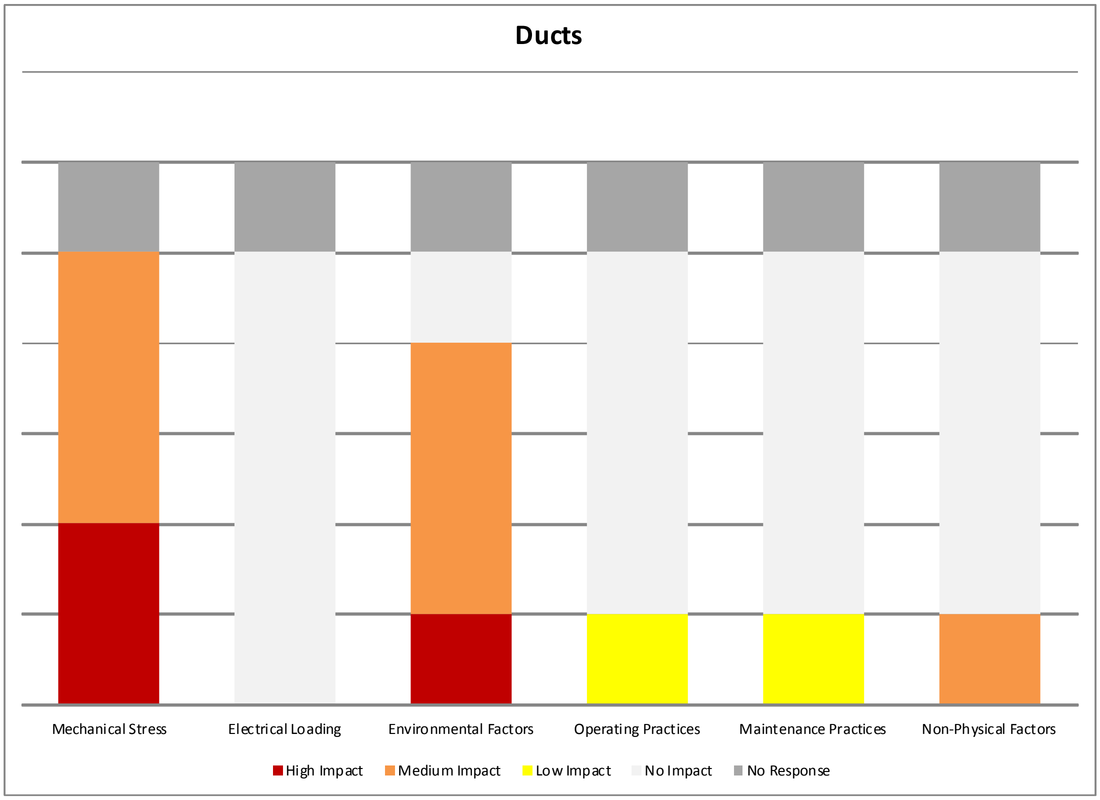


Figure 40-2 Impact of Utilization Factors on the Useful Life of Ducts

41. Concrete Encased Duct Banks

41.1 Asset Description

In areas such as road crossings, ducts provide a conduit for underground cables to travel. They are comprised of a number of ducts, in trench, and typically encased in concrete.

41.1.1 Componentization Assumptions

For the purposes of this report, the Concrete Encased Duct Banks asset category has not been componentized.

41.1.2 System Hierarchy

Concrete Encased Duct Banks are considered to be a part of the Underground Systems asset grouping.

41.2 Degradation Mechanism

The ducts connecting one utility chamber to another cannot easily be assessed for condition without excavating areas suspected of suffering failures. However, water ingress to a utility chamber that is otherwise in sound condition is a good indicator of a failure of a portion of the ductwork. Since there are no specific tests that can be conducted to determine duct integrity at reasonable cost, the duct system is typically treated on an ad hoc basis and repaired or replaced as is determined at the time of cable replacement or failure.

41.3 Useful Life

Based on the Industry Values and Utility Interviews the Useful Life Values, Minimum (MIN UL), Typical (TUL) and Maximum (MAX UL) for Concrete Encased Duct Banks are displayed in Table 41-1

Table 41-1 Useful Life Values for Concrete Encased Duct Banks

ASSET COMPONENTIZATION	USEFUL LIFE		
	MIN UL	TUL	MAX UL
Concrete Encased Duct Banks	35	55	80

41.3.1 Useful Life Data

This section displays the data used to determine the Useful Life Values for Concrete Encased Duct Banks. Five of the interviewed utilities gave Minimum Useful Life (MIN UL) Values and all six of the utilities interviewed gave TUL and MAX UL Values for Concrete Encased Duct Banks (Figure 41-1).

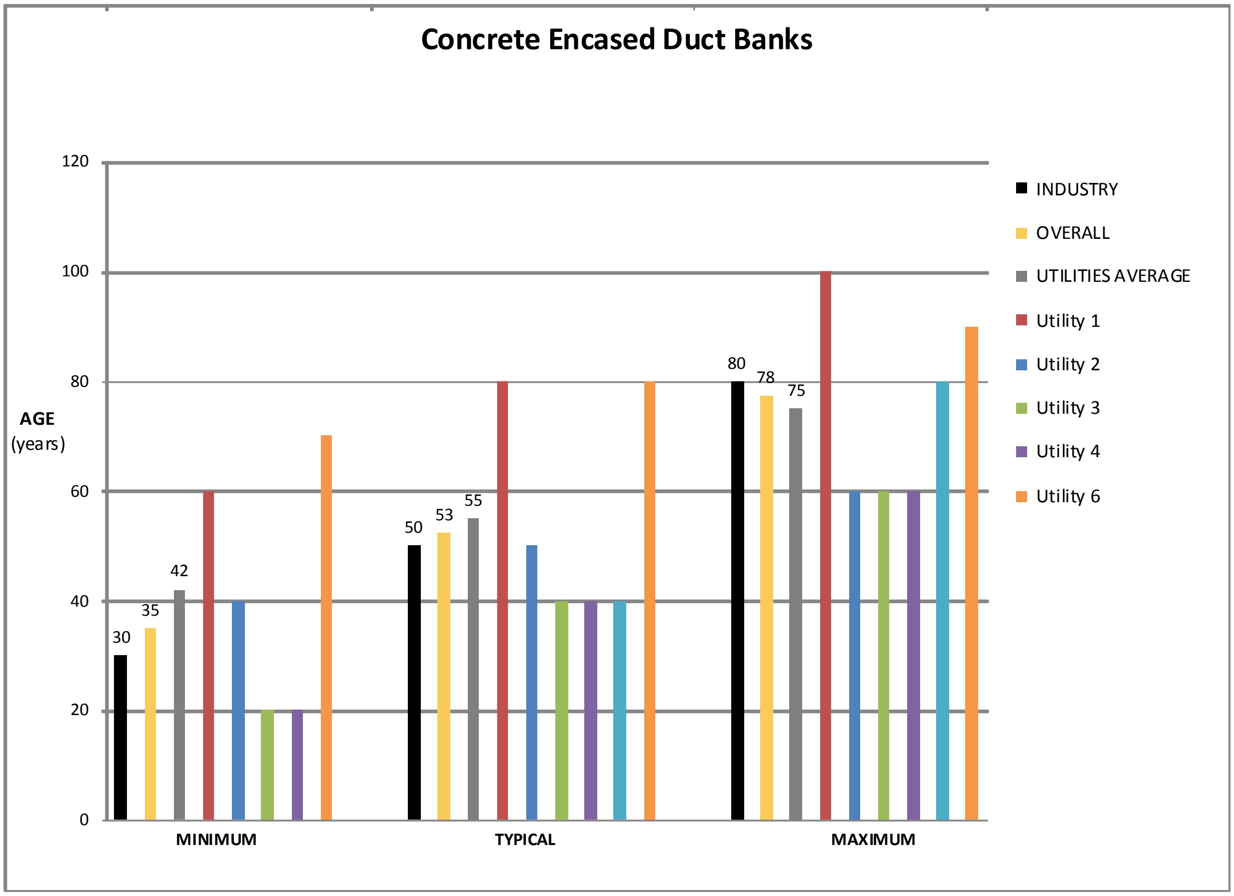


Figure 41-1 Useful Life Values for Concrete Encased Duct Banks

41.4 Impact of Utilization Factors

Based on the Utility Interviews the composite score and overall impact (high medium, low), if any, of each factor on the typical useful life of Concrete Encased Duct Banks are displayed in Table 41-2.

Table 41-2 - Composite Score for Concrete Encased Duct Banks

	Utilization Factors					
	Mechanical Stress	Electrical Loading	Environmental Factors	Operating Practices	Maintenance Practices	Non-Physical Factors
Composite Score	73%	6%	60%	0%	0%	19%
Overall Rating*	**M**	**NI**	**M**	**NI**	**NI**	**L**
* H = High Impact	M = Medium Impact		L = Low Impact		NI = No Impact	

41.4.1 Utility Interview Data

This section displays the data used to determine the composite score and overall impact (high, medium, low) of each factor on the typical useful life of Concrete Encased Duct Banks. All six of the interviewed utilities provided their input regarding the UFs for Concrete Encased Duct Banks (Figure 41-2).

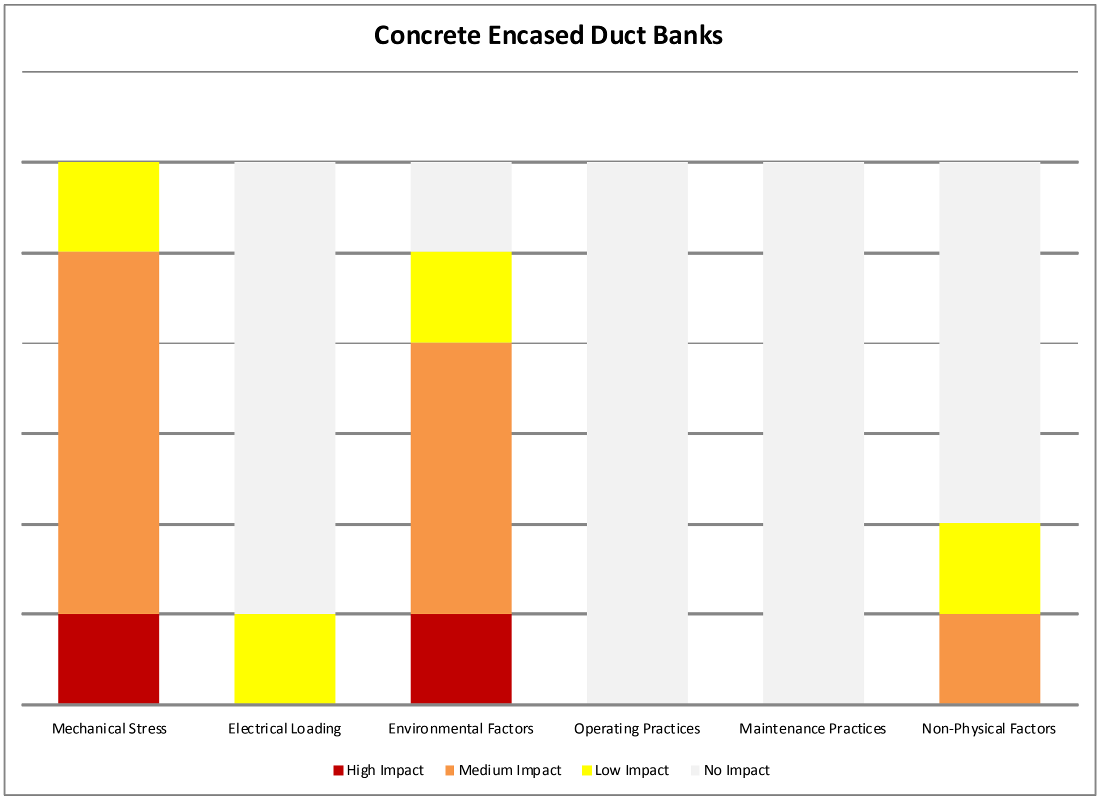


Figure 41-2 Impact of Utilization Factors on the Useful Life of Concrete Encased Duct Banks

42. Cable Chambers

42.1 Asset Description

Cable Chambers facilitate cable pulling into underground ducts and provide access to splices and facilities that require periodic inspections or maintenance. They come in different styles, shapes and sizes according to the location and application. Pre-cast cable chambers are normally installed only outside the traveled portion of the road although some end up under the road surface after road widening. Cast-in-place cable chambers are used under the traveled portion of the road because of their strength and also because they are less expensive to rebuild if they should fail. Customer cable chambers are on customer property and are usually in a more benign environment. Although they supply a specific customer, system cables loop through these chambers so other customers could also be affected by any problems.

42.1.1 Componentization Assumptions

For the purposes of this report, the Cable Chambers has not been componentized..

42.1.2 System Hierarchy

Cable Chambers is considered to be a part of the Underground Systems asset grouping.

42.2 Degradation Mechanism

When located in streets, cable chambers must withstand heavy loads associated with traffic in the street. When located in driving lanes, cable chamber chimney and collar rings must match street grading. Since utility chambers and vaults often experience flooding, they sometimes include drainage sumps and sump pumps. Nevertheless, environmental regulations in some jurisdictions may prohibit the pumping of utility chambers into sewer systems, without testing of the water for environmentally hazardous contaminants.

Although age is loosely related to the condition of underground civil structures, it is not a linear relationship. Other factors such as mechanical loading, exposure to corrosive salts, etc. have stronger effects. Cable chamber degradation commonly includes corrosion of reinforcing steel, spalling of concrete, and rusting of covers or rings. Acidic salts (i.e. sulfates or chlorides) affect corrosion rates. Cable chamber systems also may experience a number of deficiencies or defects. In roadways, defects exist when covers are not level with street surfaces. Conditions that lead to flooding, clogged sumps, and non-functioning sump-pumps also represent major deficiencies in a cable chamber system. Similarly, cable chamber systems with lights that do not function properly constitute defective systems. Deteriorating ductwork associated with cable chambers also requires evaluation in assessing the overall condition of a cable chamber system.

42.3 Useful Life

Based on the Industry Values and Utility Interviews the Useful Life Values, Minimum (MIN UL), Typical (TUL) and Maximum (MAX UL) for Cable Chambers are displayed in Table 42-1.

Table 42-1 Useful Life Values for Cable Chambers

ASSET COMPONENTIZATION	USEFUL LIFE		
	MIN UL	TUL	MAX UL
Cable Chambers	50	60	80

42.3.1 Useful Life Data

This section displays the data used to determine the Useful Life Values for Cable Chambers. Five of the interviewed utilities gave Minimum (Min UL) Values and all six of the utilities interviewed gave TUL and MAX UL for Cable Chambers (Figure 42-1).

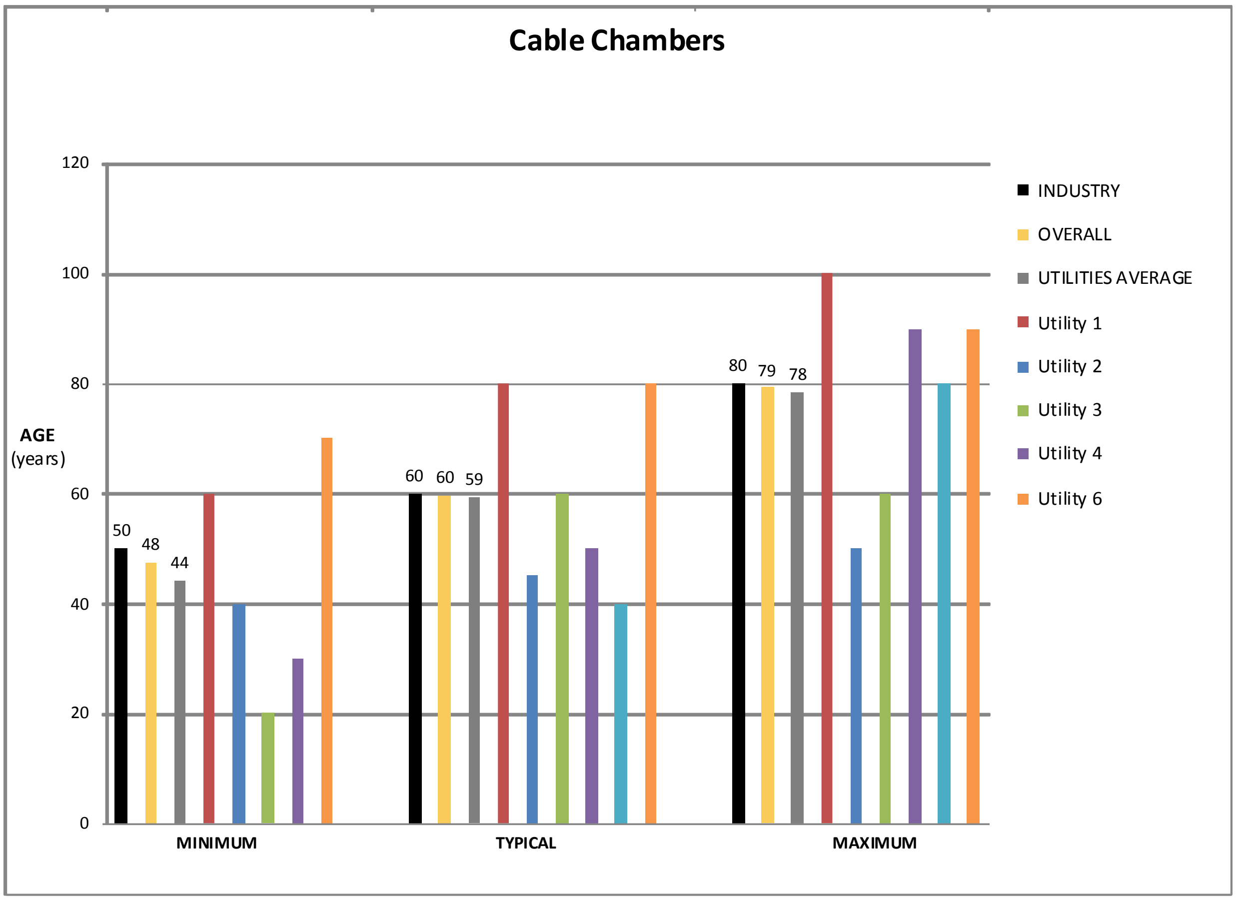


Figure 42-1 Useful Life Values for Cable Chambers

42.4 Impact of Utilization Factors

Based on the Utility Interviews the composite score and overall impact (high medium, low), if any, of each factor on the typical useful life of Cable Chambers are displayed in Table 42-2.

Table 42-2 - Composite Score for Cable Chambers

	Utilization Factors					
	Mechanical Stress	**Electrical Loading**	**Environmental Factors**	**Operating Practices**	**Maintenance Practices**	**Non-Physical Factors**
Composite Score	58%	0%	92%	0%	19%	6%
Overall Rating*	**M**	**NI**	**H**	**NI**	**L**	**NI**
* H = High Impact	M = Medium Impact		L = Low Impact		NI = No Impact	

42.4.1 Utility Interview Data

This section displays the data used to determine the composite score and overall impact (high, medium, low) of each factor on the typical useful life of Cable Chambers. All six of the interviewed utilities provided their input regarding the UFs for Cable Chambers (Figure 42-2).

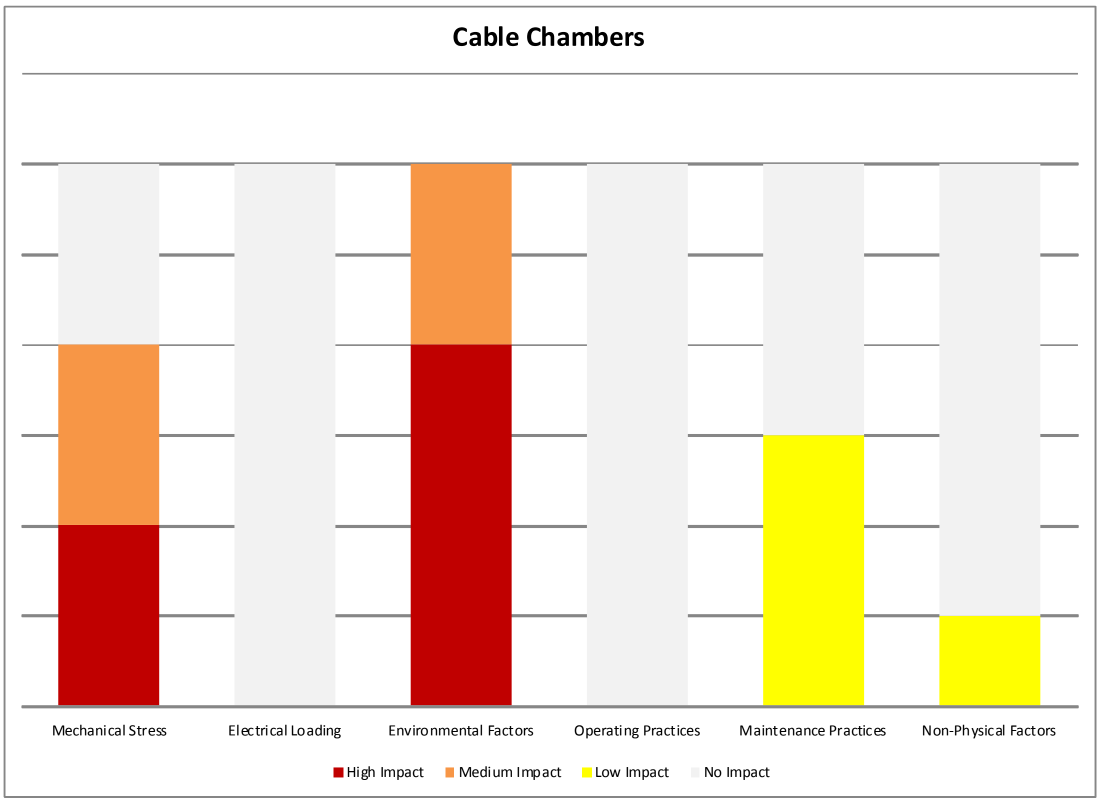


Figure 42-2 Impact of Utilization Factors on the Useful Life of Cable Chambers

43. Remote Supervisory Control and Data Acquisition

43.1 Asset Description

Supervisory Control and Data Acquisition (SCADA) refers to the centralized monitoring and control system of a facility. SCADA remote terminal units (RTUs) allow the master SCADA system to communication, often wirelessly, with field equipment. In general, RTUs collect digital and analog data from equipment, exchange information to the master system, and perform control functions on field devices. They are typically comprised of the following: power supply, CPU, I/O Modules, housing and chassis, communications interface, and software.

43.1.1 Componentization Assumptions

For the purposes of this report, the Remote Supervisory Control and Data Acquisition asset category has not been componentized.

43.1.2 System Hierarchy

Remote Supervisory Control and Data Acquisition is considered to be a part of the Monitoring and Control Systems asset grouping.

43.2 Degradation Mechanism

There are many factors that contribute to the end-of-life of RTUs. Utilities may choose to upgrade or replace older units that are no longer supported by vendors or where spare parts are no longer available. Because RTUs are essentially computer devices, they are prone to obsolescence. For example, older units may lack the ability to interface with Intelligent Electronic Devices (IEDs), be unable to support newer or modern communications media and/or protocols, or not allow for the quantity, resolution and accuracy of modern data acquisition. Legacy units may have limited ability of multiple master communication ports and protocols, or have an inability to segregate data into multiple RTU addresses based on priority.

43.3 Useful Life

Based on the Industry Values and Utility Interviews the Useful Life Values, Minimum (MIN UL), Typical (TUL) and Maximum (MAX UL) for Remote Supervisory Control and Data Acquisition are displayed in Table 43-1.

Table 43-1 Useful Life Values for Remote Supervisory Control and Data Acquisition

ASSET COMPONENTIZATION	USEFUL LIFE		
	MIN UL	TUL	MAX UL
Remote SCADA	15	20	30

43.3.1 Useful Life Data

This section displays the data used to determine the Useful Life Values for Remote Supervisory Control and Data Acquisition. Five of the interviewed utilities gave Minimum, Typical and Maximum Useful Life (MIN UL, TUL and MAX UL) Values for Remote Supervisory Control and Data Acquisition (Figure 43-1).

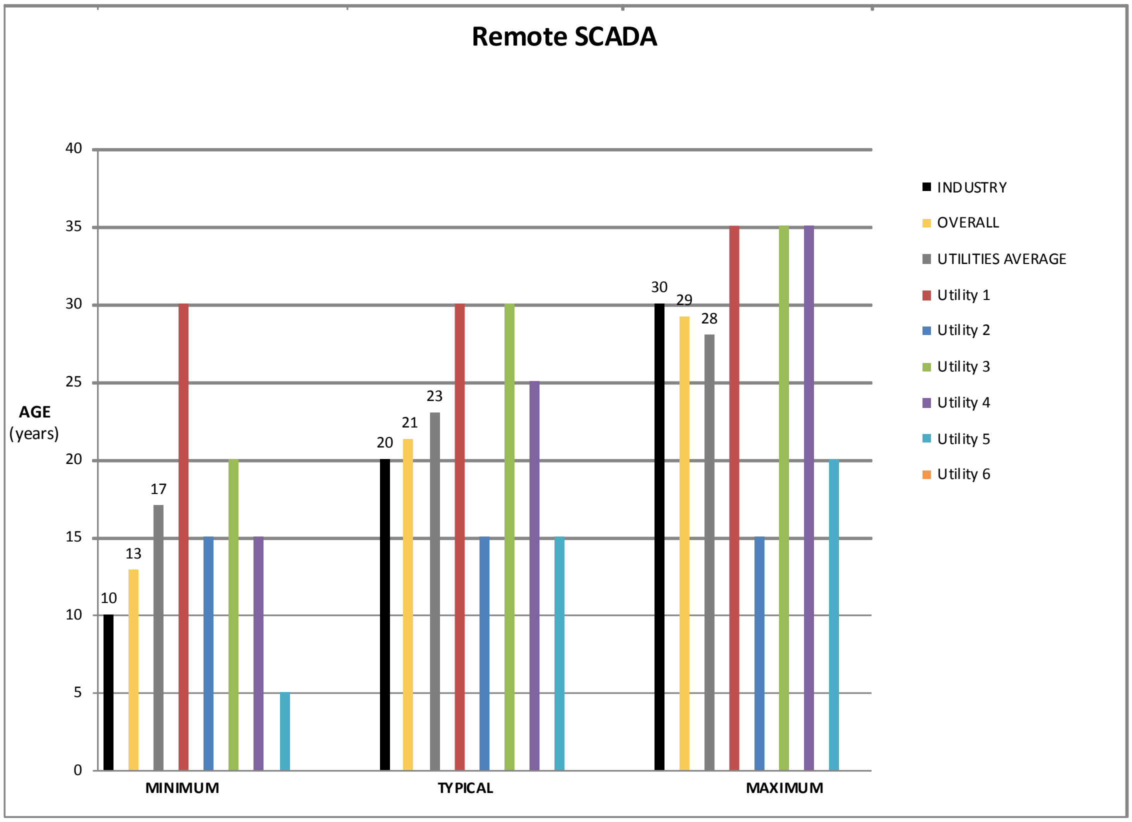


Figure 43-1 Useful Life Values for Remote Supervisory Control and Data Acquisition

43.4 Impact of Utilization Factors

Based on the Utility Interviews the composite score and overall impact (high medium, low), if any, of each factor on the typical useful life of Remote Supervisory Control and Data Acquisition are displayed in Table 43-2.

Table 43-2 - Composite Score for Remote Supervisory Control and Data Acquisition

	Utilization Factors					
	Mechanical Stress	**Electrical Loading**	**Environmental Factors**	**Operating Practices**	**Maintenance Practices**	**Non-Physical Factors**
Composite Score	0%	0%	19%	0%	44%	95%
Overall Rating*	**NI**	**NI**	**L**	**NI**	**L**	**H**
* H = High Impact	M = Medium Impact		L = Low Impact		NI = No Impact	

43.4.1 Utility Interview Data

This section displays the data used to determine the composite score and overall impact (high, medium, low) of each factor on the typical useful life of Remote Supervisory Control and Data Acquisition. Five of the interviewed utilities provided their input regarding the UFs for Remote Supervisory Control and Data Acquisition (Figure 43-2).

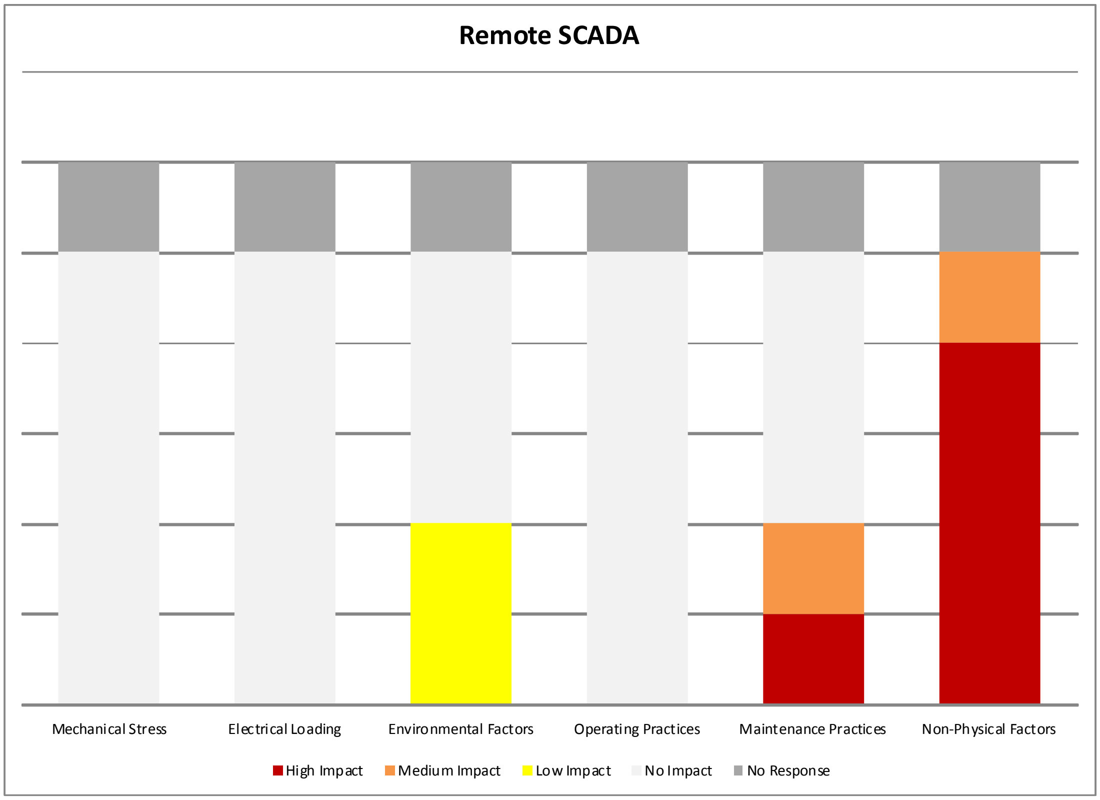


Figure 43-2 Impact of Utilization Factors on the Useful Life of Remote Supervisory Control and Data Acquisition

I APPENDIX – PERCENT OF ASSETS IN THE USEFUL LIFE RANGE

This Appendix describes the statistical analysis that was performed to estimate the percentage of assets that fall within the useful life range (MIN UL – MAX UL). Note that the values of MIN UL and MAX UL were determined using industry research and utility interviews. The statistical analysis estimates the percentage of an a asset population that will fall in the useful life range. The following is discussed:

- Review of definitions
- Assumptions used in useful life analysis
- Useful life range coverage
- Sample calculation of useful life range

Definitions used in Useful Life Analysis for Utility Asset Groups

End-of-life - An asset reaches its end-of-life when it is considered unable to perform its functions as designed physically.

Useful Life Range (MIN UL – MAX UL) - The asset life range that covers the end-of-life year data for the majority of the population in a specific asset group.

Typical useful life (TUL) - The value that corresponds to the peak of failure probability density function (useful life distribution function in this project) for a specific asset category, assuming the failure distribution is of unimodal type (i.e. with only one global maximum).

In mathematics, this value is called the mode. It is the value of end-of-life year datum that is most likely to be sampled at a single sampling, or the value that appears most frequently at a group sampling.

Mean useful life (μ) - Probability weighted average value. It is the arithmetic average value of the end-of-life year data for a group of sampled assets, provided that the sample size is sufficiently large and representative.

Minimum useful life (MIN UL) - The lower set value of useful life range. It refers to the age when a small percentage of assets reaches the physical end-of-life. In this project, it is defined as

$$\text{MIN UL} = \mu - k\sigma \qquad \text{(Equation 1)}$$

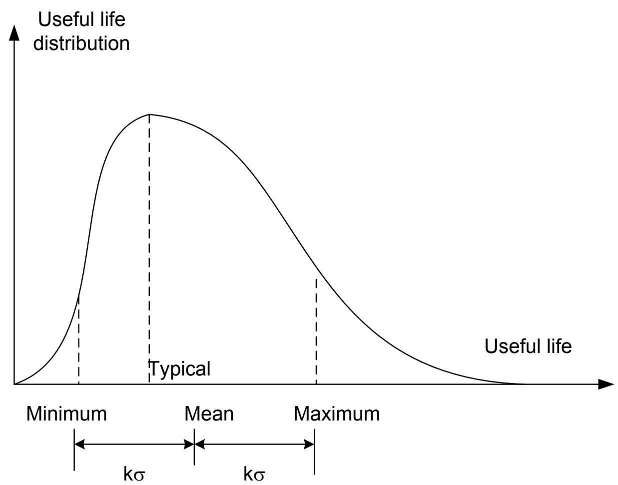
Where $k = \sqrt{3}$ (defined in later section)
σ standard deviation of useful life distribution

Maximum useful life (MAX UL)

The upper set value of useful life range. It refers to the age when most of assets reach the physical end-of-life. In this project, it is defined as

$$\text{MAX UL} = \mu + k\sigma \qquad \text{(Equation 2)}$$

Where $k = \sqrt{3}$ (defined in later section)
σ standard deviation of useful life distribution



Assumptions in Useful Life Analysis for Utility Asset Groups

To facilitate the analysis on useful life range coverage for utility asset groups, the following assumptions are made based on the information obtained during utility interviews as well as the character of various types of asset groups.

A. In a utility, there are always some asset groups that have their useful life distribution curve severely skewed to the either end of useful life range.

B. For all asset categories, the useful lives distribution is such that the mean (μ) is within k x standard deviation (σ) from MIN UL and MAX UL, regardless of where TUL is relative to the mean (μ).

C. For any specific asset group, the typical useful life is always captured within the useful life range.

D. For some asset groups, the typical values coincide with either minimum or maximum useful life values.

Assumption A is based on the fact that, due to different degradation mechanisms and operation modes, some of the asset groups have some predominant factors than exclusively determine the probability of failure of the asset group, thus making the asset end-of-life not follow normal distribution or other symmetrical distributions.

Assumption B is expanded from the special case where the asset end-of-life follows normal distribution. Under such condition, a utility needs to assign the same k coefficient to ensure that there is always a fixed percentage of asset population that is covered by the useful life range, regardless of how much the standard deviation is. If it is agreed that the same k coefficient is also adopted for the non symmetrical distribution, assumption B can be validated.

Assumptions C and D are validated by the results of interviews with various utilities.

In mathematics, it can be proven that the difference between the mean and the mode of a unimodal distribution is less than or equal to the square root of three times the standard deviation ($\sqrt{3}\sigma$).

With assumptions A, B and C, it can be concluded that the k coefficients should be greater than or equal to $\sqrt{3}$, applicable to all the asset groups.

With all the above assumptions validated, it is reasonable to conclude that the useful life range provided by utilities is within the interval between $\mu - \sqrt{3}\sigma$ and $\mu + \sqrt{3}\sigma$.

Useful Life Range Coverage

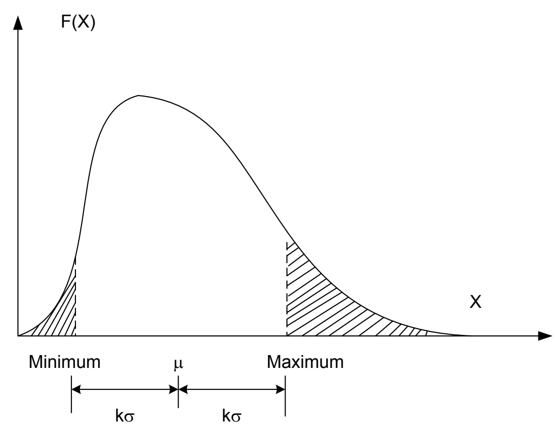
For any uni-modal useful life distribution, the coverage of a specific useful life range can be calculated using Chebyshev's inequality.

Chebyshev's Inequality

Let *X* be a random variable with mean value μ and finite variance σ^2. Then for any real number $k > 1$,

$$\Pr(|X - \mu| \geq k\sigma) \leq \frac{1}{k^2}$$

where the above inequality refers to the probability of the shadowed area in the following diagram.



Therefore the coverage of a useful life range is $1-1/k^2$.
For the useful life range specified in the previous section, it can be estimated that the range covers at least $1 - \frac{1}{(\sqrt{3})^2} = 66.7\%$ of the whole population.

In case the useful life distribution is close to normal distribution for some asset groups, the percentage of data covered by the useful life range is determined by:

$$\Pr(|X - \mu| \leq k\sigma) = \operatorname{erf}\left(\frac{k}{\sqrt{2}}\right)$$

Where erf is the error function defined as

$$erf(x) = \frac{2}{\sqrt{\pi}}\int_0^x e^{-t^2}\,dt$$

At $k = \sqrt{3}$, it can be calculated that the useful life range covers $\operatorname{erf}\left(\frac{\sqrt{3}}{\sqrt{2}}\right) = 91.7\%$ of the whole population.
In general, the percentage of the whole population covered by the useful life range defined in this study is between 66.7% and 91.7%.

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Appendix H

2019 Proposed Incremental Revenue Requirement Rate Rider Calculation to be effective May 1, 2019 – Offline Calculation

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Rate Rider Calculation

Rate Class	Service Charge % Revenue	Distribution Volumetric Rate % Revenue kWh	Distribution Volumetric Rate % Revenue kW	Service Charge Revenue	Distribution Volumetric Rate Revenue kWh	Distribution Volumetric Rate Revenue kW	Total Revenue by Rate Class	Billed Customers or Connections	Billed kWh	Billed kW	Service Charge Rate Rider	Distribution Volumetric Rate kWh Rate Rider	Distribution Volumetric Rate kW Rate Rider
	From Sheet 8	From Sheet 8	From Sheet 8	Col C * Col I total	Col D* Col I total	Col E* Col I total		From Sheet 4	From Sheet 4	From Sheet 4	Col F / Col K / 12	Col G / Col L	Col H / Col M
RESIDENTIAL	61.45%	0.00%	0.00%	$ 1,124,339	$ -	$ -	$ 1,124,339	20,188	193,694,443	-	$ 4.64	$ -	$ -
GENERAL SERVICE LESS THAN 50 KW	5.97%	4.99%	0.00%	$ 109,161	$ 91,300	$ -	$ 200,461	1,810	50,527,239	-	$ 5.03	$ 0.0018	$ -
GENERAL SERVICE 50 TO 999 KW	1.88%	0.00%	14.75%	$ 34,333	$ -	$ 269,816	$ 304,149	186	135,373,696	394,783	$ 15.38	$ -	$ 0.6835
GENERAL SERVICE 1,000 TO 4,999 KW	0.24%	0.00%	8.81%	$ 4,339	$ -	$ 161,161	$ 165,500	11	99,309,703	262,132	$ 32.87	$ -	$ 0.6148
UNMETERED SCATTERED LOAD	0.14%	0.05%	0.00%	$ 2,575	$ 894	$ -	$ 3,469	152	934,714	-	$ 1.41	$ 0.0010	$ -
SENTINEL LIGHTING	0.19%	0.00%	0.24%	$ 3,483	$ -	$ 4,478	$ 7,961	173	260,238	704	$ 1.68	$ -	$ 6.3607
STREET LIGHTING	1.25%	0.00%	0.05%	$ 22,853	$ -	$ 868	$ 23,721	4,674	1,128,400	3,155	$ 0.41	$ -	$ 0.2750
Total	71.11%	5.04%	23.85%	$ 1,301,083	$ 92,195	$ 436,322	$ 1,829,600	27,194	481,228,433	660,774			
			100.00%										
							$ 1,829,600						

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Appendix I

Proposed Bill Impacts – Offline Calculation

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Ontario Energy Board

Incentive Regulation Model for 2019 Filers

Table 1

RATE CLASSES / CATEGORIES (eg: Residential TOU, Residential Retailer)	Units	RPP? Non-RPP Retailer? Non-RPP Other?	Current Loss Factor (eg: 1.0351)	Proposed Loss Factor	Consumption (kWh)	Demand kW (if applicable)	RTSR Demand or Demand-Interval?	Billing Determinant Applied to Fixed Charge for Unmetered Classes (e.g. # of devices/connections).
RESIDENTIAL SERVICE CLASSIFICATION		RPP	1.0560	1.056	750		N/A	
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION		RPP	1.0560	1.056	2,000		N/A	
GENERAL SERVICE 50 TO 999 KW SERVICE CLASSIFICATION		Non-RPP (Other)	1.0560	1.056	328,500	500	DEMAND	
GENERAL SERVICE 1,000 TO 4,999 KW SERVICE CLASSIFICATION		Non-RPP (Other)	1.0560	1.056	1,600,000	2,500	EMAND - INTERVAL	
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION		RPP	1.0560	1.056	150		N/A	
SENTINEL LIGHTING SERVICE CLASSIFICATION		RPP	1.0560	1.056	650	1	DEMAND	
STREET LIGHTING SERVICE CLASSIFICATION		Non-RPP (Other)	1.0560	1.056	94,033	251	DEMAND	
RESIDENTIAL SERVICE CLASSIFICATION		RPP	1.0560	1.056	342		N/A	
RESIDENTIAL SERVICE CLASSIFICATION		RPP	1.0560	1.056	1,000		N/A	
RESIDENTIAL SERVICE CLASSIFICATION		RPP	1.0560	1.056	2,500		N/A	
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION		RPP	1.0560	1.056	500		N/A	
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION		RPP	1.0560	1.056	5,000		N/A	
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION		RPP	1.0560	1.056	15,000		N/A	
GENERAL SERVICE 50 TO 999 KW SERVICE CLASSIFICATION		Non-RPP (Other)	1.0560	1.056	20,000	60	DEMAND	
GENERAL SERVICE 50 TO 999 KW SERVICE CLASSIFICATION		Non-RPP (Other)	1.0560	1.056	500,000	750	DEMAND	
GENERAL SERVICE 1,000 TO 4,999 KW SERVICE CLASSIFICATION		Non-RPP (Other)	1.0560	1.056	1,000,000	2,000	EMAND - INTERVAL	
GENERAL SERVICE 1,000 TO 4,999 KW SERVICE CLASSIFICATION		Non-RPP (Other)	1.0560	1.056	3,000,000	4,000	EMAND - INTERVAL	
GENERAL SERVICE 50 TO 999 KW SERVICE CLASSIFICATION		RPP	1.0560	1.056	69,000	160	DEMAND	
Add additional scenarios if required								
Add additional scenarios if required								

Table 2

RATE CLASSES / CATEGORIES (eg: Residential TOU, Residential Retailer)	Units	Sub-Total						Total	
		A		B		C		Total Bill	
		$	%	$	%	$	%	$	%
RESIDENTIAL SERVICE CLASSIFICATION - RPP									
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION - RPP									
GENERAL SERVICE 50 TO 999 KW SERVICE CLASSIFICATION - Non-RPP (Other)									
GENERAL SERVICE 1,000 TO 4,999 KW SERVICE CLASSIFICATION - Non-RPP (Other)									
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION - RPP									
SENTINEL LIGHTING SERVICE CLASSIFICATION - RPP									
STREET LIGHTING SERVICE CLASSIFICATION - Non-RPP (Other)									
RESIDENTIAL SERVICE CLASSIFICATION - RPP									
RESIDENTIAL SERVICE CLASSIFICATION - RPP									
RESIDENTIAL SERVICE CLASSIFICATION - RPP									
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION - RPP									
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION - RPP									
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION - RPP									
GENERAL SERVICE 50 TO 999 KW SERVICE CLASSIFICATION - Non-RPP (Other)									
GENERAL SERVICE 50 TO 999 KW SERVICE CLASSIFICATION - Non-RPP (Other)									
GENERAL SERVICE 1,000 TO 4,999 KW SERVICE CLASSIFICATION - Non-RPP (Other)									
GENERAL SERVICE 1,000 TO 4,999 KW SERVICE CLASSIFICATION - Non-RPP (Other)									
GENERAL SERVICE 50 TO 999 KW SERVICE CLASSIFICATION - RPP									

Customer Class:	**RESIDENTIAL SERVICE CLASSIFICATION**
RPP / Non-RPP:	**RPP**
Consumption	**750** kWh
Demand	**-** kW
Current Loss Factor	**1.0560**
Proposed/Approved Loss Factor	**1.0560**

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 23.48	1	$ 23.48	$ 26.72	1	$ 26.72	$ 3.24	13.80%
Distribution Volumetric Rate	$ 0.0034	750	$ 2.55	$ -	750	$ -	$ (2.55)	-100.00%
RRRP Credit		750	$ -		750	$ -		
DRP Adjustment		750	$ -		750	$ -	$ -	
Fixed Rate Riders	$ -	1	$ -	$ 4.64	1	$ 4.64	$ 4.64	
Volumetric Rate Riders	$ -	750	$ -	$ -	750	$ -	$ -	
Sub-Total A (excluding pass through)			**$ 26.03**			**$ 31.36**	**$ 5.33**	**20.48%**
Line Losses on Cost of Power	$ 0.0820	42	$ 3.44	$ 0.0820	42	$ 3.44	$ -	0.00%
Total Deferral/Variance Account Rate Riders	-$ 0.0014	750	-$ 1.05	-$ 0.0053	750	-$ 3.98	$ (2.93)	278.57%
CBR Class B Rate Riders	-$ 0.0001	750	-$ 0.08	$ -	750	$ -	$ 0.08	-100.00%
GA Rate Riders	$ -	750	$ -	$ -	750	$ -	$ -	
Low Voltage Service Charge	$ 0.0026	750	$ 1.95	$ 0.0026	750	$ 1.95	$ -	0.00%
Smart Meter Entity Charge (if applicable)	$ 0.57	1	$ 0.57	$ 0.57	1	$ 0.57	$ -	0.00%
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders		750	$ -	$ -	750	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 30.87**			**$ 33.35**	**$ 2.48**	**8.04%**
RTSR - Network	$ 0.0068	792	$ 5.39	$ 0.0065	792	$ 5.15	$ (0.24)	-4.41%
RTSR - Connection and/or Line and Transformation Connection	$ 0.0056	792	$ 4.44	$ 0.0053	792	$ 4.20	$ (0.24)	-5.36%
Sub-Total C - Delivery (including Sub-Total B)			**$ 40.69**			**$ 42.70**	**$ 2.01**	**4.93%**
Wholesale Market Service Charge (WMSC)	$ 0.0036	792	$ 2.85	$ 0.0036	792	$ 2.85	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	$ 0.0003	792	$ 0.24	$ 0.0003	792	$ 0.24	$ -	0.00%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
Ontario Electricity Support Program (OESP)								
TOU - Off Peak	$ 0.0650	488	$ 31.69	$ 0.0650	488	$ 31.69	$ -	0.00%
TOU - Mid Peak	$ 0.0940	128	$ 11.99	$ 0.0940	128	$ 11.99	$ -	0.00%
TOU - On Peak	$ 0.1320	135	$ 17.82	$ 0.1320	135	$ 17.82	$ -	0.00%
Total Bill on TOU (before Taxes)			**$ 105.52**			**$ 107.53**	**$ 2.01**	**1.90%**
HST	13%		$ 13.72	13%		$ 13.98	$ 0.26	1.90%
8% Rebate	8%		$ (8.44)	8%		$ (8.60)	$ (0.16)	
Total Bill on TOU			**$ 110.80**			**$ 112.90**	**$ 2.11**	**1.90%**

Customer Class:	GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION
RPP / Non-RPP:	RPP
Consumption	2,000 kWh
Demand	- kW
Current Loss Factor	1.0560
Proposed/Approved Loss Factor	1.0560

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	$ 28.37	1	$ 28.37	$ 28.71	1	$ 28.71	$ 0.34	1.20%
Distribution Volumetric Rate	$ 0.0102	2000	$ 20.40	$ 0.0103	2000	$ 20.60	$ 0.20	0.98%
RRRP Credit		2000	$ -		2000	$ -		
DRP Adjustment		2000	$ -		2000	$ -	$ -	
Fixed Rate Riders	$ -	1	$ -	$ 5.03	1	$ 5.03	$ 5.03	
Volumetric Rate Riders	$ -	2000	$ -	$ 0.0018	2000	$ 3.61	$ 3.61	
Sub-Total A (excluding pass through)			**$ 48.77**			**$ 57.95**	**$ 9.18**	**18.82%**
Line Losses on Cost of Power	$ 0.0820	112	$ 9.18	$ 0.0820	112	$ 9.18	$ -	0.00%
Total Deferral/Variance Account Rate Riders	-$ 0.0014	2,000	-$ 2.80	-$ 0.0053	2,000	-$ 10.60	$ (7.80)	278.57%
CBR Class B Rate Riders	-$ 0.0001	2,000	-$ 0.20	$ -	2,000	$ -	$ 0.20	-100.00%
GA Rate Riders	$ -	2,000	$ -	$ -	2,000	$ -	$ -	
Low Voltage Service Charge	$ 0.0024	2,000	$ 4.80	$ 0.0024	2,000	$ 4.80	$ -	0.00%
Smart Meter Entity Charge (if applicable)	$ 0.57	1	$ 0.57	$ 0.57	1	$ 0.57	$ -	0.00%
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders		2,000	$ -	$ -	2,000	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 60.32**			**$ 61.90**	**$ 1.58**	**2.62%**
RTSR - Network	$ 0.0060	2,112	$ 12.67	$ 0.0057	2,112	$ 12.04	$ (0.63)	-5.00%
RTSR - Connection and/or Line and Transformation Connection	$ 0.0053	2,112	$ 11.19	$ 0.0050	2,112	$ 10.56	$ (0.63)	-5.66%
Sub-Total C - Delivery (including Sub-Total B)			**$ 84.19**			**$ 84.50**	**$ 0.31**	**0.37%**
Wholesale Market Service Charge (WMSC)	$ 0.0036	2,112	$ 7.60	$ 0.0036	2,112	$ 7.60	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	$ 0.0003	2,112	$ 0.63	$ 0.0003	2,112	$ 0.63	$ -	0.00%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
Ontario Electricity Support Program (OESP)								
TOU - Off Peak	$ 0.0650	1,300	$ 84.50	$ 0.0650	1,300	$ 84.50	$ -	0.00%
TOU - Mid Peak	$ 0.0940	340	$ 31.96	$ 0.0940	340	$ 31.96	$ -	0.00%
TOU - On Peak	$ 0.1320	360	$ 47.52	$ 0.1320	360	$ 47.52	$ -	0.00%
Total Bill on TOU (before Taxes)			**$ 256.66**			**$ 256.97**	**$ 0.31**	**0.12%**
HST	13%		$ 33.37	13%		$ 33.41	$ 0.04	0.12%
8% Rebate	8%		$ (20.53)	8%		$ (20.56)	$ (0.03)	
Total Bill on TOU			**$ 269.49**			**$ 269.82**	**$ 0.33**	**0.12%**

Customer Class:	**GENERAL SERVICE 50 TO 999 KW SERVICE CLASSIFICATION**	
RPP / Non-RPP:	**Non-RPP (Other)**	
Consumption	**328,500**	**kWh**
Demand	**500**	**kW**
Current Loss Factor	**1.0560**	
Proposed/Approved Loss Factor	**1.0560**	

	Current OEB-Approved			**Proposed**			**Impact**	
	Rate ($)	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	**$ 86.83**	1	$ 86.83	**$ 87.87**	1	$ 87.87	$ 1.04	1.20%
Distribution Volumetric Rate	**$ 3.8580**	500	$ 1,929.00	**$ 3.9043**	500	$ 1,952.15	$ 23.15	1.20%
RRRP Credit		500	$ -		500	$ -		
DRP Adjustment		500	$ -		500	$ -	$ -	
Fixed Rate Riders	**$ -**	1	$ -	**$ 15.38**	1	$ 15.38	$ 15.38	
Volumetric Rate Riders	**$ -**	500	$ -	**$ 0.6835**	500	$ 341.73	$ 341.73	
Sub-Total A (excluding pass through)			**$ 2,015.83**			**$ 2,397.13**	**$ 381.30**	**18.92%**
Line Losses on Cost of Power	**$ -**	-	$ -	**$ -**	-	$ -	$ -	
Total Deferral/Variance Account Rate Riders	**-$ 0.7065**	500	-$ 353.25	**-$ 1.7801**	500	-$ 890.05	$ (536.80)	151.96%
CBR Class B Rate Riders	**-$ 0.0276**	500	-$ 13.80	**$ -**	500	$ -	$ 13.80	-100.00%
GA Rate Riders	**-$ 0.0010**	328,500	-$ 328.50	**$ 0.0137**	328,500	$ 4,500.45	$ 4,828.95	-1470.00%
Low Voltage Service Charge	**$ 1.0483**	500	$ 524.15	**$ 1.0483**	500	$ 524.15	$ -	0.00%
Smart Meter Entity Charge (if applicable)	**$ -**	1	$ -	**$ -**	1	$ -	$ -	
Additional Fixed Rate Riders	**$ -**	1	$ -	**$ -**	1	$ -	$ -	
Additional Volumetric Rate Riders		500	$ -	**$ -**	500	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 1,844.43**			**$ 6,531.68**	**$ 4,687.25**	**254.13%**
RTSR - Network	**$ 2.6217**	500	$ 1,310.85	**$ 2.4869**	500	$ 1,243.45	$ (67.40)	-5.14%
RTSR - Connection and/or Line and Transformation Connection	**$ 2.2146**	500	$ 1,107.30	**$ 2.0933**	500	$ 1,046.65	$ (60.65)	-5.48%
Sub-Total C - Delivery (including Sub-Total B)			**$ 4,262.58**			**$ 8,821.78**	**$ 4,559.20**	**106.96%**
Wholesale Market Service Charge (WMSC)	**$ 0.0036**	346,896	$ 1,248.83	**$ 0.0036**	346,896	$ 1,248.83	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	**$ 0.0003**	346,896	$ 104.07	**$ 0.0003**	346,896	$ 104.07	$ -	0.00%
Standard Supply Service Charge	**$ 0.25**	1	$ 0.25	**$ 0.25**	1	$ 0.25	$ -	0.00%
Ontario Electricity Support Program (OESP)								
Average IESO Wholesale Market Price	**$ 0.1101**	346,896	$ 38,193.25	**$ 0.1101**	346,896	$ 38,193.25	$ -	0.00%
Total Bill on Average IESO Wholesale Market Price			**$ 43,808.97**			**$ 48,368.17**	**$ 4,559.20**	**10.41%**
HST	13%		$ 5,695.17	13%		$ 6,287.86	$ 592.70	10.41%
8% Rebate	8%		$ -	8%		$ -		
Total Bill on Average IESO Wholesale Market Price			**$ 49,504.14**			**$ 54,656.04**	**$ 5,151.90**	**10.41%**

Customer Class:	**GENERAL SERVICE 1,000 TO 4,999 KW SERVICE CLASSIFICATION**
RPP / Non-RPP:	**Non-RPP (Other)**
Consumption	**1,600,000 kWh**
Demand	**2,500 kW**
Current Loss Factor	**1.0560**
Proposed/Approved Loss Factor	**1.0560**

	Current OEB-Approved			**Proposed**			**Impact**	
	Rate ($)	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	$ 185.55	1	$ 185.55	$ 187.78	1	$ 187.78	$ 2.23	1.20%
Distribution Volumetric Rate	$ 3.4705	2500	$ 8,676.25	$ 3.5121	2500	$ 8,780.25	$ 104.00	1.20%
RRRP Credit		2500	$ -		2500	$ -		
DRP Adjustment		2500	$ -		2500	$ -	$ -	
Fixed Rate Riders	$ -	1	$ -	$ 32.87	1	$ 32.87	$ 32.87	
Volumetric Rate Riders	$ -	2500	$ -	$ 0.6148	2500	$ 1,537.02	$ 1,537.02	
Sub-Total A (excluding pass through)			**$ 8,861.80**			**$ 10,537.92**	**$ 1,676.12**	**18.91%**
Line Losses on Cost of Power	$ -	-	$ -	$ -	-	$ -	$ -	
Total Deferral/Variance Account Rate Riders	-$ 0.9398	2,500	-$ 2,349.50	-$ 1.9908	2,500	-$ 4,977.00	$ (2,627.50)	111.83%
CBR Class B Rate Riders	-$ 0.0341	2,500	-$ 85.25	$ -	2,500	$ -	$ 85.25	-100.00%
GA Rate Riders	-$ 0.0010	1,600,000	-$ 1,600.00	$ 0.0137	1,600,000	$ 21,920.00	$ 23,520.00	-1470.00%
Low Voltage Service Charge	$ 1.0483	2,500	$ 2,620.75	$ 1.0483	2,500	$ 2,620.75	$ -	0.00%
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders		2,500	$ -	$ -	2,500	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 7,447.80**			**$ 30,101.67**	**$ 22,653.87**	**304.17%**
RTSR - Network	$ 2.6217	2,500	$ 6,554.25	$ 2.4869	2,500	$ 6,217.25	$ (337.00)	-5.14%
RTSR - Connection and/or Line and Transformation Connection	$ 2.2146	2,500	$ 5,536.50	$ 2.0933	2,500	$ 5,233.25	$ (303.25)	-5.48%
Sub-Total C - Delivery (including Sub-Total B)			**$ 19,538.55**			**$ 41,552.17**	**$ 22,013.62**	**112.67%**
Wholesale Market Service Charge (WMSC)	$ 0.0036	1,689,600	$ 6,082.56	$ 0.0036	1,689,600	$ 6,082.56	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	$ 0.0003	1,689,600	$ 506.88	$ 0.0003	1,689,600	$ 506.88	$ -	0.00%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
Ontario Electricity Support Program (OESP)								
Average IESO Wholesale Market Price	$ 0.1101	1,689,600	$ 186,024.96	$ 0.1101	1,689,600	$ 186,024.96	$ -	0.00%
Total Bill on Average IESO Wholesale Market Price			**$ 212,153.20**			**$ 234,166.82**	**$ 22,013.62**	**10.38%**
HST	13%		$ 27,579.92	13%		$ 30,441.69	$ 2,861.77	10.38%
8% Rebate	8%		$ -	8%		$ -		
Total Bill on Average IESO Wholesale Market Price			**$ 239,733.12**			**$ 264,608.51**	**$ 24,875.39**	**10.38%**

Customer Class:	UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION
RPP / Non-RPP:	RPP
Consumption	150 kWh
Demand	- kW
Current Loss Factor	1.0560
Proposed/Approved Loss Factor	1.0560

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 7.97	1	$ 7.97	$ 8.07	1	$ 8.07	$ 0.10	1.25%
Distribution Volumetric Rate	$ 0.0054	150	$ 0.81	$ 0.0055	150	$ 0.83	$ 0.01	1.85%
RRRP Credit			$ -		150	$ -		
DRP Adjustment		150	$ -		150	$ -	$ -	
Fixed Rate Riders	$ -	1	$ -	$ 1.41	1	$ 1.41	$ 1.41	
Volumetric Rate Riders	$ -	150	$ -	$ 0.0010	150	$ 0.14	$ 0.14	
Sub-Total A (excluding pass through)			**$ 8.78**			**$ 10.45**	**$ 1.67**	**19.03%**
Line Losses on Cost of Power	$ 0.0820	8	$ 0.69	$ 0.0820	8	$ 0.69	$ -	0.00%
Total Deferral/Variance Account Rate Riders	-$ 0.0012	150	-$ 0.18	-$ 0.0053	150	-$ 0.80	$ (0.62)	341.67%
CBR Class B Rate Riders	-$ 0.0001	150	-$ 0.02	$ -	150	$ -	$ 0.02	-100.00%
GA Rate Riders	$ -	150	$ -	$ -	150	$ -	$ -	
Low Voltage Service Charge	$ 0.0024	150	$ 0.36	$ 0.0024	150	$ 0.36	$ -	0.00%
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders		150	$ -	$ -	150	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 9.63**			**$ 10.70**	**$ 1.07**	**11.11%**
RTSR - Network	$ 0.0060	158	$ 0.95	$ 0.0057	158	$ 0.90	$ (0.05)	-5.00%
RTSR - Connection and/or Line and Transformation Connection	$ 0.0053	158	$ 0.84	$ 0.0050	158	$ 0.79	$ (0.05)	-5.66%
Sub-Total C - Delivery (including Sub-Total B)			**$ 11.42**			**$ 12.40**	**$ 0.98**	**8.54%**
Wholesale Market Service Charge (WMSC)	$ 0.0036	158	$ 0.57	$ 0.0036	158	$ 0.57	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	$ 0.0003	158	$ 0.05	$ 0.0003	158	$ 0.05	$ -	0.00%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
Ontario Electricity Support Program (OESP)								
TOU - Off Peak	$ 0.0650	98	$ 6.34	$ 0.0650	98	$ 6.34	$ -	0.00%
TOU - Mid Peak	$ 0.0940	26	$ 2.40	$ 0.0940	26	$ 2.40	$ -	0.00%
TOU - On Peak	$ 0.1320	27	$ 3.56	$ 0.1320	27	$ 3.56	$ -	0.00%
Total Bill on TOU (before Taxes)			**$ 24.59**			**$ 25.57**	**$ 0.98**	**3.97%**
HST	13%		$ 3.20	13%		$ 3.32	$ 0.13	3.97%
8% Rebate	8%		$ -	8%		$ -	$ -	
Total Bill on TOU			**$ 27.79**			**$ 28.89**	**$ 1.10**	**3.97%**

Customer Class:	SENTINEL LIGHTING SERVICE CLASSIFICATION
RPP / Non-RPP:	RPP
Consumption	650 kWh
Demand	1 kW
Current Loss Factor	1.0560
Proposed/Approved Loss Factor	1.0560

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 9.47	1	$ 9.47	$ 9.58	1	$ 9.58	$ 0.11	1.16%
Distribution Volumetric Rate	$ 35.9050	1	$ 35.91	$ 36.3359	1	$ 36.34	$ 0.43	1.20%
RRRP Credit			$ -		1	$ -		
DRP Adjustment		1	$ -		1	$ -	$ -	
Fixed Rate Riders	$ -	1	$ -	$ 1.68	1	$ 1.68	$ 1.68	
Volumetric Rate Riders	$ -	1	$ -	$ 6.3607	1	$ 6.36	$ 6.36	
Sub-Total A (excluding pass through)			**$ 45.38**			**$ 53.95**	**$ 8.58**	**18.91%**
Line Losses on Cost of Power	$ 0.0820	36	$ 2.98	$ 0.0820	36	$ 2.98	$ -	0.00%
Total Deferral/Variance Account Rate Riders	-$ 0.4711	1	-$ 0.47	-$ 1.9425	1	-$ 1.94	$ (1.47)	312.33%
CBR Class B Rate Riders	-$ 0.0298	1	-$ 0.03	$ -	1	$ -	$ 0.03	-100.00%
GA Rate Riders	$ -	650	$ -	$ -	650	$ -	$ -	
Low Voltage Service Charge	$ 0.7547	1	$ 0.75	$ 0.7547	1	$ 0.75	$ -	0.00%
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders		1	$ -	$ -	1	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 48.61**			**$ 55.75**	**$ 7.14**	**14.68%**
RTSR - Network	$ 1.8704	1	$ 1.87	$ 1.7742	1	$ 1.77	$ (0.10)	-5.14%
RTSR - Connection and/or Line and Transformation Connection	$ 1.5942	1	$ 1.59	$ 1.5069	1	$ 1.51	$ (0.09)	-5.48%
Sub-Total C - Delivery (including Sub-Total B)			**$ 52.08**			**$ 59.03**	**$ 6.95**	**13.35%**
Wholesale Market Service Charge (WMSC)	$ 0.0036	686	$ 2.47	$ 0.0036	686	$ 2.47	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	$ 0.0003	686	$ 0.21	$ 0.0003	686	$ 0.21	$ -	0.00%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
Ontario Electricity Support Program (OESP)								
TOU - Off Peak	$ 0.0650	423	$ 27.46	$ 0.0650	423	$ 27.46	$ -	0.00%
TOU - Mid Peak	$ 0.0940	111	$ 10.39	$ 0.0940	111	$ 10.39	$ -	0.00%
TOU - On Peak	$ 0.1320	117	$ 15.44	$ 0.1320	117	$ 15.44	$ -	0.00%
Total Bill on TOU (before Taxes)			**$ 108.30**			**$ 115.25**	**$ 6.95**	**6.42%**
HST	13%		$ 14.08	13%		$ 14.98	$ 0.90	6.42%
8% Rebate	8%		$ -	8%		$ -	$ -	
Total Bill on TOU			**$ 122.38**			**$ 130.24**	**$ 7.86**	**6.42%**

Customer Class:	**STREET LIGHTING SERVICE CLASSIFICATION**
RPP / Non-RPP:	**Non-RPP (Other)**
Consumption	**94,033 kWh**
Demand	**251 kW**
Current Loss Factor	**1.0560**
Proposed/Approved Loss Factor	**1.0560**

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	$ **2.30**	1	$ 2.30	$ **2.33**	1	$ 2.33	$ 0.03	1.30%
Distribution Volumetric Rate	$ **1.5523**	251	$ 389.63	$ **1.5709**	251	$ 394.30	$ 4.67	1.20%
RRRP Credit			$ -		251	$ -		
DRP Adjustment		251	$ -		251	$ -	$ -	
Fixed Rate Riders	$ **-**	1	$ -	$ **0.41**	1	$ 0.41	$ 0.41	
Volumetric Rate Riders	$ **-**	251	$ -	$ **0.2750**	251	$ 69.02	$ 69.02	
Sub-Total A (excluding pass through)			**$ 391.93**			**$ 466.06**	**$ 74.13**	**18.91%**
Line Losses on Cost of Power	$ **-**	-	$ -	$ **-**	-	$ -	$ -	
Total Deferral/Variance Account Rate Riders	-$ **0.9785**	251	-$ 245.60	-$ **1.8794**	251	-$ 471.73	$ (226.13)	92.07%
CBR Class B Rate Riders	-$ **0.0285**	251	-$ 7.15	$ **-**	251	$ -	$ 7.15	-100.00%
GA Rate Riders	-$ **0.0010**	94,033	-$ 94.03	$ **0.0137**	94,033	$ 1,288.26	$ 1,382.29	-1470.00%
Low Voltage Service Charge	$ **0.7393**	251	$ 185.56	$ **0.7393**	251	$ 185.56	$ -	0.00%
Smart Meter Entity Charge (if applicable)	$ **-**	1	$ -	$ **-**	1	$ -	$ -	
Additional Fixed Rate Riders	$ **-**	1	$ -	$ **-**	1	$ -	$ -	
Additional Volumetric Rate Riders		251	$ -	$ **-**	251	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 230.70**			**$ 1,468.15**	**$ 1,237.45**	**536.39%**
RTSR - Network	$ **1.8617**	251	$ 467.29	$ **1.7660**	251	$ 443.27	$ (24.02)	-5.14%
RTSR - Connection and/or Line and Transformation Connection	$ **1.5617**	251	$ 391.99	$ **1.4761**	251	$ 370.50	$ (21.49)	-5.48%
Sub-Total C - Delivery (including Sub-Total B)			**$ 1,089.97**			**$ 2,281.92**	**$ 1,191.94**	**109.35%**
Wholesale Market Service Charge (WMSC)	$ **0.0036**	99,299	$ 357.48	$ **0.0036**	99,299	$ 357.48	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	$ **0.0003**	99,299	$ 29.79	$ **0.0003**	99,299	$ 29.79	$ -	0.00%
Standard Supply Service Charge	$ **0.25**	1	$ 0.25	$ **0.25**	1	$ 0.25	$ -	0.00%
Ontario Electricity Support Program (OESP)								
Average IESO Wholesale Market Price	$ **0.1101**	99,299	$ 10,932.85	$ **0.1101**	99,299	$ 10,932.85	$ -	0.00%
Total Bill on Average IESO Wholesale Market Price			**$ 12,410.34**			**$ 13,602.28**	**$ 1,191.94**	**9.60%**
HST	13%		$ 1,613.34	13%		$ 1,768.30	$ 154.95	9.60%
8% Rebate	8%		$ -	8%		$ -		
Total Bill on Average IESO Wholesale Market Price			**$ 14,023.68**			**$ 15,370.58**	**$ 1,346.89**	**9.60%**

Customer Class:	**RESIDENTIAL SERVICE CLASSIFICATION**	
RPP / Non-RPP:	**RPP**	
Consumption	**342**	**kWh**
Demand	**-**	**kW**
Current Loss Factor	**1.0560**	
Proposed/Approved Loss Factor	**1.0560**	

	Current OEB-Approved			**Proposed**			**Impact**	
	Rate ($)	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	$ 23.48	1	$ 23.48	$ 26.72	1	$ 26.72	$ 3.24	13.80%
Distribution Volumetric Rate	$ 0.0034	342	$ 1.16	$ -	342	$ -	$ (1.16)	-100.00%
RRRP Credit		342	$ -		342	$ -		
DRP Adjustment		342	$ -		342	$ -	$ -	
Fixed Rate Riders	$ -	1	$ -	$ 4.64	1	$ 4.64	$ 4.64	
Volumetric Rate Riders	$ -	342	$ -	$ -	342	$ -	$ -	
Sub-Total A (excluding pass through)			**$ 24.64**			**$ 31.36**	**$ 6.72**	**27.26%**
Line Losses on Cost of Power	$ 0.0820	19	$ 1.57	$ 0.0820	19	$ 1.57	$ -	0.00%
Total Deferral/Variance Account Rate Riders	-$ 0.0014	342	-$ 0.48	-$ 0.0053	342	-$ 1.81	$ (1.33)	278.57%
CBR Class B Rate Riders	-$ 0.0001	342	-$ 0.03	$ -	342	$ -	$ 0.03	-100.00%
GA Rate Riders	$ -	342	$ -	$ -	342	$ -	$ -	
Low Voltage Service Charge	$ 0.0026	342	$ 0.89	$ 0.0026	342	$ 0.89	$ -	0.00%
Smart Meter Entity Charge (if applicable)	$ 0.57	1	$ 0.57	$ 0.57	1	$ 0.57	$ -	0.00%
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders		342	$ -	$ -	342	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 27.16**			**$ 32.58**	**$ 5.42**	**19.95%**
RTSR - Network	$ 0.0068	361	$ 2.46	$ 0.0065	361	$ 2.35	$ (0.11)	-4.41%
RTSR - Connection and/or Line and Transformation Connection	$ 0.0056	361	$ 2.02	$ 0.0053	361	$ 1.91	$ (0.11)	-5.36%
Sub-Total C - Delivery (including Sub-Total B)			**$ 31.64**			**$ 36.84**	**$ 5.20**	**16.44%**
Wholesale Market Service Charge (WMSC)	$ 0.0036	361	$ 1.30	$ 0.0036	361	$ 1.30	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	$ 0.0003	361	$ 0.11	$ 0.0003	361	$ 0.11	$ -	0.00%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
Ontario Electricity Support Program (OESP)								
TOU - Off Peak	$ 0.0650	222	$ 14.45	$ 0.0650	222	$ 14.45	$ -	0.00%
TOU - Mid Peak	$ 0.0940	58	$ 5.47	$ 0.0940	58	$ 5.47	$ -	0.00%
TOU - On Peak	$ 0.1320	62	$ 8.13	$ 0.1320	62	$ 8.13	$ -	0.00%
Total Bill on TOU (before Taxes)			**$ 61.34**			**$ 66.54**	**$ 5.20**	**8.48%**
HST	13%		$ 7.97	13%		$ 8.65	$ 0.68	8.48%
8% Rebate	8%		$ (4.91)	8%		$ (5.32)	$ (0.42)	
Total Bill on TOU			**$ 64.40**			**$ 69.87**	**$ 5.46**	**8.48%**

Customer Class:	RESIDENTIAL SERVICE CLASSIFICATION
RPP / Non-RPP:	RPP
Consumption	1,000 kWh
Demand	- kW
Current Loss Factor	1.0560
Proposed/Approved Loss Factor	1.0560

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 23.48	1	$ 23.48	$ 26.72	1	$ 26.72	$ 3.24	13.80%
Distribution Volumetric Rate	$ 0.0034	1000	$ 3.40	$ -	1000	$ -	$ (3.40)	-100.00%
RRRP Credit		1000	$ -		1000	$ -		
DRP Adjustment		1000	$ -		1000	$ -	$ -	
Fixed Rate Riders	$ -	1	$ -	$ 4.64	1	$ 4.64	$ 4.64	
Volumetric Rate Riders	$ -	1000	$ -	$ -	1000	$ -	$ -	
Sub-Total A (excluding pass through)			**$ 26.88**			**$ 31.36**	**$ 4.48**	**16.67%**
Line Losses on Cost of Power	$ 0.0820	56	$ 4.59	$ 0.0820	56	$ 4.59	$ -	0.00%
Total Deferral/Variance Account Rate Riders	-$ 0.0014	1,000	-$ 1.40	-$ 0.0053	1,000	-$ 5.30	$ (3.90)	278.57%
CBR Class B Rate Riders	-$ 0.0001	1,000	-$ 0.10	$ -	1,000	$ -	$ 0.10	-100.00%
GA Rate Riders	$ -	1,000	$ -	$ -	1,000	$ -	$ -	
Low Voltage Service Charge	$ 0.0026	1,000	$ 2.60	$ 0.0026	1,000	$ 2.60	$ -	0.00%
Smart Meter Entity Charge (if applicable)	$ 0.57	1	$ 0.57	$ 0.57	1	$ 0.57	$ -	0.00%
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders		1,000	$ -	$ -	1,000	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 33.14**			**$ 33.82**	**$ 0.68**	**2.05%**
RTSR - Network	$ 0.0068	1,056	$ 7.18	$ 0.0065	1,056	$ 6.86	$ (0.32)	-4.41%
RTSR - Connection and/or Line and Transformation Connection	$ 0.0056	1,056	$ 5.91	$ 0.0053	1,056	$ 5.60	$ (0.32)	-5.36%
Sub-Total C - Delivery (including Sub-Total B)			**$ 46.24**			**$ 46.28**	**$ 0.05**	**0.10%**
Wholesale Market Service Charge (WMSC)	$ 0.0036	1,056	$ 3.80	$ 0.0036	1,056	$ 3.80	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	$ 0.0003	1,056	$ 0.32	$ 0.0003	1,056	$ 0.32	$ -	0.00%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
Ontario Electricity Support Program (OESP)								
TOU - Off Peak	$ 0.0650	650	$ 42.25	$ 0.0650	650	$ 42.25	$ -	0.00%
TOU - Mid Peak	$ 0.0940	170	$ 15.98	$ 0.0940	170	$ 15.98	$ -	0.00%
TOU - On Peak	$ 0.1320	180	$ 23.76	$ 0.1320	180	$ 23.76	$ -	0.00%
Total Bill on TOU (before Taxes)			**$ 132.59**			**$ 132.64**	**$ 0.05**	**0.04%**
HST	13%		$ 17.24	13%		$ 17.24	$ 0.01	0.04%
8% Rebate	8%		$ (10.61)	8%		$ (10.61)	$ (0.00)	
Total Bill on TOU			**$ 139.22**			**$ 139.27**	**$ 0.05**	**0.04%**

Customer Class:	RESIDENTIAL SERVICE CLASSIFICATION	
RPP / Non-RPP:	RPP	
Consumption	2,500	kWh
Demand	-	kW
Current Loss Factor	1.0560	
Proposed/Approved Loss Factor	1.0560	

	Current OEB-Approved			**Proposed**			**Impact**	
	Rate ($)	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	$ 23.48	1	$ 23.48	$ 26.72	1	$ 26.72	$ 3.24	13.80%
Distribution Volumetric Rate	$ 0.0034	2500	$ 8.50	$ -	2500	$ -	$ (8.50)	-100.00%
RRRP Credit		2500	$ -		2500	$ -		
DRP Adjustment		2500	$ -		2500	$ -	$ -	
Fixed Rate Riders	$ -	1	$ -	$ 4.64	1	$ 4.64	$ 4.64	
Volumetric Rate Riders	$ -	2500	$ -	$ -	2500	$ -	$ -	
Sub-Total A (excluding pass through)			**$ 31.98**			**$ 31.36**	**$ (0.62)**	**-1.94%**
Line Losses on Cost of Power	$ 0.0820	140	$ 11.48	$ 0.0820	140	$ 11.48	$ -	0.00%
Total Deferral/Variance Account Rate Riders	-$ 0.0014	2,500	-$ 3.50	-$ 0.0053	2,500	-$ 13.25	$ (9.75)	278.57%
CBR Class B Rate Riders	-$ 0.0001	2,500	-$ 0.25	$ -	2,500	$ -	$ 0.25	-100.00%
GA Rate Riders	$ -	2,500	$ -	$ -	2,500	$ -	$ -	
Low Voltage Service Charge	$ 0.0026	2,500	$ 6.50	$ 0.0026	2,500	$ 6.50	$ -	0.00%
Smart Meter Entity Charge (if applicable)	$ 0.57	1	$ 0.57	$ 0.57	1	$ 0.57	$ -	0.00%
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders		2,500	$ -	$ -	2,500	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 46.78**			**$ 36.66**	**$ (10.12)**	**-21.63%**
RTSR - Network	$ 0.0068	2,640	$ 17.95	$ 0.0065	2,640	$ 17.16	$ (0.79)	-4.41%
RTSR - Connection and/or Line and Transformation Connection	$ 0.0056	2,640	$ 14.78	$ 0.0053	2,640	$ 13.99	$ (0.79)	-5.36%
Sub-Total C - Delivery (including Sub-Total B)			**$ 79.51**			**$ 67.81**	**$ (11.70)**	**-14.72%**
Wholesale Market Service Charge (WMSC)	$ 0.0036	2,640	$ 9.50	$ 0.0036	2,640	$ 9.50	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	$ 0.0003	2,640	$ 0.79	$ 0.0003	2,640	$ 0.79	$ -	0.00%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
Ontario Electricity Support Program (OESP)								
TOU - Off Peak	$ 0.0650	1,625	$ 105.63	$ 0.0650	1,625	$ 105.63	$ -	0.00%
TOU - Mid Peak	$ 0.0940	425	$ 39.95	$ 0.0940	425	$ 39.95	$ -	0.00%
TOU - On Peak	$ 0.1320	450	$ 59.40	$ 0.1320	450	$ 59.40	$ -	0.00%
Total Bill on TOU (before Taxes)			**$ 295.04**			**$ 283.33**	**$ (11.70)**	**-3.97%**
HST	13%		$ 38.35	13%		$ 36.83	$ (1.52)	-3.97%
8% Rebate	8%		$ (23.60)	8%		$ (22.67)	$ 0.94	
Total Bill on TOU			**$ 309.79**			**$ 297.50**	**$ (12.29)**	**-3.97%**

Customer Class:	GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	
RPP / Non-RPP:	RPP	
Consumption	500	kWh
Demand	-	kW
Current Loss Factor	1.0560	
Proposed/Approved Loss Factor	1.0560	

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 28.37	1	$ 28.37	$ 28.71	1	$ 28.71	$ 0.34	1.20%
Distribution Volumetric Rate	$ 0.0102	500	$ 5.10	$ 0.0103	500	$ 5.15	$ 0.05	0.98%
RRRP Credit		500	$ -		500	$ -		
DRP Adjustment		500	$ -		500	$ -	$ -	
Fixed Rate Riders	$ -	1	$ -	$ 5.03	1	$ 5.03	$ 5.03	
Volumetric Rate Riders	$ -	500	$ -	$ 0.0018	500	$ 0.90	$ 0.90	
Sub-Total A (excluding pass through)			**$ 33.47**			**$ 39.79**	**$ 6.32**	**18.88%**
Line Losses on Cost of Power	$ 0.0820	28	$ 2.30	$ 0.0820	28	$ 2.30	$ -	0.00%
Total Deferral/Variance Account Rate Riders	-$ 0.0014	500	-$ 0.70	-$ 0.0053	500	-$ 2.65	$ (1.95)	278.57%
CBR Class B Rate Riders	-$ 0.0001	500	-$ 0.05	$ -	500	$ -	$ 0.05	-100.00%
GA Rate Riders	$ -	500	$ -	$ -	500	$ -	$ -	
Low Voltage Service Charge	$ 0.0024	500	$ 1.20	$ 0.0024	500	$ 1.20	$ -	0.00%
Smart Meter Entity Charge (if applicable)	$ 0.57	1	$ 0.57	$ 0.57	1	$ 0.57	$ -	0.00%
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders		500	$ -	$ -	500	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 36.79**			**$ 41.21**	**$ 4.42**	**12.01%**
RTSR - Network	$ 0.0060	528	$ 3.17	$ 0.0057	528	$ 3.01	$ (0.16)	-5.00%
RTSR - Connection and/or Line and Transformation Connection	$ 0.0053	528	$ 2.80	$ 0.0050	528	$ 2.64	$ (0.16)	-5.66%
Sub-Total C - Delivery (including Sub-Total B)			**$ 42.75**			**$ 46.85**	**$ 4.10**	**9.60%**
Wholesale Market Service Charge (WMSC)	$ 0.0036	528	$ 1.90	$ 0.0036	528	$ 1.90	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	$ 0.0003	528	$ 0.16	$ 0.0003	528	$ 0.16	$ -	0.00%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
Ontario Electricity Support Program (OESP)								
TOU - Off Peak	$ 0.0650	325	$ 21.13	$ 0.0650	325	$ 21.13	$ -	0.00%
TOU - Mid Peak	$ 0.0940	85	$ 7.99	$ 0.0940	85	$ 7.99	$ -	0.00%
TOU - On Peak	$ 0.1320	90	$ 11.88	$ 0.1320	90	$ 11.88	$ -	0.00%
Total Bill on TOU (before Taxes)			**$ 86.06**			**$ 90.16**	**$ 4.10**	**4.77%**
HST	13%		$ 11.19	13%		$ 11.72	$ 0.53	4.77%
8% Rebate	8%		$ (6.88)	8%		$ (7.21)	$ (0.33)	
Total Bill on TOU			**$ 90.36**			**$ 94.67**	**$ 4.31**	**4.77%**

Customer Class:	GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION
RPP / Non-RPP:	RPP
Consumption	5,000 kWh
Demand	- kW
Current Loss Factor	1.0560
Proposed/Approved Loss Factor	1.0560

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 28.37	1	$ 28.37	$ 28.71	1	$ 28.71	$ 0.34	1.20%
Distribution Volumetric Rate	$ 0.0102	5000	$ 51.00	$ 0.0103	5000	$ 51.50	$ 0.50	0.98%
RRRP Credit		5000	$ -		5000	$ -		
DRP Adjustment		5000	$ -		5000	$ -	$ -	
Fixed Rate Riders	$ -	1	$ -	$ 5.03	1	$ 5.03	$ 5.03	
Volumetric Rate Riders	$ -	5000	$ -	$ 0.0018	5000	$ 9.03	$ 9.03	
Sub-Total A (excluding pass through)			**$ 79.37**			**$ 94.27**	**$ 14.90**	**18.77%**
Line Losses on Cost of Power	$ 0.0820	280	$ 22.96	$ 0.0820	280	$ 22.96	$ -	0.00%
Total Deferral/Variance Account Rate Riders	-$ 0.0014	5,000	-$ 7.00	-$ 0.0053	5,000	-$ 26.50	$ (19.50)	278.57%
CBR Class B Rate Riders	-$ 0.0001	5,000	-$ 0.50	$ -	5,000	$ -	$ 0.50	-100.00%
GA Rate Riders	$ -	5,000	$ -	$ -	5,000	$ -	$ -	
Low Voltage Service Charge	$ 0.0024	5,000	$ 12.00	$ 0.0024	5,000	$ 12.00	$ -	0.00%
Smart Meter Entity Charge (if applicable)	$ 0.57	1	$ 0.57	$ 0.57	1	$ 0.57	$ -	0.00%
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders		5,000	$ -	$ -	5,000	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 107.40**			**$ 103.30**	**$ (4.10)**	**-3.82%**
RTSR - Network	$ 0.0060	5,280	$ 31.68	$ 0.0057	5,280	$ 30.10	$ (1.58)	-5.00%
RTSR - Connection and/or Line and Transformation Connection	$ 0.0053	5,280	$ 27.98	$ 0.0050	5,280	$ 26.40	$ (1.58)	-5.66%
Sub-Total C - Delivery (including Sub-Total B)			**$ 167.06**			**$ 159.79**	**$ (7.27)**	**-4.35%**
Wholesale Market Service Charge (WMSC)	$ 0.0036	5,280	$ 19.01	$ 0.0036	5,280	$ 19.01	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	$ 0.0003	5,280	$ 1.58	$ 0.0003	5,280	$ 1.58	$ -	0.00%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
Ontario Electricity Support Program (OESP)								
TOU - Off Peak	$ 0.0650	3,250	$ 211.25	$ 0.0650	3,250	$ 211.25	$ -	0.00%
TOU - Mid Peak	$ 0.0940	850	$ 79.90	$ 0.0940	850	$ 79.90	$ -	0.00%
TOU - On Peak	$ 0.1320	900	$ 118.80	$ 0.1320	900	$ 118.80	$ -	0.00%
Total Bill on TOU (before Taxes)			**$ 597.85**			**$ 590.59**	**$ (7.27)**	**-1.22%**
HST	13%		$ 77.72	13%		$ 76.78	$ (0.94)	-1.22%
8% Rebate	8%		$ (47.83)	8%		$ (47.25)	$ 0.58	
Total Bill on TOU			**$ 627.75**			**$ 620.12**	**$ (7.63)**	**-1.22%**

Customer Class:	GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION
RPP / Non-RPP:	RPP
Consumption	15,000 kWh
Demand	- kW
Current Loss Factor	1.0560
Proposed/Approved Loss Factor	1.0560

	Current OEB-Approved			**Proposed**			**Impact**	
	Rate ($)	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	$ 28.37	1	$ 28.37	$ 28.71	1	$ 28.71	$ 0.34	1.20%
Distribution Volumetric Rate	$ 0.0102	15000	$ 153.00	$ 0.0103	15000	$ 154.50	$ 1.50	0.98%
RRRP Credit		15000	$ -		15000	$ -		
DRP Adjustment		15000	$ -		15000	$ -	$ -	
Fixed Rate Riders	$ -	1	$ -	$ 5.03	1	$ 5.03	$ 5.03	
Volumetric Rate Riders	$ -	15000	$ -	$ 0.0018	15000	$ 27.10	$ 27.10	
Sub-Total A (excluding pass through)			**$ 181.37**			**$ 215.34**	**$ 33.97**	**18.73%**
Line Losses on Cost of Power	$ -	-	$ -	$ -	-	$ -	$ -	
Total Deferral/Variance Account Rate Riders	-$ 0.0014	15,000	-$ 21.00	-$ 0.0053	15,000	-$ 79.50	$ (58.50)	278.57%
CBR Class B Rate Riders	-$ 0.0001	15,000	-$ 1.50	$ -	15,000	$ -	$ 1.50	-100.00%
GA Rate Riders	$ -	15,000	$ -	$ -	15,000	$ -	$ -	
Low Voltage Service Charge	$ 0.0024	15,000	$ 36.00	$ 0.0024	15,000	$ 36.00	$ -	0.00%
Smart Meter Entity Charge (if applicable)	$ 0.57	1	$ 0.57	$ 0.57	1	$ 0.57	$ -	0.00%
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders		15,000	$ -	$ -	15,000	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 195.44**			**$ 172.41**	**$ (23.03)**	**-11.78%**
RTSR - Network	$ 0.0060	15,840	$ 95.04	$ 0.0057	15,840	$ 90.29	$ (4.75)	-5.00%
RTSR - Connection and/or Line and Transformation Connection	$ 0.0053	15,840	$ 83.95	$ 0.0050	15,840	$ 79.20	$ (4.75)	-5.66%
Sub-Total C - Delivery (including Sub-Total B)			**$ 374.43**			**$ 341.90**	**$ (32.53)**	**-8.69%**
Wholesale Market Service Charge (WMSC)	$ 0.0036	15,840	$ 57.02	$ 0.0036	15,840	$ 57.02	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	$ 0.0003	15,840	$ 4.75	$ 0.0003	15,840	$ 4.75	$ -	0.00%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
Ontario Electricity Support Program (OESP)								
TOU - Off Peak	$ 0.0650	10,296	$ 669.24	$ 0.0650	10,296	$ 669.24	$ -	0.00%
TOU - Mid Peak	$ 0.0940	2,693	$ 253.12	$ 0.0940	2,693	$ 253.12	$ -	0.00%
TOU - On Peak	$ 0.1320	2,851	$ 376.36	$ 0.1320	2,851	$ 376.36	$ -	0.00%
Total Bill on TOU (before Taxes)			**$ 1,735.18**			**$ 1,702.65**	**$ (32.53)**	**-1.87%**
HST	13%		$ 225.57	13%		$ 221.34	$ (4.23)	-1.87%
8% Rebate	8%		$ (138.81)	8%		$ (136.21)	$ 2.60	
Total Bill on TOU			**$ 1,821.94**			**$ 1,787.78**	**$ (34.16)**	**-1.87%**

Customer Class:	**GENERAL SERVICE 50 TO 999 KW SERVICE CLASSIFICATION**
RPP / Non-RPP:	**Non-RPP (Other)**
Consumption	**20,000 kWh**
Demand	**60 kW**
Current Loss Factor	**1.0560**
Proposed/Approved Loss Factor	**1.0560**

	Current OEB-Approved			**Proposed**			**Impact**	
	Rate ($)	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	$ 86.83	1	$ 86.83	$ 87.87	1	$ 87.87	$ 1.04	1.20%
Distribution Volumetric Rate	$ 3.8580	60	$ 231.48	$ 3.9043	60	$ 234.26	$ 2.78	1.20%
RRRP Credit		60	$ -		60	$ -		
DRP Adjustment		60	$ -		60	$ -	$ -	
Fixed Rate Riders	$ -	1	$ -	$ 15.38	1	$ 15.38	$ 15.38	
Volumetric Rate Riders	$ -	60	$ -	$ 0.6835	60	$ 41.01	$ 41.01	
Sub-Total A (excluding pass through)			**$ 318.31**			**$ 378.52**	**$ 60.21**	**18.91%**
Line Losses on Cost of Power	$ -	-	$ -	$ -	-	$ -	$ -	
Total Deferral/Variance Account Rate Riders	-$ 0.7065	60	-$ 42.39	-$ 1.7801	60	-$ 106.81	$ (64.42)	151.96%
CBR Class B Rate Riders	-$ 0.0276	60	-$ 1.66	$ -	60	$ -	$ 1.66	-100.00%
GA Rate Riders	-$ 0.0010	20,000	-$ 20.00	$ 0.0137	20,000	$ 274.00	$ 294.00	-1470.00%
Low Voltage Service Charge	$ 1.0483	60	$ 62.90	$ 1.0483	60	$ 62.90	$ -	0.00%
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders		60	$ -	$ -	60	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 317.16**			**$ 608.61**	**$ 291.45**	**91.89%**
RTSR - Network	$ 2.6217	60	$ 157.30	$ 2.4869	60	$ 149.21	$ (8.09)	-5.14%
RTSR - Connection and/or Line and Transformation Connection	$ 2.2146	60	$ 132.88	$ 2.0933	60	$ 125.60	$ (7.28)	-5.48%
Sub-Total C - Delivery (including Sub-Total B)			**$ 607.34**			**$ 883.42**	**$ 276.08**	**45.46%**
Wholesale Market Service Charge (WMSC)	$ 0.0036	21,120	$ 76.03	$ 0.0036	21,120	$ 76.03	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	$ 0.0003	21,120	$ 6.34	$ 0.0003	21,120	$ 6.34	$ -	0.00%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
Ontario Electricity Support Program (OESP)								
Average IESO Wholesale Market Price	$ 0.1101	21,120	$ 2,325.31	$ 0.1101	21,120	$ 2,325.31	$ -	0.00%
Total Bill on Average IESO Wholesale Market Price			**$ 3,015.27**			**$ 3,291.35**	**$ 276.08**	**9.16%**
HST	13%		$ 391.99	13%		$ 427.88	$ 35.89	9.16%
8% Rebate	8%		$ -	8%		$ -		
Total Bill on Average IESO Wholesale Market Price			**$ 3,407.26**			**$ 3,719.23**	**$ 311.97**	**9.16%**

Customer Class:	GENERAL SERVICE 50 TO 999 KW SERVICE CLASSIFICATION
RPP / Non-RPP:	Non-RPP (Other)
Consumption	500,000 kWh
Demand	750 kW
Current Loss Factor	1.0560
Proposed/Approved Loss Factor	1.0560

	Current OEB-Approved			**Proposed**			**Impact**	
	Rate ($)	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	$ 86.83	1	$ 86.83	$ 87.87	1	$ 87.87	$ 1.04	1.20%
Distribution Volumetric Rate	$ 3.8580	750	$ 2,893.50	$ 3.9043	750	$ 2,928.23	$ 34.72	1.20%
RRRP Credit		750	$ -		750	$ -		
DRP Adjustment		750	$ -		750	$ -	$ -	
Fixed Rate Riders	$ -	1	$ -	$ 15.38	1	$ 15.38	$ 15.38	
Volumetric Rate Riders	$ -	750	$ -	$ 0.6835	750	$ 512.59	$ 512.59	
Sub-Total A (excluding pass through)			**$ 2,980.33**			**$ 3,544.07**	**$ 563.74**	**18.92%**
Line Losses on Cost of Power	$ -	-	$ -	$ -	-	$ -	$ -	
Total Deferral/Variance Account Rate Riders	-$ 0.7065	750	-$ 529.88	-$ 1.7801	750	-$ 1,335.08	$ (805.20)	151.96%
CBR Class B Rate Riders	-$ 0.0276	750	-$ 20.70	$ -	750	$ -	$ 20.70	-100.00%
GA Rate Riders	-$ 0.0010	500,000	-$ 500.00	$ 0.0137	500,000	$ 6,850.00	$ 7,350.00	-1470.00%
Low Voltage Service Charge	$ 1.0483	750	$ 786.23	$ 1.0483	750	$ 786.23	$ -	0.00%
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders		750	$ -	$ -	750	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 2,715.98**			**$ 9,845.22**	**$ 7,129.24**	**262.49%**
RTSR - Network	$ 2.6217	750	$ 1,966.28	$ 2.4869	750	$ 1,865.18	$ (101.10)	-5.14%
RTSR - Connection and/or Line and Transformation Connection	$ 2.2146	750	$ 1,660.95	$ 2.0933	750	$ 1,569.98	$ (90.97)	-5.48%
Sub-Total C - Delivery (including Sub-Total B)			**$ 6,343.21**			**$ 13,280.37**	**$ 6,937.16**	**109.36%**
Wholesale Market Service Charge (WMSC)	$ 0.0036	528,000	$ 1,900.80	$ 0.0036	528,000	$ 1,900.80	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	$ 0.0003	528,000	$ 158.40	$ 0.0003	528,000	$ 158.40	$ -	0.00%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
Ontario Electricity Support Program (OESP)								
Average IESO Wholesale Market Price	$ 0.1101	528,000	$ 58,132.80	$ 0.1101	528,000	$ 58,132.80	$ -	0.00%
Total Bill on Average IESO Wholesale Market Price			**$ 66,535.46**			**$ 73,472.62**	**$ 6,937.16**	**10.43%**
HST	13%		$ 8,649.61	13%		$ 9,551.44	$ 901.83	10.43%
8% Rebate	8%		$ -	8%		$ -		
Total Bill on Average IESO Wholesale Market Price			**$ 75,185.06**			**$ 83,024.06**	**$ 7,838.99**	**10.43%**

Customer Class:	GENERAL SERVICE 1,000 TO 4,999 KW SERVICE CLASSIFICATION
RPP / Non-RPP:	Non-RPP (Other)
Consumption	1,000,000 kWh
Demand	2,000 kW
Current Loss Factor	1.0560
Proposed/Approved Loss Factor	1.0560

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 185.55	1	$ 185.55	$ 187.78	1	$ 187.78	$ 2.23	1.20%
Distribution Volumetric Rate	$ 3.4705	2000	$ 6,941.00	$ 3.5121	2000	$ 7,024.20	$ 83.20	1.20%
RRRP Credit		2000	$ -		2000	$ -		
DRP Adjustment		2000	$ -		2000	$ -	$ -	
Fixed Rate Riders	$ -	1	$ -	$ 32.87	1	$ 32.87	$ 32.87	
Volumetric Rate Riders	$ -	2000	$ -	$ 0.6148	2000	$ 1,229.62	$ 1,229.62	
Sub-Total A (excluding pass through)			**$ 7,126.55**			**$ 8,474.47**	**$ 1,347.92**	**18.91%**
Line Losses on Cost of Power	$ -	-	$ -	$ -	-	$ -	$ -	
Total Deferral/Variance Account Rate Riders	-$ 0.9398	2,000	-$ 1,879.60	-$ 1.9908	2,000	-$ 3,981.60	$ (2,102.00)	111.83%
CBR Class B Rate Riders	-$ 0.0341	2,000	-$ 68.20	$ -	2,000	$ -	$ 68.20	-100.00%
GA Rate Riders	-$ 0.0010	1,000,000	-$ 1,000.00	$ 0.0137	1,000,000	$ 13,700.00	$ 14,700.00	-1470.00%
Low Voltage Service Charge	$ 1.0483	2,000	$ 2,096.60	$ 1.0483	2,000	$ 2,096.60	$ -	0.00%
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders		2,000	$ -	$ -	2,000	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 6,275.35**			**$ 20,289.47**	**$ 14,014.12**	**223.32%**
RTSR - Network	$ 2.6217	2,000	$ 5,243.40	$ 2.4869	2,000	$ 4,973.80	$ (269.60)	-5.14%
RTSR - Connection and/or Line and Transformation Connection	$ 2.2146	2,000	$ 4,429.20	$ 2.0933	2,000	$ 4,186.60	$ (242.60)	-5.48%
Sub-Total C - Delivery (including Sub-Total B)			**$ 15,947.95**			**$ 29,449.87**	**$ 13,501.92**	**84.66%**
Wholesale Market Service Charge (WMSC)	$ 0.0036	1,056,000	$ 3,801.60	$ 0.0036	1,056,000	$ 3,801.60	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	$ 0.0003	1,056,000	$ 316.80	$ 0.0003	1,056,000	$ 316.80	$ -	0.00%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
Ontario Electricity Support Program (OESP)								
Average IESO Wholesale Market Price	$ 0.1101	1,056,000	$ 116,265.60	$ 0.1101	1,056,000	$ 116,265.60	$ -	0.00%
Total Bill on Average IESO Wholesale Market Price			**$ 136,332.20**			**$ 149,834.12**	**$ 13,501.92**	**9.90%**
HST	13%		$ 17,723.19	13%		$ 19,478.44	$ 1,755.25	9.90%
8% Rebate	8%		$ -	8%		$ -		
Total Bill on Average IESO Wholesale Market Price			**$ 154,055.39**			**$ 169,312.55**	**$ 15,257.16**	**9.90%**

Customer Class:	**GENERAL SERVICE 1,000 TO 4,999 KW SERVICE CLASSIFICATION**
RPP / Non-RPP:	**Non-RPP (Other)**
Consumption	**3,000,000** **kWh**
Demand	**4,000** **kW**
Current Loss Factor	**1.0560**
Proposed/Approved Loss Factor	**1.0560**

	Current OEB-Approved			**Proposed**			**Impact**	
	Rate ($)	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	$ 185.55	1	$ 185.55	$ 187.78	1	$ 187.78	$ 2.23	1.20%
Distribution Volumetric Rate	$ 3.4705	4000	$ 13,882.00	$ 3.5121	4000	$ 14,048.40	$ 166.40	1.20%
RRRP Credit		4000	$ -		4000	$ -		
DRP Adjustment		4000	$ -		4000	$ -	$ -	
Fixed Rate Riders	$ -	1	$ -	$ 32.87	1	$ 32.87	$ 32.87	
Volumetric Rate Riders	$ -	4000	$ -	$ 0.6148	4000	$ 2,459.23	$ 2,459.23	
Sub-Total A (excluding pass through)			**$ 14,067.55**			**$ 16,728.28**	**$ 2,660.73**	**18.91%**
Line Losses on Cost of Power	$ -	-	$ -	$ -	-	$ -	$ -	
Total Deferral/Variance Account Rate Riders	-$ 0.9398	4,000	-$ 3,759.20	-$ 1.9908	4,000	-$ 7,963.20	$ (4,204.00)	111.83%
CBR Class B Rate Riders	-$ 0.0341	4,000	-$ 136.40	$ -	4,000	$ -	$ 136.40	-100.00%
GA Rate Riders	-$ 0.0010	3,000,000	-$ 3,000.00	$ 0.0137	3,000,000	$ 41,100.00	$ 44,100.00	-1470.00%
Low Voltage Service Charge	$ 1.0483	4,000	$ 4,193.20	$ 1.0483	4,000	$ 4,193.20	$ -	0.00%
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders		4,000	$ -	$ -	4,000	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 11,365.15**			**$ 54,058.28**	**$ 42,693.13**	**375.65%**
RTSR - Network	$ 2.6217	4,000	$ 10,486.80	$ 2.4869	4,000	$ 9,947.60	$ (539.20)	-5.14%
RTSR - Connection and/or Line and Transformation Connection	$ 2.2146	4,000	$ 8,858.40	$ 2.0933	4,000	$ 8,373.20	$ (485.20)	-5.48%
Sub-Total C - Delivery (including Sub-Total B)			**$ 30,710.35**			**$ 72,379.08**	**$ 41,668.73**	**135.68%**
Wholesale Market Service Charge (WMSC)	$ 0.0036	3,168,000	$ 11,404.80	$ 0.0036	3,168,000	$ 11,404.80	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	$ 0.0003	3,168,000	$ 950.40	$ 0.0003	3,168,000	$ 950.40	$ -	0.00%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
Ontario Electricity Support Program (OESP)								
Average IESO Wholesale Market Price	$ 0.1101	3,168,000	$ 348,796.80	$ 0.1101	3,168,000	$ 348,796.80	$ -	0.00%
Total Bill on Average IESO Wholesale Market Price			**$ 391,862.60**			**$ 433,531.33**	**$ 41,668.73**	**10.63%**
HST	13%		$ 50,942.14	13%		$ 56,359.07	$ 5,416.94	10.63%
8% Rebate	8%		$ -	8%		$ -		
Total Bill on Average IESO Wholesale Market Price			**$ 442,804.74**			**$ 489,890.40**	**$ 47,085.67**	**10.63%**

Customer Class:	GENERAL SERVICE 50 TO 999 KW SERVICE CLASSIFICATION	
RPP / Non-RPP:	RPP	
Consumption	69,000	kWh
Demand	160	kW
Current Loss Factor	1.0560	
Proposed/Approved Loss Factor	1.0560	

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 86.83	1	$ 86.83	$ 87.87	1	$ 87.87	$ 1.04	1.20%
Distribution Volumetric Rate	$ 3.8580	160	$ 617.28	$ 3.9043	160	$ 624.69	$ 7.41	1.20%
RRRP Credit		160	$ -		160	$ -		
DRP Adjustment		160	$ -		160	$ -	$ -	
Fixed Rate Riders	$ -	1	$ -	$ 15.38	1	$ 15.38	$ 15.38	
Volumetric Rate Riders	$ -	160	$ -	$ 0.6835	160	$ 109.35	$ 109.35	
Sub-Total A (excluding pass through)			**$ 704.11**			**$ 837.29**	**$ 133.18**	**18.92%**
Line Losses on Cost of Power	$ -	-	$ -	$ -	-	$ -	$ -	
Total Deferral/Variance Account Rate Riders	-$ 0.7065	160	-$ 113.04	-$ 1.7801	160	-$ 284.82	$ (171.78)	151.96%
CBR Class B Rate Riders	-$ 0.0276	160	-$ 4.42	$ -	160	$ -	$ 4.42	-100.00%
GA Rate Riders	$ -	69,000	$ -	$ -	69,000	$ -	$ -	
Low Voltage Service Charge	$ 1.0483	160	$ 167.73	$ 1.0483	160	$ 167.73	$ -	0.00%
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders		160	$ -	$ -	160	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 754.38**			**$ 720.20**	**$ (34.18)**	**-4.53%**
RTSR - Network	$ 2.6217	160	$ 419.47	$ 2.4869	160	$ 397.90	$ (21.57)	-5.14%
RTSR - Connection and/or Line and Transformation Connection	$ 2.2146	160	$ 354.34	$ 2.0933	160	$ 334.93	$ (19.41)	-5.48%
Sub-Total C - Delivery (including Sub-Total B)			**$ 1,528.19**			**$ 1,453.04**	**$ (75.15)**	**-4.92%**
Wholesale Market Service Charge (WMSC)	$ 0.0036	72,864	$ 262.31	$ 0.0036	72,864	$ 262.31	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	$ 0.0003	72,864	$ 21.86	$ 0.0003	72,864	$ 21.86	$ -	0.00%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
Ontario Electricity Support Program (OESP)								
TOU - Off Peak	$ 0.0650	47,362	$ 3,078.50	$ 0.0650	47,362	$ 3,078.50	$ -	0.00%
TOU - Mid Peak	$ 0.0940	12,387	$ 1,164.37	$ 0.0940	12,387	$ 1,164.37	$ -	0.00%
TOU - On Peak	$ 0.1320	13,116	$ 1,731.25	$ 0.1320	13,116	$ 1,731.25	$ -	0.00%
Total Bill on TOU (before Taxes)			**$ 7,786.73**			**$ 7,711.58**	**$ (75.15)**	**-0.97%**
HST	13%		$ 1,012.27	13%		$ 1,002.50	$ (9.77)	-0.97%
8% Rebate	8%		$ -	8%		$ -	$ -	
Total Bill on TOU			**$ 8,799.00**			**$ 8,714.08**	**$ (84.92)**	**-0.97%**

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